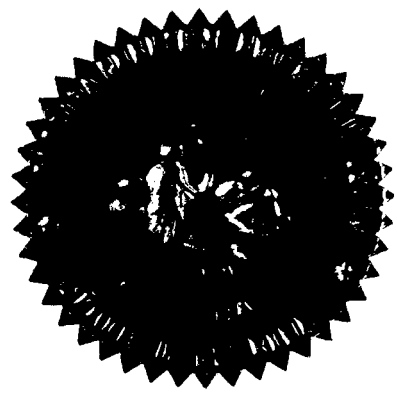
BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010142-EM

In the Matter of:

JOINT PETITION FOR DETERMINATION OF NEED FOR PROPOSED STANTON ENERGY CENTER COMBINED CYCLE UNIT A BY ORLANDO UTILITIES COMMISSION, KISSIMMEE UTILITY AUTHORITY, FLORIDA MUNICIPAL POWER AGENCY, AND SOUTHERN COMPANY-FLORIDA, LLC.



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PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN E. LEON JACOBS, JR. COMMISSIONER BRAULIO L. BAEZ COMMISSIONER MICHAEL A. PALECKI
DATE:	Monday, April 23, 2001
TIME:	Commenced at 9:35 a.m. Concluded at 10:10 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR FPSC Division of Records & Reporting Chief, Bureau of Reporting

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APPEARANCES:

ROY YOUNG, Young, van Assenderp and Varnadoe, P. A., appearing on behalf of Orlando Utilities Commission and Kissimmee Utility Authority.

THOMAS B. TART, 500 South Orange Avenue, Orlando, Florida 32802, appearing on behalf of Orlando Utilities Commission.

D. BRUCE MAY, and SUSAN COMENSKY, Holland & Knight, 315 South Calhoun Street, Suite 600, Tallahassee, Florida 32302, appearing on behalf of Southern Company-Florida LLC.

WILLIAM COCHRAN KEATING, Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

INDEX

WITNESSES

NAME:	PAGE NO.
PREFILED TESTIMONY OF THE FOLLOWING WITNESSES INSERTED IN THE RECORD:	
FREDERICK F. HADDAD	9
DOUGLAS E. JONES	22
THOMAS O. ANDERSON	29
PAUL A. ARSUAGA	39
WILLIAM HERRINGTON	52
STEPHEN L. THUMB	56
JILL SCHUEPBACH	71
ERIC FOX	80
MYRON ROLLINS	87
JOHN E. HEARN	110
ABANI KUMAR SCARMA	115
JONATHAN SCHAEFER	125
RICHARD L. CASEY	131

EXHIBITS

NUMBER:		ID.	ADMTD.
1	OUC-1 and OUC-2	144	144
2	Confidential Exhibit A	145	145
3	DEJ-1	146	146
4	Confidential Exhibit B	146	146
5	PAA-1 and PAA-2	147	147
6	PAA-3 and PAA-4	147	147
7	SLT-1, 2, and 3	147	147
8	JAS-1	147	147
9	Staff 1	148	148
10	Executed PPAs for Southern-Florida, OUC, KUA and FMPA	150	150
11	Affidavits of all Witnesses	151	151

CERTIFICATE OF REPORTER 159

PROCEEDINGS

CHAIRMAN JACOBS: Call this hearing to order. Good morning.

Counsel, read the notice.

MR. KEATING: Pursuant to notice dated February 21st, 2001, this time and place have been set for a hearing in Docket Number 010142-EM, joint petition for determination of need for proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, and Southern Company of Florida LLC.

CHAIRMAN JACOBS: Take appearances.

MR. MAY: Mr. Chairman, my name is Bruce May. I am with the law firm of Holland and Knight appearing on behalf of Southern Company-Florida LLC, a joint petitioner in this proceeding. My business address is P.O. Drawer 810, Tallahassee, Florida 32302.

MR. YOUNG: Mr. Chairman, my name is Roy Young. I am with the law firm of Young, van Assenderp, Varnadoe & Anderson here in Tallahassee, appearing today on behalf of Orlando Utilities Commission, the Kissimmee Utility Authority, and the Florida Municipal Power Agency.

MR. TART: Good morning, Mr. Chairman. Thomas Brogdon Tart. I am the general counsel for the Orlando Utilities Commission and also Vice-president of Orlando Utilities, Orlando, Florida.

MR. KEATING: Cochran Keating appearing on behalf of Commission Staff.

CHAIRMAN JACOBS: Very well. I understanding that we have worked through many of the issues here.

Staff counsel, how should we proceed?

MR. KEATING: First, I want to point out that our notices for this proceeding provide that members of the public who are not parties to the proceeding shall have the opportunity to submit sworn testimony regarding the need for the proposed plant. The notices state that any person wishing to present testimony should be present at the beginning of the hearing. So before we go on, I believe now would be the time to find out if anyone is here from the public to present testimony.

CHAIRMAN JACOBS: Is there anyone from the public who has appeared to present testimony in this docket pursuant to notice that was issued? Let the record reflect that no one has come forward.

MR. KEATING: And as --

CHAIRMAN JACOBS: Now -- go ahead.

MR. KEATING: As you indicated, staff and the joint petitioners in this case are in agreement as to the appropriate resolution of the issues and as to the positions to take on all the issues. There are no intervenors in the docket and all the witnesses have been excused, so staff proposes that we proceed by moving all the prefiled testimony and exhibits into the record.

And the prefiled testimony would be for those witnesses listed on Pages 5 and 6 of the prehearing order.

CHAIRMAN JACOBS: Very well. It is the case that all parties have stipulated to the prefiled testimony? Very well.

MR. YOUNG: Yes, sir. Mr. Chairman, we also filed sworn affidavits for each of the witnesses to affirm the correctness of their testimony and associated exhibits. We informed the Chairman and the other Commissioners of that.

CHAIRMAN JACOBS: Very well. Good. Thank you, Mr. Young. Here is how we will proceed. And I assume that there are no formal stipulation, we are just going to go issue-by-issue?

MR. KEATING: We would still need to move the remaining exhibits into the record.

CHAIRMAN JACOBS: I understand.

MR. KEATING: And then we could proceed with the staff recommendation. We could go issue-by-issue, we could make a blanket recommendation and just address the issues that you have questions about.

CHAIRMAN JACOBS: Very well. Here is how we would like to proceed. Let's go ahead and enter the prefiled testimony and exhibits into the record, and then we will come back and we will do the recommendation from staff. Is that okay with you, Commissioners? Very well.

We will start. We will go in order as they are on

page -- I guess, beginning on Page 5. And that would be -- who is it going to be, Mr. Young or Mr. May?

MR. MAY: Mr. Chairman, we can individually admit the testimony of our own witnesses, or as Mr. Keating suggested, we can admit all of the prefiled testimony at this time.

CHAIRMAN JACOBS: Okay. If that works for everyone, that will be fine. No need to delay it.

MR. KEATING: That would be fine.

CHAIRMAN JACOBS: So, it is basically the request that we move in the prefiled testimonies of Mr. Haddad, Mr. Jones, Mr. Anderson, Mr. Arsuaga, Mr. Herrington, Mr. Thumb, Ms. Schuepbach, Mr. Fox, Mr. Rollins, Mr. Hearn, Doctor Sharma, Mr. Schaefer, and Mr. Casey. Without objection, show each of those prefiled testimonies entered into the record as though read.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF FREDERICK F. HADDAD, JR

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

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 Power Resources.

Q. Please describe your responsibilities in that position.

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

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 Power Resources.

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

A. The purpose of my testimony is to describe OUC and discuss the restructuring of generating assets that OUC is undergoing. I will provide the background on how the Stanton A joint development project evolved. I will also discuss both the Joint Development and Power Supply Requests for Proposals. Additionally, I will explain the process used to evaluate the bids from the proposals, as well as self-build alternatives. I will also summarize the agreements resulting from negotiations with Southern-Florida and provide the current status of the negotiations. Finally, I will discuss OUC's fuel procurement strategy for the project and the status of those negotiations.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ and the revisions to the Need for Power Application identified as Exhibit OUC-2__ that you are sponsoring as your testimony?

A. Yes. I am sponsoring Sections 1A.3.1.1, 1A.3.2, 1A.3.4.3, 1A.3.9, 1A.4.0, 1A.6.1, 1A.6.2, 1A.6.4, 1A.6.5, Appendix 1A.A, Appendix 1A.B, and Section 1B.2.0.

Q. Are there any corrections to these sections?

A. No, only the revisions shown in Exhibit OUC-2__ which was a formatting error in Table 1B.2-1.

Q. Please briefly describe OUC.

A. 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 of Orlando. OUC is authorized to provide electric and water service in Orange County and electrical service to municipalities in Osceola County. In 1997, OUC entered into an interlocal agreement with the City of St. Cloud, in Osceola County, to take responsibility for supplying all of St. Cloud's electric loads for the term of the 25-year agreement. In addition, OUC is now responsible for the management of St. Cloud's existing generation and purchase power contracts. OUC is a utility as defined in the Florida Energy Efficiency and Conservation Act (FEECA) Section 366.82(1), Fla. Stat. and serves retail loads in OUC's service territory and serves St. Cloud's retail loads in St. Cloud's service territory.

Q. Please describe OUC's power supply resources.

A. OUC jointly owns and operates the four natural gas and oil fueled Indian River Combustion Turbine Units, as well as the Stanton 1 and 2 coal-fueled units. OUC jointly owns 40 percent of Lakeland Electric's McIntosh Unit 3 coal-fueled unit. OUC is a joint participant with 6.1 percent ownership of Florida Power & Light's St. Lucie 2 nuclear unit and 1.6 percent of Florida Power Corporation's Crystal River 3 nuclear unit. In addition, OUC operates six small diesel generating units owned by the City of St. Cloud. OUC's total generating capacity, including the St. Cloud diesel units, is 1047 MW based on the summer rating.

OUC has a power purchase agreement with Reliant Energy for 593 MW through September 30, 2001, and between 525 MW and 577.5 MW annually beginning October 1, 2001 through September 30, 2003. The Reliant Power Purchase Agreement contains options for up to an additional 500 MW from October 1, 2003 through September 30, 2007. In addition, OUC manages St. Cloud's 15 MW partial requirements purchase from Tampa Electric Company, which extends through 2012.

OUC has agreed to purchase KUA's excess entitlements from Stanton A which are estimated to be 40 MW for fiscal year 2004, 24 MW for fiscal year 2005, and 10 MW for fiscal year 2006.

Q. Please describe OUC's transmission system.

A. OUC's existing transmission system consists of 26 substations interconnected through approximately 302 miles of 230 kV and 115 kV lines and cables. OUC and its existing generating unit sites are fully integrated into the State transmission grid through its twelve 230 kV interconnections with other generating units that are members of the Florida Reliability Coordinating Council (FRCC).

Q. Does OUC have any long term power sales agreements?

A. Yes. OUC has long term power sales agreements with FMPA, Seminole Electric Cooperative (SEC), KUA, and Reedy Creek Improvement District (RCID). The details of these power sales agreements are presented in Tables 1B.2-4 through 1B.2-6 of the Need for Power Application, Exhibit OUC-1 __.

Q. Please briefly describe the generation asset restructuring process you alluded to earlier.

A. The generation asset restructuring process is a continuing process by which OUC is attempting to maintain a cost-competitive asset basis over the long-term considering uncertainties as we approach a deregulated environment. A goal of this process is to include purchase power resources as a component of this asset base. Three major activities associated with this process have been undertaken. The first was the sale of the three Indian River Steam Units in 1999 in exchange for cash and a purchase power agreement with an energy component which is tied to actively traded energy hubs. The second phase was the development and implementation of a financial energy price-hedging program. This was approved by OUC's commission in February 2000. The third phase is to optimize the redeployment of proceeds from the sale of the Indian River Steam Units for both debt retirement and reinvestment into newer, more efficient generating technologies. Stanton A represents this redeployment strategy.

Q. Please briefly describe how the joint development project initiated.

A. OUC, KUA, and FMPA have had a long history of participation in joint development projects. Each utility had a need for capacity in the same timeframe as noted in Table 1A.2-1 of the Need for Power Application, Exhibit OUC-1 __. As a result, the three utilities agreed to pursue a joint development project that would be both flexible and achieve an economy of scale greater than what the individual utilities could achieve individually.

Q. How did involvement in the joint development project evolve?

A. OUC was selected as the agent by KUA and FMPA to develop the project structure and lead the negotiations. Three independent paths were pursued to determine the best economic option for the participants consisting of joint development, power supply, and self-build.

Q. Please describe the joint development RFP?

A. The joint development RFP involved the exploration of joint development projects with large generating entities utilizing sites available at Stanton Energy Center and/or Cane Island. The RFP process began with a solicitation of interest, which was sent to 35 utilities and developers. All respondents to the solicitation of interest were sent a joint development RFP and given the option of responding to the power supply RFP as well, if they so desired.

WHH Enterprises was commissioned by OUC to independently evaluate the responses to the joint development RFP.

Q. Please describe the power supply RFP process.

A. To ensure that there were no other more cost-effective opportunities available, a second RFP was developed which solicited power supply proposals from any source and/or technology, other than units built on either the Stanton Energy Center or Cane Island site. The power supply RFP was advertised nationally and posted on the internet.

OUC contracted with R.W. Beck, Incorporated to independently evaluate proposals from the power supply RFP.

Q. Please describe the OUC self-build alternative evaluation process.

A. OUC contracted with Black & Veatch to provide detailed cost estimates for two configurations of 2 x 1 F-class combined cycle units. One configuration included a steam turbine with minimal duct firing, while the other configuration was sized with a larger steam turbine to maximize plant output.

Q. Describe the overall evaluation process.

A. There were two tiers of evaluation. First, WHH Enterprises and R.W. Beck, Incorporated, independently evaluated the RFPs using a ten-year levelized cost per megawatt-hour basis as presented in Volume 1E-Confidential Exhibit A __. The least-cost proposal from each RFP was compared with the self-build option prepared by Black & Veatch on a consistent ten-year levelized cost per megawatt-hour basis. The second tier of evaluation compared all viable alternatives submitted utilizing a standardized assumption base for offerings from the joint development RFP, power supply RFP, and self-build alternatives.

Q. How did the self-build capital cost compare to the capital cost in the Southern-Florida proposal?

The capital cost estimates based on current market conditions indicated that there was significant capital cost savings opportunity with the Southern-Florida proposal compared to the self-build estimates since Southern-Florida had previously reserved combustion turbines.

Q. What was the result of comparing the least-cost proposals from the joint development RFP and the power supply RFP with the self-build alternative?

A. Ranking on a consistent ten-year levelized cost per megawatt-hour basis resulted in the Southern-Florida joint development proposal being the least-cost alternative compared to the least-cost power supply and the self-build alternative.

Q. Were there any other evaluations conducted?

A. Yes. Black & Veatch evaluated the Southern-Florida joint development proposal against a number of self-build alternatives on an individual system basis for OUC, KUA, and FMPA. The evaluations showed that the Southern-Florida joint development proposal was the most cost-effective alternative for each system.

Q. Were there also concerns with respect to combustion turbine delivery schedules for the self-build alternative?

A. Yes. At the time of the evaluation the delivery schedule for F-class combustion turbines which were not already on order was the first quarter of 2004, which obviously precluded the October 1, 2003 commercial operation date.

Q. Was there any other alternative available to obtain combustion turbines in the required timeframe to achieve October 1, 2003 commercial operation?

A. No. For OUC alone there were no other alternatives other than the Southern-Florida proposal. However, the inclusion of KUA and FMPA in the project offered a possible alternative of using KUA's option for two General Electric 7F combustion turbines that was obtained when KUA purchased the combustion

turbine for Cane Island 3. This option expired prior to receipt of the proposals. However, KUA was able to extend the option through the evaluation period.

Q. How did the cost of the combustion turbines under the KUA option compare to those in the self-build cost estimate?

A. The cost of the combustion turbines under KUA's option were $2 million more expensive than those assumed in the self-build alternative cost estimate.

Q. Please describe the Stanton A project.

A. The joint development project between Southern-Florida and OUC, KUA, and FMPA consists of a 633 MW combined cycle, natural gas fired unit to be constructed at OUC's existing Stanton Energy Center. OUC, KUA, and FMPA collectively will own 35 percent of the plant, with Southern-Florida owning the remaining 65 percent. OUC, KUA, and FMPA have the unilateral right to purchase the 65 percent of the unit capacity owned by Southern-Florida for the 30-year life of the plant. The capacity is initially purchased through a 10-year power purchase agreement (PPA) with four 5 year unilateral extension options. OUC, KUA, and FMPA have entitlements to both the ownership portion and the purchase power portion of 80 percent, 10 percent, and 10 percent, respectively.

Q. Please describe the features of the Stanton A combined cycle unit.

A. Stanton A is a 2 x 1 General Electric 7FA combined cycle with duct firing and power augmentation to increase plant output. Stanton A is fueled with natural gas as the primary fuel and No. 2 oil as the back-up fuel. The unit has the condenser sized such that the combustion turbines can be operated at full load without the

steam turbine being in service. This plant configuration and design provides high efficiency and flexibility coupled with high reliability.

Q. Please describe the unit's environmental features.

A. Stanton A will include selective catalytic reduction (SCR) to reduce NO_x emissions. Stanton A will also use treated sewage effluent as its source of cooling water and will treat wastewater on site such that there will be no off-site discharges. Similar to Stanton 1 and 2, Stanton A will be one of the most environmentally friendly units in the State.

Q. Does Stanton A provide fuel diversification for OUC?

A. Yes. In fiscal 2000, OUC obtained 72 percent of their energy requirements from coal-fueled resources. Stanton A will add a much needed diversity component of highly efficient natural gas-fueled capacity to OUC's fuel mix.

Q. If natural gas prices were to remain at high levels could Stanton A use alternate fuels?

A. Yes. The ability to deliver coal to the existing coal-fueled units at Stanton Energy Center provides the unique opportunity for coal gasification if economic conditions dictated such a process. This fuel-switching ability will help to cap the exposure to natural gas prices.

Q. Please describe the Purchase Power Agreement with Southern-Florida.

A. The entire Purchase Power Agreement (PPA) with Southern-Florida is contained in redacted form in Appendix 1A.A. The un-redacted PPA has been provided in

Volume 1F-Confidential Exhibit B __. OUC, KUA, and FMPA will each sign identical PPAs.

As previously stated, OUC, KUA and FMPA has the unilateral right to purchase Southern-Florida's 65 percent ownership share of the capacity from Stanton A for up to 30 years. The capacity charges for the initial 10-year term and the four 5-year extensions have been specified in the PPA. The capacity charge for the initial 10-year term and the first 5-year extension are fixed. The capacity charge for the three additional 5-year extensions will be either the specified capacity charge or the market price if Southern-Florida elects the market price pursuant to the provisions of the PPA.

OUC, KUA, and FMPA have the further flexibility to reduce their capacity levels during years six through ten of the PPA by either 25 or 50 MW per year, up to a maximum of 200 MW. This provides additional economic benefit to OUC, KUA, and FMPA if future conditions merit such reductions.

Variable O&M and start-up costs are specified in the PPA. The PPA provides an availability guarantee for the purchased capacity, which increases its availability over that of a self-build alternative. During periods when Stanton A is unavailable, Southern-Florida may provide energy from alternate resources. During periods when Stanton A is available, Southern-Florida may provide energy from alternate resources provided that Stanton A is on-line and committed at least at its minimum load. OUC, KUA, and FMPA are entitled to schedule any and all ancillary resources from the unit.

OUC will be the agent for providing fuel and managing gas transportation throughout the term of the PPA. Fuel cost for energy from the unit will be based on the actual cost of fuel burned.

Q. Please describe the Construction and Ownership Participation Agreement.

A. Southern-Florida is responsible for construction of Stanton A for a fixed price for the capital equipment costs and for a fixed price within a specified range for the balance of plant capital costs as specified in the Construction and Ownership Participation Agreement (COA). OUC, KUA, and FMPA will pay for the construction of the interconnection facilities and Southern-Florida will be responsible for constructing the interconnection facilities at a fixed price. The Project will pay OUC an annual lease fee for the site.

Q. Please discuss the fuel procurement strategy for Stanton A.

A. The primary fuel for Stanton A will be natural gas, with No. 2 oil as a back-up fuel. The No. 2 oil can be delivered by both truck and rail. OUC is currently in negotiations with Florida Gas Transmission Company (FGT) and Gulfstream for natural gas transportation. The FGT pipeline is located 2.5 miles south of Stanton Energy Center and intersects OUC's railroad and transmission corridor. This allows a lateral to be constructed to the site on the existing right-of-way. FGT has indicated they have the ability to supply the transportation requirements for Stanton A. Gulfstream recently received final Federal Energy Regulatory Commission (FERC) approval. Gulfstream plans to be in commercial operation in time to serve Stanton A through an expansion of their original system. Final

natural gas transportation for Stanton A will result in transportation from one or both of FGT and Gulfstream based on the overall terms and conditions negotiated.

OUC has not yet completed specific plans for the purchase of natural gas commodity but plans to mitigate price risks through financial energy price hedging programs.

Q. Please summarize the status of negotiations with Southern-Florida.

A. The major agreements including the PPA and the COA have been negotiated and are scheduled to be signed by the end of April.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

INTRODUCTION

Q: Please state your name and business address.

A: My name is Douglas Jones and my business address is Southern Company Services, 270 Peachtree Street, Atlanta, Georgia 30303.

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

A: I am employed by Southern Company Services ("SCS") as Vice President of Energy Marketing. SCS is a wholly-owned subsidiary of The Southern Company ("Southern Company") and provides a comprehensive set of services to the Southern Company's operating companies, including engineering, fuel procurement, finance, accounting and marketing services. I am also a Vice President of Southern Power Company.

BACKGROUND AND QUALIFICATIONS

Q: Please summarize your educational background.

A: I hold a Bachelor of Science degree in Mechanical Engineering from Virginia Polytechnic Institute and State University and a Masters of Business Administration with a concentration in finance from Kennesaw State University.

Q: Please summarize your employment history and work experience.

A: I have 20 years of experience in the electric utility industry, all with Southern Company or one of its affiliates. Since 1980, I have held various positions with Southern Company or one of its affiliates in

the areas of retail marketing, regulatory affairs and wholesale power marketing. I have served as Vice-President of Energy Marketing for Southern Company Services since 1998.

Q. What are your responsibilities as Vice President of Energy Marketing?

A. I am responsible for the competitive wholesale marketing activities for Southern Company's operating companies, including the Stanton A Project in which Southern Company - Florida LLC ("Southern - Florida") is participating.

SUMMARY AND PURPOSE OF TESTIMONY

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Southern - Florida. My testimony supports a petition filed on behalf of the Orlando Utilities Commission ("OUC"), the Kissimmee Utilities Authority ("KUA") and the Florida Municipal Power Agency ("FMPA") for a determination of need for a 633 MW natural gas fired combined-cycle generating unit in Orange County, Florida (the "Project"). Southern - Florida has joined in that petition as a non-need applicant because: it was the successful bidder in OUC's RFP for the joint-development project; it will be a 65% equity owner of the Project; and, it will operate the generating plant. In addition, Southern - Florida has entered into Power Purchase Agreements ("PPAs") under which Southern - Florida will sell, and OUC, KUA, and FMPA will purchase, all of the

Project capacity owned by Southern - Florida during the term of the agreement. Southern has also joined with OUC, KUA, and FMPA and applied 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 Southern - Florida, its relationship with Southern Company, and its experience in the development, construction and operation of electrical generating facilities. My testimony also generally explains Southern - Florida's involvement in the Project.

Q: Are you sponsoring any exhibits to your testimony?

A: Yes, I am sponsoring Exhibit ___(DEJ-1) which charts the ownership structure of Southern – Florida.

Q: Are you sponsoring any sections of the Need for Power Application for Stanton Energy Center Combined Cycle Unit A which has been identified as Exhibit OUC-1?

A: Yes, I am sponsoring that portion of Section 1A.1.0 that describes Southern - Florida.

OVERVIEW OF SOUTHERN - FLORIDA

Q: Please describe Southern - Florida and its affiliation with Southern Company.

A: Southern - Florida is a Delaware limited liability corporation authorized to transact business in Florida. Southern - Florida is a wholly-owned subsidiary of Southern Power Company ("Southern Power"). Southern Power is one of the six operating subsidiaries of Southern Company and was created to own and manage wholesale generating assets in the Southeast. The ownership structure of of Southern – Florida is shown in Exhibit ___ (DEJ-1).

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

A: Southern Company is the largest producer of electricity in the United States, and one of the largest in the world, with a proven record of designing, owning and operating electric power plants. With 69 plants, comprised of 278 units, Southern Company generates more than 31,000 MW of capacity in the southeast United States. 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 2000, Southern Company had revenues of $23.4 billion dollars and net income of $1.4 billion dollars.

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

A: Yes. Southern - Florida is a wholly-owned subsidiary of Southern Company and will have Southern Company's direct support in the areas of plant engineering, operations and maintenance, marketing, accounting, financial services and procurement.

Q: You previously stated that Southern – Florida is a wholly-owned subsidiary of Southern Power. Please describe Southern Power and its business objectives.

A: Southern Power was established to actively participate in the evolving competitive wholesale marketplace. Southern Power's strategic position in this wholesale market is enhanced by its abilities to: (i) centralize wholesale generation development within the Southern Company system, and (ii) capitalize on the core competencies of the Southern Company. These core competencies include over 70 years of experience in the engineering, construction, operation and maintenance of low-cost, clean, and reliable electric generation facilities.

Where appropriate market conditions exist, Southern Power is

prepared to design, build and operate new wholesale generation facilities and sell output from those facilities under negotiated long-term bilateral contracts with other strong, well-respected electric utilities.

Q: Why is Southern - Florida interested in building and operating the Project in Florida?

A: Southern - Florida is a subsidiary of Southern Power and was created to advance Southern Power's business objectives of building, owning and operating environmentally advanced, wholesale generating facilities and selling at wholesale the output produced therefrom. The Stanton A Project allows Southern - Florida to achieve those business objectives. By participating in the Project, Southern - Florida will jointly own and operate a highly efficient, environmentally advanced combined cycle generating unit and will sell capacity and energy produced to OUC, KUA and FMPA – all of which are strong and well-respected Florida electric utilities. The Project allows Southern - Florida to bring its significant plant development and operating experience into the Florida wholesale market to the benefit of OUC, KUA and FMPA. By developing and operating the Project, Southern - Florida will assist those utilities in reliably and economically meeting their retail obligations.

Q: Will Southern - Florida apply for the regulatory approvals necessary to sell its capacity and energy to OUC, KUA and FMPA under the PPAs?

A: Yes. Within the next month, Southern – Florida will file with the Federal Energy Regulatory Commission ("FERC") an application for exempt wholesale generator ("EWG") status under the Public Utility Holding Company Act of 1953. Southern - Florida also will apply for approval of market-based rates with the FERC.

Q: Does this conclude your direct testimony?

A: Yes.

INTRODUCTION

Q: Please state your name and business address.

A: My name is Thomas O. Anderson. My business address is 600 North 18th Street, Birmingham, Alabama 35203.

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

A: I am employed by Southern Company Services, Inc. ("SCS") as Manager of Generation Development.

Q: Please describe your duties with SCS.

A: As Manager of Generation Development, I am responsible for the development of new power plant projects by Southern Company-Florida, LLC ("Southern - Florida") and other Southern Company affiliates. My responsibilities include siting and development of financial business models for new generation. I am also responsible for various aspects of project management including engineering-procurement-construction ("EPC"), environmental, transmission, O&M, finance and other functions.

QUALIFICATIONS AND EXPERIENCE

Q: Please summarize your educational background.

A: I received a Bachelor's degree in Electrical Engineering from Auburn University in 1982.

Q: Please summarize your employment history and work experience.

A: I have been employed with SCS for approximately twenty-two years. I have worked in various areas including nuclear plant field support, design engineering, system planning, market analysis, finance, energy marketing and generation development. I have held a number of positions ranging from design engineer to engineering group manager to my current position as Manager of Generation Development. I have served as Manager of Generation Development with SCS since October 1998.

SUMMARY AND PURPOSE OF TESTIMONY

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Southern - Florida. My testimony supports the petition filed by the Orlando Utilities Commission ("OUC"), the Kissimmee Utilities Authority ("KUA"), the Florida Municipal Power Agency ("FMPA"), and Southern – Florida as a non-need applicant, for a determination of need for a 633 MW natural gas-fired combined cycle generating unit, which will be the third unit installed at the Stanton Energy Center in Orange County, Florida approximately 12 miles southeast of Orlando (the "Project" or "Stanton A").

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

A: My primary responsibilities are to ensure that all of the siting, environmental, EPC, transmission, O&M, financial, and other aspects of the Project meet Southern - Florida's financial and business goals. Additionally, I am responsible for ensuring that the major equipment is available to support the EPC schedule.

Q: What is the purpose of your testimony?

A: My testimony generally describes the Project, its performance characteristics, its environmental profile, and its EPC schedule. In addition, my testimony generally addresses the capital and O&M costs of the Project.

Q: Are you sponsoring any sections of The Need for Power Application for Stanton Energy Center Combined Cycle Unit A which has been identified as Exhibit OUC-1?

A. Yes, I am sponsoring Sections 1A.3.1.2, 1A.3.3, 1A.3.4.1, 1A.3.4.2, 1A.3.5, and 1A.3.7 of Exhibit OUC-1.

OVERVIEW OF THE PROJECT AND ITS OPERATION

Q: Please summarize the Project.

A: The Project is a natural gas-fired power plant utilizing advanced combustion turbine technology in combined cycle configuration with two heat recovery steam generators with duct-firing and power

augmentation capability. The Project's rated new and clean capacity at average ambient site conditions is 633 MW, based on manufacturers' guarantees. The Project is projected to have a technical and economic life of 30 years.

Q. Please describe the generating technology of the Project.

A. The Project will consist of two General Electric PG-7241 FA combustion turbine generators ("CTGs"), two Deltak heat recovery steam generators ("HRSGs") with gas-fired duct burners, an ABB/Alstom STF30C single reheat condensing steam turbine generator ("STG"), and associated support systems. The CTGs will be equipped with dry low Nitrogen Oxide ("NOx") combustors, evaporative coolers and power augmentation capability. The CTGs are dual fuel units that will burn natural gas as the primary fuel and No. 2 distillate oil as the backup fuel. The HRSGs will be equipped with duct-firing capability and selective catalytic reduction ("SCR"). A CO catalyst spool will be included for possible future addition of CO catalyst.

Q. Please summarize the performance characteristics of the Project.

A: Stanton A will have three basic operating modes. The first mode is Normal Operation, where both CTGs will operate without supplemental duct firing of the HRSGs or CTG power augmentation. The second mode is Supplemental Firing Operation, where both

CTGs will operate at full load with supplemental duct firing of the HRSGs, but no CTG power augmentation. The third mode is Power Augmentation Operation, where both CTGs will operate at full load, with the necessary HRSG supplemental duct firing to support both full STG output and CTG power augmentation. The performance of these operating modes is dependent on the temperature, relative humidity and physical condition of the equipment. At certain temperatures, CTG Evaporative Cooling may be in operation during any of the three operating modes. The expected performance of Stanton A at various temperatures and operating modes is set forth in Table 1A.3-4 of Exhibit OUC-1 [Volume 1F – Confidential Exhibit B].

Q: Are there advantages to combined cycle technology?

A: Yes. Combined cycle generation technology is very efficient because it generates electrical energy from the input fuel both directly, through the combustion turbines, and indirectly, through the heat recovery steam generator and steam turbine. Furthermore, by reheating the steam between sections of the steam turbine, additional improvements in cycle efficiency can be achieved. Combined cycle technology simply makes the most of the input fuel, achieving increased efficiency in the generation of electrical energy from the available fuel source. For all of these reasons, the modern combined cycle power plant is one of the most efficient power cycles available today.

Another advantage of the combined cycle design is that it allows for greater flexibility in matching system operating characteristics over time. Because of its technological efficiency, it can readily be called on to meet varying operational load requirements in an economical manner. Thus, if required, Stanton A can function as a baseload or intermediate unit.

Q: Are there environmental advantages to the Project?

A: Yes. Combined cycle units operating on natural gas, like the Project, are one of the cleanest sources of fossil generation. Flue gas is the only byproduct of the combustion process, whether burning natural gas or distillate oil. Both are low sulfur, low ash fuels. Thus, sulfur and particulate emissions are virtually non-existent. NOx will be controlled by state-of-the-art NOx combustors and SCR equipment. Airborne emissions, therefore, will be limited by the use of relatively clean fuel and the appropriate application of control technologies.

In addition, combined cycle units use considerably less water than traditional steam turbine cycles. On average, combined cycle technology requires approximately one-half the amount of water used by a steam-only cycle. For these reasons, Stanton A's impact on the environment is relatively benign.

Q. When is the Project expected to achieve commercial in-service status?

A. Based on the present schedule, the expected commercial operation date is October 1, 2003.

Q: You previously stated that you are responsible for certain aspects of the EPC process for Stanton A. Please provide a general description of that process.

A: The EPC process ensures that a new generating plant is properly designed and constructed in a reliable, efficient and timely manner. The process fully integrates the engineering, procurement and construction phases of a generating project, and applies to virtually all aspects of a project from its inception to its commercial in-service date. Generally, the EPC process begins with the selection of a site and generating technology for a new plant. For a combined cycle plant, this can occur anywhere from two to four years prior to the scheduled commercial in-service date. Once the site and the generating technology are selected, the procurement process for major equipment can proceed. For combined cycle plants, the CTGs, the HRSGs and the STG are large, capital intensive pieces of equipment with long lead times – usually about a year and a half from the time of order to the time of delivery. Coincident with the procurement, detailed, site specific design begins, a process that is closely tied to procurement because the major equipment utilized has a direct impact on the scope of the design work. The detailed

design typically takes about a year to a year and a half to complete. Near the completion of the design phase, planning begins for the physical construction of the plant. The planning phase is closely coordinated with the permitting phase. Once the necessary permit approvals are obtained and the project design process nears completion, the construction process commences. The construction of a combined cycle generating unit typically includes several sub-contracts, including site clearing and grading, foundation and concrete work, installation of major equipment and mechanical erection of the plant, and the start-up and testing of the plant. From receipt of the requisite permits, physical construction of a combined cycle generating unit takes approximately two years.

Q: What is the EPC schedule for Stanton A?

A: The Stanton A project's EPC schedule is set forth in Figure 1A.3-2 of Exhibit OUC-1.

Q: What is the status of the EPC schedule for Stanton A?

A: With respect to engineering, SCS has completed the conceptual engineering for the Project. The Site Plan, Plot Plan, Process Flow Diagram, Electrical One-line Diagram, Water Balance, Capital Cost Estimate and Operation and Maintenance Estimates are complete. With respect to procurement, all of the major equipment, including the CTGs, the HRSGs, and the STG, have been procured. With respect to construction, the construction of Stanton A is

scheduled to take twenty-four months after the receipt of all required regulatory and environmental approvals.

Q: Are there advantages to having SCS manage the entire EPC process for the Stanton A Project?

A: Yes. SCS brings a wealth of experience, efficiency and accountability to the Project. SCS is the service provider for over 35,000 MW of generation built and/or operated by Southern Company and its affiliates, and consequently has extensive EPC management expertise. In addition to coal, nuclear, oil and gas generation, SCS has been actively engaged in building over 5,500 MW of new combined cycle generation since 1999 (exclusive of Stanton A). The design for Stanton A is based on SCS's reference plant design, which provides real benefits in terms of cost-savings, continuity, and efficiency. SCS has fully integrated all development phases for its referenced plant so that design, procurement and construction can be efficiently and effectively replicated without having to start each project anew. Furthermore, because SCS utilizes its own experienced staff to serve as EPC manager, single points of responsibility and accountability are established for any new generation project. When these advantages are brought to bear in the Stanton A Project, the experience, efficiency and accountability that SCS brings to the EPC process allows Southern – Florida to provide a fixed cost for the major equipment and a cap for the Balance of Plant cost for the Project.

Q. Are there other advantages to having SCS and Southern - Florida involved in the Project?

A. Yes. Southern Company, the parent company for both SCS and Southern - Florida, is an industry leader in the purchase of major equipment needed for natural gas-fired generation. The economies of scale associated with Southern Company's bulk procurement of equipment gives affiliates like Southern - Florida timely access to generating equipment and supplies which, in turn, allows Southern - Florida to meet Stanton A's desired commercial operation date at competitive prices.

PROJECT COSTS

Q: What are the projected capital costs for Stanton A?

A: OUC, KUA, and FMPA's direct construction costs for Stanton A are set forth in Table 1A.3-1 of Exhibit OUC-1 [Volume 1F – Confidential Exhibit B].

Q: What are the projected O&M costs of the Project?

A: The O&M costs for Stanton A are set forth in Sections 1A.3.4.1 and 1A.3.4.2 of Exhibit OUC-1 [Volume 1F – Confidential Exhibit B].

Q: Does this conclude your direct testimony?

A: Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF PAUL A. ARSUAGA

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. Paul A. Arsuaga, 800 North Magnolia Avenue, Suite 300, Orlando, Florida 32803-3472.

Q. What is your occupation?

A. I am presently a principal of and employed as a Senior Director by R. W. Beck, Inc.

Q. Please describe R. W. Beck, Inc.

A. R. W. Beck, Inc. is a corporation of engineers and consultants. The firm was originally founded in 1942 for the purpose of rendering professional engineering and consulting services in planning, financing, designing and operating facilities for utilities and energy users.

Q. Please summarize your educational background and your experience in the electric utility industry.

A. I received a Bachelor of Science Degree in Electrical Engineering in 1969 from Tulane University, New Orleans, Louisiana. I also received a Master of Business Administration degree in 1975 from University of Hawaii, Honolulu,

Hawaii. I am a registered engineer in the states of Florida, Mississippi, and Missouri. I have over 30 years of experience in planning utility infrastructure, which includes 23 years associated with planning electric power facilities. Exhibit No. ___ (PAA-1) provides a brief description of my employment history and professional experience.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Orlando Utilities Commission ("OUC"), the Kissimmee Utility Authority ("KUA"), and the Florida Municipal Power Agency ("FMPA").

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

A. The purpose of my testimony is:

(a) to discuss the tasks performed by the firm under my direction and supervision as authorized by OUC as agent for KUA and FMPA;

(b) to discuss the "Request for Power Supply Proposals" dated May 24, 2000 (the "RFP") issued by the OUC;

(c) to discuss the evaluation methodology and techniques employed in evaluating the responses to the RFP; and

(d) to discuss the results of the analysis and evaluation of the responses to RFP.

Q. Have you prepared exhibits to support your testimony?

A. Yes. In addition to Exhibit No. ___ (PAA-1) which I have mentioned, I have prepared, or had prepared under my supervision, the following exhibits:

(a) Exhibit No. ___ (PAA-2) The Form of the Proposal Evaluation used in Evaluating the Responses to the RFP (the "Evaluation Guidelines");

(b) Exhibit No. ___ (PAA-3) contained in Confidential Exhibit C ___. Status Report: Orlando Utilities Commission Proposal Evaluation – Stage Two Screening Results dated August 15, 2000 (the "August 15th Stage Two Screening Results"); and

(c) Exhibit No. ___ (PAA-4) contained in Confidential Exhibit C ___. Status Report: Orlando Utilities Commission Proposal Evaluation – Revised Stage Two Screening Results dated August 23, 2000 (the "Revised Stage Two Screening Results").

Q. In addition to your exhibits, are you also sponsoring portions of the Need for Power Application Exhibit OUC-1 ___ as your testimony?

A. Yes, I am sponsoring Appendix 1A.C, which is the Request for Power Supply Proposals (RFPs) dated May 24, 2000. I am also sponsoring the Power Supply RFP evaluation contained in Confidential Exhibit A __ Volume 1E of the Need for Power Application consisting of the Stage One and August 8, 2000 Stage Two Screening Results.

Q. Will you please describe the assignment and the tasks that were authorized by OUC?

A. Yes. In April 2000, the firm was authorized by OUC, acting in its own behalf and as agent for FMPA and KUA pertaining to the potential acquisition of additional generating resources, to provide independent consulting services to OUC in three general areas: first, the preparation of an RFP to solicit

proposals to supply capacity and energy; second, the preparation of the Evaluation Guidelines documenting the criteria and methodology to be utilized in evaluating the responses to the request for proposals; and third, the review and evaluation of the power supply proposals and the preparation of reports.

Working closely with representatives of OUC, the RFP was prepared, was publicly disseminated on May 24, 2000 and is contained in Appendix 1A.C of the Need for Power Application Exhibit OUC-1 _____. Again, working closely with representatives of OUC, the proposal evaluation criteria and methodology set forth in the Evaluation Guidelines were developed and are set forth in Exhibit No. ___ (PAA-2).

At the direction of representatives of OUC, the Evaluation Guidelines, expressly provided, among other things, that the evaluation criteria and methodology be established to consider responses to the RFP and that such evaluation will not consider a "self-build" option, which I understood would be evaluated by OUC or another consultant, or responses to the Joint Development Solicitation, which I understood would be evaluated by OUC or another consultant. This exclusionary language contained in the Evaluation Guidelines is consistent with the language contained in the RFP that placed potential respondents on notice that

> "...OUC has issued a separate solicitation on behalf of the Participants for joint development of a combined cycle power

plant at the OUC Stanton site and/or FMPA's/KUA's Cane Island site and will not consider such proposals as a part of this RFP." (See page 18 of the RFP, Appendix 1A.C of the Need for Power Application Exhibit OUC-1 _____.)

In addition, at page 27 of the RFP, Appendix 1A.C of the Need for Power Application Exhibit OUC-1 _____, the respondents were informed that:

> "In addition to this RFP, OUC has issued a Joint Development Solicitation for a combined cycle project in which OUC will take an ownership position.... The proposals from the Joint Development Solicitation will be ranked and the proposals from this RFP will be ranked, and then the highest-ranking proposals from each solicitation will be ranked together against each other."

In summary, the firm's assignment, as authorized by the OUC, was limited to evaluating the responses to the May 24, 2000 RFP.

Q. Do you have any first-hand knowledge pertaining to the self-build option and the joint development solicitation?

A. Yes. I have very limited knowledge of the self-build option and the Joint Development Solicitation. While neither representatives of the firm nor I were authorized to and did not participate in the development of the self-build option and in the Joint Development Solicitation or the evaluation of any responses thereto, representatives of the firm met with representatives of the

OUC including a representative of WHH Enterprises to discuss and to agree on certain common assumptions which were to be used in both evaluation processes. The agreement on certain common assumptions was made in order that there would be a high degree of congruence between the RFP evaluation by Beck, and any similar analyses performed by others on any proposals received in response to the Joint Development Solicitation or the self-build option.

Q. What was the criteria used in evaluating the responses to the RFP?

A. The criteria is set forth in the Evaluation Guidelines Exhibit No. ___ (PAA-2).

Q. What is the purpose of the Evaluation Guidelines?

A. In general, the Evaluation Guidelines are substantially completed prior to receiving proposals and serve as a guide for the evaluation and provide objectivity to the evaluation process. That is not to say that once the evaluation guidelines are established they should never be altered or modified during the evaluation phase. Typically, as new factors become apparent during the evaluation, changes may be considered that would improve or streamline the evaluation process and yet maintain objectivity during the process.

Q. Please describe the Evaluation Guidelines.

A. The Evaluation Guidelines set forth a three stage process to obtain the best resource opportunity for OUC, while working within time and resource constraints, and maintaining a fair process. The first stage was generally

focused on eliminating proposals, which were not complete or did not satisfy minimum requirements. The second stage of the process was a busbar screening evaluation which allowed the proposals emerging from the Stage One Screening to be compared on the basis of readily quantified costs at various capacity factors. The third stage evaluation was to take into account non-price factors as well as price related factors.

Q. Was the third stage evaluation process completed?

A. No. After Stage Two Screening, representatives of OUC informed me that the Stage Two Screening was adequate and suspended work on Stage Three Screening activities.

Q. Did the suspension of the Stage Three Screening have a material adverse impact on the respondents or on the evaluation process?

A. No. Since the purpose of the Stage Three Screening was to further refine and reduce the number of proposals, not completing the Stage Three Screening, if anything, made more proposals available for comparison to the self-build and Joint Development option. I am not knowledgeable of what other factors, besides busbar costs, were used by OUC to compare the proposals with the Joint Development and self-build option. The Stage Three Screening would have provided an evaluation of non-price factors of the proposals.

Q. Please describe in more detail how the process was conducted for each stage.

A. In general, the Stage One Screening called for a general review of the responses of the respondents to insure completeness and to determine that the minimum proposal requirements set forth at Section 14 of the RFP have been supplied. This was accomplished by logging in each response and inventorying the contents of the proposal. If a respondent was determined to have omitted certain requested minimum requirements and such information was deemed by OUC not to materially change the original response, discussions with the respondent were initiated to obtain such information.

Upon completion of the Stage One review, a letter report was prepared and submitted to OUC. The letter report set forth the proposals which were determined to be complete, and should be considered in the next level of screening and the proposals which were deemed incomplete or unresponsive and should no longer be considered.

The Stage Two Screening consisted of a simple analysis to determine the annual cost of power under each proposal. Consistent with the Evaluation Guidelines, each proposal was evaluated using uniform assumptions over a representative range of capacity factors to determine the most economic resource at selected capacity factors. As a part of the Stage Two Screening using data and information contained in each respondent's proposal and using uniform assumptions, comparisons for each of the proposals were made at the selected capacity factors on an annual basis and on a levelized cumulative present value basis. During this stage, discussions were held with each of the respondents to verify certain data and to obtain clarification, if necessary. The

results of the Stage Two Screening were summarized in letter reports and were submitted to OUC.

The Stage Three Screening envisioned a more comprehensive evaluation of the respondents' proposals taking into account both price and non-price factors in a quantitative manner. As stated previously, the Stage Three Screening activities were never completed. On August 8, 2000, representatives of OUC instructed Beck that essentially all work should stop on activities related to the Stage Three Screening.

Q. Based on your experience in evaluating power supply proposals, do you believe the evaluation criteria set forth in Exhibit No. ___ (PAA-2) to review, analyze and evaluate proposals was reasonable and fair, and in compliance with industry standards?

A. Yes.

Q. How many respondents submitted proposals to the RFP?

A. Four entities submitted proposals in response to the RFP prior to the 5:00 p.m. EDT deadline on July 11, 2000.

The proposal submitted by one respondent contained three alternatives. In an attempt to identify the best proposal, the three alternatives were evaluated separately.

Q. Were the proposals submitted by these entities evaluated pursuant to the provisions contained in the evaluation guidelines?

A. Yes. During the Stage One Screening, it was determined that each of the respondents had not satisfactorily complied with Section 14 (the Minimum Requirements) of the RFP. As mentioned in the Stage One Screening Report (Confidential Exhibit A ____), each of the respondents were contacted in an attempt to obtain the omitted information. Of the four respondents, one elected not to provide the requested information. In recognition of the respondent's election not to provide the requested information, the proposal was deemed to be non-compliant and R.W. Beck recommended that it not be evaluated further. The remaining three respondents provided the additional information required to meet the Minimum Requirements and R.W. Beck recommended the proposals be considered for the next level of evaluation. These findings were submitted to OUC for confirmation on August 2, 2000 as a part of the Stage One Screening Report (Confidential Exhibit A _____).

Q. In general terms, will you please describe the proposals submitted by the respondents?

A. Yes, with the exception of the proposal that was deemed non-compliant, the other respondents offered to sell varying amounts of physically firm power including ancillary services on a first call, non recallable basis for a period of at least five years. The amount of capacity offered to OUC ranged from a minimum of 150 MW specified in the RFP to 651.5 MW. A more complete listing of the specific proposals submitted by each of the respondents is

contained in the August 8th Stage Two Screening Results, Confidential Exhibit A ____.

Q. Will you describe the results of the Stage Two Screening?

A. Yes. Based on the results of the Stage One Screening, OUC authorized the next level of evaluation to be performed on the three remaining proposals. Because of the expedited schedule imposed by OUC, telephonic discussions were held with representatives of each respondent to obtain further clarification. In situations where additional research on the part of the respondent was necessary, the respondents were advised to submit such information in writing no later than the end of the day on Friday, August 4, 2000.

On August 8, 2000, the first of three Stage Two Screening Reports was issued, which is contained in Confidential Exhibit A _____. As the result of receiving additional information from the respondents and revisions in the basic assumptions, the results of the analysis and evaluation were revised. On August 15, 2000, the second Stage Two Screening Report, contained in Exhibit No. PAA-3 in Confidential Exhibit C _____, was submitted to OUC. As can be seen by comparing the tabulation in the Stage Two Screening Report dated August 8, 2000 to the second report dated August 15, 2000, the Levelized Annual Busbar Delivered Costs, expressed in $/MWh, calculated as a part of the evaluation analysis changed by small amounts for each respondent.

On August 23, 2000, a further revised Stage Two Screening Report, contained in Exhibit No. PAA-4 in Confidential Exhibit C ___, was submitted to the OUC which revised the Levelized Annual Busbar Delivered Costs calculated for one of the respondents. At the capacity factors discussed during meetings with OUC (70 percent to 80 percent) which OUC was planning to utilize for its evaluation of the Joint Development Proposals, there was no change in the relative position of the respondent's proposal with respect to levelized busbar costs. The result of the Stage Two Screening was that five proposal alternatives were available to be advanced to Stage Three Screening. This was consistent with Evaluation Guidelines on Page 5, "OUC may select up to 4 to 6 proposal alternatives for advancement to Stage Three Screening."

Q. Did the August 23, 2000 revision have an adverse effect on the selection process?

A. No, for two reasons. First, the change in busbar costs for the respondent's proposal was a reduction of approximately $0.5/MWh which was a relatively minor change of approximately 1.0 percent. Secondly, the respondent whose costs were reduced had the same relative position with respect to the other proposals in the August 23 Stage Two Screening at the capacity factors which I understand OUC used for comparison to the self-build and Joint Development option as the August 15 Stage Two Screening in Exhibit PAA-3 contained in Confidential Exhibit C ___.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF WILLIAM HERRINGTON

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO 010142-EM

MARCH 5, 2001

Q. Please state your name and address.

A. My name is William Herrington. My business address is 107 Island Drive, Howey-In-The-Hills, Florida.

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

A. I am the Principal of WHH Enterprises.

Q. Please describe your responsibilities in that position.

A. I have offered consulting services to the utility industry for the past four years.

Q. Please state your educational background and professional experience.

A. I have a bachelor's of science in mechanical engineering from the University of Florida. I am a registered professional engineer in the State of Florida since 1974. I have an MBA from Rollins College awarded in 1985, as well as post-graduate courses in finance at the University of Central Florida.

I was employed by the Orlando Utilities Commission (OUC) from 1969 to 1997. My duties during this time included Power Plant Engineer, Power Plant

Manager, Director of Power Production, and Senior Vice President of the Electric Business Unit of OUC.

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

A. The purpose of my testimony is to describe the methodology used to evaluate and present the results of the evaluation of the responses to OUC, KUA, and FMPA's Request for Joint Development Proposals (RFP).

Q. Are there portions of the Need for Power Application contained in OUC-1__ that you are sponsoring as your testimony?

A. Yes. I am sponsoring the evaluation of the joint development proposals contained in Volume 1E-Confidential Exhibit A__.

Q. Please describe the evaluation process used to determine the least-cost joint development proposal.

A. Initially, each response to the RFP was reviewed to determine which were incomplete and which should be considered for evaluation. Those proposals found to be responsive were then ranked on a levelized cost per megawatt-hour basis over a ten-year period, beginning in 2004 and ending in 2013. Performing the evaluation in this regard accounts for the time value of the cash flows and allows for the evaluation of proposals with differing capacities. Analysis was performed at 60, 70, and 80 percent capacity factors.

Q. How many responses to the Joint Development RFP were evaluated?

A. Proposals were received from five bidders. One of the bidders' proposals did not include pricing and therefore was considered non-responsive and eliminated from further evaluation. The names of the bidders are presented in Volume 1E-Confidential Exhibit A ___.

Q. What were the results of the evaluation process?

A. The two lowest priced proposals were relatively similar in price with the Southern-Florida proposal being lowest at two of the capacity factors evaluated and another proposal being lowest at the third. The Southern-Florida proposal was judged to be the most responsive of all the proposals for the following reasons. The pricing of the extension options that was required by the RFP was included by Southern-Florida. However, pricing of the extension options was not provided in the second lowest priced proposal. The second lowest respondent was given the opportunity, in follow up questions, to price extension options but declined. Additionally, the Southern-Florida proposal had a guaranteed commercial operation date of October 1, 2003, while the second lowest cost proposal would not be commercially operational until October of 2006. A sensitivity analysis of the effect of various discount rates showed no changes to the base case ranking of the proposals. The rankings of the four proposals are presented in Volume 1E-Confidential Exhibit A ___.

Q. Overall, what do you conclude from your evaluation of the responses to the Joint Development RFP?

A. The evaluation showed that the Southern-Florida proposal was the most responsive as well as the least-cost and lowest risk of the responses to the Joint Development RFP. I recommended that the Southern-Florida proposal be evaluated against the highest ranked response to the Request for Power Supply Proposals.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen L. Thumb. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209.

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 United States Environmental Protection Agency, and the United States 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 nine 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.

Q. Have you previously provided testimony before the Florida Public Service Commission?

A. Yes. I provided rebuttal testimony in Docket No. 960409-EI on fuel related matters on behalf of Tampa Electric Company.

QUALIFICATIONS AND BACKGROUND

Q. Please describe your educational background and experience.

A. I received a Bachelor of Science degree in chemical engineering from Northwestern University and a Masters Degree in Business Administration (concentration in Finance) from American University. In addition, I was qualified as a Certified Public Accountant in the state of West Virginia. Prior to joining EVA, I spent 15 years in the oil and gas industry working for Ashland Oil, Burlington Northern and Meridian Oil. I am currently a principal at EVA responsible for the firm's oil and gas practice. This work includes a wide range of assignments for a variety of clients, including electric utilities. I have either authored or coauthored 24 reports for EPRI (Electric Power Research Institute) and/or the Gas Research Institute on a

variety of topics concerning fossil fuels. My resume is attached as Exhibit ____ (SLT-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 OUC, KUA, FMPA and Southern - Florida. 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 A unit is the most cost-effective alternative available to meet the capacity needs of OUC, KUA and FMPA, were reasonable.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit ___ (SLT-1) is a copy of my resume. Exhibit __ (SLT-2) is an update to the forecast for crude oil. Exhibit ___ (SLT-3) provides a comparison of natural gas price forecasts, which I refer to later in my testimony.

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 A project, EVA prepared a base case price forecast for natural gas, coal, petroleum coke and crude oil. Each of these price forecasts were used by Black & Veatch to prepare high, likely and low delivered price projections for a potential power project at the Stanton facility. EVA reviewed each of the high, likely and low price projections and determined that they represented a reasonable assessment of the outlook for the prices for these fuels. EVA's review process included comparing the high and low forecasts with similar material that had been developed by EVA, as well as comparing the natural gas price projections to forecasts prepared by other organizations.

THE FUELS FORECAST

Q. How did EVA become involved in this proceeding?

A. Southern - Florida and OUC retained EVA to provide an accurate forecast of prices for various fuels that potentially could be used by OUC, KUA and FMPA 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 A unit is the most cost-effective generating alternative available to OUC, KUA and FMPA.

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 Southern - Florida and OUC?

A. EVA prepared the following four constant dollar ($2001) price forecasts for the period 2000 through 2020: (a) natural gas prices at the Henry Hub, which is in Erath, Louisiana; (b) delivered coal prices to the Stanton site; (c) delivered petroleum coke prices to the Stanton site; and (d) West Texas Intermediate (WTI) crude oil prices.

Q. How was this information used in the economic assessment for the Stanton A Project?

A. While there are some unique aspects as to how each fuel forecast was used in this assessment, in broad terms Black & Veatch took the following steps to integrate EVA's fuel price projections into their economic model:

(1) Converted EVA's 2001 constant dollar price projections to 2000 constant dollar price projections in order to have all economic information on the same basis.

(2) Developed current dollar price forecasts by escalating the 2000 constant dollar price projections at the same escalation rate (i.e., 2.5 percent per year) as used for all other economic assumptions used in the assessment. This became the base case fuel price forecast.

(3) Developed high case current dollar price forecasts by using a two (2) percent higher inflation rate.

(4) Developed low case current dollar price forecasts by using a two (2) percent lower inflation rate.

Q. Were any other fuel price forecasts developed for this assessment?

A. Yes. As a basis for an additional sensitivity analysis, Black & Veatch first took actual 2000 fuel prices and escalated them at the 2.5 percent per year inflation rate used throughout the project. In addition, Black & Veatch examined the real price escalation rates used by the Energy Information Administration (EIA) and used these plus the project's standard 2.5 percent inflation rate to develop current dollar fuel price forecasts. While both of these approaches to developing additional price forecasts result in outlier projections among industry forecasts, they are useful in testing the overall robustness of the assessment.

Q. You mentioned that there were unique aspects to each fuel price forecast. Were there any unique aspects to the natural gas price forecast?

A. Yes. EVA developed a price forecast for natural gas supply at the Henry Hub. In order to arrive at a delivered gas price forecast to the Stanton site, Black & Veatch added $0.75 per million BTU as a transportation charge.

Q. Was this approach reasonable?

A. Yes. There are two alternatives for natural gas transportation to the Stanton site: the existing Florida Gas Transmission system; and, the planned Gulfstream pipeline, which has ordered pipe and is estimated to be completed in June of 2002. The average tariff for these two systems is close to the $0.75 per million BTU assumed by the project.

Q. Were there any unique aspects associated with the crude oil price forecast?

A. Yes. EVA developed a price forecast for WTI crude oil. In order to arrive at a delivered price forecast for the petroleum products (i.e., No. 2 distillate fuel oil and No. 6 residual fuel oil) that might be used for one of the generation alternatives considered for the Stanton site, Black & Veatch used existing relationships between cost of crude oil and the delivered cost of these petroleum products to arrive at long-term price projections for distillate and residual fuel oil at the

Stanton site.

Q. Was this approach reasonable?

A. Yes. The major determinant, particularly over the long term, of petroleum product prices is crude oil prices.

Q. One of your exhibits concerns crude oil prices. Please explain this exhibit.

A. Since the time EVA was requested to prepare a forecast of crude oil prices for Southern - Florida and OUC, EVA has updated its crude oil price forecast. In order to provide the parties interested in this project with the benefit of EVA's latest crude oil price forecast, Exhibit ___ (SLT-2) presents EVA's updated crude oil price forecast.

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 both at specified hubs and on a delivered basis. The natural gas price forecast prepared for Southern - Florida and 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 forecast for natural gas prices is based upon an analysis of the supply and demand fundamentals for natural gas. With respect to demand, approximately 70 percent of the overall growth in gas demand over the next 20 years will come from the power sector. Non-power sector growth (i.e., residential, commercial and industrial) will be between less than 1.0 and 1.5 percent per year. On the supply side, increases in supply to meet increases in demand will come from a variety of sources and will not be limited to just increases in lower-48 production. For example, over approximately the next five years about 37 percent of incremental supply will come from Canadian imports from both Western Canada and offshore Eastern Canada, as well as increases in LNG imports. During the next five-year period the combination of gas from Prudhoe Bay, Alaska and the MacKenzie Delta, Canada plus additional imports from the rest of Canada will account for approximately 50 percent of incremental supplies. While there is less certainty over the various sources of supply in the latter half of the forecast period, significant contributions will come from the continued development of the Arctic regions, the further development of offshore Eastern Canada and additional LNG imports. Within the lower-48, major additions to supply are expected from the deepwater region of the Gulf of Mexico, the development of coal bed methane in at least eight basins, and the drilling for deeper reserves.

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. Recently, the price of natural gas on the spot market has risen significantly. What are the primary factors causing this rise in gas prices?

A. The spot market for natural gas is still a relatively young industry. When it was deregulated initially, approximately 15 years ago, there was considerable excess deliverability (gas bubble), as a direct result of the change in regulatory status for the industry. Then came an era (1995 to 1999) of relatively balanced supply and demand. Today short-term increases in supply are having difficulty keeping pace with short-term increases in demand, hence the high prices. The primary reason for this current era for natural gas was the sharp decline in gas-directed drilling (i.e., from 650 to 371 rigs) in 1999, which caused deliverability to decline 1.5 to 2.5 BCFD. Unlike in the past, this decline in drilling was not due to a decline in gas prices. Rather the decline was due to external events, namely the 1998/1999 low oil price crisis. As a result of the low oil price crisis, exploration and production (E&P) firms suffered significant declines in profits and cash flow (i.e., up to 75 percent declines), which caused them to

stop virtually all capital expenditures (i.e., both oil and gas drilling). As a result, in the near-term the E&P industry has had a difficult time making up: (a) for this lost deliverability, (b) offsetting declines in existing production and (c) matching increases in demand, particularly those associated with the severe winter weather.

Q. How has this impacted EVA's price forecast?

A. The combination of recent record drilling levels in both the U.S. and Canada, the reemergence of LNG imports and development of new supply areas, such as offshore Eastern Canada, eventually will bring near-term supply and demand back into balance. At present, EVA projects these high prices moderating over three years, however the severity, or lack of it, of winter weather over the next two years is a major unknown, since the difference between a mild and cold winter can be 500 to 800 BCF per year. As a result it could be five years before gas prices moderate. After this three to five year period gas prices should begin to moderate and reach values one would anticipate when supply and demand is in balance.

Q. Were the high, likely and low delivered gas price forecasts prepared by Black & Veatch reasonable?

A. Yes. EVA, as part of its normal practice, prepares high and low price forecasts for natural gas using a Monte Carlo technique which analyzes the potential range for a series of variables that impact natural gas supply and demand fundamentals and hence gas prices.

EVA compared and contrasted the Black & Veatch high and low gas price forecast with those generated by its Monte Carlo technique and found them to be reasonable.

Q. Are the Black & Veatch gas price forecasts in line with other recognized industry forecasts?

A. Yes. In Exhibit ____ (SLT-3) the gas price forecast for six other organizations are compared to the price forecasts prepared by Black & Veatch. This comparison is done for the year 2015, which is the only year for which information on all of the forecasts is available. In addition, each of the forecasts have been placed upon a common basis by including the appropriate transportation charge and using the standard inflation rate for the Stanton A project. As illustrated in Exhibit ___ (SLT-3) the Black & Veatch gas price forecasts are in the same range as the gas price forecasts prepared by other organizations.

COAL PRICE FORECAST

Q. How did EVA prepare its coal price forecast?

A. As part of its normal practice, EVA tracks both the short-term and long-term supply and demand for coal in order to prepare coal price forecasts for a variety of clients. The coal price forecasts have been both for mine mouth prices and delivered coal prices. In the case for the Stanton project, EVA examined the following five alternatives for supplying coal to the Stanton facility:

(1) Lower sulfur coal from Central Appalachia.

(2) High sulfur coal from Northern Appalachia.

(3) High sulfur coal from the Illinois Basin.

(4) Lower sulfur 8,800 BTU/lb coal from the Powder River Basin.

(5) Imported coal.

The lower sulfur coal from Central Appalachia was the least expensive. In addition, the Stanton facility currently uses this coal, which would allow for a common stockpile (i.e., reduces overall costs). Also, OUC currently has a rail contract (CSX) for coal deliveries, which could be used for additional coal deliveries (i.e., reduces overall costs). With respect to the other alternatives, the higher sulfur Northern Appalachian and Illinois Basin coal alternatives resulted in higher freight charges, partially offset by lower mine mouth costs. The net result was no reduction in costs and the proposed project was left with a higher sulfur coal. The Powder River Basin option was just too far to be economic (i.e., approximately 2,000 miles). Lastly, imported coal proved to be impractical because the inland transportation costs were too high.

Q. Recently, the price of coal on the spot market has risen. How has this impacted EVA's price forecast?

A. During the last half of 2000, the spot coal price for Central Appalachian coal (i.e., FOB rail car) has risen approximately 50 percent. This sharp increase in coal prices is in part due to the depressed coal prices that previously existed, which caused some

decline in production, and in part to an increase in demand. EVA has incorporated this recent price phenomenon in its price forecast, which projects the coal prices to moderate within two years, as supply and demand comes back into balance, but coal prices are not projected to return to their previously depressed levels. The FOB rail car price for Central Appalachian coal represents approximately 60 percent of the forecasted delivered coal price to the Stanton facility.

Q. Were the high, likely and low delivered coal price forecasts prepared by Black & Veatch reasonable?

A. Yes. EVA, as part of its normal practice, prepares high and low price forecasts for coal. These forecasts analyze the potential range for a series of variables that impact coal supply and demand fundamentals and hence coal prices. EVA compared and contrasted the Black & Veatch high and low coal price forecast with those generated by EVA and found them to be reasonable.

PETROLEUM COKE PRICE FORECAST

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

A. Petroleum coke represents a niche market for fuels that tends 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. For Southern - Florida and OUC, EVA updated its prior analysis 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. Were the high, likely and low petroleum coke prices prepared by Black & Veatch reasonable?

A. Yes. Based upon EVA's analysis of the market for fuel grade petroleum coke, the ranges of forecasts prepared by Black & Veatch were reasonable.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JILL SCHUEPBACH

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and address.

A. My name is Jill Schuepbach. My business address is 11401 Lamar Avenue, Overland Park, Kansas.

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

A. I am employed by Black & Veatch as a Project Engineer.

Q. Please describe your responsibilities in that position.

A. As a Project Engineer for Black & Veatch, I am responsible for providing consulting services for utility and non-utility clients. The consulting services encompass a wide variety of tasks including: load forecasts, conservation and demand-side management evaluations, reliability criteria and evaluations, development of generation unit addition alternatives, optimal generation expansion modeling, production cost modeling, economic and financial evaluations, feasibility studies, pro forma analysis, and power market studies.

Q. Please state your educational background and professional experience.

A. I received a Bachelors of Science degree in Mechanical Engineering from the University of Missouri – Columbia. I have been employed by Black & Veatch since 1998 as a Project Engineer in the Energy Consulting Service Area. Since then I have provided planning services for several projects including many projects in Florida. I have provided system planning consulting services for the following Florida utilities: Lakeland Electric (Lakeland), Orlando Utilities Commission (OUC), JEA, Kissimmee Utility Authority (KUA), and Florida Municipal Power Agency (FMPA). In 1998, I assisted in preparing the Need for Power Application for Lakeland's McIntosh Unit 5. In 1999, I helped develop the Demand-Side Management Plans for OUC and JEA, and I am currently working on the Need for Power Application for Lakeland's and FMPA's McIntosh Unit 4. I have also assisted in the preparation of Ten-Year Site Plans for various Florida utilities.

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

A. The purpose of my testimony is to describe the methodology used to determine if there are any conservation and demand-side management measures available to OUC, KUA, and FMPA that would mitigate the need for Stanton A.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. Exhibit No. ___ (JAS-1) FIRE Model Results.

Q. In addition to your exhibit, are there sections of the Need for Power Application identified as Exhibit OUC-1__ and the revision to the Need for Power Application, Exhibit OUC-2__ that you are sponsoring as your testimony?

A. Yes. Sections 1A.8.0, 1B.5.2, 1C.5.2, and 1D.5.2

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

A. Yes, I am.

Q. Are there any corrections to these sections?

A. No, only those minor word changes shown in Exhibit OUC-2__ and the minor change in the DSM test results for OUC stemming from the revision in the crude oil price and for KUA.

Q. What methodology was used to evaluate demand-side management (DSM) for OUC, KUA, and FMPA?

A. The explicit evaluation of all available conservation and demand-side management measures is very expensive. Historically in the last few years, conservation and demand-side management measures have not been found to be cost-effective for municipal utilities, as evidenced by the Need for Power Dockets for Cane Island 3 and McIntosh 5, and the Conservation Goals Dockets for JEA and OUC. In addition, cost and performance information for DSM measures is difficult and expensive to obtain. In order to reduce the cost of evaluating DSM measures and ensure that all reasonable measures have been evaluated, Black & Veatch has used the data and results from the Florida

Power and Light Company's (FPL's) Conservation Goal's Docket No. 991788-EG. FPL has done extensive evaluations having evaluated approximately 250 DSM measures in that Docket. It has been assumed that if the DSM measures found to be most cost-effective by FPL were not found to be cost-effective for OUC, KUA, and FMPA, then none of the 250 DSM measures evaluated by FPL would be cost-effective for OUC, KUA, and FMPA. Using this approach eliminated specific evaluations of hundreds of DSM measures that weren't cost-effective.

Q. How is the cost-effectiveness of DSM measures evaluated?

A. Black & Veatch used the PSC-approved Florida Integrated Resource Evaluator (FIRE) model which provides output in the form of the Rate Impact Test, the Total Resource Test, and the Participant's Test.

Q. Please describe how the FIRE Model works.

A. The FIRE Model evaluates the benefits and costs of DSM measures from several perspectives based on a comparison to costs for an avoided unit, which in this case is Stanton A. The model starts by evaluating the cost of the avoided unit in terms of capital cost, O&M costs, and fuel costs. Additional system costs, which could be avoided, are also evaluated, including transmission system capital and O&M costs and distribution system capital and O&M costs. The avoidance of these costs are considered benefits of the DSM measure being evaluated.

Next, the model evaluates the cost of the DSM measure being evaluated from several perspectives. The first perspective is the utility's cost for the DSM measure being evaluated. These costs include the actual cost of installing or implementing the measure paid by the utility. These costs are incurred through incentives paid for by the utility. Examples include rebates, subsidies, installation costs, and administrative costs associated with developing and maintaining the DSM program as well as lost revenues. Costs are also incurred by the participants. These costs can include the cost of purchase and installation of the measure, as well as costs associated with maintaining it.

The model compares these costs with the benefits and savings associated with the DSM measure. Again, these benefits and savings are evaluated from several perspectives. From the utility perspective, these savings and benefits stem from avoided generation and load shifting. From the participants' perspective, these savings and benefits stem from reduced electric bills from both lower rates and reduced consumption. The participant also benefits from any rebates and subsidies.

Q. Please describe in more detail the Rate Impact Test, the Total Resource Test, and the Participant Test referenced earlier.

A The Rate Impact Test (RIM) evaluates the above benefits and costs from the utility rate perspective. The RIM test compares the utility's savings from the measure such as avoided generation and fuel costs to the utility's cost for the measure such as costs for installation and utility rebates and subsidies. Thus if

the utility saves more from the program than the program costs, the RIM test is greater than 1 (the benefit/cost ratio is greater than 1), and rates to all customers will be lower. Generally, utilities require the RIM test to be greater than 1 before they will consider the DSM measure. In other words, if the program does not lower rates, utilities generally will not implement it.

The Total Resource Test evaluates the above benefits and costs from a combined perspective of the customer and the utility. For the Total Resource Test, only costs external to the customer and the utility are considered. For instance, rebates for a measure paid by the utility to the customer are merely a transfer between the utility and the customer and have no effect on the benefit/cost ratio; whereas fuel cost savings paid to external fuel suppliers would have an effect on the benefit/cost ratio. In general, if the result of the Total Resource Test is greater than 1, society as a whole would benefit but some groups in society may be harmed.

Finally, the Participant Test evaluates benefits and costs solely from the perspective of the customer, or participant. If the benefit/cost ratio is greater than 1, the customer saves more money on the measure than they spend on it. In general, unless the Participant Test is greater than 1, there is no incentive for the customer, or participant, to participate.

Generally, for a DSM program to be successful, the program should pass (have benefit/cost ratio greater than 1) all three tests, the RIM Test, the Total Resource Test, and the Participant Test.

Q. Specifically, what were the results of Black & Veatch's evaluations of DSM measures for OUC, KUA, and FMPA?

A. Black & Veatch evaluated the most cost-effective measures in FPL's Conservation Goal's Docket that weren't already being implemented by OUC, KUA, and FMPA for both residential and commercial/industrial sectors. In all cases the most cost-effective of FPL's measures were found to not be cost-effective based on the RIM test. As such, it is assumed that none of FPL's conservation measures that aren't already being implemented by OUC, KUA, and FMPA would be cost-effective for any of the three utilities. Each utility bases cost-effectiveness on the RIM test.

Q. What factors preclude DSM measures from proving cost-effective?

A. The cost-effectiveness of many DSM measures has decreased over the years for various reasons. This is especially true when evaluating potentially cost-effective DSM measures for municipal utilities, which are subject to lower cost tax exempt financing. Additionally, the cost of installing new generation has decreased, while the efficiency of the new units has increased. Combining these two factors with government mandates, which force appliance manufacturers to increase the efficiencies of their products, reduces the potential of energy savings through an external DSM measure.

Q. How does the recent spike in natural gas prices affect the cost-effectiveness of DSM measures?

A. For DSM measures that result primarily in capacity reduction without significant energy reduction, such as Direct Load Control, the increase in fuel

prices would have little effect because the cost-effectiveness is primarily driven by savings in avoided unit capacity charges.

For DSM measures that primarily reduce energy consumption, such as appliance efficiency measures, increases in fuel prices will have a greater effect. However, appliance efficiency has already improved tremendously in most areas. Further incremental improvements in efficiency are fairly expensive and result in relatively small incremental savings in energy consumption.

Q. Is there a natural gas price above which DSM measures for OUC, KUA, and FMPA become cost-effective?

A. Cost-effectiveness is specific to each utility and DSM measure. The DSM measures are evaluated using the base case fuel forecast shown in Table 1A.5-5 of the revised Need for Power Application Exhibit OUC-2 __. As such, there is no single natural gas price that determines cost-effectiveness. Exhibit JAS-1 represents the RIM, Participant, and Total Resource Test results for the DSM measures evaluated by the FIRE Model for each utility for the base case and high fuel price projections presented in Table 1A.5-6 of the revised Need for Power Application Exhibit OUC-2__. As expected, the high fuel price case has little effect on the RIM test especially for the load shifting alternatives which are the residential direct load control (Res-DLC) and the commercial off-peak battery charging (Comm-OPBC). Where there is more energy conservation involved such as the Residential Build Smart

measure (Res-Build Smart) there is relatively more impact from the higher fuel prices, but the RIM test is still significantly below 1.0.

Q. Does this conclude your prefiled testimony.

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF ERIC FOX

ON BEHALF OF OUC

DOCKET NO. 010142-EM

MARCH 5, 2001

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 Regional Economic Research, Inc (RER). I am a Vice President in the Company's Forecasting Division.

Q. Please describe your responsibilities in that position

A. I am responsible for managing forecast support work and forecast project implementations for electric and gas utilities. I am also responsible for the day-to-day operation of RER's Boston office. I also provide forecast training through workshops sponsored by RER and other organizations such as EPRI and the Institute of Business Forecasting, and forecasting consulting services to electric and gas utilities.

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. After graduating, I started work at San Diego Gas & Electric as an Analyst in the Forecasting Department. I have been involved in energy forecasting and analysis, load research, rate design, and DSM program evaluation since that time. In 1994 I joined RER as a Project Manager. I was promoted to Vice President in 1999.

I have provided testimony for regulatory proceedings for forecasting and rate related matters.

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 there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A. Yes. Section 1B.4.0 and Appendix 1B.A.

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

A. Yes, I am.

Q. Are there any corrections to these sections?

A. No.

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. 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 service (large commercial and industrial customers), and 4) street lighting. Models are estimated using monthly sales data covering the period 1991 through 1999.

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 marketing staff and include adjustments for large individual projects such as the expansion at Universal Studios, a new convention center, and expected expansion at the Orlando International Aiport. 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?

To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as a Statistically Adjusted Engineering (SAE) model, entails specifying end-use variables –

heating, cooling, and base use – 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 twenty-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 impact historical appliance purchase behavior. Future efficiency trends due to expected changes in appliance standards are embedded in the end-use model variables.

As a result of projected economic, price, and appliance trends, average use is projected to increase at a relatively low rate. For OUC residential average use is expected to increase 0.8 percent per year through 2005, and further slows to

just 0.5 percent growth through 2015. St. Cloud residential average use growth is slightly lower. Nonresidential average use also increases relatively slowly over the forecast horizon. Forecasted sales growth is primarily driven by projected customer growth.

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

A. OUC and St. Cloud's combined summer peak demand is forecast to increase from 1,062 MW in 2000 to 1,679 MW in 2020 for a compound annual growth rate of 2.3 percent which is significantly lower than the historical growth rate of 4.3 percent over the past five years.

Similarly, the winter peak is forecast to grow from 1,051 MW in 2000 to 1,697 by 2020, or a compound annual average growth rate of 2.4 percent which is also considerably lower than the historical growth rate of 3.7 percent over the past five years.

OUC and St. Cloud's net energy for load is expected to grow at a compound annual average growth rate of 2.3 percent over the twenty year forecast period which compares with a historical growth rate of 4.1 percent over the past five years.

While the economy (and thus energy and demand growth) is expected to slow from the pace experienced over the last five years, regional economic growth will remain relatively strong over the long-term forecast horizon. The number of households in the Orlando MSA is expected to increase 1.9 percent per year

and employment 2.1 percent annually over the forecast horizon. In a recent analysis, Regional Financial Associates (now Economy.com) ranked the Orlando MSA 16 out of 321 MSAs in terms of current and projected economic growth.

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 the potential outcome. High forecast assumes stronger population, employment and regional output growth than in the base case. Further the high case assumes stronger growth in computer loads as reflected by the commercial base use variables. The low case is driven by slower population, employment, and output growth. The result is that retail energy demand grows roughly 0.7 percent faster in the high case and 0.6 percent slower in the low case. The high and low forecast scenarios are presented in Table 1B.4-20 of the 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 provided by Regional Financial Associates (RFA). RFA has an excellent reputation in

regional modeling and forecasting. The economic projections are in line with projections from the University of Florida. Long-term population forecast from the University of Florida are used to drive household growth after 2010.

The forecast scenarios provide a means to help bound forecast uncertainty. High and low growth economic assumptions yields a reasonable bound around the base case forecast with retail sales growing 0.7 percent faster in the high case and 0.6 percent slower in the low case.

Q. Does this complete your prefiled testimony?

A. Yes it does it.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF MYRON ROLLINS

ON BEHALF OF OUC, KUA, AND FMPA

DOCKET NO 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

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

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.

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 twenty-four years of experience in the power industry specializing in generation planning and project development. In the past ten 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 Lakeland – Electric, Kissimmee Utility Authority, Florida Municipal Power Agency, Orlando Utilities Commission, JEA, City of St. Cloud, 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 Stanton 1 and 2, 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 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 discuss the economic assumptions and fuel price projections used in the evaluation of the Southern-Florida joint development project. In addition, I will discuss the need for capacity for OUC, KUA and FMPA based on their reliability criteria. I will also discuss other supply-side alternatives considered for each utility, demand-side management, the consistency of the project with Peninsular Florida's needs, and the consequences of delaying the commercial operation of Stanton A.

My testimony will also show that OUC, KUA, and FMPA have adequately explored alternative generating technologies under a number of different load and fuel price scenarios, demonstrating that Stanton A is the most cost effective alternative, and that the project will provide necessary electricity at a reasonable cost, while contributing to the electric system reliability and integrity of OUC, KUA, and FMPA, as well as Peninsular Florida.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1 _____ and the revisions to the Need for Power Application identified as Exhibit OUC-2 _____ that you are sponsoring?

A. Yes. Sections 1A.1, 1A.2, 1A.3.5, 1A.3.8, 1A.5, 1A.6.3, 1A.7, 1A.9, 1A.10, 1A.11, 1B.1, 1B.3, 1B.6, 1B.7, 1B.8, 1C.1, 1C.3, 1C.6, 1C.7, 1C.8, 1D.1, 1D.3, 1D.6, 1D.7, and 1D.8 and Appendices 1A.D, 1A.E, 1B.B, 1C.A, and 1D.A.

Are you adopting these sections as part of your testimony?

A. Yes, I am.

Q. Are there any corrections to these sections?

A. No other than the revisions in OUC-2 _____. The revisions to OUC-2 ___ result from updates to the crude oil forecast, provided by EVA, from application of appropriate escalation rates from the Annual Energy Outlook and from the addition of insurance costs in the FMPA fixed charge rate. While several numbers changed, the results remained the same. OUC-2 _____ also corrected some typographical errors.

Evaluation Methodology

Q. Please briefly describe the process that led to the determination that participation in the Southern-Florida joint development project represents the most cost-effective alternative to meet OUC, KUA, and FMPA's capacity need.

A. OUC, KUA, and FMPA went through a multi-stage process to develop the most cost-effective generation expansion plan that meets their respective need for capacity. This process included issuing a request for power supply proposals and a request for joint development proposals. The responses to these request for proposals were evaluated and ranked on a levelized cost per megawatt hour basis. OUC also evaluated a self-build alternative in the same manner. The Southern-Florida proposal was found to be the most cost-effective, and was selected for further negotiations. These negotiations led to development of a Power Purchase Agreement (PPA), as well as other agreements associated with the project. The

next step in the evaluation process was to develop individual optimal generation expansion plans for each utility over a 20-year period for a base case and a number of sensitivity cases.

The results of this multi-staged process showed the Southern-Florida joint development proposal was the most cost-effective alternative to allow OUC, KUA, and FMPA to meet their capacity needs.

Economic Criteria

Q. Please describe the economic criteria used in the evaluations.

A. A consistent set of economic criteria were used for the evaluations. A general inflation rate of 2.5 percent was assumed and the general inflation rate was used as the escalation rate for O&M and capital costs. An interest rate of 6.0 was assumed for interest during construction.

Levelized fixed charge rates were developed to apply to the capital costs for new generating units. The fixed charge rate was based on the estimated weighted average cost of capital for OUC of 8 percent with a capital recovery period of 20 years plus one percent for insurance. The resultant annual fixed charge rate is 11.19 percent. KUA's fixed charge rate was assumed to be equal with OUC's. A present worth discount rate of 8 percent equal to the estimated weighted average cost of capital was used for OUC and KUA.

FMPA traditionally finances their generating units entirely with tax exempt municipal bonds. The estimated long term tax exempt municipal bond rate is assumed to be 6 percent. The fixed charge rate assuming a 2.9 percent bond issuance fee, a one year debt service reserve fund earning interest at the 6 percent bond rate, one percent for insurance and a 30 year bond term is 8.602 percent. Due to the relative small amount of equity required for Stanton A, FMPA plans on using the FMPA Pooled Loan Project to finance FMPA's 3.5 percent ownership share of Stanton A. The estimated interest rate over a 20-year period from FMPA's Pooled Loan Project is 5.0 percent resulting in a fixed charge rate of 9.02 percent including one percent for insurance. A present worth discount rate of 6 percent equal to the long term bond rate was used for FMPA.

Q. Do you believe these economic criteria are reasonable and appropriate for evaluating Stanton A for OUC, KUA, and FMPA?

A. Yes. I believe these economic criteria are reasonable and appropriate for OUC, KUA, and FMPA.

Fuel Price Projections

Q. Please describe the process undertaken to arrive at the various fuel price forecasts presented in the Need for Power Application.

A. EVA developed a base case forecast in constant dollars for natural gas, crude oil, petroleum coke, and coal as presented in the testimony of Stephen Thumb. The projections for petroleum coke and coal were on a delivered basis. The fuel price

projections were converted to normal dollars by applying the 2.5 percent general inflation rate to obtain the delivered cost. For evaluation purposes, an assumed $0.75/MBtu was added to Henry Hub natural gas price to obtain a delivered price. Nuclear fuel prices were based on OUC's 2000 actual costs escalated at the general inflation rate. No.2 and No. 6 oil price projections were developed by applying the ratio of OUC's actual 2000 costs to the projected 2000 crude oil prices The base case fuel price projections were used for OUC, KUA, and FMPA.

High and low fuel forecasts were developed for each fuel type in the base case forecast, with the exception of petroleum coke. For the high scenario, an additional 2 percent was added to each year's escalation rate, while for the low scenario, the annual escalation rate was reduced by 2 percent. For petroleum coke, EVA provided specific high and low forecasts which were used for the respective fuel price scenarios.

Several other fuel price scenarios were developed. First, fuel prices were assumed to remain constant in real terms. OUC's actual 2000 delivered costs for No. 2 and No. 6 oil, nuclear, and coal were assumed to escalate at the 2.5 percent general inflation rate. For natural gas, the general inflation rate of 2.5 percent was added to the 2000 commodity price and $0.75/MBtu was added for transportation. Since OUC did not purchase any petroleum coke in 2000, the base case forecast supplied by EVA for 2000 was used as the starting point, with the 2.5 percent general inflation applied.

A fuel price scenario was also analyzed which incorporated projections from the Energy Information Administration's *2001 Annual Energy Outlook (AEO)*. The AEO fuel price forecast provided a constant dollar delivered forecast for coal, as well as for No. 2 and No. 6 oil. AEO's well head projection for natural gas was used and $0.75/MBtu was added to each year's well head price to determine the delivered natural gas forecast. Since AEO did not provide projections for petroleum coke or nuclear fuel, the base case forecasts for these fuels were used. The 2.5 percent general inflation rate was included in all the fuel price projections.

The final fuel scenario was developed by applying the escalation rates presented in the AEO forecast to the average price paid by OUC in 2000 for natural gas, coal, and No. 2 and No.6 oil. Again, a $0.75/Mbtu transportation charge was added to each year's natural gas forecast to determine the delivered price. Since AEO forecasts were not available for either petroleum coke or nuclear fuel, the base case forecast for these fuels were used.

Q. Do you believe the five fuel forecasts developed adequately reflect any fuel price scenarios that may reasonably be expected?

A. Yes, I believe the fuel forecasts developed and analyzed adequately reflect any fuel price scenarios that may be reasonably expected. The various forecasts reflect a wide range of fuel prices.

Q. Were any demand-side management (DSM) measures in addition to their existing programs found to be cost effective for OUC, KUA and FMPA?

A. No. Based on the rate impact test (RIM) there were no additional DSM measures beyond those in their existing programs that were found to be cost effective.

Q. Do you feel that the RIM test is the appropriate criterion for determining if DSM measures are cost effective?

A. Yes. For municipalities, I believe that it is appropriate to require that DSM measures pass the RIM test. Programs that do not pass the RIM test will result in increased rates. I also believe that it is appropriate for DSM measures to be required to pass the participant and total resource tests as well.

Generating Unit Alternatives

Q. What generating units were considered as alternatives to Stanton A?

A. A large number of generating unit alternatives were considered including renewable technologies, waste to energy technologies, advanced technologies, energy storage systems, and conventional technologies. Cost and performance characteristics were developed for each of the alternatives.

Q. Please describe the process through which alternatives were selected for detailed analysis.

A. The generating unit alternatives considered were evaluated and screened with respect to availability of resources and commercial development. Generating unit alternatives which were deemed to be commercially available and have adequate resources available were considered for further evaluation. All of the conventional alternatives as well as solar thermal, solar photovoltaic, fuel cells,

and supercritical coal units met these criteria. They were compared to similar conventional alternatives on a levelized $/MWh basis. The conventional alternatives were lower in cost on a $/MWh basis and thus only the conventional alternatives were considered for further evaluation.

Q. What conventional alternatives were considered?

A. In general, the conventional alternatives considered included pulverized coal units, fluidized bed units, combined cycle units, and simple cycle combustion turbine units. Specific alternatives were developed for each utility considering their ownership of existing sites, potential for joint participation, and size.

Q. Were specific alternatives developed for direct comparison to Stanton A?

A. Yes. Initially Black & Veatch developed cost estimates for two 2 x 1 Siemens-Westinghouse 501 F combined cycle units. One configuration incorporated minimum duct firing, while the other configuration incorporated the greatest amount of duct firing possible resulting in a larger unit. The scope and cost estimate for these units are contained in the Need for Power Application Exhibit OUC-1 _____, Appendices 1A.D and 1A.F respectively. OUC used these cost estimates to compare the cost of a self-build alternative to proposals received from the joint development and power supply RFPs.

Q. Could OUC obtain combustion turbines in time to achieve the specified October 1, 2003 commercial operation date?

A. No. The delivery schedule for new Siemens-Westinghouse combustion turbines was the beginning of 2004. Thus, a 2005 commercial operation date would be the

earliest possible commercial operation date. Nevertheless the capital cost estimates based on current market prices were useful to OUC in order to indicate the capital cost savings in the proposals in response to the joint development RFP. OUC was also able to evaluate the benefit of the earlier commercial operation dates provided in the proposals.

Q. Were there any other alternatives available to OUC, KUA and FMPA that could be directly compared to Stanton A?

A. Possibly. KUA had an option for two General Electric 7 F combustion turbines which was obtained when KUA purchased the combustion turbine for Cane Island 3. The original option for the combustion turbine was scheduled to expire before the proposals from the joint development RFP were due. KUA was able to extend the option for the combustion turbines through the evaluation period for the joint development RFP. Thus, a technically identical self-build alternative utilizing KUA's extended option for combustion turbines with a delivery schedule that would support an October 1, 2003 commercial operation date was available. The estimated cost for the technically identical alternative was based on the actual cost of the combustion turbines under option to KUA. The performance of the self-build alternative was assumed to be identical to Stanton A.

Q. Were there any other possible obstacles to the construction of the self-build alternative for a commercial operation date of October 1, 2003?

A. Yes. First, KUA's combustion turbine option had a provision indicating that the delivery date for the combustion turbines could be subject to General Electric's prior sales. Second, the option was not specific as to whether the combustion

turbines could be used for a power plant constructed at Stanton Energy Center. In the event that the combustion turbines could not be used at Stanton, the project could have been constructed at Cane Island. Finally, OUC would have had to been able to engage a firm to design and construct the project for the October 1, 2003 commercial operation date. While adequate time existed for the design and construction of the project, many of the firms providing design and construction services are fully booked through 2003. Nevertheless, cost and performance estimates were developed and used to evaluate the technically identical self-build alternative to Stanton A.

Q. Are the combustion turbines under KUA's extended option still available?

A. No. The extended option has expired.

Expansion Planning Methodology

Q. Please describe the process used to determine the least cost expansion plan.

A. POWROPT, an optional generation expansion model is used to determine the least cost expansion plan.

Q. Please describe how POWROPT works.

A. POWROPT is an optional generation expansion model. POWROPT models the utility's existing generating units as well as candidate units. The units are committed and dispatched in a least cost manner as in actual utility operation. The simulation calculates fuel and O&M costs on an hourly basis and accumulates the costs on an annual basis. The model projects hourly loads for

every year throughout the planning period based on the load forecast. As loads grow and additional capacity is required to meet reserve margin requirements, the model evaluates all combinations of candidate units available to meet the capacity requirements and selects the plan that results in the lowest cumulative present worth costs considering system fuel and O&M costs and annual capital costs obtained by applying an annual fixed charge rate to the capital cost for the new unit installation costs. POWROPT then uses the user specified present worth discount rate to calculate the cumulative present worth of each possible expansion plan that meets the reserve margin requirements and then ranks the expansion plans based on cumulative present worth costs.

Q. What planning period is used for the evaluations?

A. A 20-year planning period from 2000 through 2019 is used.

Q. Is the planning period appropriate?

A. Yes. A 20-year planning period is appropriate and 20-year planning periods have often been used by utilities for evaluating expansion plans.

Q. How are the POWROPT results used?

A. The expansion plans developed by POWROPT are modeled by POWRPRO, Black & Veatch's hourly chronological production costing model. POWRPRO provides detailed fuel and O&M costs by unit. These costs are summarized on an annual basis and included with the annual capital costs and any other costs to provide detailed annual costs which are also discounted using the present worth discount rate to provide cumulative present worth costs.

Q. Please discuss the sensitivity analyses evaluated.

A. Because the evaluations are based on projections of fuel costs, load forecasts and other parameters which are difficult to accurately project, varying scenarios of fuel cost projections and load forecasts are made and evaluated to determine the robustness of the expansion plan under varying projections for the future. The sensitivity analyses are conducted identically to the base case analyses.

Reliability Criteria

Q. Please explain the concept of a "reliability criteria" and why it is important for planning purposes.

A. To serve native load, a utility must have firm capacity resources in excess of its expected firm peak demand. This margin of capacity over firm peak load is needed because factors affecting either demand or supply could cause load to go unserved if a utility maintained only enough resources to meet its expected firm peak demand. On the demand side, higher than expected demand can occur due to a greater number of customers on the system, greater than expected usage per customer, extreme weather conditions, or lower than anticipated demand-side measure impacts. On the supply side, generation capacity could be unavailable due to factors such as forced or scheduled outages on generation equipment, unanticipated transmission constraints limiting power imports, generator deratings due to equipment failures, and unanticipated constraints on fuel supplies or water supplies.

Due to uncertainties involved with projecting both demand and available supply, utilities maintain a "margin" of firm capacity resources over and above the anticipated peak level of firm demand. Traditionally in the industry, reserve levels of 15 percent are typical, with some utilities having adopted an even higher reserve margin. The appropriate level of reserve margin varies by utility, but generally, the smaller the utility and the fewer number of interconnections with other utilities, the greater is the reserve margin.

OUC Reliability Criteria

Q. What is the target reserve margin adopted by OUC.

A. OUC has adopted a 15 percent reserve margin level. This is based on the work of the Florida Reliability Coordinating Council (FRCC) which has found that a planned reserve margin criterion of 15 percent is adequate for Peninsular Florida. The 15 percent reserve margin has also been established as a minimum planned reserve margin in Rule 25-6.035(1) Florida Administrative Code for purposes of reserve sharing. Therefore, OUC believes this to be the minimum level it should maintain, consistent with prudent utility planning and Florida regulations.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for OUC?

A. In order to maintain a 15 percent reserve margin requirement, OUC will likely encounter capacity shortfalls beginning in the summer of 2002. Initially, these capacity needs are small enough that they will likely be met through seasonal power purchases. However, by the winter of 2004, the earliest that new capacity

can be brought on-line, the forecast deficit grows to 564 MW with the expiration of the Reliant PPA, and either remains relatively steady or increases thereafter. By the summer of 2019, OUC will require an additional 879 MW of capacity in order to maintain its required reserve margin.

Q. What generating unit alternatives did OUC consider?

A. OUC considered units that were appropriate in size and technology for OUC's system. For installation by October 1, 2003, OUC considered the Southern-Florida joint development project as well as a technically identical combined cycle unit based on KUA's option for General Electric 7 F combustion turbines. Due to the delivery schedule for F class combustion turbines and the construction and licensing requirements for solid fuel units, no other alternatives were considered available which could meet an October 1, 2003 commercial operation date. Other combustion turbine based technologies including simple cycle 7 F combustion turbines and 2 x 1 501 F combined cycle units were assumed to be available for June 1, 2005 commercial operation date. A circulating fluidized bed unit was assumed to be available in 2005 and an identical pulverized coal unit to Stanton 2 was assumed to be available for commercial operation by June 1, 2006.

OUC Economic Evaluation and Sensitivity Analyses

Q. What was the conclusion of the detailed economic analysis performed in POWROPT/POWRPRO?

A. The economic analysis indicates that participation in the joint development project with Southern-Florida is the most economical option available to OUC.

On a cumulative present worth basis, participation in the joint development project results in a $6.611 million saving as compared to the second least-cost expansion plan.

Q. What were the results of the sensitivity analyses for OUC?

A. The sensitivity analyses demonstrate that participation in the joint development project with Southern-Florida is a very sound decision for OUC. The joint development project proves to be the least-cost alternative in all but two of the sensitivity scenarios.

Q. What conclusions did you draw from this analysis?

A. Based on the results of the extensive screening analysis and production costing analysis, participation with Southern-Florida in the joint development project proves to be the most cost effective option for OUC's ratepayers under the most likely future conditions expected on the system. It is also the most cost-effective alternative for all but two of the sensitivity scenarios analyzed. Based on these facts, I conclude that the joint development project with Southern-Florida represents the most cost effective option for OUC's ratepayers.

KUA Reliability Criteria

Q. What is the target reserve margin adopted by KUA.

A. KUA has adopted a 15 percent reserve margin level. The FRCC has found that a planned reserve margin criterion of 15 percent is adequate for Peninsular Florida. The 15 percent reserve margin has also been established as a minimum planned

reserve margin in Rule 25-6.035(1) Florida Administrative Code for purposes of reserve sharing. Therefore, KUA believes this to be the minimum level it should maintain, consistent with prudent utility planning and Florida regulations.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for KUA?

A. In order to maintain a 15 percent reserve margin requirement, KUA will likely encounter capacity shortfalls beginning in the summer of 2004. Initially, these capacity needs are small (11 MW); however, by the summer of 2019, KUA will require an additional 216 MW of capacity in order to maintain its required reserve margin.

KUA Generating Unit Alternatives

Q. What generating unit alternatives did KUA consider?

A. Generating unit alternatives considered by KUA were based on sole and joint ownership of alternatives that were judged to be appropriate sizes and technology for KUA's system. Alternatives considered include joint participation in the Southern-Florida joint development project, joint participation in an identical self-build project, joint ownership in a pulverized coal, simple and combined cycle units, as well as sole ownership in simple cycle units.

Q. What was the conclusion of the detailed economic analysis performed in POWROPT/POWRPRO?

A. The economic analysis indicates that participation in the joint development project with Southern-Florida is the most economical option available to KUA. On a cumulative present worth basis, participation in the joint development project results in a $1.621 million saving as compared to the second least-cost expansion plan.

Q. What were the results of the sensitivity analyses?

A. The sensitivity analyses demonstrate that participation in the joint development project with Southern-Florida is a very sound decision for KUA. The joint development project proves to be the least-cost alternative in all but one of the sensitivity scenarios.

Q. What conclusions did you draw from this analysis?

A. Participation with Southern-Florida in the joint development project proves to be the most cost effective option for KUA's ratepayers under the most likely future conditions expected on the system. It is also the most cost-effective alternative for all but one of the sensitivity scenarios analyzed. Based on these facts, I conclude that the joint development project with Southern-Florida is the most cost effective option for KUA's ratepayers.

Q. What is the target reserve margin adopted by FMPA.

A. FMPA has adopted an 18 percent reserve margin in summer and 15 percent in winter. FRCC has determined that a 15 percent reserve margin is adequate for Peninsular Florida and the PSC has established 15 percent as the minimum reserve margin in Rule 25-6.035(1), Florida Administrative Code, for purposes of

reserve sharing. FMPA's 18 percent reserve margin in summer provides additional assurance of reliability of supply.

Q. How does the need to meet this reliability criteria impact the timing and need for additional capacity resources for FMPA?

A. In order to maintain an 18 percent summer reserve margin requirement, FMPA will likely encounter capacity shortfalls beginning in the summer of 2003. Initially, these capacity needs are small (39 MW) and, due to the delivery schedule of combustion turbines, must be satisfied with purchased power. However, by the summer of 2019, FMPA will require an additional 617 MW of capacity in order to maintain its required reserve margin.

FMPA Generating Unit Alternatives

Q. What generating unit alternatives did FMPA consider?

A. Generating unit alternatives considered by FMPA were based on sole and joint ownership of alternatives that were judged to be appropriate sizes and technology for FMPA's system. Alternatives considered include joint participation in the Southern-Florida joint development project, joint participation in an identical self-build project, joint ownership in pulverized coal and combined cycle units, as well as sole ownership in the simple cycle units.

Q. What was the conclusion of the detailed economic analysis performed in POWROPT/POWRPRO?

A. The economic analysis indicates that participation in the joint development project with Southern-Florida is the most economical option available to FMPA in order to help satisfy its 18 percent summer reserve margin criteria. On a cumulative present worth basis, participation in the joint development project results in a $38.7 million saving as compared to the second least-cost expansion plan.

Q. **What were the results of the sensitivity analyses?**

A. The sensitivity analyses demonstrate that participation in the joint development project with Southern-Florida is a very sound decision for FMPA. The joint development project proves to be the least-cost alternative in all but two of the sensitivity scenarios.

Q. What conclusions did you draw from this analysis?

A. Participation with Southern-Florida in the joint development project proves to be the most cost effective option for FMPA's ratepayers under the most likely future conditions expected on the system. It is also the most cost-effective alternative for all but one of the sensitivity scenarios analyzed. Based on these facts, I conclude that the joint development project with Southern-Florida is the most cost effective option for FMPA's ratepayers.

Peninsular Florida Need

Q. Is the proposed project consistent with Peninsular Florida's needs?

A. Yes. The Florida Reliability Coordinating Council (FRCC) is responsible for coordinating power supply reliability in Peninsular Florida for the North American Electric Reliability Council. The FRCC has selected a minimum 15 percent reserve margin criterion to ensure reliability for Peninsular Florida. As part of its reliability coordination activities, the FRCC provides an annual summary and report of Peninsular Florida Ten Year Site Plans. The most recent planning summary conducted by FRCC is the 2000 Load and Resource Plan for the State of Florida.

As shown in Section 1A.9 of the Need for Power Application Exhibit OUC-1 ___, Peninsular Florida reserve margins are projected to exceed the 15 percent planning criteria through 2009. Without the inclusion of units that have not yet received certification under the Power Plant Siting Act, this reserve margin would drop below 15 percent in 2004. Thus, the joint development venture with Southern-Florida makes a critical contribution to maintaining Peninsular Florida reliability at acceptable levels.

Q. In your opinion, will the joint development project with Southern-Florida contribute to maintaining reliability and integrity for the OUC, KUA, FMPA, and Peninsular Florida systems?

A. Yes. The joint development project utilizes proven F-class combined cycle technology and will provide a reliable source of power to contribute to the OUC, KUA, FMPA, and Peninsular Florida capacity requirements.

Consequences of Delay

Q. What would be the consequences of a significant delay or non-approval of the joint development project?

A. In the event that the commercial operation of the joint development project were delayed or not approved, OUC, KUA, and FMPA would experience adverse consequences, both from an economic as well as a reliability perspective.

A delay in the commercial operation of the joint development project would force OUC, KUA, and FMPA to incur additional costs to replace the capacity and energy that Stanton A would otherwise provide. The only generating unit alternative available to meet the October 1, 2003, commercial operation date of Stanton A is an LM 6000. The LM 6000 has a 30 percent higher heat rate than Stanton A, and is considerably more expensive on a $/kW basis. Additionally, the assumption that a LM 6000 could be available for commercial operation by October of 2003 may be optimistic based on actual delivery schedules. If in fact the delivery schedule would preclude installation of an LM 6000 in a timely fashion, OUC, KUA, and FMPA would be forced to look to purchasing power as a means of satisfying their capacity and energy requirements. In addition to the price of purchase power being uncertain, its availability is perhaps even more questionable.

In the event that commercial operation of Stanton A is delayed significantly, OUC, KUA, and FMPA would face a collective capacity shortfall of 214 MW by the summer of 2004 even with OUC exercising the full 500 MW available from the Reliant PPA.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JOHN E. HEARN

ON BEHALF OF OUC

DOCKET NO. 010142-EM

March 5, 2001

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 14 years.

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

A. The purpose of my testimony is to discuss OUC's existing conservation and demand-side management programs and to discuss OUC's ability to finance Stanton A.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A. Yes. Sections 1B.5.1 and 1B.9.0.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe OUC's current conservation programs that reduce peak demands and energy consumption?

A. Significant changes have occurred in the market during the last 5 years. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Economic conditions have changed significantly, for example, the cost of power plants and interest rates have decreased drastically. As a result, conservation programs are not always as cost-effective, but greater emphasis is placed on customer satisfaction. OUC's existing programs include the following:

- Residential Energy Survey Program
- Residential Heat Pump Program
- Residential Weatherization Program
- Low Income Home Energy Fixup Program
- Educational Outreach Program

- Commercial Energy Survey Program

These programs are provided because they have been proven to meet the needs of OUC's customers and contribute to reduction of energy consumption and peak demand. OUC will continue to evaluate DSM programs to identify programs that add customer value.

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

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 2000 was 2.23. We have strong credit ratings on all of our senior debt consisting of AA+ by Fitch, Aa1 by Moody's, and AA by Standard & Poor's. In fact, no municipal utility in the United States has higher credit ratings. 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, O&M costs, and administrative and general costs. Fuel and purchase power costs including capacity and energy charges are recovered through a fuel charge.

Q. How do OUC's wholesale power sales affect rates?

A. OUC's wholesale power sales are generally structured such that fuel is a pass through. The nonfuel revenue from wholesale power sales reduces base rates.

Q. How did the sale of the Indian River Steam Units affect OUC's rate making process?

A. The sale of the Indian River Steam Units resulted in unique opportunities for OUC.

The proceeds from the sale of the Indian River Steam Units were allocated in three areas. First, the outstanding debt related to the Indian River Steam Units was eliminated. This was accomplished by reducing other borrowing to offset the remaining debt on the Indian River Steam Units. Next, two funds were set up with the remaining proceeds. The first fund was for approximately $45 million and along with the interest from the second fund is used to offset the higher cost of the Reliant Power Purchase Agreement (Reliant PPA) over the four year term so that the net cost under the Reliant PPA would be the same as if OUC had not sold the Indian River Steam Units. The balance representing approximately $140 million comprises the second fund which is

earmarked either to retire existing generation debt or for new generation such as Stanton A.

Q. How will the cost for OUC's ownership share of Stanton A be recovered?

A. The capital and O&M costs for OUC's ownership share of Stanton A will be recovered through base rates. As mentioned above, the capital may be paid from funds from the sale of the Indian River Steam Units. The fuel cost will be recovered through the fuel charge.

Q. How will the cost for OUC's entitlement to purchase power from Stanton A be recovered?

A. OUC's costs for our entitlement to the purchase power from Stanton A will be recovered through the fuel charge.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF ABANI KUMAR SHARMA

ON BEHALF OF KUA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Abani (Ben) Kumar Sharma. My business address is 1701 West Carroll Street, Kissimmee, Florida, 34741.

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

A. I am employed by Kissimmee Utility Authority (KUA) as Director of Power Supply.

Q. Please describe your responsibilities in that position

A. I am responsible for KUA's Power Supply Department. The department has a staff of 80 employees and an annual operating budget of $47 million. The department consists of three divisions, which include the power production division, system control division, and the bulk system planning division. As part of my responsibilities, I am also involved in the planning, permitting and construction of new generation facilities, fuel supply and transportation contracting, and purchase power negotiations and contracting. As Director of Power Supply, I am accountable to the President, General Manager, and CEO on all matters concerning the department. I have held this position for eleven and one-half years.

Q. Please state your professional experience and educational background.

A. I have more than 27 years of professional engineering experience including 22 years of utility experience. Prior to joining KUA, I was employed by the City of Tallahassee Electric Department during the years 1979 through 1989. I began my employment with the City of Tallahassee Electric Department as a System Planning Engineer. I was promoted to Superintendent of Planning in 1981 and after certain reorganization in the department renamed as Superintendent of Planning in 1988. During my period of employment with the City of Tallahassee Electric Department, I was responsible for performing various planning and engineering activities including preparation of Ten-Year Site Plans, initiation of the Jackson Bluff Hydro Electric Project, including completion of the feasibility study, acquisition of DOE grants of $1.75 million and obtaining the construction and operating license from FERC.

My background includes 4 years of experience with Southern Engineering Company of Atlanta, Georgia. I was responsible for preparation of distribution expansion plans, long-range capacity expansion plans, system design studies and preparation of Power Requirements Studies necessary for cooperatives to acquire REA (now RUS) and Cooperative Financing Corporation (CFC) loans.

I am a registered professional engineer in the States of Florida and Georgia. I graduated with a bachelor's degree in electrical engineering in 1962 from Banaras Engineering College in Banaras, India, and a master's degree in

electrical engineering in 1965 from the Georgia Institute of Technology in Atlanta, Georgia.

From 1996 to 2000, I also served as Chairman of Florida Gas Utility (FGU), a non-profit organization which procures natural gas and manages natural gas transportation for its members. Currently FGU has 22 municipal members and three full service industrial members.

As for my community involvement, I was President of the Rotary Club of Kissimmee-West during 1998-1999.

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

A. The purpose of my testimony is to provide a description of KUA, discuss KUA's need for Stanton A, describe KUA's benefits from its participation in Stanton A, and to discuss KUA's ability to finance Stanton A. I also will show that Stanton A will provide reliability and integrity to KUA's system, that Stanton A will provide adequate electricity at a reasonable cost to KUA, and that Stanton A is the most cost-effective alternative available to KUA.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A. Yes. Sections 1C.2.0 and 1C.9.0.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe the structure of KUA?

A. Kissimmee Utility Authority (KUA) operates as an independent utility authority owned by the City of Kissimmee and is directed by a five-member Board of Directors plus the mayor of the City of Kissimmee who serves as a non-voting member. KUA serves retail customers in Osceola County. The retail customers are located within and outside of the city limits of Kissimmee. The primary goal of KUA is to provide reliable electric service to its customers at the lowest possible cost in an environmentally acceptable manner. In order to accomplish this, KUA has diversified its power supply resources, which are based on KUA's own generation, offsite generation through joint participation projects, and long- and short-term purchase power contracts. Since becoming an independent utility authority, KUA has maintained stable management and has been operated in a very business-like environment.

Q. What generating units does KUA own?

A. KUA owns and operates or has ownership interest in generating units comprised of several technologies, including nuclear, coal fired, diesel, simple cycle combustion turbine, and combined cycle. KUA owns and operates eight diesel generating units and a combined cycle generating unit at the Roy B. Hansel Generating Station in downtown Kissimmee. KUA is a 50 percent owner of Cane Island Unit 1, a simple cycle General Electric LM 6000 combustion turbine, and Cane Island Unit 2, a 1 x 1 General Electric 7EA combined cycle project. KUA has a 12.2 percent (9 MW) ownership in

OUC's Indian River Combustion Turbine Units A and B and a 0.68 percent (6 MW) ownership in Florida Power Corporation's Crystal River Unit 3. KUA also has a 4.8 percent ownership share (21 MW) in OUC's Stanton Energy Center Unit 1. In total, KUA owns 172 MW of capacity based on summer ratings.

Q. Does KUA have any entitlement to capacity from FMPA projects?

A. Yes. KUA has entitlement to approximately 7 MW of the St. Lucie 2 nuclear unit and 8 MW of the Stanton 1 and 33 MW of the Stanton 2 coal-fueled units. While these entitlements are officially purchase power, they are essentially ownership shares.

Q. In addition to the entitlement capacity from FMPA, does KUA have any other purchase power?

A. Yes. KUA is purchasing 20 MW through 2003 from Orlando Utilities Commission (OUC).

Q. Does KUA have any generating units under construction?

A. Yes. KUA is constructing Cane Island Unit 3 which is a 250 MW 1 x 1 General Electric 7F combined cycle unit with a scheduled commercial operation date of June 28, 2001. Cane Island 3 received its Need Order on October 7, 1998, and construction commenced in late November of 1999.

Q. Why is KUA interested in joint participation in Stanton A?

A. KUA has a need for additional capacity beginning in the summer of 2004. As a smaller utility, it is difficult for KUA to obtain the economies of scale that larger utilities have available to them. To mitigate this disadvantage, KUA has historically used joint participation to obtain the economies of scale from larger projects. This joint participation has been both through participation in projects managed by others such as Stanton 1 and 2, Crystal River 3, and St. Lucie 2, and joint participation in projects managed by KUA such as Cane Island 1, 2, and 3.

OUC and FMPA also have a need for capacity by the summer of 2004. The three utilities decided to jointly explore capacity addition alternatives to benefit from economies of scale as they have on several other existing projects.

Q. Please discuss KUA's need for Stanton A.

A. KUA has historically been one of the fastest growing utilities in the United States with a 5.7 percent annual growth rate in peak demand over the last ten years. Rapid growth is projected to continue with a 3.7 percent annual growth rate in peak demand projected through the end of the 20-year planning period. The development of the proposed World Exposition Center (Expo Center) is projected to contribute significantly to KUA's load growth. KUA is currently using a 15 percent reserve margin for planning purposes. By the summer of 2004, KUA is projected to require additional capacity to meet its reserve margin requirements. Additional capacity is projected to be required regardless of the status of the Expo Center.

Q. Will KUA fully utilize its entire entitlement in Stanton A beginning in the summer of 2004?

A. KUA is projected to need 11 MW of additional capacity beginning in the summer of 2004 to meet its minimum reserve requirement of 15 percent. Joint participation in Stanton A provides approximately 59 MW of summer capacity to KUA. In order to better take advantage of the benefits of joint participation, KUA and OUC have agreed that OUC will purchase a portion of KUA's excess entitlements.

Q. Is Stanton A the most cost-effective option for KUA?

A. As presented in the Need for Power Application, Exhibit OUC-1 __, KUA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. Appropriate alternatives to Stanton A have been evaluated to determine if they are lower in cumulative present worth revenue requirements. Stanton A has proven to be KUA's most cost-effective option through all evaluations as well as a thorough test of the marketplace. Furthermore, the flexibility incorporated in the joint ownership and power purchase agreement for Stanton A provides significant additional benefits to KUA, especially in light of future uncertainties such as the uncertainty associated with the development of the Expo Center and possible deregulation of the utility industry. Also, KUA believes that Stanton A represents minimal cost and performance risk to its customers due to the proven performance of the "F" class combined cycle technology.

Q. How does KUA intend to finance its ownership share of the construction of Stanton A?

A. KUA has not made a final decision regarding the financing of KUA's 3.5 percent ownership share of Stanton A. The relatively small amount of equity required may come from a number of sources including retained earnings, tax exempt bond proceeds from either existing or future issues, short term commercial paper or similar instruments, or the FMPA Pooled Loan Project.

Q. What is KUA's overall financial position?

A. KUA is in strong financial position and can support any of the methods of financing discussed above. In Fiscal 2000, KUA operating revenues were $90.2 million with an operating income of $7.2 million. KUA's debt service coverage ratio was 1.77 for Fiscal 2000.

Q. Does Stanton A contribute to providing KUA with adequate electricity at a reasonable cost?

A. Yes. The timeframe for Stanton A provides a unique opportunity for KUA to obtain the economies of scale of a large, highly efficient generating unit with an amount of capacity appropriate for KUA's system requirements, thus providing adequate electricity at lower cost than would be available without such a joint participation arrangement.

Q. Does Stanton A contribute to the reliability and integrity of KUA's system?

A. Yes. Stanton A provides KUA's additional capacity requirements beginning in the summer of 2004, and its proven technology will provide reliable power for KUA's system.

Q. Generally describe how KUA sets its rates.

A. KUA sets its rates on a cost of service basis by customer class. The rates consist of a base rate component, a fuel component, and a cost of power adjustment comprised of adjustments in the cost of purchase power and fuel. The cost of power adjustment is determined monthly by KUA's Board of Directors. It may be revised monthly or held constant for several months.

Q. How will the costs for KUA's ownership participation in Station A be recovered?

A. The capital and O&M costs of KUA's ownership participation in Stanton A will ultimately be recovered in base rates. The relatively small amount of capital and O&M cost associated with KUA's ownership share in Stanton A may not require a specific adjustment in base rates. The fuel costs associated with KUA's ownership share of Stanton A will be recovered in the cost of power adjustment. Depending upon the price of natural gas, the cost of power adjustment may decrease with Stanton A.

Q. How will the costs for the purchase power portion of KUA's entitlement in Stanton A be recovered?

A. The capacity and fuel costs for KUA's entitlement in the Stanton A PPA will be recovered through cost of power adjustment.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JONATHAN SCHAEFER

ON BEHALF OF KUA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Jonathan Schaefer and my business address is1701 West Carroll Street, Kissimmee, Florida 34741.

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

A. I am employed by the Kissimmee Utility Authority as a Planning Engineer in the Bulk System Planning division.

Q. Please describe your responsibilities in that position

A. I am responsible for the preparation of the customer, energy and peak load forecast. In addition, I am also responsible for the preparation of a residential and commercial customer survey. I also assist in the preparation of the fuel and purchased power budget, ten-year site plan and evaluation of power supply alternatives.

Q. Please state your educational background and professional experience.

A. I earned a Master of Science in Industrial Engineering from the University of Central Florida in Orlando, Florida, a Bachelor of Science in Industrial Engineering from Geneva College in Beaver Falls, Pennsylvania, and I am a

candidate for a Master of Science in Systems Management from the Florida Institute of Technology

While employed with KUA, I have also attended a short course in econometrics at the University of California at Berkeley, and several courses on applied business forecasting moderated by Business Forecast Systems.

I have been employed at KUA for seven years as a Planning Engineer. Prior to that I was employed by R.W. Beck, Incorporated, for six years as a consultant.

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

A. The purpose of my testimony is to address KUA's need for power in light of the long-term load and energy forecast and existing demand-side management programs.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ that you are sponsoring as your testimony?

A. Yes. Sections 1C.4.0 and 1C.5.1.

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

A. Yes, I am.

Q. Are there any corrections to these sections?

A. No.

Q. Please describe the methodology used in forecasting KUA's energy consumption and power demand.

A. KUA prepares a detailed long-term customer, energy consumption, and power demand forecast using a combination of econometrics, exponential smoothing and linear trending coupled with expert judgement. The detailed forecast is developed on a fiscal year basis (October through September), and serves as a primary driver in annual planning activities.

The econometric models and associated statistical relationships were developed to forecast annual changes in customers and electricity consumption by rate classification as function of demographic, weather and economic factors such as income, temperature, and real price of electricity.

To mitigate the effect of migration among general service demand rate classifications, the general service demand forecast includes all demand rate classifications: demand, large demand, time of use, interruptible, large time of use and contract rate customers. The historical data on accounts billed revealed that no significant change in the number of general service demand accounts has occurred since the rate re-classification in October of 1990. Because of this the customer growth in the general service demand classification was held flat. An econometric model was built for general service demand. However, even though statistically the model was a good fit for the historical period, the projected sales increased too rapidly. These results are unreasonable because the conclusion drawn is that general service demand use per customer is also increasing rapidly, a conclusion that is not supported by historical data. At this point, we met with

City of Kissimmee planners, and gathered information on large facilities scheduled to be built in our service territory over the next 5 years. Using planning level estimates of energy consumption per thousand square feet and information provided by City planners, a schedule of spot loads to be phased into our load forecast evenly over a 5 year period was prepared. Also included was an estimate of the World Expo Center beginning phased construction in fiscal year 2001. At the end of the 5 year period, the energy sales in the general service demand rate classification was escalated at 1 percent per year, which was the lowest annual growth experienced in the previous 5 year period. The peak load forecast is derived by applying average system load factors for winter and summer peak demand to the forecast net energy for load.

Q. What was the source for the input data for the econometric forecast models?

A. Historical customer and energy sales information was taken from our billed revenue report, and monthly peak load information was taken from our monthly operations and maintenance report. Economic and population forecasts from the Bureau of Economic and Business Research (BEBR) were included in the analysis as econometric variables. The BEBR economic forecast was utilized through 2010. To develop economic data beyond 2010, the economic data were adjusted by using their rate of change with respect to population in the base case. Weather data was provided the National Climatic Data Center weather station located at the Orlando International Airport. The real price of electricity was calculated by taking projected rate increases from our Finance Department and deflating them by an estimate of the CPI.

Q. Were cases other than the base case analyzed?

A. Yes, in addition to the base case, a high and low load forecast case was analyzed for sensitivity purposes. These were developed by evaluation of BEBR's high and low economic forecast. For data beyond 2010, the rate of change with respect to the population ratio was maintained in the high and low cases.

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.

Q. In your opinion are the assumptions in the base case load forecast reasonable for planning purposes?

A. Yes.

Q. Describe KUA's current conservation programs that reduce peak demands and energy consumption.

A. KUA is committed to conservation and load management programs and continues to evaluate old and new demand side management (DSM) programs for the electric system that add value for their customers. KUA conservation programs were originally established for the City of Kissimmee under the Florida Energy Efficiency and Conservation Act (FEECA) program. A list of these programs includes the following:

- Residential Load Management (SAVE)
- Residential and Energy Audit
- Fix up program

- High pressure sodium street lighting/private area lighting conversion
- Elimination of electric strip heating

Q. Does this conclude your prefiled testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RICHARD L. CASEY

ON BEHALF OF FMPA

DOCKET NO. 010142-EM

MARCH 5, 2001

Q. Please state your name and business address.

A. My name is Richard L. Casey. My business mailing address is 8553 Commodity Circle, Orlando, Florida, 32819.

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

A. I am employed by Florida Municipal Power Agency (FMPA) as System Planning Manager.

Q. Please describe your responsibilities in that position.

A. As the System Planning Manager for FMPA, I am responsible for conducting and supervising system planning needs. As System Planning Manager, I have responsibility for managing the Agency's planning functions for its expanding 1,000 MW All-Requirements Power Supply Project including production of annual load forecasts, annual reporting to regulatory bodies, transmission planning, demand-side planning, and generation planning. I manage the development, issuance, and evaluation of requests for proposals involving both short-term and long-term purchases and generation construction options. I am also responsible for negotiation of contracts with successful bidders. I am directly

responsible for development, modeling, and production of annual O&M budgets for four of the five FMPA power supply projects totaling over $100 million.

Q. Please state your educational background and professional experience.

A. I received a Bachelors of Science degree in electrical engineering from Lamar University, in Beaumont, Texas. I am a member of the Institute for Electronic & Electrical Engineers (IEEE).

My past 29 years in the electric utility industry have encompassed many facets of the business including distribution engineering and operations, coal mining and rate design and administration. Before joining FMPA, I served as a Transmission Services Consultant for Texas Utilities Electric Co. which required the analysis, development, negotiation, and administration of various contractual arrangements including transmission wheeling service and interconnection agreements, joint transmission line ownership agreements, and microwave interconnection agreements.

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

A. The purpose of my testimony is to provide a description of FMPA and the All-Requirements Power Supply Project (All-Requirements Project). I will also discuss the process by which FMPA became involved in the Stanton A joint development project. I will summarize FMPA's load forecast and existing DSM programs. I will summarize the reliability criteria used by FMPA. I will discuss FMPA's ability to finance Stanton A. I will describe the proposed contribution of Stanton A to the reliability and integrity of FMPA's and Peninsular Florida's

system. I will demonstrate that FMPA adequately explored and evaluated the availability of purchased power options through the two RFP processes. Finally, I will demonstrate that Stanton A provides adequate electricity at a reasonable cost and is the most cost-effective alternative available to FMPA.

Q. Are there sections of the Need for Power Application identified as Exhibit OUC-1__ and the revisions to the Need for Power Application identified as OUC-2___ that you are sponsoring as your testimony?

A. Yes. Sections 1D.2.0, 1D.4.0, 1D.5.1, and 1D.9.0.

Q. Are there any corrections to these sections?

A. No, only the one revision in OUC-2__ indicates that there are nine instead of eight members of the St. Lucie Project that are members of the All-Requirements Project.

Q. Please describe the purpose and structure of FMPA.

A. The Florida Municipal Power Agency (FMPA or Agency) was created on February 24, 1978, under the provisions of the Florida Constitution, the Joint Power Act, and the Florida Interlocal Cooperation Act of 1969. FMPA was formed to allow its members to cooperate with each other, on the basis of mutual advantage, to provide services and facilities in a manner and in a form of governmental organization relevant to geographic, economic, population, and other factors influencing the needs and development of local communities. Specifically, FMPA is involved in the joint financing, construction, acquisition, ownership, management, and operation of electric generation resources. FMPA is

governed by a Board of Directors consisting of one representative from each of the 29 municipal members which hires a general manager and establishes operations and policies.

Q. Please summarize FMPA's existing generation system including purchased power and transmission arrangements.

A. FMPA is a project-oriented, joint action agency where each project stands on its own. FMPA currently has five power supply projects in operation: (i) the St. Lucie Project near Fort Pierce, (ii) the Stanton Project in East Orlando, (iii) the Tri-City Project in East Orlando, (iv) the Stanton II Project in East Orlando, and (v) the All-Requirements Project located throughout Florida. The need for Stanton A is based upon the All-Requirements Project participants' load growth and need for power.

Q. Please describe the All-Requirements Project.

A. The All-Requirements Project was formed on May 1, 1986, initially with five municipal participants and several other municipals have joined over time. The All-Requirements Project participants now consist of:

- City of Bushnell
- City of Clewiston
- City of Fort Meade
- Fort Pierce Utilities Authority
- City of Green Cove Springs
- Town of Havana
- City of Jacksonville Beach

- City of Key West
- City of Leesburg
- City of Newberry
- Ocala Electric Utility
- City of Starke
- City of Vero Beach

Presently Lake Worth Utilities is planned to join in 2002. Under the All-Requirements Project, the Agency is contractually obligated to serve all the power requirements (above certain excluded resources) for the 13 municipal members, which, in turn, are contractually obligated to purchase all their requirements from the Agency to serve retail loads in Florida. Tables 1D.2-4 1D.2-5, and 1D.2-6 of the Need for Power Application Exhibit OUC-1 __ display the existing All-Requirements power supply resources which are owned, purchased from All-Requirements Project participants, and purchased under other contracts with a current total net summer capability of 1203 MW. As a joint operating agency, engaged in the business of generating and transmitting electric energy, the FMPA All-Requirements project is an "Electric Utility" under 403.503(13) Fla. Stat.

FMPA is planning on participating in Lakeland Electric's proposed McIntosh Unit 4 with a projected commercial operation date of June 2005. Currently, Lakeland Electric and FMPA are evaluating proposals for either construction of a unit at the McIntosh site or purchased power. The proposals are based on solid-fueled units. For evaluation purposes, a 100 MW participation is assumed for FMPA.

The capacity and energy for the All-Requirements Project is transmitted to the members primarily utilizing the transmission systems of Florida Power & Light (FPL), Florida Power Corporation (FPC), and Orlando Utilities Commission (OUC). FMPA divides the All-Requirements Project members into two categories: members located in the FPL service area (east cities) and members located in the FPC service area (west cities). Network transmission service for the east cities is provided under an existing agreement with FPL. FMPA began purchasing network transmission service from FPL effective April 1, 1996. Network transmission for the west cities is provided under an agreement with FPC.

Q. Why is FMPA interested in joint participation in Stanton A?

A. Historically FMPA has jointly participated in projects to obtain economies of scale. These are FPL's St. Lucie Unit 2, OUC's Stanton 1 and 2, OUC's Indian River Combustion Turbines A, B, C, and D, and KUA's Cane Island Units 1, 2, and 3. FMPA along with OUC and KUA identified a need for additional capacity by the summer of 2004 and again decided to investigate joint participation for additional power supplies. To further the benefits of joint participation FMPA, along with the OUC, KUA, and Lakeland Electric formed the Florida Municipal Power Pool (FMPP) to economically dispatch the FMPP members' power supply resources.

Q. What is FMPA's need for the Stanton Energy Center Combined Cycle Project?

A. FMPA's All-Requirements Project has been growing rapidly through the addition of new municipal members, with Lake Worth also anticipated to join in 2002. FMPA's peak demand is projected to grow at a 1.8 percent annual rate from 2000 through the end of the planning period in 2019. The forecast loads are shown in Tables 1D.6-1 and 1D.6-2 of the Need for Power Application Exhibit OUC-1 __. The projected load growth assumes no new members will join after Lake Worth in 2002. FMPA uses an 18 percent summer reserve margin and a 15 percent winter reserve margin as reliability criterion. FMPA's reserve margin is projected to drop to 7.3 percent by the summer of 2004, dictating the need to add capacity.

Q. Describe the methodology used in forecasting FMPA's electric power peak demands and energy production?

A. Several techniques are used to develop portions of the load forecast including: 1) econometric modeling, 2) aggregate econometric modeling of system requirements, 3) statistical analysis techniques, 4) incremental load analysis and 5) informed judgement. The forecast methodology varies from member to member to provide the most reliable forecast consistent with available data. Generally, FMPA used Forecast Pro to forecast peak demand and energy requirement loads for its member cities. The forecasts are compared and checked for reasonableness by FMPA and any known unusual incremental load additions or reductions are integrated into the overall forecast.

Q. Were sensitivity scenarios to the base load forecast evaluated?

A. Uncertainty in assumptions dictate the development of high and low load forecasts to ensure that the addition of Stanton A is the most cost-effective option

under reasonable alternative conditions that model the future. The high load growth sensitivity assumes an initial value that is 2.9 percent higher than the base case value, as this has been the historical standard deviation from predicted values. For the following years, there is an increase in nominal projected growth of 100 percent of the base case increase for each year. The low load growth sensitivity assumes an initial value that is 2.9 percent lower than the base case value, as this has been the historical standard deviation from predicted values. For the following years, there is a decrease in nominal projected growth of 50 percent of the base case increase for each year.

Q. Please describe FMPA's current conservation programs that reduce peak demands and energy consumption?

A. FMPA staff and member cities promote conservation programs through a number of methods including providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. Additionally, bill inserts are utilized to keep customers aware of available conservation programs. FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers. The following is a combined list of conservation programs offered by FMPA members:

- Residential Energy Audits Program
- High-Pressure Sodium Outdoor Lighting Conservation
- Assistance for Commercial/Industrial Audits
- Commercial Time-of-Use Program

- Natural Gas Promotion
- Fix-Up Program for the Elderly and Handicapped
- Residential Load Management Program

Q. How does FMPA intend to finance its ownership share of the construction of Stanton A?

A. FMPA typically relies on debt financing to fund capital additions to its system. The All-Requirements Project is planning to use the FMPA Pooled Loan Project to obtain the financing for FMPA's 3.5 percent ownership share of Stanton A. The FMPA Pooled Loan Project is a financing pool in which participating members or the Agency itself can obtain loans for electric system projects. The All-Requirements Project can borrow the necessary funds at an interest rate of approximately 5 percent for a period of twenty years.

Q. Is Stanton A the most cost-effective option for FMPA?

A. FMPA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. As discussed in the Need for Power Application Exhibit OUC-1__, FMPA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements. As demonstrated in the Application, Stanton A has proven to be FMPA's most cost-effective option through all evaluations as well as a thorough test of the marketplace. These evaluations are described in more detail in the testimony of Myron Rollins.

Q. Will Stanton A provide FMPA adequate electricity at a reasonable price?

A. Yes. In addition, the flexibility associated with the combination of purchase power from and ownership in Stanton A further enhances the cost-effectiveness of the project.

Q. Will Stanton A provide reliability and integrity to FMPA's system?

A. Yes. The proven reliability of the equipment to be utilized in Stanton A coupled with the reliability guarantee in the Power Purchase Agreement will contribute to the reliability and integrity of FMPA's system.

Q. Explain in general how the All-Requirements project recovers costs through rates.

A. The All-Requirements project recovers all costs through billing rates. Billing rates consist of customer, demand capacity charges, transmission capacity charge, and energy charge components. These rates are set annually based on expected costs and then are adjusted for any over or under recovery of expenses on a twelve month basis for the capacity charges and on a six month basis for the energy charges.

Q. How will the costs of FMPA's ownership share of Stanton A be recovered in rates?

A. The fixed costs will be recovered through the demand and transmission capacity charge and the variable costs will be recovered through the energy charge.

Q. How will the costs from FMPA's purchase power entitlement in Stanton A be recovered in rates?

A. The fixed costs will be recovered through the demand and transmission capacity charge and the variable costs will be recovered through the energy charge.

Q. Does this conclude your prefiled testimony?

A. Yes it does.

CHAIRMAN JACOBS: Now, let's go to the prefiled exhibits and we will identify those. We will identify the prefiled exhibits of Mr. Haddad as --

MR. KEATING: Before we go forward, I would like to notify you as to one sort of difference in the way that the exhibits are listed in this case and make it a little easier to identify them. You will notice that the same exhibit number often appears after several witnesses' names. For example, OUC-1 and OUC-2 appears after Mr. Haddad --

CHAIRMAN JACOBS: Correct.

MR. KEATING: -- Mr. Anderson and so on. This reflects the fact that more than one witness has sponsored a portion of these particular exhibits. I have gone through and I can walk through the exhibits for you if you would like to have each one marked that needs to be separately marked.

CHAIRMAN JACOBS: Well, it was my intent to mark them as a composite and that way all witnesses who sponsor a composite exhibit could be listed however you would like.

MR. KEATING: That would be fine.

CHAIRMAN JACOBS: Okay. It looks like the first composite exhibit would be OUC-1. Now, let me make sure I understand. OUC-1, OUC-2, and -- there seemed to be just OUC-1 and 2. Are those separate documents?

MR. KEATING: Yes. OUC-1 is essentially Volumes 1A through 1D of their need for power application, and OUC-2 is a

separate volume that consists of revisions to the need for power application.

CHAIRMAN JACOBS: What I would like to do is identify the composite as the need for determination and then list the volumes as OUC11 through OUC-2. Is that acceptable? Okay. So Composite Exhibit 1 would be the need application, need for determination application, and that will consist of volumes in OUC-1 and OUC-2.

MR. KEATING: And I believe there is one other exhibit that is sponsored by -- portions of it are sponsored by one other witness, and that is what is listed in the prehearing order as Confidential Exhibit A.

CHAIRMAN JACOBS: One moment. Now, for the court reporter's benefit, let me go ahead and list out the witnesses that are sponsoring this composite exhibit. I show Mr. Haddad, Mr. Anderson, Mr. Arsuaga, Ms. Schuepbach, Mr. Fox, Mr. Rollins, Mr. Hearn, Doctor Sharma, Mr. Schaefer, and Mr. Casey. Those are the various sponsors of Composite Exhibit 1.

MR. KEATING: Mr. Chairman, I believe there should be one correction to that. I don't believe that Witness Arsuaga has sponsored a portion of OUC-1 or 2.

CHAIRMAN JACOBS: On Page 16, at the top, it says OUC, so you want to revise that in the prehearing order?

MR. KEATING: I'm sorry, I didn't hear you.

CHAIRMAN JACOBS: At the top of Page 16 it lists Mr.

Arsuaga as proffering part of OUC. Oh, I'm sorry, that's a company name, that is not the exhibit number. Thank you for that correction.

MR. KEATING: That is a separate exhibit.

CHAIRMAN JACOBS: I was moving too fast. Very well. Show that corrected. Mr. Arsuaga is not a sponsor of that composite exhibit. Very well. That takes care of the need determination application. Without objection, show Composite Exhibit 1 is admitted into the record.

(Composite Exhibit 1 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: That takes us next to -- now, I don't see an identification marker for a confidential exhibit on the top of Page 15 being sponsored by Mr. Haddad, do we have an identification for that?

MR. MAY: It's on the bottom of Page 14, Confidential Exhibit A.

CHAIRMAN JACOBS: Oh, that is a continuation of OUC-2. I see. Very well. So we have taken care of that. The next exhibit then is the Exhibit D as in David, DEJ-1 proffered by Mr. Jones of Southern.

MR. KEATING: Mr. Chairman, I would like to maybe take a step back. I think Confidential Exhibit A is separate from OUC-2. It has been filed as a separate volume that consists of just the confidential portions of the --

CHAIRMAN JACOBS: That was my thought. So why don't we mark it as separate.

MR. KEATING: I'm sorry?

CHAIRMAN JACOBS: If it has been filed separately, let's mark it as a separate exhibit, then.

MR. KEATING: Okay. Yes.

CHAIRMAN JACOBS: So let's mark that as Exhibit 2. And Confidential Exhibit A, should we give it an identification or will that be sufficient?

MR. KEATING: I think that would be sufficient. And just to be thorough, Confidential Exhibit A, portions of it have been sponsored by Witness Haddad, and this is at the top of Page 15. And then at the bottom of Page 15 you will notice that Witness Anderson has also sponsored a portion of that exhibit. Turning to Page 17, Witness Schuepbach has also sponsored a portion of that exhibit. And then finally, Witness Rollins on Page 19.

CHAIRMAN JACOBS: Very well. Just one moment. Very well. So show that Confidential Exhibit A -- now, that is just one document, right?

MR. KEATING: That is correct. Show that -- without objection, show Confidential Exhibit A is admitted into the record.

(Exhibit 2 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: Now, we will go back. On Page 15, Mr. Jones, Exhibit DEJ-1, that is by Southern. Show that marked as Exhibit 3 and without objection show it admitted into the record as Exhibit 3.

(Exhibit Number 3 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: On Page 16, we have Confidential Exhibit B.

MR. KEATING: And you will notice about halfway down that page Witness Herrington also sponsors a portion of Confidential Exhibit B. And I believe he is the only other witness who sponsors a portion of that exhibit.

CHAIRMAN JACOBS: Very well. Show that marked as Exhibit 4. And without objection show Exhibit 4 admitted into the record.

(Composite Exhibit Number 4 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: Again, on Page 16, Mr. Arsuaga, Exhibits PAA-1, 2, 3, and 4. Is PAA-4 also Confidential Exhibit C?

MR. KEATING: PAA-3 and PAA-4 comprise Confidential Exhibit C. That is actually a separate document.

CHAIRMAN JACOBS: Why don't we make PAA-1 and 2 a composite exhibit.

MR. KEATING: Okay.

CHAIRMAN JACOBS: Mark that as Exhibit 5. And PAA-3 and 4 are Confidential Exhibit C, mark that as Exhibit 6. And without objection, show Exhibits 5 and 6 are admitted into the record.

(Composite Exhibit Number 5 and 6 marked for identification and admitted into evidence.)

CHAIRMAN JACOBS: On Page 16 we have Mr. Thumb, SLT-1, 2, and 3. It does not appear that any of those are confidential, so we will mark those as Composite Exhibit 7. And without objection, show Composite Exhibit 7 entered into the record.

(Composite Exhibit 7 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: On Page 17, we have Ms. Schuepbach, Exhibit JAS-1. We will mark that as Exhibit 8. And without objection, show Exhibit 8 is admitted into the record.

(Exhibit Number 8 marked for identification and admitted into the record.)

MR. KEATING: Mr. Futrell is handing out the last exhibit that is listed in the prehearing order on Page 20 that has yet to be marked, and that is a staff composite exhibit consisting of deposition transcripts from Mr. Haddad and Mr. Rollins' depositions along with proof of publication of the newspaper notice of this proceeding.

CHAIRMAN JACOBS: Okay. Just one moment.

MR. KEATING: And it is my understanding that the

parties would have no objection to this composite exhibit being moved into the record?

MR. MAY: That is correct.

CHAIRMAN JACOBS: Okay. And this is designated as Staff 1?

MR. KEATING: Yes.

CHAIRMAN JACOBS: We will show this as Composite Exhibit 9. And without objection show Composite Exhibit 9 entered into the record. That concludes the exhibits according to the prehearing order.

(Composite Exhibit Number 9 marked for identification and admitted into the record.)

MR. KEATING: There is one other item that is not listed. Staff just requested late last week that the petitioners provide the signed power purchase agreements. The petitioners had filed along with their need for power application a draft purchased power agreement that we have looked at. To complete the record, we feel it would be a good idea to include the signed purchase power agreements, as well. They filed those this morning under confidential cover with records. They have copies of those documents if you would like to see them, but the staff would request that that document be marked for identification.

CHAIRMAN JACOBS: So you want to mark that? We will need to get a copy for the court reporter.

Commissioners, would you like one?

MR. MAY: Mr. Chairman, we provided the court reporter with a copy with the confidential portions under seal and the redacted portions public. She has that now. We would ask that it be marked as Confidential Composite Exhibit Number 10.

CHAIRMAN JACOBS: Okay.

MR. MAY: The title for that exhibit would be executed PPAs for Southern-Florida, and OUC, KUA, and FMPA.

CHAIRMAN JACOBS: Since it is confidential, I won't get it now. I would like to review it at some point in the future just to let the parties be aware. But I know I won't get at it today.

MR. KEATING: And, Chairman, it is my understanding that the terms are essentially the same as what was filed in the draft agreement that staff had looked at. Now that we have signed -- at the time that the filing was made there weren't signed agreements. But now that we have signed agreements, I think the intent of including them in the record is to show that they are signed.

CHAIRMAN JACOBS: I'm sorry, say again.

MR. KEATING: I think the intent of including them in the record is simply to show that they are signed and to have those in the record.

CHAIRMAN JACOBS: This is the executed agreement, so it should be signed and formal and all of that.

MR. MAY: When we originally filed the need for power

application, the PPAs were essentially negotiated but not executed. Subsequent to filing, they have been executed and we wanted the record to reflect that you do have now three executed PPAs.

CHAIRMAN JACOBS: Great. Just for my information, I am interested in -- what is that fancy legal term -- privity. So each organization signed with the adjoining or how did that --

MR. MAY: That is correct. There are three power purchase agreements. One between Southern-Florida and OUC, one between Southern-Florida and KUA, and one between Southern-Florida and FMPA.

CHAIRMAN JACOBS: Okay. Very good. Interesting. Without objection then, show Composite Confidential Exhibit 10 is admitted into the record.

(Confidential Composite Exhibit Number 10 marked for identification and admitted into the record.)

MR. KEATING: And just one other matter that I suppose would be helpful to have in the record. Mr. Young mentioned earlier that they had filed the affidavits of their witnesses who aren't here today who have been excused.

CHAIRMAN JACOBS: Very well.

MR. KEATING: We would ask that that be included as an exhibit, as well. Those are on file with Records.

CHAIRMAN JACOBS: Okay. And these will be affidavits of which witnesses?

MR. KEATING: This will be affidavits for all the witnesses that are listed in the prehearing order whose prefiled testimony has been moved into the record.

MR. YOUNG: We thought it would be important, Mr. Chairman, to have the testimony not only put in the record as though read, but also sworn to. So we filed affidavits, sworn affidavits for each of the witnesses just to affirm the correctness of their testimony.

CHAIRMAN JACOBS: Great. Show that marked as Composite Exhibit 11, and it will be entitled affidavit of all witnesses. And without objection, show Composite Exhibit 11 is admitted into the record.

(Composite Exhibit Number 11 marked for identification and admitted into the record.)

CHAIRMAN JACOBS: Let the record reflect that there are no motions pending. We do not a stipulation, so we are going to -- Commissioners, if it is your desire, we can -- would you want to pursue a bench decision at this time?

COMMISSIONER PALECKI: Yes. I would like to see we vote on this this morning.

CHAIRMAN JACOBS: Very well. Staff.

MR. KEATING: I guess as a general statement, staff can recommend approval of all the positions listed in the prehearing order as positions for each of the issues. And I guess more importantly that will include Issue 15, which is the catch-all

issue that says based on the resolution of the foregoing, should the Commission grant the joint petition for determination of need, staff recommends that you do grant that petition. Staff can address questions on any individual issues that you have or any general questions, as well.

COMMISSIONER PALECKI: I can move staff's recommendation.

CHAIRMAN JACOBS: Is there a second?

COMMISSIONER BAEZ: Second.

CHAIRMAN JACOBS: I had a question. I don't think it goes into too much of the substance of the recommendation, but it goes to a point that I would like for us to pursue on a going-forward basis. Specifically, there are three issues, Issue 6, Issue 10, and Issue 14. And really it goes to the wording of the issue. And I think it has been tradition and policy there that we look at conservation in the context of need determinations to determine whether or not they will mitigate or offset the need to build that plant.

And what I would like to explore, and is what I think is the reality of the world, conservation measures are never in my mind going to really offset the need for a plant. What they do is they supplement the output of the plant to enhance its effectiveness. And what I would like for us to do is to begin to explore conservation measures in that context when we look at need determinations. What conservation measures can be

instituted that will enhance the effectiveness of a particular plant.

And this goes really -- it's interesting because we had this discussion at the Governor's 20/20 Study Commission the other day, and the point that came out, and Mr. Tart can confirm, is that we look at conservation from a fairly narrow perspective and context. And so what I want to do on a going-forward basis is to begin to explore how in a need determination we can look at conservation from a different view. Because this question in a need determination as is stated is probably irrelevant.

I have doubt in this day and age with this technology you are going to find conservation measures that will accumulate to offsetting the need for a plant once that need is demonstrated. So, how would you like to do this? We can sit down and have a meeting or you can workshop it, however you want to do it. I want to explore a more effective way of addressing conservation in the context of need determination proceedings. But I don't disagree with -- as the issue is stated here, I don't disagree with your recommendation. And having said that, that is my two cents worth.

We have a motion and a second to approve Issues 1 through, I believe it is 16. All in favor, aye.

(Simultaneous affirmative vote.)

CHAIRMAN JACOBS: Opposed?

Show that Issues 1 through 16 are approved. Is there

any other matter to come before us today?

MR. YOUNG: Mr. Chairman, if I might take just a moment. I would like to express on behalf of OUC, FMPA, and KUA our deep gratitude for the hard work of the staff. This was our first time to deal with the confidentiality rule of the Commission, and it was a bear for me. And it took Bob, and Cochran, and several other people to work us through that. But they were responsive, they were willing to meet with us when we needed to meet, they were willing to work with us and help us.

Our whole goal was to try to present to the staff whatever information it needed in order for them to make what we hoped to be the correct decision. And they went about it in a very professional way. I hope you all know, and I'm not blowing smoke, I don't do that, but I hope you all know what a good staff you have. They work hard. They work on weekends. They work when they need to work to get the job done. Just like Commissioner Palecki used to do, and our prehearing Chairman when they were staff folks. So we appreciate it very much.

And I would like to mention that Fred Haddad is here from OUC, we have Ben Sharma from KUA, and Rick Casey from FMPA. And Fred Bryant said to tell you all hello.

CHAIRMAN JACOBS: Great.

MR. YOUNG: Thank you very much.

CHAIRMAN JACOBS: Well, I will concur and echo your comments. I think perhaps we don't demonstrate it enough, but I

can tell you that we do understand and appreciate the caliber of the staff that we have.

MR. YOUNG: And I would be remiss, Mr. Chairman, and I forgot this, the person that did all the work for this is this young man right here, Myron Rollins with Black and Veatch from Kansas City.

CHAIRMAN JACOBS: Mr. Rollins and I have talked on several occasions.

MR. YOUNG: And I wouldn't want the day to go by without thanking him, as well.

CHAIRMAN JACOBS: Great.

MR. MAY: Mr. Chairman, I would like to echo what Mr. Young just said on behalf of Southern-Florida. This is Southern's first entree into Peninsular Florida, and they are certainly impressed with the Florida Public Service Commission and its staff, and they look forward to doing business and working with you all in the future.

CHAIRMAN JACOBS: Well, I would like to also state that in a time when apparently there is more than enough confusion to go around about what is going to happen in the energy industry, it was good to see the diversity of interest and parties to come together and demonstrate the ability to work things out as in this docket. I really believe that -- you know, I have been hearing for the last few weeks that unless magic happens downtown then we are stuck for three years in figuring out what to do

about energy in this state. And I have doubted that, but today I am absolutely convinced otherwise. That we can figure out something to do in the next two to three years about what we can do with regard to our energy needs in the State of Florida. And I congratulate the parties in this docket for having been a real clear example of that.

MR. MAY: And I would be remiss if I didn't introduce my principal and my client, Mark Wimberley (phonetic), who is the project developer and head of Southern-Florida, and also Susan Comensky. They are both with Southern-Florida and fine people. And, again, they share my respect for you as an institution and your staff.

CHAIRMAN JACOBS: Welcome. And if I may, I would like to kind of impose myself and make sure I get an invitation as this project gets underway to come down and visit.

MR. TART: Mr. Chairman, Thomas Tart. You and your fellow Commissioners are always welcome. I want to thank you, too. This project is going to serve cities from Jacksonville Beach all the way to Key West. And we have done this before with a group of cities. Kissimmee is our neighbor to the south and St. Cloud is our neighbor to the southeast right below our airport. We are in a fast growing area. Little cities like Ocala, and Fort Pierce, and Vero, retirement villages are growing up there.

And this plant with the new technology of combined

cycle will help serve those people in the future and we won't face that California situation. But I, too, want to thank the staff in working with us and all of this because this is so important to the people of Orlando whom I serve.

CHAIRMAN JACOBS: Now, this project takes reuse also, doesn't it?

MR. TART: Yes. Mr. Haddad can tell you, and the folks in Southern, that we are fortunate to have a county sewage treatment plant up the road. And it's water along some water from the landfill will help keep the Floridan aquifer in hold, and we are in the water business also, and we try to be stewards of our drinking water as future generations come to Florida.

CHAIRMAN JACOBS: That is extremely important. Well, I think now -- unfortunately, I think now it is becoming pretty obvious the nature of the problem we have with water. But, if I may just for a moment, one of the first people that I remember talking to me about using reuse in power plants and really got me fired up about the idea was Mr. Tart when I came down to visit with you all, and he showed me the Scranton plant and some of the things -- Stranton -- whatever the name of the plant.

MR. TART: Stanton.

CHAIRMAN JACOBS: Stanton. And some of the things you were doing there. I think we now are absolutely at a point where that is almost a litmus test. We can no longer treat drinking water, particularly in that area, in the cavalier matter that we

have done before. And I think what OUC and the City of Kissimmee and others in the area have done have demonstrated how much they regard water is much to your credit. And you are to be complimented and congratulated for that.

And with that, Commissioners, anything else?

MR. KEATING: If I could add one closing comment. I wanted to echo the comments of Mr. Young and Mr. May, and say that you have an excellent staff. And I did want to express our appreciation to both of them and the parties in this case. They have been very responsive to our request for information and very willing to work with us when we needed them.

CHAIRMAN JACOBS: Very well. We can all leave here today feeling very well. In that instance, thank everyone. Thank the parties very much, and this hearing is adjourned.

(The hearing concluded at 10:10 a.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, FPSC Bureau of Reporting FPSC Commission Reporter, do hereby certify that the hearing in Docket No. 010142-EM was heard by Commissioners Jacobs, Baez and Palecki at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript, consisting of 158 pages, constitutes a true transcription of my notes of said proceedings and the prefiled testimony.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 29th day of April, 2001.

JANE FAUROT, RPR
FPSC Division of Records & Reporting
Chief, Bureau of Reporting
(850) 413-6732

Stanton Energy Center Combined Cycle Unit A

Need for Power Application

Volume 1A - Common Information

Orlando Utilities Commission

Kissimmee Utility Authority

Florida Municipal Power Agency

January 29, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 1 (Pt 1 of 1)
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DATE: 4-23-01

BLACK & VEATCH

11401 Lamar, Overland Park, Kansas, 66211, USA (913) 458-2000

Table of Contents

1A.1.0 Introduction 1-1

1A.2.0 Overview and Summary 2-1
1A.2.1 Overview 2-1
1A.2.2 Summary 2-1

1A.3.0 Description of Project 3-1
1A.3.1 History of the Project Development 3-1
1A.3.1.1 Stanton Energy Center 3-2
1A.3.1.2 Stanton A Project 3-2
1A.3.2 Description of Stanton A Fuel Supply 3-10
1A.3.2.1 Fuel Transportation 3-10
1A.3.3 Capital Costs 3-11
1A.3.4 O&M Costs 3-12
1A.3.4.1 Fixed O&M Costs 3-12
1A.3.4.2 Variable O&M and Startup Costs 3-13
1A.3.4.3 OUC, KUA, and FMPA Provided O&M Services 3-14
1A.3.5 Heat Rate 3-15
1A.3.6 Availability 3-16
1A.3.7 Schedule 3-16
1A.3.8 Transmission System Requirements 3-16
1A.3.8.1 Circuit Breaker Upgrades 3-16
1A.3.8.2 Onsite Transmission System Upgrades 3-17
1A.3.9 Cooling Water 3-17

1A.4.0 Power Purchase Agreements 4-1
1A.4.1 PPA Term and Capacity Charges 4-1
1A.4.2 Fuel Costs 4-2
1A.4.3 O&M and Startup Costs 4-2
1A.4.4 Availability 4-3

1A.5.0 Evaluation Criteria 5-1
1A.5.1 Economic Parameters 5-1
1A.5.1.1 Escalation Rates 5-1
1A.5.1.2 Cost of Capital 5-1

Table of Contents (Continued)

1A.5.1.3 Present Worth Discount Rate 5-1
1A.5.1.4 Interest During Construction Interest Rate 5-2
1A.5.1.5 Levelized Fixed Charge Rate 5-2
1A.5.2 Fuel Price Projections 5-2
1A.5.2.1 EVA Fuel Price Projections 5-4
1A.5.2.2 Base Case Fuel Price Projections 5-9
1A.5.2.3 High and Low Case Fuel Price Projections 5-9
1A.5.2.4 Constant 2000 Fuel Price Projections 5-13
1A.5.2.5 2001 Annual Energy Outlook Fuel Price Projections 5-13
1A.5.3 Fuel Availability 5-15
1A.5.3.1 Service to Proposed Plant Site. 5-15
1A.5.3.2 Florida Gas Transmission Company 5-19
1A.5.3.3 Florida Gas Transmission Market Area Pipeline System 5-19
1A.5.3.4 Florida Gas Transmission Expansion Project 5-20
1A.5.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida 5-21

1A.6.0 Methodology to Evaluate Power Supply Alternatives 6-1
1A.6.1 Joint Development RFP Summary 6-1
1A.6.2 Power Supply RFP Summary 6-2
1A.6.3 Self-Build Alternative 6-3
1A.6.4 Results of RFPs and Self-Build Alternative Comparison 6-4
1A.6.5 Results of Contract Negotiations 6-6

1A.7.0 Supply-Side Alternatives 7-1
1A.7.1 Renewable Technologies 7-1
1A.7.1.1 Wind 7-2
1A.7.1.2 Solar Thermal 7-3
1A.7.1.3 Solar Photovoltaics 7-4
1A.7.1.4 Biomass 7-5
1A.7.1.5 Geothermal 7-7
1A.7.1.6 Hydroelectric 7-7
1A.7.1.7 Ocean Wave Energy 7-9

Table of Contents (Continued)

1A.7.1.8 Ocean Tidal Energy 7-9
1A.7.1.9 Ocean Thermal Energy 7-11
1A.7.2 Waste to Energy Technologies 7-11
1A.7.2.1 Municipal Solid Waste to Energy Conversion 7-12
1A.7.2.2 Refuse Derived Fuel to Energy Conversion 7-12
1A.7.2.3 Landfill Gas to Energy Conversion 7-13
1A.7.2.4 Tire Derived Fuel to Energy Conversion 7-15
1A.7.2.5 Sewage Sludge to Energy Conversion 7-15
1A.7.3 Advanced Technologies 7-16
1A.7.3.1 Advanced Gas Technologies 7-17
1A.7.3.2 Advanced Coal Technologies 7-19
1A.7.3.3 Magnetohydrodynamics 7-21
1A.7.3.4 Fuel Cells 7-22
1A.7.3.5 Nuclear Fusion 7-23
1A.7.4 Energy Storage Systems 7-24
1A.7.4.1 Pumped Hydro Energy Storage 7-24
1A.7.4.2 Battery Energy Storage 7-24
1A.7.4.3 Compressed Air Energy Storage 7-25
1A.7.4.4 Flywheel Energy Storage 7-27
1A.7.4.5 Superconducting Magnetic Energy Storage 7-28
1A.7.5 Nuclear (Fission) 7-28
1A.7.6 Conventional Technologies 7-28
1A.7.6.1 Performance Estimates 7-30
1A.7.6.2 Pulverized Coal 7-31
1A.7.6.3 Circulating Fluidized Bed 7-32
1A.7.6.4 Combined Cycle Units 7-33
1A.7.6.5 Simple Cycle Combustion Turbine Generator 7-43
1A.7.7 Supply-Side Screening 7-47
1A.7.7.1 Phase I Screening 7-48
1A.7.7.2 Phase II Screening 7-49

1A.8.0 Demand-Side Programs 8-1
1A.8.1 FIRE Model Methodology 8-1
1A.8.1.1 FIRE Model Assumptions 8-1
1A.8.1.2 FIRE Model Outputs 8-2

Table of Contents (Continued)

1A.9.0 Peninsular Florida Needs 9-1
1A.9.1 Peninsular Florida Capacity and Reliability Needs 9-1
1A.9.2 Impact to Transmission System 9-5

1A.10.0 Analysis of 1990 Clean Air Act Amendments 10-1
1A.10.1 History of the Clean Air Act 10-1
1A.10.2 Authority to Construct 10-1
1A.10.3 Title V Operating Permit 10-2
1A.10.4 Title IV Acid Rain Permit 10-2

1A.11.0 Consequences of Delay 11-1
1A.11.1 Economic Consequences 11-1
1A.11.2 Reliability Consequences 11-1

Appendix

1A.A Power Purchase Agreement
1A.B Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency Request for Detailed Proposals For the Joint Development of the Stanton Energy Center and/or The Cane Island Power Park
1A.C Orlando Utilities Commission Request for Power Supply Proposals
1A.D Orlando Utilities Commission Stanton Energy Center Stanton Unit A – 2x1 Capital Cost Estimate
1A.E Orlando Utilities Commission Stanton Energy Center Stanton Unit A – 2x1 Large STG Capital Cost Estimate

Tables

Table 1A.2-1 Utility Summer Deficits (MW) 2-3
Table 1A.3-1 Stanton A Capital Cost for OUC, KUA, and FMPA 3-13
Table 1A.3-2 Hourly Variable O&M Charges for Operation on Natural Gas (2003 $) 3-14
Table 1A.3-3 Startup Rates for Operation 3-14
Table 1A.3-4 Net Plant Heat Rate (NPHR) – HHV CONFIDENTIAL 3-15

Table of Contents (Continued)
Tables (Continued)

Table 1A.3-5	Stanton A Interconnection Facilities	3-17
Table 1A.4-1	Capacity Charges	4-2
Table 1A.4-2	Hourly Variable O&M Rate for Operation on Natural Gas CONFIDENTIAL	4-3
Table 1A.4-3	Startup Rates for Operation CONFIDENTIAL	4-3
Table 1A.5-1	EVA Forecast Natural Gas Prices At Henry Hub ($2001)	5-5
Table 1A.5-2	EVA Forecast Long-Term Coal Prices ($2001)	5-6
Table 1A.5-3	EVA Forecast WTI Crude Oil Price ($2000)	5-7
Table 1A.5-4	EVA Forecast Petroleum Coke Demand and Delivered Prices ($2001)	5-8
Table 1A.5-5	Base Case Fuel Price Forecast Summary (Delivered Price $/MBtu)	5-10
Table 1A.5-6	High Case Fuel Price Forecast Summary (Delivered Price $/MBtu)	5-11
Table 1A.5-7	Low Case Fuel Price Forecast Summary (Delivered Price $/MBtu)	5-12
Table 1A.5-8	Constant 2000 Fuel Price Forecast ($/MBtu)	5-14
Table 1A.5-9	2001 Annual Energy Outlook Real Fuel Price Projections and CAERs	5-16
Table 1A.5-10	AEO 2001 Fuel Price Forecast ($/MBtu)	5-17
Table 1A.5-11	AEO 2001 Escalation Applied to 2000 OUC Fuel Prices ($/MBtu)	5-18
Table 1A.6-1	Results of Contract Negotiations	6-7
Table 1A.7-1	Wind Energy Conversion - Performance and Costs	7-3
Table 1A.7-2	Solar Thermal - Performance and Costs	7-4
Table 1A.7-3	Solar Photovoltaic - Performance and Costs	7-5
Table 1A.7-4	Biomass - Performance and Costs	7-6
Table 1A.7-5	Geothermal - Performance and Costs	7-8
Table 1A.7-6	Hydroelectric - Performance and Costs	7-8
Table 1A.7-7	Ocean Wave Energy - Performance and Costs	7-9
Table 1A.7-8	Ocean Tidal Energy - Performance and Costs	7-10
Table 1A.7-9	MSW Mass Burning Unit - Performance and Costs	7-13
Table 1A.7-10	RDF Stoker Fired Unit - Performance and Costs	7-14
Table 1A.7-11	Landfill Gas IC Engine - Performance and Costs	7-15
Table 1A.7-12	TDF Multi-Fuel CFB (10 Percent Cofire) - Performance and Costs	7-16
Table 1A.7-13	Humid Air Turbine Cycle - Performance and Costs	7-17

Table of Contents (Continued)
Tables (Continued)

Table 1A.7-14	Kalina Cycle - Performance and Costs	7-18
Table 1A.7-15	Cheng Cycle - Performance and Costs	7-19
Table 1A.7-16	Supercritical Pulverized Coal - Performance and Costs	7-20
Table 1A.7-17	Pressurized Fluidized Bed Combustion - Performance and Costs	7-21
Table 1A.7-18	Fuel Cell - Performance and Costs	7-23
Table 1A.7-19	Pumped Hydro Energy Storage - Performance and Costs	7-25
Table 1A.7-20	Lead-Acid Battery Energy Storage - Performance and Costs	7-26
Table 1A.7-21	Compressed Air Energy Storage - Performance and Costs	7-27
Table 1A.7-22	Utility Generation Expansion Candidates	7-29
Table 1A.7-23	Degradation Factors	7-31
Table 1A.7-24	Generating Unit Characteristics 446 MW Pulverized Coal Unit	7-32
Table 1A.7-25	Generating Unit Characteristics 267 MW Circulating Fluidized Bed Unit	7-33
Table 1A.7-26	Siemens-Westinghouse 2 x 1 F Combined Cycle Cost Estimates	7-36
Table 1A.7-27	Revised Siemens-Westinghouse 2 x 1 F Combined Cycle Cost Estimates	7-37
Table 1A.7-28	Estimated O&M Costs and Performance Siemens-Westinghouse 501F Combined Cycle Units	7-38
Table 1A.7-29	Levelized Busbar Comparison-Peaking and Intermediate	7-50
Table 1A.7-30	Levelized Busbar Comparison-Base Load	7-50
Table 1A.9-1	2000 Load and Resource Plan--Peninsular Florida Peak Demand and Available Capacity	9-2
Table 1A.9-2	2000 Load and Resource Plan -- Peninsular Florida Peak Demand and Available Capacity Excluding Capacities Pending Approval Under the Florida Electrical Power Plant Siting Act but Not Yet Approved	9-3

Figures

Figure 1A.3-1	Stanton Energy Center Site Arrangement	3-3
Figure 1A.3-2	Stanton A Construction Schedule	3-5
Figure 1A.3-3	Southern Site Arrangement Drawings	3-6
Figure 1A.3-4	Southern Site Arrangement Drawings	3-7
Figure 1A.3-5	Southern Site Arrangement Drawings	3-8

Table of Contents (Continued)

Figures (Continued)

Figure 1A.3-6 Southern Site Arrangement Drawings 3-9
Figure 1A.9-1 2000 Load and Resource Plan – Peak Demand and Reserve Margin Excluding Capacity Required to be Approved Under the Florida Electrical Power Plant Siting Act but Not Yet Approved 9-4

1A.1.0 Introduction

This Need for Power (NFP) Application is submitted as part of the Supplemental Site Certification Application (SSCA) by Orlando Utilities Commission (OUC), Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and Southern Company - Florida, LLC (Southern-Florida) as a nonneed joint applicant, for the addition of Combined Cycle Unit A to the Curtis H. Stanton Energy Center (Stanton Energy Center) in accordance with the Florida Electrical Power Plant Siting Act. Stanton Energy Center Combined Cycle Unit A (Stanton A) is a proposed combined cycle unit with a nominal rating of 633 MW at 70° F, consisting of two F class combustion turbines, two heat recovery steam generators (HRSGs), and a steam turbine.

The first volume of the SSCA, containing the NFP Application, is divided into subvolumes labeled 1A, 1B, 1C, and 1D and comprises Section 1 of the SSCA. These subvolumes contain the Public Service Commission NFP portion of the SSCA. The joint NFP Application is based on the needs of OUC, KUA, and FMPA, which are participating in the Stanton A Project pursuant to the Florida Joint Power Act and the Interlocal Cooperation Act of 1969, as amended. OUC, KUA, and FMPA are 35 percent joint owners of Stanton A. Southern-Florida owns the remaining 65 percent of Stanton A.

OUC, KUA, and FMPA will purchase all of the 65 percent capacity owned by Southern-Florida pursuant to the Power Purchase Agreements (PPAs).

The power purchased by OUC, KUA, and FMPA under the PPAs is for a minimum term of 10 years. The PPAs also provide OUC, KUA, and FMPA unilateral options to acquire Southern-Florida's capacity for a term of up to 30 years, which is the expected life of the plant.

Subvolumes 1A, 1B, 1C, and 1D contain the following information:

- 1A - NFP information common to all participants.
- 1B - NFP information specific to OUC.
- 1C - NFP information specific to KUA.
- 1D - NFP information specific to FMPA.

OUC is the agent for KUA and FMPA for the development and licensing of Stanton A as it was for Stanton 1 and 2.

Supplemental Site Certification for the proposed Stanton A is being sought under the Florida Electrical Power Plant Siting Act, Sections 403.501-403.518, Fla. Stat. The determination of need for the proposed Stanton A is being sought under Section 403.519, Fla. Stat. Notices regarding the project should be sent to OUC's attention.

Some of the information presented in Volume 1A of the application is confidential information provided in proposals obtained through the request for proposals (RFPs). In addition, some of the information presented in Volume 1A of the application resulting from negotiations with Southern-Florida is considered confidential by Southern-Florida. This confidential information has been redacted and is contained in the accompanying confidential exhibits.

Applicant's Official Names and Mailing Addresses

Orlando Utilities Commission
P.O. Box 3193
Orlando, Florida 32802

Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, Florida 32742-3219

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002

Southern Company-Florida, LLC
600 North 18th Street
Birmingham, Alabama 35203

Address of Official Headquarters

Orlando Utilities Commission
P.O. Box 3193
Orlando, Florida 32802

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002

Southern Company-Florida, LLC
600 North 18th Street
Birmingham, Alabama 35203

Business Entities

OUC and KUA are bodies politic, duly organized, and legally existing as part of the respective governments of the Cities of Orlando and Kissimmee. OUC and KUA are engaged in the generation, transmission, and distribution of electric power.

Florida Municipal Power Agency (FMPA) is a joint agency formed pursuant to the Interlocal Cooperation Act that exercises powers under the Joint Power Act. FMPA has authority to undertake and finance electric projects and, among other things, to plan, finance, acquire, construct, reconstruct, own, lease, operate, maintain, repair, improve, extend, or otherwise participate jointly in those projects and to issue bonds or bond anticipation notes for the purpose of financing or refinancing the costs of such projects.

Southern-Florida is a Delaware limited liability corporation authorized to transact business in Florida. Southern-Florida is a wholly owned subsidiary of Southern Power Company, which is one of the six operating subsidiaries of The Southern Company (Southern Company). Southern Company is the largest producer of electricity in the United States and one of the largest in the world, with a proven record of designing, owning, and operating electric power plants. With 69 plants, comprising 278 units, Southern Company generates more than 31,000 MW of capacity in the southeast United States. 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.

Name, Address, and Telephone Number of Official Representative Responsible for Obtaining Certification

Frederick F. Haddad
Orlando Utilities Commission
P.O. Box 3193
Orlando, Florida 32802
Ph. 407/236-9698

Site Location

Orange County

Nearest Incorporated City

Orlando

Name, Address, and Telephone Number of Official Representative Responsible for Obtaining Certification

Frederick F. Haddad
Orlando Utilities Commission
P.O. Box 3193
Orlando, Florida 32802
Ph. 407/236-9698

Site Location

Orange County

Nearest Incorporated City

Orlando

Longitude and Latitude

Latitude: 28 degrees 29' 17"
Longitude: 81 degrees 10' 3"

UTMs (Center of Site)

483609.12 East
3151118.65 North

Section, Township, Range

Sec 13 T23S/R31E

Location of Any Directly Associated Facilities

Orange County

Nameplate Generating Capacity

The nameplate rating of Stanton A will depend upon final detailed design. It is estimated that Stanton A will have a nameplate gross generating capacity of 791 MVA with a nominal new and clean net rating of 633 MW at 70° F.

Commercial Operation Date

Stanton A is scheduled for commercial operation on October 1, 2003.

1A.2.0 Overview and Summary

1A.2.1 Overview

Stanton A will be the third unit installed at the Stanton Energy Center site located approximately 10 miles east of Orlando, Florida. Stanton A is being planned for a nominal net generating capacity of 633 MW at 70° F based on new and clean conditions.

Stanton A is jointly owned by OUC, KUA, FMPA, and Southern-Florida as follows:

- OUC - 28 percent.
- KUA - 3.5 percent.
- FMPA - 3.5 percent.
- Southern-Florida - 65 percent.
- OUC, KUA, and FMPA will purchase all of the capacity owned by Southern-Florida, pursuant to the PPAs, for a minimum 10 year term. The PPAs provide OUC, KUA, and FMPA the unilateral option to acquire Southern-Florida capacity for a term of up to 30 years, which is assumed to be the life of the plant. The purchased capacity will be allocated among these utilities as follows:
  - OUC - 80 percent.
  - KUA - 10 percent.
  - FMPA - 10 percent.

The details of the PPAs are set forth in Section 1A.4.0.

1A.2.2 Summary

Stanton A is planned to utilize a 2 x 1 combined cycle configuration with two General Electric PG-7241 FA combustion turbines, two heat recovery steam generators, and a steam turbine. The estimated capital cost for OUC's, KUA's, and FMPA's collective share is [redacted] including costs for the power block as well as interconnection facilities. Stanton A is projected to have a new and clean output of 633 MW at 70° F with a higher heating value (HHV) heat rate of [redacted] Btu/kWh. Stanton A is planned to be equipped with evaporative inlet cooling, duct firing, and power augmentation to increase output. Natural gas is the primary fuel for Stanton A and No. 2 oil is the planned backup fuel. Stanton A will not be equipped with bypass stacks and dampers, but will have the condenser sized such that both combustion turbines can be operated at full load with the steam turbine out of service.

The collective need of OUC, KUA, and FMPA for capacity is summarized in Table 1A.2-1. In 2004, the need for capacity totals 714 MW. Meeting this need in a cost-effective manner forms the basis for the optimal generation expansion plans contained in Volumes B, C, and D of this application.

OUC, KUA, and FMPA went through a multi-stage process to develop the most cost-effective generation expansion plan that meets their respective needs for capacity. Step one involved soliciting letters of interest followed by more detailed proposals from developers for a new generating facility at the OUC Stanton Energy Center or KUA Cane Island Power Park and soliciting purchase power proposals. These two market options were evaluated by estimating the levelized cost per megawatt-hour for each. After ranking the development proposals and the purchase power proposals, the Southern-Florida[1] proposal was selected for further negotiations based on it being the lowest cost at 70 percent capacity factor and having a number of other favorable attributes. Step two involved negotiations with Southern-Florida to develop Power Purchase Agreements, a Construction and Ownership Participation Agreement, and other agreements associated with the project. Step three involved the development of individual optimal generation expansion plans over a 20 year period for OUC, KUA, and FMPA, incorporating consideration of the Southern-Florida proposal as well as self-build alternatives. This process was tailored to the individual systems of OUC, KUA, and FMPA. Using the results of the individual optimal generation expansion plans, it was found that the Southern-Florida joint development proposal was the most cost-effective alternative for OUC, KUA, and FMPA to ensure that capacity is available to serve retail load beginning October 1, 2003.

[1]The original proposal was submitted by Southern Wholesale Energy, an affiliate of Southern-Florida, which will now own and operate the project.

Table 1A.2-1
Utility Summer Deficits (MW)

Year	OUC	KUA	FMPA	Total
2000	17	0	0	17
2001	0	0	0	0
2002	55	0	0	55
2003	85	0	0	85
2004	593*	11	110	714
2005	560	27	27	614
2006	557	42	119	718
2007	587	53	163	803
2008	623	66	273	962
2009	663	78	305	1,046
2010	703	91	325	1,119
2011	567	104	497	1,168
2012	600	118	516	1,234
2013	640	130	532	1,302
2014	695	144	549	1,388
2015	730	159	564	1,453
2016	766	173	580	1,519
2017	805	187	593	1,585
2018	844	201	605	1,650
2019	879	216	617	1,712

* Reliant purchase power agreement expires September 30, 2003.

1A.3.0 Description of Project

This section summarizes the history of the development of the project, describes the existing facilities at Stanton Energy Center, and provides details of the project including ownership, fuel supply, estimated capital costs, O&M costs, heat rate, availability, project schedule, and transmission system requirements.

1A.3.1 History of the Project Development

OUC, KUA, and FMPA have all identified a collective need for low cost and reliable power consistent with the timing of the project. OUC, KUA, and FMPA are joint owners in several regional power plants and share common transmission links. They, along with the City of Lakeland, also form the Florida Municipal Power Pool (FMPP) which dispatches its members' generation. Recent OUC, KUA, and FMPA planning studies have identified a collective need for new generating capacity to supply growing loads and to meet reserve requirements. In an effort to reduce costs through joint participation and economies of scale, OUC, KUA, and FMPA jointly pursued the development of the project with OUC leading the project as an agent for KUA and FMPA.

In order to obtain reliable power at the lowest possible cost consistent with the flexibility to adjust to potential future changes in the utility industry, a three-pronged approach was used which led to the selection of the project. First, two separate requests for proposals (RFPs) were developed and issued. One RFP was for purchased power from any source of capacity, excluding units built at the Stanton Energy Center. The other RFP requested proposals that included a jointly owned project to be constructed at the Stanton Energy Center with an option to construct a project at the Cane Island Power Park. While the RFPs required certain minimum requirements, they were purposefully unrestrictive to allow the maximum amount of innovation to be obtained from the marketplace. The RFP process was designed such that the best evaluated proposal would be selected and negotiations conducted to further improve the project. The RFPs are discussed in detail in Section 1A.6.0. Next, self-build alternatives were developed in detail. These alternatives consisted of 2 x 1 combined cycles to be built on the Stanton Energy Center site.

The proposals from the RFP process were evaluated on a levelized cost basis and a ranking was developed. As a result of the ranking process, Southern-Florida was selected for negotiations. The Southern-Florida proposal was comprised of a 633 MW 2 x 1 combined cycle unit burning natural gas with duct burners, power augmentation, and evaporative cooling with an October 1, 2003 commercial operation date. OUC,

KUA, and FMPA would collectively own 35 percent of the unit, with the remaining 65 percent owned by Southern-Florida. As further described in Section 1A.4.0, all of the capacity owned by Southern-Florida would be sold under purchase power contracts to OUC, KUA, and FMPA for a minimum term of 10 years, with additional unilateral extension options for a maximum term of 30 years, which is the expected life of the plant.

OUC initiated negotiations with Southern-Florida to obtain additional detail on the proposal, minimize costs, and develop acceptable agreements. The negotiations led to power purchase agreements (PPAs), a Construction and Ownership Participation Agreement, and an Operation and Maintenance Agreement that results in additional savings and value to OUC, KUA, and FMPA. Section 1A.4.0 provides a detailed description of the PPAs.

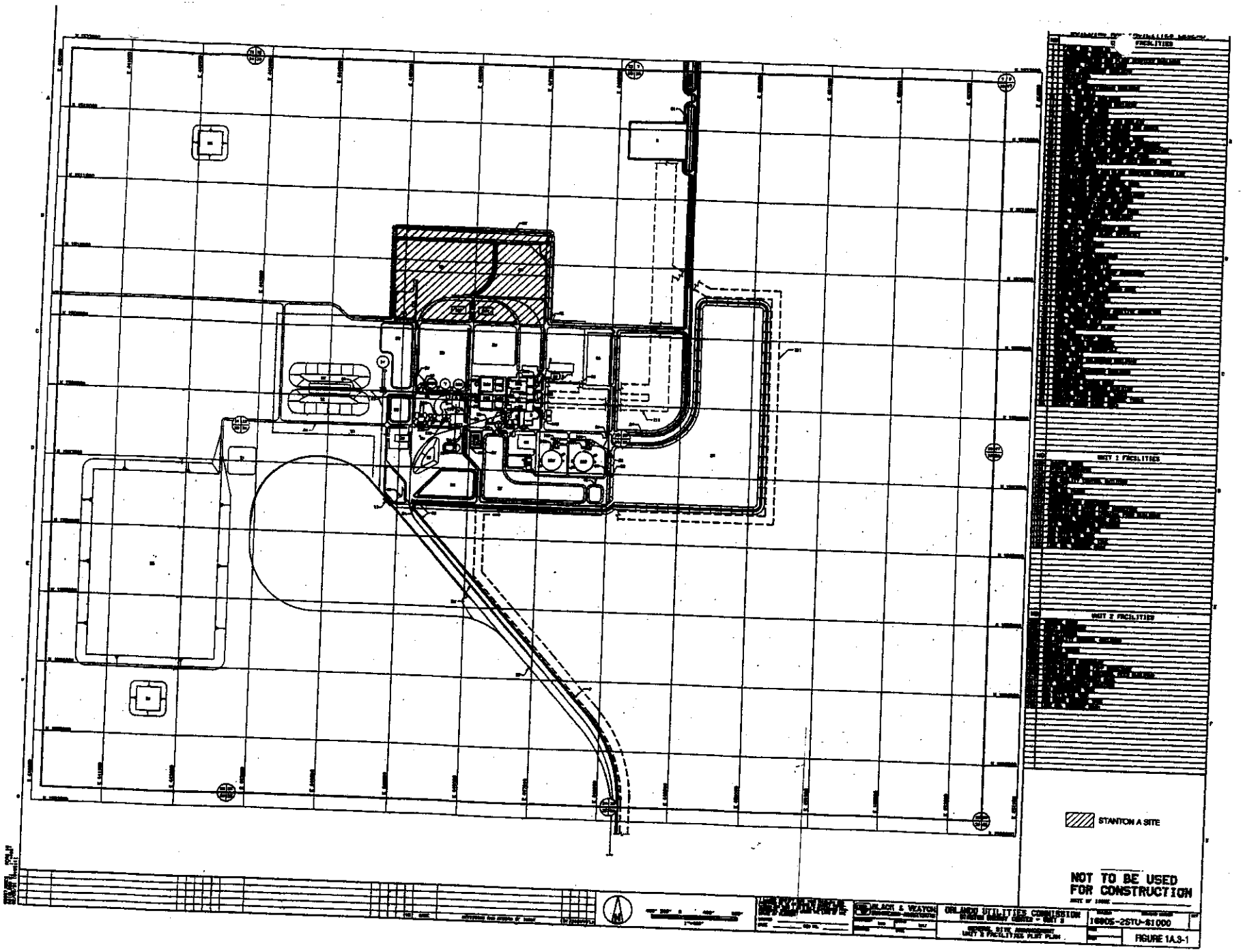
1A.3.1.1 Stanton Energy Center

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280 acre site contains Stanton Energy Center Units 1 and 2 (Stanton 1 and 2) and the necessary supporting facilities. Stanton 1 was placed in commercial operation on July 1, 1987, followed by Stanton 2, which was placed in commercial operation on June 1, 1996. Both units are fueled by pulverized coal and operate at emission levels that are within the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection requirement standards for SO_2, NO_x, and particulates.

Stanton 1 is a 440 MW net coal-fired facility jointly owned by OUC, KUA, and FMPA. Stanton 2 is a 446 MW net coal-fired generating facility jointly owned by OUC and FMPA. OUC is the project manager and agent for KUA and FMPA for Stanton 1 and the project manager and agent for FMPA for Stanton 2. Figure 1A.3-1 shows the site arrangement drawing for Stanton 1 and 2 with the area for Stanton A identified.

1A.3.1.2 Stanton A Project

As previously stated, 35 percent of the Stanton A unit capacity will be owned by OUC, KUA, and FMPA, with the remaining capacity owned by Southern-Florida. As described in Section 1A.4.0, under the PPAs, OUC, KUA, and FMPA have agreed to purchase, and Southern-Florida has agreed to sell, all of the capacity owned by Southern-Florida for a minimum term of 10 years. The PPAs also provide OUC, KUA, and FMPA with unilateral options to acquire Southern-Florida's capacity for a term of up to 30 years. Southern-Florida will construct and be responsible for operating Stanton A and OUC, KUA, and FMPA will be responsible for providing water, natural gas, transmission services, and other support to the plant.


UNIT 1 FACILITIES
UNIT 2 FACILITIES
STANTON A SITE
NOT TO BE USED FOR CONSTRUCTION
BLACK & VEATCH
ORLANDO UTILITIES COMMISSION
16905-2STU-81000
FIGURE 1A.3-1

The Stanton A combined cycle facility will have a nameplate capacity rating of 791 MVA with a nominal new and clean output of 633 MW at 70° F. Stanton A is scheduled for commercial operation on October 1, 2003, with the detailed schedule presented in Figure 1A.3-2. The facility will consist of two General Electric 7FA combustion turbine generators (CTGs), two Deltak heat recovery steam generators (HRSGs), and an ABB/Alstom STF30C steam turbine generator (STG) to be located at Stanton Energy Center. Figures 1A.3-3 through 1A.3-6 present the site arrangement drawings for Stanton A. Other details of the proposed facility are as follows:

- CTGs are complete with dry low NO_x combustors, evaporative coolers, and power augmentation. They are dual fuel units firing natural gas as the primary fuel and fuel oil as backup fuel.
- HRSGs are complete with supplemental firing capability and selective catalytic reduction (SCR). A CO catalyst spool is included for possible future addition of CO catalyst.
- A steam bypass system is included in lieu of bypass stacks and dampers for simple cycle operation.
- Storm water discharge will utilize the existing Stanton site storm water basin.
- 1,680,000 gallons of fuel oil storage is included
- A mechanical draft cooling tower will be provided.

OUC, KUA, and FMPA will provide certain services from existing Stanton 1 and 2 facilities with expansion of existing facilities as necessary. Services provided include service water, demineralized water, and cooling water. The following describes the facilities to be used to provide these services:

- Service water will be provided from Stanton Energy Center's existing service water system using well water.
- Demineralized water will be provided from Stanton Energy Center's existing demineralizer system.
- Cooling water will be primarily treated sewage effluent supplied from Stanton Energy Center's existing cooling water pond. Makeup to the cooling water pond is provided through the existing treated sewage effluent pipeline from the Orange County Easterly Subregional Wastewater Treatment Plant. Small amounts of water from the steam turbine condensate collection tank, HRSG blowdown, and collected stormwater will also be used for cooling water.

ID	Task Name	Start	Finish
1	Engineering Activities	03/05/01	04/03/02
2	Procurement Activities	07/24/01	10/28/02
3	Site Activities	10/01/01	07/11/02
4	HRSG Installation	03/25/02	01/24/03
5	Fire Protection	04/05/02	04/05/02
6	BOP Systems	04/29/02	12/17/02
7	Turbine Installation	05/20/02	03/21/03
8	Energize Station Service	11/06/02	11/06/02
9	Cooling Tower Makeup	12/06/02	12/06/02
10	Brine Waste Water System	12/06/02	12/06/02
11	Demineralized Water	01/03/03	01/03/03
12	Gas Supply	02/07/03	02/07/03
13	Unit First Fire	04/01/03	04/01/03
14	Startup and Commissioning Activities	04/02/03	08/31/03
15	Provisional Acceptance	09/01/03	09/30/03
16	Commercial Operation Date	10/01/03	10/01/03

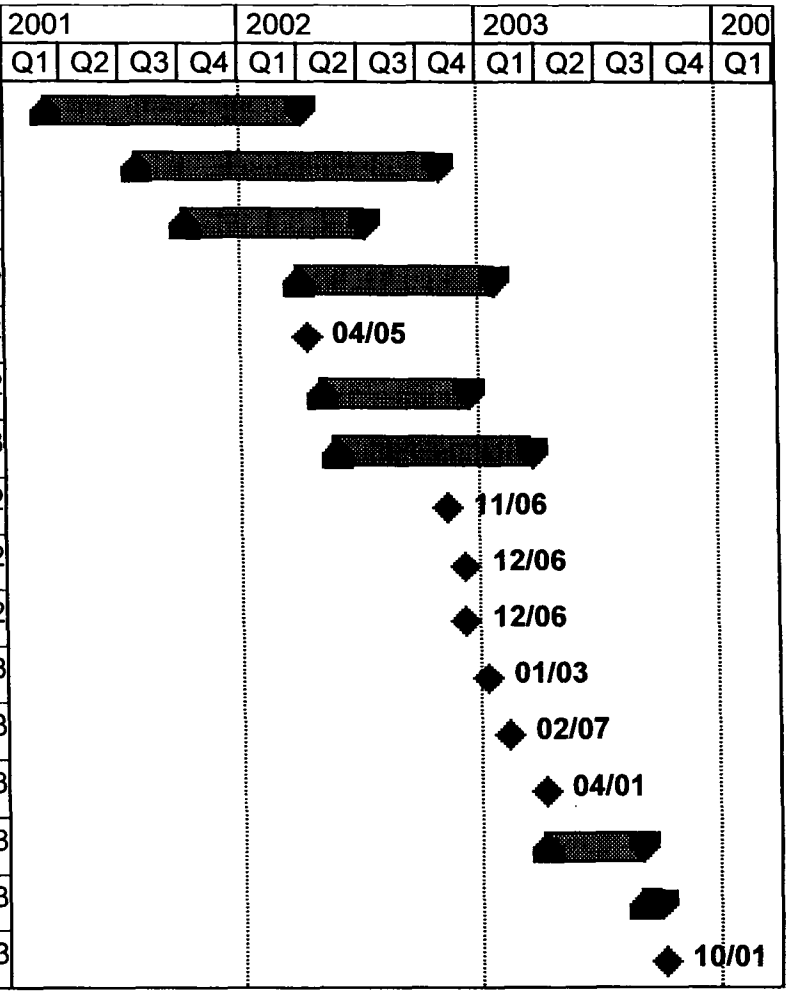
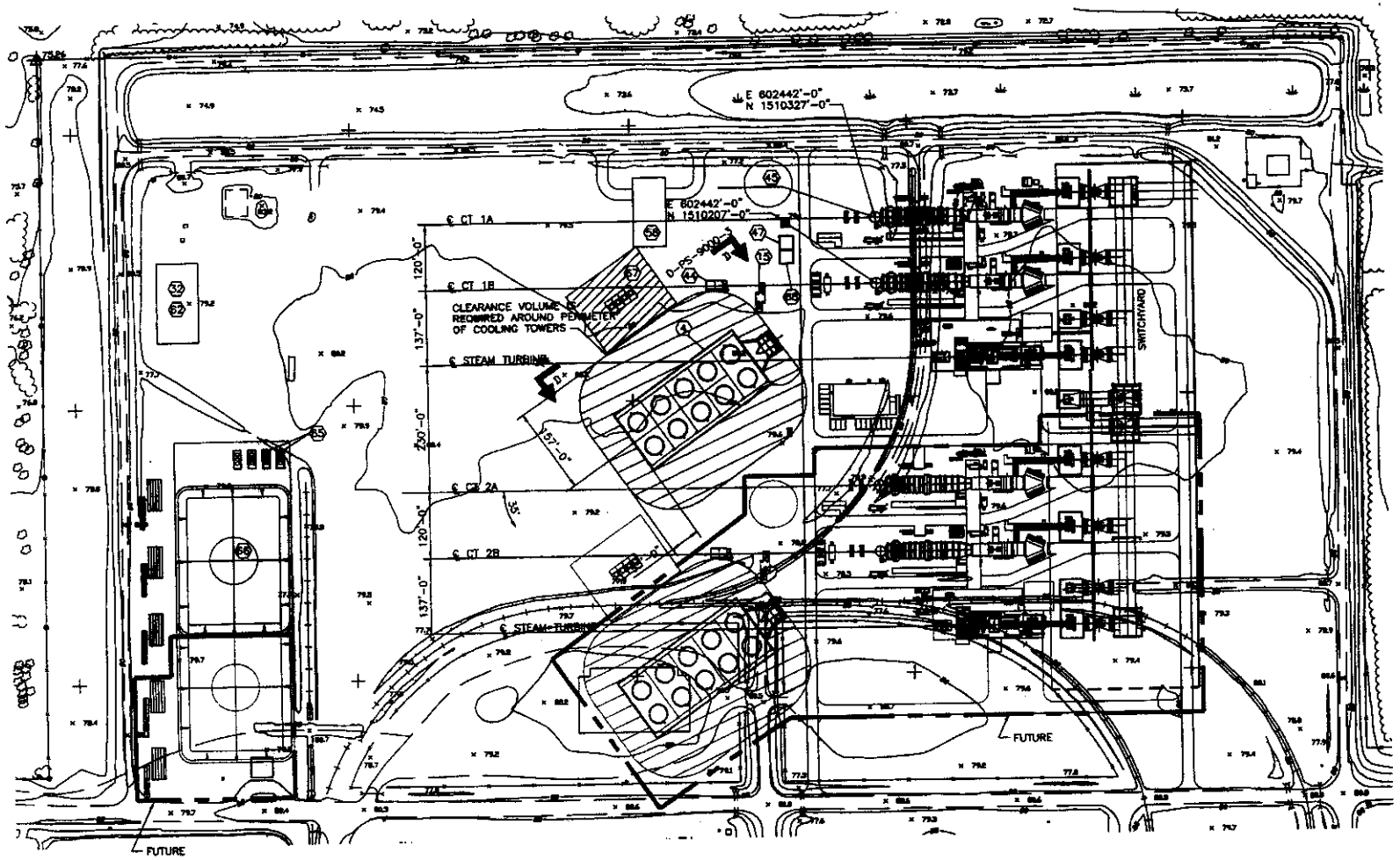


Figure 1A.3-2
Stanton A Construction Schedule

D-PS-9000-1



NOTES:

NEW STACK COORDINATES BASED ON NAD83 FLORIDA STATE PLANES, EASTERN ZONE, U.S. FOOT:

CENTER UNIT 1A HRSG STACK:	E 602442'-0" N 1510327'-0"
CENTER UNIT 1B HRSG STACK:	E 602442'-0" N 1510207'-0"
CENTER UNIT 2A HRSG STACK:	E 602442'-0" N 1509840'-0"
CENTER UNIT 2B HRSG STACK:	E 602442'-0" N 1509720'-0"

NEW STACK COORDINATES BASED ON NAD83 UTM, ZONE 16 NORTH, METER:

CENTER UNIT 1A HRSG STACK:	E 1071425.2056 N 3165216.3816
CENTER UNIT 1B HRSG STACK:	E 1071427.0434 N 3165179.7166
CENTER UNIT 2A HRSG STACK:	E 1071432.6837 N 3165067.5830
CENTER UNIT 2B HRSG STACK:	E 1071434.5014 N 3165030.9181

⬡ DENOTES EQUIP. NO. – SEE D-PS-9000-2 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=60'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=400'-0"

CAD 9000-1D.DWG | AutoCad | SHV-14

PRELIMINARY

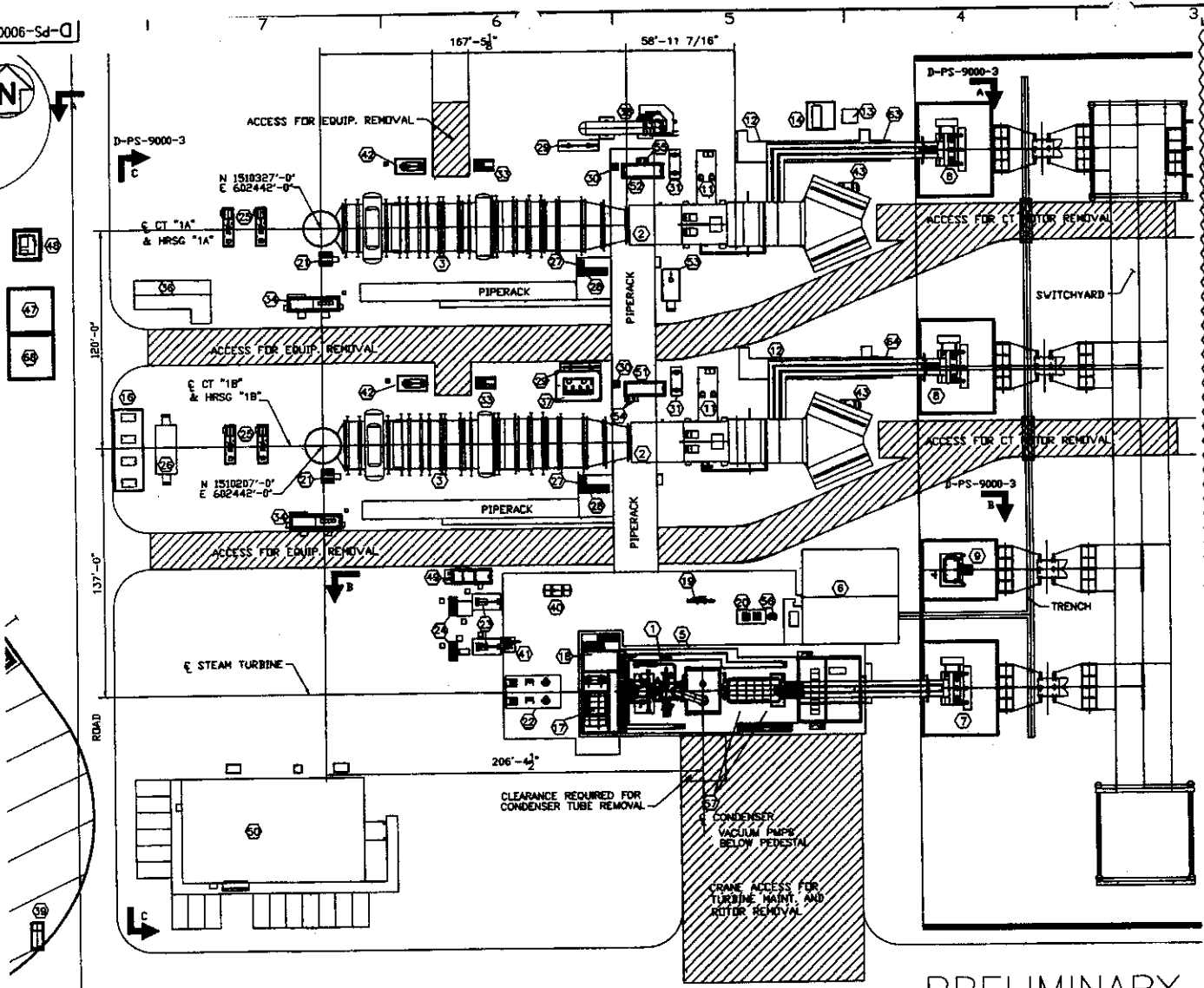
REVISION	DATE	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
REVISION	DATE	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
REVISION D 1. REVISED TITLE BLOCK	DATE 01/16/00	SHW						
REVISION C 1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	DATE 12/7/00	DWR						
REVISION B 1. ADDED SERVICE WATER COOLER 1. ADDED LOCATION OF FUTURE BLOCK.	DATE 10/24/00	SHW						
REVISION A ISSUED FOR REVIEW	DATE 9/22/00	SHW						

Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

DESIGNED SHW	DRAWN SHW	CHECKED
SCALE 1"=200'-0"	PROJECT LD	DRAWING NUMBER D-PS-9000-1

D-PS-9000-2



LEGEND

1. STEAM TURBINE
2. COMBUSTION TURBINE
3. HEAT RECOVERY STEAM GENERATOR
4. COOLING TOWER (SEE D-PS-9000-1)
5. CONDENSER
6. ELECTRICAL BUILDING
7. STEAM GENERATOR GSU
8. COMBUSTION TURBINE GSU
9. STATION SERVICE TRANSFORMER
10. AUX. TRANSFORMER (N/A)
11. COMBUSTION TURBINE ACCESSORY MOD.
12. COMBUSTION TURBINE PEEC
13. DC LINK TRANSFORMER
14. ISOLATION TRANSFORMER
15. 480V TRANSFORMER & MCC (SEE DWG. D-PS-9000-1)
16. FEEDWATER TRANSFORMER
17. STEAM TURBINE LUBE OIL SKID
18. STEAM TURBINE HPU
19. GLAND STEAM CONDENSER
20. CONDENSATE PUMPS
21. CONDENSATE RECIRC PUMPS
22. AIR COMPRESSOR
23. SERVICE WATER HEAT EXCHANGER
24. SERVICE WATER PUMPS
25. BOILER FEED PUMPS
26. BOILER FEED PUMP DRIVE SKID
27. SCANNER AIR BLOWER
28. FUEL GAS PIPING MODULES
29. FUEL GAS HEATER
30. FUEL GAS ELECTRIC WATER HEATER
31. FUEL GAS FILTER
32. GAS METERING STATION (SEE D-PS-9000-1)
33. SCR AMMONIA BLR/CONTROL
34. CEMS BUILDING
35. WATER TREATMENT BUILDING (N/A)
36. WATER ANALYSIS BUILDING
37. PHOSPHATE FEED PUMP SKID
38. AMMONIA SUPPLY SYSTEM
39. CO2 SKID
40. CLOSED LOOP COOLING WTR TANK
41. STEAM TURBINE BLOWDOWN TANK
42. HRSG BLOWDOWN TANK
43. CT CO2 TANK
44. CHEMICAL FEED TANKS (SEE D-PS-9000-1)
45. DEMIN STORAGE TANK (SEE DWG. D-PS-9000-1)
46. RAW WATER STORAGE TANK (N/A)
47. WASTE WATER SUMP
48. OIL/WATER SEPARATOR
49. MAIN STEAM SUMP
50. CONTROL/ADMIN BLDG
51. SUMP "A"
52. SUMP "B"
53. WASH WATER SKID
54. SUMP "A" PUMPS
55. SUMP "B" PUMPS
56. TURBINE SEAL OIL SKID
57. VACUUM PUMPS
58. WAREHOUSE (SEE DWG. D-PS-9000-1)
59. FIRE PROT. PUMP HSE (N/A)
60. FIRE PROT. STORAGE TK (N/A)
61. FILTERED WTR STORAGE TK (N/A)
62. GAS CONDITIONING STATION (SEE DWG. D-PS-9000-1)
63. LCI EXCITATION COMPT (LEC)
64. STATIC EXCITATION COMPT (EC)
65. FUEL OIL FORWARDING PUMPS (SEE DWG. D-PS-9000-1)
66. FUEL OIL STORAGE TANK (SEE DWG. D-PS-9000-1)
67. IPC (SEE DWG. D-PS-9000-1)
68. CONCENTRATION WASTE BLOWDOWN SUMP

REFERENCES:

D-PS-9000-1	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=400'-0"

CAD 9000-2D.DWG
AutoCad SHW-14

PRELIMINARY

THIS DRAWING AND DESIGN, CONCEPT, SPECIFICATION, AND COMPUTER FILES PREPARED OR FURNISHED BY SOUTHERN COMPANY SERVICES, INC. ARE INSTRUMENTS OF SERVICE IN RESPECT OF THE PROJECT. NONE OF THE FOREGOING MATERIALS SHALL BE COPIED, REUSED, OR OTHERWISE APPROPRIATED BY ANY PERSON OR ENTITY WITHOUT THE EXPRESS WRITTEN CONSENT OF SOUTHERN COMPANY SERVICES, INC. ANY UNAUTHORIZED USE THEREOF SHALL BE AT THE USER'S SOLE RISK AND WITHOUT LIABILITY OR LEGAL EXPOSURE TO SOUTHERN COMPANY SERVICES, INC.

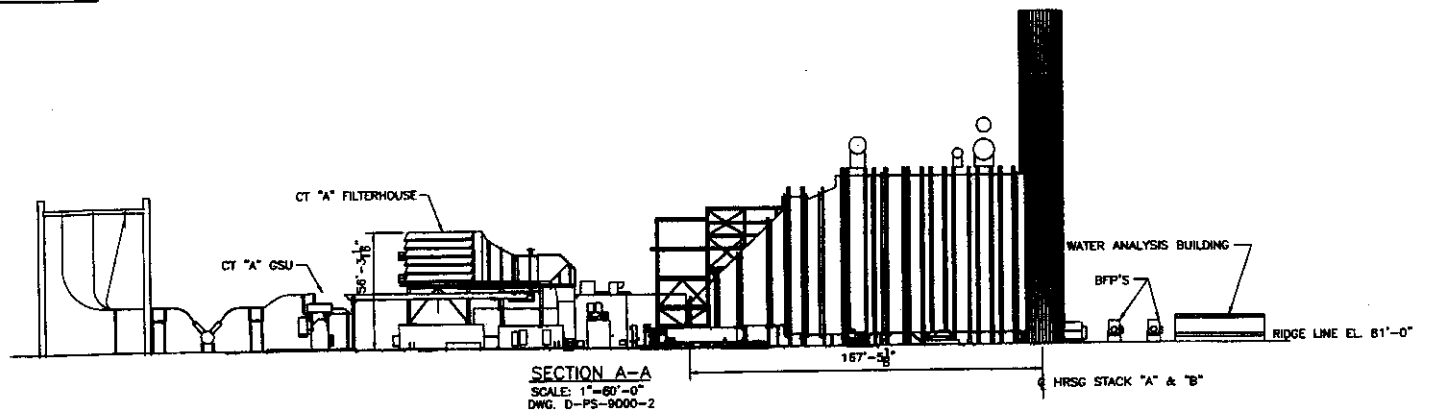
Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=60'-0"

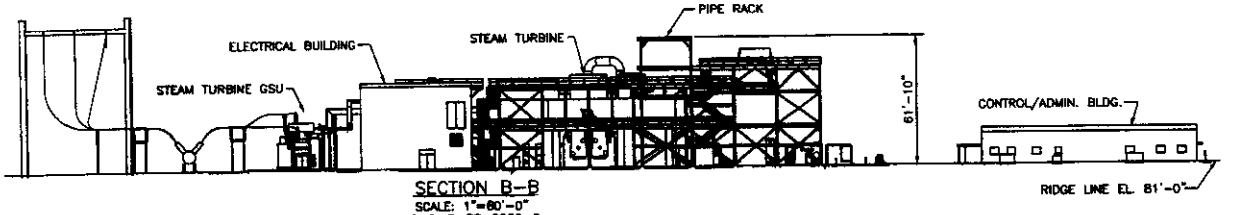
REVISION	DATE	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
REVISION D: 1. REVISED TITLE BLOCK.	01/16/01	SHW						
REVISION C: 1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	12/7/00	DWR						
REVISION B: ADDED ITEM NO. 67 IPC	10/24/00	SHW						
REVISION A: ISSUED FOR REVIEW	9/22/00	SHW						

DESIGNED	DRAWN	CHECKED
SHW	SHW	

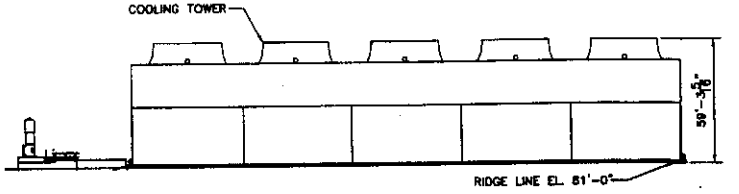
SCALE	PROJECT I.D.	DRAWING NUMBER	REV
1"=60'-0"		D-PS-9000-2	D



SECTION A-A
SCALE: 1"=60'-0"
DWG. D-PS-9000-2



SECTION B-B
SCALE: 1"=60'-0"
DWG. D-PS-9000-2



SECTION D-D
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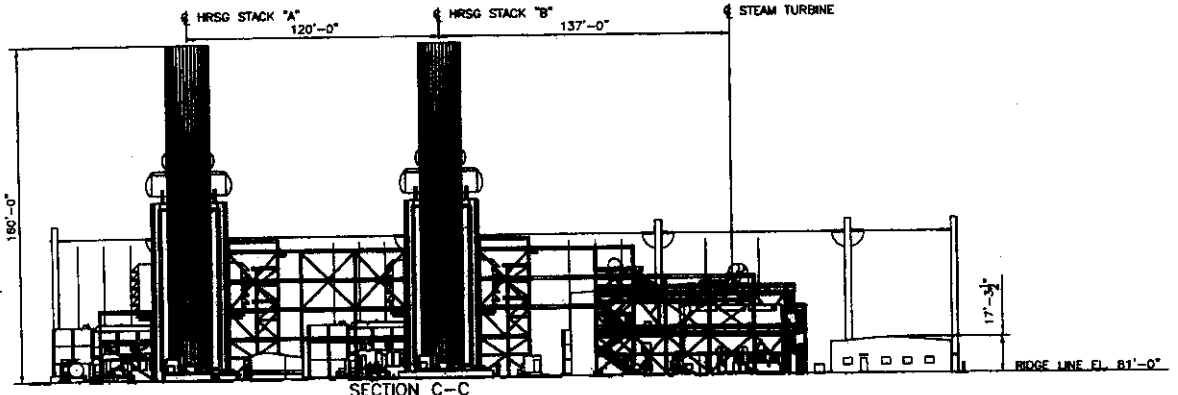

SECTION C-C
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DWG. D-PS-9000-2

REFERENCES:

D-PS-9000-1	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"
D-PS-9000-2	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=60'-0"
D-PS-9000-4	STANTON ENERGY CENTER - UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=400'-0"

PRELIMINARY

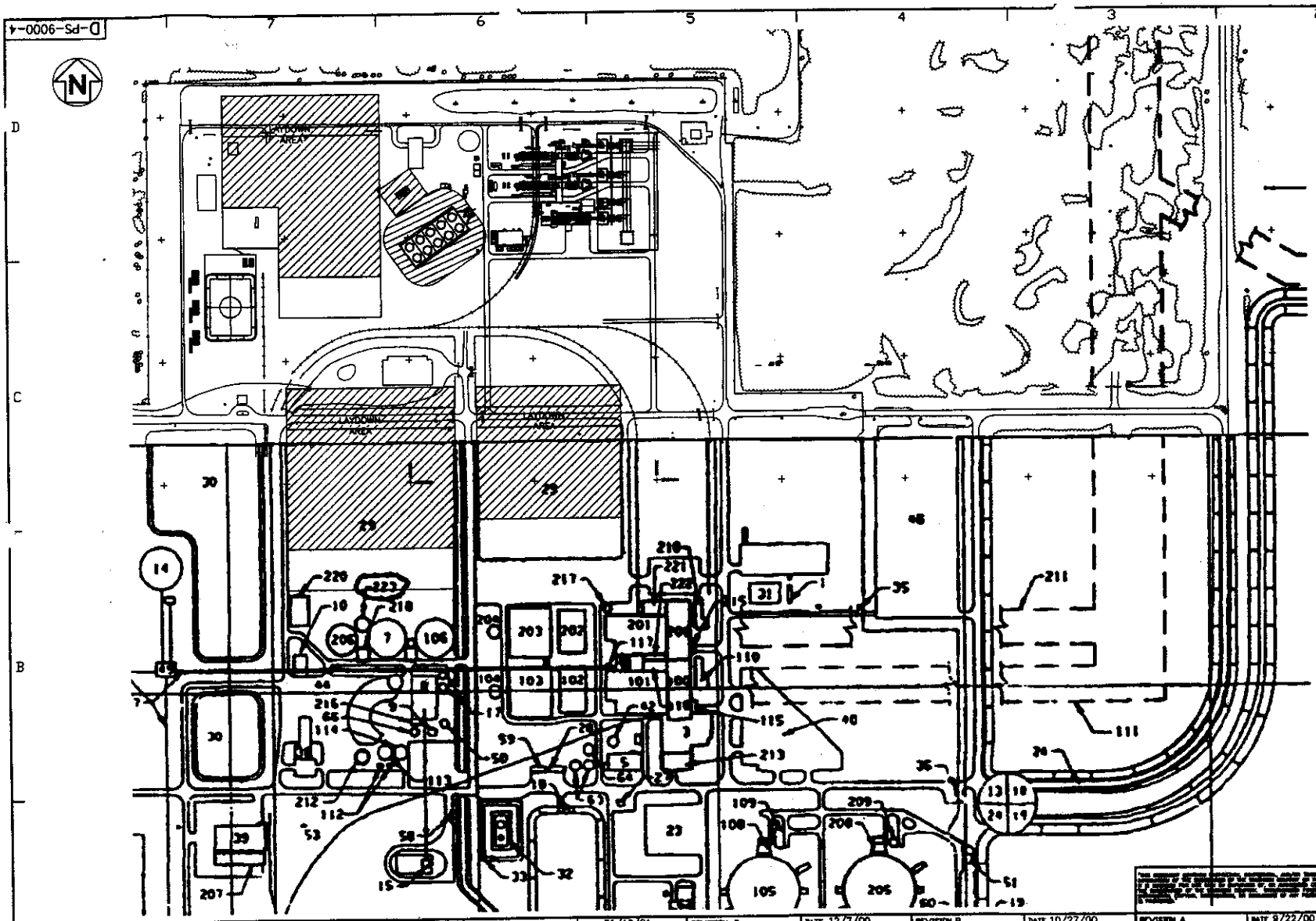
CAD 9000-32.DWG
AutoCad | SHV-14

REVISION	DATE	BY
B. 1. REVISED TITLE BLOCK.	01/16/00	SHW
A. ISSUED FOR REVIEW	9/22/00	SHW

Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER - UNIT A
1-2x1 COMBINED CYCLE BLOCK
SECTIONS

DESIGNED SHW | DRAWN SHW | CHECKED
SCALE: AS NOTED | PROJECT 13.
DRAWING NUMBER: D-PS-9000-3



REFERENCES:

D-PS-9000-1	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"
D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1 – 2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=60'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS

CAD 9000-4D
AutoCad SHW-14

REVISION	DATE	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
REVISION C: 1. REVISED TITLE BLOCK.	DATE 01/16/01	SHW						
REVISION C: 1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP	DATE 12/7/00	SHW						
REVISION B: ADDED IPC	DATE 10/27/00	SHW						
REVISION A: ISSUED FOR REVIEW	DATE 9/22/00	SHW						

Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=400'-0"

DESIGNED SHW	DRAWN SHW	CHECKED
SCALE 1"=400'-0"	PROJECT I.D.	DRAWING NUMBER D-PS-9000-4

- Negotiations are currently underway with natural gas transportation providers. It is assumed that the natural gas transportation provider will supply natural gas to the Stanton A site boundary. OUC is also licensing the existing OUC transmission line and railroad spur right-of-way for the addition of a natural gas pipeline lateral connecting to Florida Gas Transmission's (FGT's) 26 inch pipeline located 2.5 miles south of the Stanton Energy Center site.
- Interconnection with OUC's transmission system will be accomplished through the installation of 230 kV breakers located at the combustion turbine and steam turbine generators, a collector bus, a 230 kV transmission line located entirely onsite to the existing Stanton Energy Center Substation, and a 230 kV breaker position in the existing Stanton Energy Center Substation.

1A.3.2 Description of Stanton A Fuel Supply

Natural gas will be the primary fuel for Stanton A. OUC is responsible for obtaining natural gas for the project throughout the term of the PPA. Natural gas supply is under negotiation; a final selection of a supplier has not been made. For evaluation purposes, it has been assumed that FGT will be the natural gas supplier. OUC may contract with Gulfstream for natural gas transportation if adequate assurances are provided that the Gulfstream pipeline will be operational in the time frame required and will result in lower costs and/or more favorable terms and conditions than FGT. It is assumed that the natural gas transportation provider will supply natural gas to the Stanton A site boundary. OUC is also licensing the existing OUC transmission line and railroad spur right-of-way for the addition of a natural gas pipeline lateral connecting to FGT's 26 inch pipeline located 2.5 miles south of the Stanton Energy Center site.

No. 2 oil capacity at Stanton A will be provided by a 1.68 million gallon storage tank. At ISO conditions, Stanton A can operate for approximately 1.5 days at full load with this storage capacity.

1A.3.2.1 Fuel Transportation

Natural gas is the primary fuel for Stanton A. Negotiations are being conducted with FGT and Gulfstream for natural gas transportation. A detailed analysis and description of FGT's system and Gulfstream's proposed system is presented in Section 1A.5.3, Fuel Availability.

No. 2 oil is the planned secondary (backup) fuel for Stanton A. The No. 2 oil will be delivered to Stanton A utilizing either tanker trucks or rail. Once onsite, the fuel will be transferred to a storage tank.

1A.3.3 Capital Costs

The capital cost estimates for OUC, KUA, and FMPA are based on the Southern-Florida response to OUC, KUA, and FMPA Request for Proposal dated May 26, 2000, and the Construction and Ownership Participation Agreement. The capital cost estimate is based on OUC, KUA, and FMPA having a 35 percent ownership share of the project.

OUC's, KUA's, and FMPA's ownership share of the Capital Equipment Costs, which consist of the cost for the combustion turbines, steam generator, HRSGs, and generator step-up transformers is fixed by Southern-Florida at [redacted], subject to adjustment up or down to account for any agreed upon design changes or modifications to the Facility. OUC's, KUA's, and FMPA's ownership share of the BOP Capital Costs, which consist of all the costs of construction prior to commercial operation excluding the Capital Equipment Costs, will be based on actual costs incurred by Southern-Florida and OUC as defined by Southern-Florida's proposal, but are fixed by Southern-Florida between [redacted] (the "BOP Capital Cost Range"), adjusted for any changes to the scope of the project. For evaluation purposes, a BOP Capital Cost midpoint of [redacted] is assumed, but will be subject to adjustment for agreed scope changes. The BOP Capital Costs exclude the cost of obtaining the Site Certification. The BOP Capital Cost Range and midpoint are subject to adjustment up or down to account for any increases or decreases in Southern-Florida's costs resulting from (i) agreed upon design changes or modifications to the Facility as described in Southern's proposal, (ii) incorrect assumptions included in Southern-Florida's proposal, or (iii) activities that were specifically excluded from Southern-Florida's proposal.

Southern-Florida's proposal assumed that an interconnection with the Stanton sewage treatment facilities would be provided at the site boundary. Further evaluation has concluded that a septic system can be provided for a lower cost than the interconnection to the Stanton sewage treatment facilities. As a result, the BOP Capital Cost midpoint has been increased by [redacted] percent of the $15,200 for the cost of the septic system.

The RFP required the bidders to include an allowance for material and services provided by OUC of $5.5 million to ensure that all bids were developed on a consistent basis. These materials and services include the following:

- Need for Power and Site Certification Permitting.
- Transmission Interconnection Costs.
- Natural Gas Pipeline Lateral.

For evaluation purposes, this $5.5 million allowance is removed from the BOP Capital Costs. OUC and Southern-Florida have agreed that the Need for Power and Site Certification Permitting and the Transmission Interconnection Costs will be the responsibility of OUC, KUA, and FMPA. Negotiations with the potential natural gas transportation suppliers indicate that the most likely outcome will be that the natural gas transportation supplier selected will provide the natural gas transportation to the Stanton A site boundary, eliminating a separate cost for the natural gas pipeline lateral.

The Southern-Florida proposal requires OUC, KUA, and FMPA to provide treated sewage effluent, demineralized water, fire protection water, and potable/service water. The estimated costs to interconnect these systems are as follows:

- $1.564 million for cooling tower makeup.
- $0.443 million for demineralized water.
- $0.309 million for fire protection water.
- $0.236 million for potable/service water.

The total for these costs is $2.552 million and is the responsibility of OUC, KUA, and FMPA.

The total estimated capital cost for OUC's, KUA's, and FMPA's ownership share for the project is [redacted]. Table 1A.3-1 shows the development of the capital costs.

1A.3.4 O&M Costs

The O&M cost estimates were based on the following assumptions:

- Primary fuel - natural gas.
- Potable water, demineralized water, cooling tower makeup water, and fire service water, natural gas, and transmission are provided at the site boundary at the required conditions.
- Site security services for the Project are provided.
- Grounds maintenance services for the Project are provided.

1A.3.4.1 Fixed O&M Costs

Southern-Florida provided an estimate for annual operating and maintenance costs for the first year of commercial operation of approximately [redacted] (base year 2003 dollars) in its proposal.

Table 1A.3-1
Stanton A Capital Cost for OUC, KUA, and FMPA

	$ (Millions)
Capital Equipment Cost	[redacted]
Adjusted BOP Capital Costs[1]	[redacted]
Total Capital Equipment and Adjusted BOP Costs for OUC, KUA, and FMPA	[redacted]
Adjustment to Remove Allowance for OUC Provided Materials and Services[2]	[redacted]
Resulting Capital Equipment and BOP Costs for OUC, KUA, and FMPA	[redacted]
Electrical Interconnection Costs	[redacted]
Need for Power and Site Certification Permitting	[redacted]
Other Interconnection Costs	[redacted]
Total Capital Cost for OUC, KUA, and FMPA	[redacted]

[1]Includes septic system.
[2]35 percent share.

1A.3.4.2 Variable O&M and Startup Costs

Variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls under a maintenance service agreement with General Electric. Variable O&M costs vary as a function of plant generation. The variable O&M costs are fixed for the PPA and are assumed to be the same for the OUC, KUA, and FMPA ownership portion. The variable O&M cost is [redacted] in 2003 dollars plus the hourly variable O&M cost presented in Table 1A.3-2. Thus, total variable O&M cost assuming an [redacted] capacity factor based on the 70° F rating is [redacted] in 2003 dollars. The above variable O&M costs assume operation on natural gas. Variable O&M cost for operation on No. 2 oil is assumed to be [redacted] the variable O&M costs on natural gas.

Startup rates are presented in Table 1A.3-3. The startup rates are in 2003 dollars and escalate at the assumed general inflation rate. The startup rates shown in Table 1A.3-3 are based on 65 percent of the output of the unit.

Table 1A.3-2
Hourly Variable O&M Charges for Operation on Natural Gas (2003 $)

On Line Factor	Hourly Variable O&M Rate ($/hour)*
Greater than or equal to 73%	[redacted]
70%	[redacted]
60%	[redacted]
50%	[redacted]
40%	[redacted]
30%	[redacted]
20%	[redacted]
10%	[redacted]

*For 65 percent of the unit capacity.

Table 1A.3-3
Startup Rates for Operation

Cumulative Number of Startups per Gas Turbine per Contract Year	Startup Rate per Start per Gas Turbine ($)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

1A.3.4.3 OUC, KUA, and FMPA Provided O&M Services

OUC, KUA, and FMPA will provide water, transmission services, and other support to Stanton A from the existing Stanton 1 and 2 facilities. Water will be provided by upgrading existing Stanton Energy Center facilities. Transmission services will be provided by OUC from the high side of generator step-up transformers. OUC will provide dispatching and automatic generation control (AGC) services from its existing control center in Orlando. OUC will add new remote terminal units and AGC equipment at Stanton A to provide these services. For providing these services as well as the site lease, Southern-Florida will pay OUC, KUA, and FMPA [redacted] per year, escalating annually at the [redacted]

1A.3.5 Heat Rate

The estimates for average net plant heat rate (NPHR) and output for Stanton A at various ambient temperatures are listed in Table 1A.3-4. Plant heat rate and output estimates include a [redacted] percent degradation factor, respectively.

Table 1A.3-4
Net Plant Heat Rate (NPHR) – HHV
CONFIDENTIAL

Evaporative Cooling	Supplemental Firing	Power Augmentation	Net kW to High Side of GSU*	NPHR* (Btu/kWh)
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				

1A.3.6 Availability

Equivalent availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs, and routine maintenance activities. The equivalent availability for OUC's, KUA's, and FMPA's ownership portion of Stanton A is assumed to be 92 percent based on an annual average of 16.5 maintenance days per year and a 4 percent forced outage rate.

1A.3.7 Schedule

The Southern-Florida schedule for Stanton A is based on a 24 month construction period. To meet an October 1, 2003, commercial operation date, construction site activities start October 1, 2001, after receiving site certification.

This project schedule is based on reasonable activity durations and a logical, efficient approach to the project. This approach supports completing the project on time with minimum total cost. The detailed schedule is presented on Figure 1A.3-2.

1A.3.8 Transmission System Requirements

In order to accommodate the addition of Stanton A, $11,524,222 (2002 dollars) in onsite substation and transmission additions and upgrades must be made as identified in the following sections. The only offsite transmission requirements are upgrading existing circuit breakers in substations; thus, no associated transmission facilities as defined by the Florida Electrical Power Plant Siting Act are required.

1A.3.8.1 Circuit Breaker Upgrades

Thermal and short-circuit studies were conducted by OUC to determine the electrical impacts that Stanton A would have on the area transmission grid. The following circuit breaker upgrades are required to provide adequate circuit interrupting capability based on the additional fault duty that Stanton A will contribute to the grid. The estimate for circuit breaker upgrades is $2,261,785 (2002 dollars) as follows:

- **Country Club Substation**. Replacement of four breakers at an estimated cost of $476,143, excluding any ground grid enhancements which may be necessary.
- **America Substation.** Replacement of six breakers at an estimated cost of $714,215, excluding any ground grid enhancements which may be necessary.

- **Bennett Substation.** Replacement of six breakers at an estimated cost of $714,215, excluding any ground grid enhancements which may be necessary.
- **SEC and Indian River.** Upgrading of seventeen breakers at an estimated cost of $357,212.

1A.3.8.2 Onsite Transmission System Upgrades

Transmission upgrades at the Stanton Energy Center will require expansion of the existing substation, the addition of a transmission line to interconnect the switchyard at Stanton A to the Stanton Energy Center substation, and a new switchyard at Stanton A. Table 1A.3-5 identifies the upgrades needed for the Stanton A interconnection.

Table 1A.3-5
Stanton A Interconnection Facilities

Interconnection Item	**Estimated Cost [2002$]**
Expansion of Existing Stanton 230 kV Substation and 230 kV Transmission Line from Stanton A to Substation	5,337,556
230 kV Switchyard at Stanton A	3,924,881
Total Onsite Transmission System Upgrades	9,262,437

1A.3.9 Cooling Water

Stanton A will purchase cooling water from OUC, KUA, and FMPA at the rate of $0.45/1,000 gallons. The water mass balance for Stanton A estimates that 2,778.8 gpm of makeup water will be required for the 633 MW output. Assuming an [redacted] percent capacity factor, the annual cost for cooling water will be approximately [redacted] to be paid to OUC, KUA, and FMPA in proportion to Stanton 1 and 2 ownership shares.

1A.4.0 Power Purchase Agreements

This section summarizes the Power Purchase Agreements (PPAs) which govern the sale of capacity and energy from Southern-Florida's 65 percent ownership share of the project to OUC, KUA, and FMPA. OUC, KUA, and FMPA are entitled to 80, 10, and 10 percent of the purchased power, respectively. The PPAs represent the results of the negotiations between Southern-Florida and OUC, which culminated in more favorable terms and conditions for OUC, KUA, and FMPA than were contained in Southern-Florida's original proposal. Individual PPAs will be signed between Southern-Florida and OUC, KUA, and FMPA. The PPAs are scheduled to be signed for OUC on February 5, 2001, and for KUA and FMPA at their March board meetings. Appendix 1A.A contains the PPA that will form the basis of the individual PPAs. Final executed copies of the PPAs will be provided to the Commission upon their execution.

1A.4.1 PPA Term and Capacity Charges

The PPAs have an initial term of 10 years, which will be automatically extended for an additional 5 year period at the sole option of OUC, KUA, and FMPA. The PPAs also provide for three additional 5 year contract extensions for a maximum term of 30 years, which is the expected life of the plant. Table 1A.4-1 presents the capacity payments for the initial contract term and the four 5 year extensions. For each of the last three 5 year extensions, the capacity charge will be the higher of the capacity charge shown in Table 1A.4-1 or the market price as determined by Southern-Florida and subject to negotiation by OUC. In addition, OUC, KUA, and FMPA can collectively reduce their purchase power capacity by either 25 or 50 MW per year beginning in the sixth contract year and ending in the tenth contract year with an aggregate total reduction not to exceed 200 MW. Once a capacity reduction is implemented by OUC, KUA, and FMPA, the capacity reduction remains in place throughout the remainder of the contract term and for any extensions. This additional flexibility has not been explicitly evaluated in the NFP Application because in the event that conditions existed that caused additional savings for OUC, KUA, and FMPA from this capacity reduction, it would only serve to make the Southern-Florida joint development project more cost-effective. The capacity charges are based on unit output at [redacted]

The PPAs provide for adjustments in the capacity payments based on changes in (i) OUC's, KUA's, and FMPA's ownership share in Capital Equipment Costs, and (ii) BOP Capital Costs range and mid-point. For each change of [redacted] in either of the foregoing costs categories, the capacity payment changes (up or down) by $[redacted]

Based on the BOP Capital Cost adjustments presented in Table 1A.3-1, the capacity payment decreases [redacted] as shown in Table 1A.4-1.

Table 1A.4-1
Capacity Charges

Term Years	Capacity Charge $/kW-mo		
	Base	Adjustment	Total
0 - 10	[redacted]	[redacted]	[redacted]
11 - 15	[redacted]	[redacted]	[redacted]
15 - 20	[redacted]	[redacted]	[redacted]
21 - 25	[redacted]	[redacted]	[redacted]
26 - 30	[redacted]	[redacted]	[redacted]

*Capacity charge will be the higher of these rates or the market price if Southern-Florida elects the market price.

1A.4.2 Fuel Costs

Fuel costs for the purchase power are based on the actual cost of fuel used to produce the energy. OUC will be responsible for procuring fuel during the term of the PPA. Southern-Florida will be responsible for fuel procurement after the term of the PPA.

1A.4.3 O&M and Startup Costs

The variable O&M costs for energy purchased under the PPA consist of a variable O&M charge of [redacted] and an hourly variable O&M rate as presented in Table 1A.4-2. Both are in [redacted]. The hourly variable O&M rate applies to the 65 percent of total unit capacity covered by the PPA.

Startup rates are presented in Table 1A.4-3. The startup rates in Table 1A.4-3 are in 2003 dollars and are escalated at the Consumer Price Index. The startup rates apply to the 65 percent of total unit capacity covered by the PPA.

The above variable O&M costs are based on operation on natural gas. For operation on No. 2 oil, the variable O&M costs are multiplied by [redacted]. For evaluation purposes, the unit is assumed to run entirely on natural gas.

Table 1A.4-2 Hourly Variable O&M Rate for Operation on Natural Gas CONFIDENTIAL	
On-Line Factor (Percent)	Hourly Variable O&M Rate ($/hour)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Table 1A.4-3 Startup Rates for Operation CONFIDENTIAL	
Cumulative Number of Startups per Gas Turbine per Contract Year	Startup Rate per Start per Gas Turbine $
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

1A.4.4 Availability

The PPA allows capacity and energy to be provided by Southern-Florida from other resources. The availability of power purchased under the PPA is guaranteed at a minimal level of [redacted] by Southern-Florida. For availability below [redacted] capacity payments are reduced by the difference in the actual availability and [redacted] during peak periods, and by [redacted] of the difference during off-peak periods. When availability under capacity purchased under the PPA exceeds [redacted] bonus on the capacity payment is paid during peak periods, [redacted] of the capacity payments is paid during off-peak periods. For evaluation purposes, the availability of capacity purchased under the PPA is assumed to be 97 percent.

1A.5.0 Evaluation Criteria

1A.5.1 Economic Parameters

With several different entities having ownership interests in Stanton A, the economic parameters used for evaluation vary between the various participants primarily due to differences in their cost of money. Other economic parameters such as general inflation rates and escalation rates which do not vary between the participants are kept consistent for evaluation purposes. Because Southern-Florida is the majority owner of Stanton A, its economic parameters are used for decisions dealing with equipment selection. Because OUC is the agent for KUA and FMPA and has the largest entitlement to output from the project, OUC's economic criteria are used to determine the cost-effectiveness of the project as a whole. KUA's and FMPA's economic parameters are described in Volumes 1C and 1D and are used to determine the cost-effectiveness of their portion of the project for their respective systems.

1A.5.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is assumed to be 2.5 percent.

1A.5.1.2 Cost of Capital

Southern-Florida uses a real interest rate of [redacted] percent, which with the general inflation rate of 2.5 percent corresponds to a nominal interest rate of [redacted] percent. The real interest rate of [redacted] percent is used to evaluate emission control equipment in accordance with the Environmental Protection Agency guidelines.

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio, which is approximately 70/30, the embedded debt rate, which is approximately 6.6 percent, and the return on equity, which is approximately 10.3 percent. The weighted average cost of capital is thus approximately 7.7 percent. For economic evaluation for the need for power, the weighted average cost of capital is rounded to 8 percent.

1A.5.1.3 Present Worth Discount Rate

Southern-Florida uses a real present worth discount rate of [redacted] percent, corresponding to Southern-Florida's real interest rate.

OUC's present worth discount rate is assumed to be equal to the weighted average cost of capital of 8.0 percent.

1A.5.1.4 Interest During Construction Interest Rate

The interest during construction interest rate is assumed to be 6.0 percent.

1A.5.1.5 Levelized Fixed Charge Rate

The levelized fixed charge rate is assumed to be the sum of the capital recovery rate and insurance rate. Based on the weighted average cost of capital of 8.0 percent, a 1.0 percent annual insurance cost, and a capital recovery period of 20 years, the levelized fixed charge rate is assumed to be 11.19 percent.

1A.5.2 Fuel Price Projections

This section presents the fuel price projections for coal, petroleum coke, natural gas, oil, and nuclear fuel. For consistency, a single set of fuel price projections is developed to apply to OUC, KUA, and FMPA. In general, the projections are developed based on projected prices for OUC since OUC has the largest amount of generation of the three applicants. Also, many of the generating units are jointly owned by the three applicants and thus have similar fuel costs. Natural gas and oil are generally fungible and would be expected to have generally the same costs for each of the utilities for the same general geographical region over time.

The base case forecasts are based on forecasts provided by Energy Ventures Analysis, Inc. (EVA) who were commissioned by OUC and Southern-Florida because of its fuel forecasting expertise and the belief that the EVA forecast would be the best available. EVA developed fuel forecasts for natural gas, coal, West Texas Intermediate (WTI) crude oil, and petroleum coke.

Fuel prices are highly volatile and are dependent not only on supply and demand, but also political stability and interdependent markets. Even the best forecasters face a tough job of forecasting in such a volatile market. Figure 1A.5-1 shows historical US fuel prices and the wide range of fluctuations and responses to market conditions. Because of the difficulty of forecasting in this environment, several sensitivity scenarios have been developed. These sensitivity scenarios include a high and low forecast based on the forecast developed from the EVA forecast, a scenario where OUC's actual 2000 fuel prices remain constant throughout the evaluation period in real terms and, finally, the 2001 Annual Energy Outlook (AEO) projections developed by the United States Department of Energy (DOE).

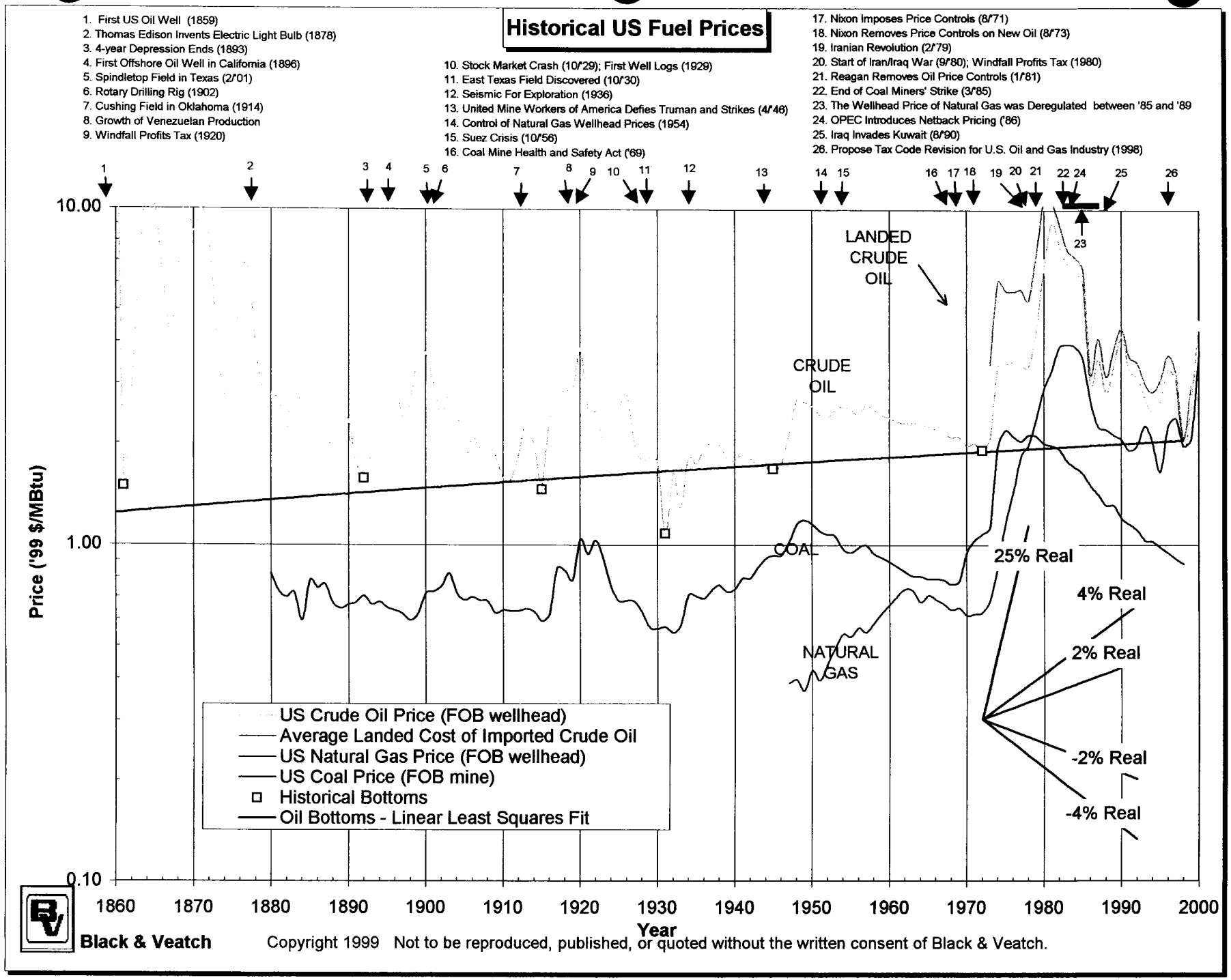


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Figure 1A.5-1

1A.5.2.1 EVA Fuel Price Projections

EVA developed projections for natural gas, coal, WTI crude oil, and petroleum coke on a real price basis.

1A.5.2.1.1 Natural Gas. The natural gas price projections are for Henry Hub. The greatest concern with the forecast is in the years 2003 and 2004. The industry has entered a new era in which short-term supply increases cannot keep pace with short-term demand increases. This imbalance has resulted in very high gas prices. Despite record levels of drilling in both the United States and Canada, it appears this era will last for at least 3 years and could last up to 5 years. The big variable in the length of this era is the severity of winter weather in each of the forthcoming years 2002 through 2004, as the difference between a mild and cold winter can represent between 1.5 and 2.0 BCFD per year in additional demand. The projection does not assume any carbon taxes or other such major pieces of legislation that could significantly impact supply and demand. The Henry Hub natural gas projection in constant 2001 dollars is presented in Table 1A.5-1.

1A.5.2.1.2 Coal. The long-term coal price projection is based on low sulfur (1.8-2.5 lb SO_2/MBtu with a 12,500 Btu/lb heating value) Appalachian coal delivered to Orlando in railcars. The projection by mine and rail costs in constant 2001 dollars is presented in Table 1A.5-2.

1A.5.2.1.3 WTI Crude Oil. Crude oil prices are expected to decline. The projected WTI crude oil prices in constant 2000 dollars are presented in Table 1A.5-3.

1A.5.2.1.4 Petroleum Coke. The petroleum coke forecast is a delivered price where the initial delivery is via barge from the Gulf Coast refineries and then offloaded to railcars. Crude oil prices, which are the largest cost component, are expected to decline as indicated in Table 1A.5-3. Larger coke volumes are projected to be produced as crude oil becomes heavier. Refinery upgrades are producing a larger gasoline fraction from residue, which increases coke production, which has risen 36 percent in the last 3 years. Higher value markets for petroleum coke are limited including calcined coke for aluminum production and needle grade for steel refineries. Fuel grade (green coke) is the lowest value use for petroleum coke, but also is the only remaining expansion market. Petroleum coke is a thinly traded commodity and is at risk of rapid price escalation with large increases in demand. However, the cap is set by alternative coal prices ($1.80/MBtu) in the US market and alternative fuels in Europe. Fuel use, however, has discounted value because of the high metals content, high sulfur content, and low volatile content. Market potential for petroleum coke could grow and the price increase if more flue gas desulfurization (FGD) systems are retrofitted on existing plants. The projected power demand and projected price of petroleum coke delivered to Stanton Energy Center in constant 2001 dollars are presented in Table 1A.5-4.

Table 1A.5-1
EVA Forecast Natural Gas Prices At Henry Hub ($2001)

Year	[$/MBtu]
2000	4.30
2001	5.64
2002	4.24
2003	3.27
2004	2.75
2005	2.65
2006	2.59
2007	2.63
2008	2.67
2009	2.71
2010	2.75
2011	2.80
2012	2.85
2013	2.90
2014	2.95
2015	3.01
2016	3.07
2017	3.13
2018	3.20
2019	3.26

Table 1A.5-2
EVA Forecast Long-Term Coal Prices ($2001)

Year	Mine $/ton	Rail $/ton	Delivered $/ton	Delivered $/MBtu
2000	23.43	19.95	43.38	1.74
2001	28.97	19.50	48.47	1.94
2002	25.85	19.07	44.92	1.80
2003	24.99	18.77	43.76	1.75
2004	24.89	18.50	43.39	1.74
2005	24.65	18.42	43.07	1.72
2006	24.45	18.29	42.74	1.71
2007	24.31	18.15	42.45	1.70
2008	24.17	18.01	42.18	1.69
2009	24.10	17.88	41.98	1.68
2010	24.03	17.75	41.78	1.67
2011	23.98	17.64	41.62	1.66
2012	23.92	17.54	41.46	1.66
2013	23.87	17.43	41.30	1.65
2014	23.79	17.33	41.12	1.64
2015	23.74	17.23	40.96	1.64
2016	23.69	17.14	40.84	1.63
2017	23.68	17.06	40.74	1.63
2018	23.68	16.98	40.65	1.63
2019	23.66	16.89	40.55	1.62

Note: Long-term delivered cost to Stanton Energy Center based on Appalachian low-sulfur coal with 12,500 Btu/lb heating value and 1.8 to 2.5 lb SO_2/MBtu.

Table 1A.5-3
EVA Forecast WTI Crude Oil Price ($2000)

Year	WTI Crude Oil [$/BBL]
2000	30.26
2001	26.61
2002	23.70
2003	21.00
2004	19.50
2005	18.50
2006	17.50
2007	17.00
2008	16.50
2009	16.00
2010	16.00
2011	15.50
2012	15.50
2013	15.50
2014	15.54
2015	15.58
2016	15.66
2017	15.73
2018	15.81
2019	15.89

Table 1A.5-4
EVA Forecast Petroleum Coke Demand and Delivered Prices ($2001)

Year	Power Demand 1,000 tons	Most Probable $/MBtu	Low $/MBtu	High $/MBtu
2000	3,254	1.29	0.83	1.64
2001	3,686	1.28	0.75	1.64
2002	3,686	1.20	0.74	1.64
2003	3,761	1.14	0.73	1.63
2004	3,987	1.12	0.73	1.63
2005	4,101	1.11	0.72	1.63
2006	4,214	1.09	0.72	1.63
2007	4,341	1.09	0.71	1.62
2008	4,471	1.08	0.70	1.62
2009	4,605	1.08	0.70	1.62
2010	4,743	1.09	0.69	1.61
2011	4,886	1.09	0.68	1.61
2012	5,032	1.10	0.68	1.61
2013	5,183	1.12	0.67	1.61
2014	5,338	1.13	0.66	1.60
2015	5,498	1.15	0.66	1.60
2016	5,663	1.17	0.65	1.60
2017	5,833	1.19	0.66	1.60
2018	6,008	1.21	0.65	1.59
2019	6,189	1.23	0.64	1.59

1A.5.2.2 Base Case Fuel Price Projections

The coal price projections are assumed to apply to McIntosh 3 as well as units at Stanton Energy Center.

The annual general inflation rate of 2.5 percent is added to EVA's constant dollar fuel price forecasts to obtain nominal fuel price projections for evaluation purposes which are presented in Table 1A.5-5.

For natural gas, transportation charges must be added to obtain a delivered fuel cost. OUC, KUA, and FMPA, as well as FMPA's generating member cities, all have varying amounts of natural gas transportation capability from Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs. The FTS-2 tariff is expected to change as additional expansions are conducted on FGT's system. In general, it is expected that FTS-2 tariff rates will lower somewhat as additional expansions are added. Also impacting the natural gas transportation situation is the proposed Gulfstream pipeline. In general, increased competition would be expected to increase pressure to lower transportation costs. Finally, the impacts of transportation capacity being bought and sold on the secondary market will also influence the average natural gas transportation costs. For the purposes of this evaluation, OUC has assumed that natural gas transportation costs will be approximately $0.75/MBtu over the evaluation period. The $0.75/MBtu natural gas transportation cost is assumed to remain constant over the forecast period and is included in the natural gas price forecast in Table 1A.5-5.

EVA did not provide forecasts for No. 2 and No. 6 oil. Delivered projections of No. 2 and No. 6 oil were developed by comparing OUC's actual delivered cost for No. 2 and No. 6 oil in 2000 to EVA's projected 2000 WTI crude oil price and applying the percentage difference in cost to EVA's WTI crude oil price.

Projections for nuclear fuel prices are based on OUC's actual 2000 nuclear fuel cost escalating at the general inflation rate.

1A.5.2.3 High and Low Case Fuel Price Projections

High and low case fuel price projections for all fuels except petroleum coke are developed by applying a 2 percent higher annual escalation rate to the base case fuel price projections for the high case and a 2 percent lower annual escalation rate to the base case projections for the low case except for the petroleum coke projections which apply the 2.5 percent general inflation rate to the EVA high and low projections. The high and low petroleum coke forecasts were provided directly by EVA. The high and low case fuel price projections are presented in Tables 1A.5-6 and 1A.5-7, respectively.

Table 1A.5-5
Base Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	1.26
2001	1.94	6.39	5.22	3.98	0.53	1.28
2002	1.85	5.10	4.76	3.64	0.55	1.23
2003	1.84	4.19	4.33	3.30	0.56	1.20
2004	1.87	3.71	4.12	3.14	0.57	1.21
2005	1.90	3.56	4.00	3.06	0.59	1.23
2006	1.93	3.68	3.88	2.96	0.60	1.23
2007	1.97	3.80	3.87	2.95	0.62	1.26
2008	2.01	3.92	3.85	2.94	0.63	1.28
2009	2.05	4.05	3.82	2.92	0.65	1.32
2010	2.09	4.18	3.92	2.99	0.67	1.36
2011	2.12	4.33	3.89	2.97	0.68	1.40
2012	2.20	4.49	3.99	3.04	0.70	1.44
2013	2.22	4.65	4.09	3.12	0.72	1.51
2014	2.26	4.82	4.20	3.21	0.73	1.56
2015	2.32	5.00	4.32	3.30	0.75	1.62
2016	2.36	5.20	4.45	3.40	0.77	1.69
2017	2.42	5.40	4.58	3.50	0.79	1.77
2018	2.48	5.62	4.72	3.60	0.81	1.84
2019	2.53	5.83	4.86	3.71	0.83	1.92
Average Annual Escalation (%)	2.12%	0.87%	-0.92%	-0.92%	2.50	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-6
High Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	1.60
2001	1.97	6.47	5.33	4.07	0.54	1.64
2002	1.92	5.26	4.98	3.80	0.57	1.68
2003	1.95	4.40	4.62	3.53	0.59	1.71
2004	2.02	3.98	4.49	3.43	0.62	1.76
2005	2.09	3.88	4.46	3.40	0.65	1.80
2006	2.17	4.08	4.41	3.37	0.68	1.84
2007	2.26	4.28	4.48	3.42	0.71	1.88
2008	2.35	4.50	4.54	3.47	0.74	1.93
2009	2.44	4.72	4.61	3.52	0.77	1.97
2010	2.53	4.96	4.82	3.68	0.81	2.01
2011	2.63	5.23	4.88	3.72	0.84	2.06
2012	2.78	5.51	5.10	3.89	0.88	2.11
2013	2.86	5.81	5.33	4.07	0.92	2.17
2014	2.97	6.13	5.58	4.26	0.96	2.21
2015	3.10	6.49	5.85	4.46	1.01	2.26
2016	3.22	6.86	6.14	4.69	1.05	2.32
2017	3.37	7.26	6.44	4.92	1.10	2.38
2018	3.52	7.70	6.77	5.17	1.15	2.42
2019	3.65	8.15	7.11	5.43	1.20	2.48
Average Annual Escalation (%)	4.12%	2.66%	1.09%	1.09%	4.50%	2.33%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-7
Low Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	0.81
2001	1.91	6.31	5.10	3.90	0.52	0.75
2002	1.77	4.91	4.56	3.48	0.53	0.76
2003	1.73	3.94	4.05	3.09	0.53	0.77
2004	1.73	3.46	3.77	2.88	0.53	0.79
2005	1.72	3.26	3.59	2.74	0.53	0.79
2006	1.72	3.32	3.41	2.60	0.54	0.81
2007	1.72	3.37	3.33	2.54	0.54	0.82
2008	1.71	3.43	3.24	2.48	0.54	0.83
2009	1.71	3.48	3.16	2.41	0.54	0.85
2010	1.71	3.54	3.18	2.42	0.55	0.86
2011	1.71	3.60	3.09	2.36	0.55	0.87
2012	1.74	3.67	3.11	2.37	0.55	0.89
2013	1.72	3.74	3.12	2.38	0.55	0.90
2014	1.71	3.80	3.14	2.40	0.56	0.91
2015	1.72	3.88	3.17	2.42	0.56	0.93
2016	1.72	3.96	3.20	2.44	0.56	0.94
2017	1.73	4.04	3.23	2.47	0.57	0.96
2018	1.74	4.14	3.26	2.49	0.57	0.99
2019	1.73	4.22	3.30	2.52	0.57	1.00
Average Annual Escalation (%)	0.11%	-0.83%	-2.92%	-2.92%	0.50%	1.11%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

1A.5.2.4 Constant 2000 Fuel Price Projections

The constant 2000 fuel price projection assumes that the actual OUC 2000 fuel costs remain constant in real terms over the forecast period. The constant 2000 fuel price projection thus applies the 2.5 percent general inflation rate to OUC's actual 2000 fuel costs for all fuels except petroleum coke. The constant 2000 projection for petroleum coke was developed by applying the 2.5 percent general inflation rate to the base case forecast provided by EVA. Figure 1A.5-1 indicates that it would be unprecedented for high fuel prices such as those occurring in 2000 to continue in real terms for an entire 20 year period. Nevertheless, the constant 2000 fuel price projection offers the opportunity to evaluate the cost effectiveness of Stanton A with continuing high fuel prices. The constant 2000 fuel price projection is presented in Table 1A.5-8. For purposes of this evaluation, the delivered gas price projection assumes the commodity portion of the price escalates at the 2.5 percent general inflation rate and the $0.75/MBtu transportation cost remains constant over the forecast period. This results in the delivered cost of natural gas escalating at slightly less than the general inflation rate of 2.5 percent. The constant 2000 fuel price projection for natural gas is 33 percent higher than the base case by 2019.

1A.5.2.5 2001 Annual Energy Outlook Fuel Price Projections

The final two fuel price projections used in the sensitivity evaluations are based on the Annual Energy Outlook (AEO) fuel price data published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2001 energy data is a comprehensive and reliable source of domestic and international energy supply, consumption, and price information.

AEO provides energy forecasts through the year 2020 and takes into account a number of important factors, some of which include:

- Restructuring of the US electricity markets
- Current regulations and legislation affecting the energy markets
- Current energy issues:
  - Appliance, gasoline, and diesel fuel, and renewable portfolio standards.
  - Expansion of natural gas industry
  - Carbon emissions
  - Competitive energy pricing

AEO 2001 energy information is objective and nonpartisan. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

Table 1A.5-8
Constant 2000 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.67	5.03	5.79	4.42	0.52	1.26
2001	1.71	5.14	5.94	4.53	0.53	1.29
2002	1.75	5.25	6.09	4.64	0.55	1.32
2003	1.80	5.36	6.24	4.76	0.56	1.36
2004	1.84	5.47	6.39	4.88	0.57	1.39
2005	1.89	5.59	6.55	5.00	0.59	1.43
2006	1.94	5.71	6.72	5.13	0.60	1.46
2007	1.99	5.84	6.88	5.25	0.62	1.50
2008	2.03	5.96	7.06	5.39	0.63	1.54
2009	2.09	6.10	7.23	5.52	0.65	1.57
2010	2.14	6.23	7.41	5.66	0.67	1.61
2011	2.19	6.37	7.60	5.80	0.68	1.65
2012	2.25	6.51	7.79	5.94	0.70	1.69
2013	2.30	6.65	7.98	6.09	0.72	1.74
2014	2.36	6.80	8.18	6.25	0.73	1.78
2015	2.42	6.95	8.39	6.40	0.75	1.82
2016	2.48	7.10	8.60	6.56	0.77	1.87
2017	2.54	7.26	8.81	6.73	0.79	1.92
2018	2.60	7.43	9.03	6.89	0.81	1.97
2019	2.67	7.59	9.26	7.07	0.83	2.01
Average Annual Escalation (%)	2.50%	2.19%	2.50%	2.50%	2.50%	2.50%

AEO 2001 publishes 1999, 2005, 2010, 2015, and 2020 fuel price projections, which are presented in Table 1A.5-9. From these projections, real compound annual escalation rates (CAERs) can be calculated for 1999 through 2005, 2005 through 2010, 2010 through 2015, and 2015 through 2020 periods. These real CAERs are used to develop annual fuel price projections to which the 2.5 percent general inflation rate is applied. The AEO 2001 fuel price projections are presented in Table 1A.5-10. The delivered price of natural gas adds a constant $0.75/MBtu transportation cost to the AEO 2001 commodity projection. AEO does not project nuclear or petroleum coke prices. The nuclear and petroleum coke projections are those presented in the base case in Table 1A.5-5. The AEO 2001 fuel price projections for 2000 are much lower than the actual 2000 OUC fuel prices shown in Table 1A.5-8. Furthermore, the AEO projections are on a national average basis, which is heavily weighted by low cost western coal and do not reflect the relatively higher coal transportation costs to Florida. As a result, the AEO projections understate coal costs for Florida.

The second fuel price projection based on the AEO 2001 fuel price projections applies the AEO 2001 real escalation rates along with the 2.5 percent annual general inflation rate to the actual 2000 OUC fuel prices. These fuel price projections are presented in Table 1A.5-11. The nuclear and petroleum coke projections are those presented in the base case in Table 1A.5-5. This projection initially matches the actual 2000 OUC fuel prices and continues to escalate them into the future. High fuel prices continuing to escalate for a 20 year period would be unprecedented compared to historical prices presented in Figure 1A.5-1.

1A.5.3 Fuel Availability

Plentiful coal and natural gas reserves exist both in the United States and North American mainland and coastal regions. Large coal reserves within the east, central, and western United States are adequate to supply power generation needs for the foreseeable future. Oil reserves are dependent on both domestic and offshore production and imports. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home heating and power production is contributing to the volatility of its price, which in turn has provided incentives for increased production. A somewhat cyclic effect is expected, where short-term demand and volatility will drive increased production and future price stability.

1A.5.3.1 Service to Proposed Plant Site.

FGT's 26 inch pipeline is located approximately 2.5 miles south of the Stanton Energy Center site.

Table 1A.5-9
2001 Annual Energy Outlook Real Fuel Price Projections and CAERs

	1999	2005	2010	2015	2020
No. 2 Oil,* $/MBtu	4.05	4.65	4.84	5.10	5.28
Residual Oil,* $/MBtu	2.42	3.52	3.88	4.00	4.07
Coal,* $/MBtu	1.21	1.13	1.05	1.01	0.98
Natural Gas,** $/MBtu	2.08	2.49	2.69	2.83	3.13
	1999-2005	2005-2010	2010-2015	2015-2020	1998-2020
No. 2 Oil* Real CAERs, percent	2.33	0.80	1.05	0.70	2.23
Residual Oil* Real CAERs, percent	6.49	1.97	0.61	0.35	2.79
Coal* Real CAERs, percent	-1.13	-1.46	-0.77	-0.60	-1.17
Natural Gas** Real CAERs, percent	3.04	1.56	1.02	2.04	2.01

*Delivered price.

**Well head price.

Source: DOE Energy Information Administration web site

Table 1A.5-10
AEO 2001 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.23	3.42	4.25	2.64	0.52	1.26
2001	1.25	3.54	4.64	2.88	0.53	1.28
2002	1.26	3.67	5.06	3.14	0.55	1.23
2003	1.28	3.81	5.52	3.43	0.56	1.20
2004	1.30	3.95	6.02	3.74	0.57	2.21
2005	1.31	4.06	6.29	3.91	0.59	2.23
2006	1.32	4.18	6.58	4.09	0.60	1.23
2007	1.34	4.30	6.88	4.27	0.62	1.26
2008	1.35	4.42	7.19	4.46	0.63	1.28
2009	1.36	4.55	7.51	4.67	0.65	1.32
2010	1.39	4.70	7.75	4.81	0.67	1.36
2011	1.41	4.86	7.99	4.96	0.68	1.40
2012	1.43	5.02	8.24	5.12	0.70	1.44
2013	1.46	5.18	8.49	5.28	0.72	1.51
2014	1.48	5.35	8.76	5.44	0.73	1.56
2015	1.51	5.57	9.01	5.60	0.75	1.62
2016	1.54	5.79	9.27	5.76	0.77	1.69
2017	1.57	6.02	9.53	5.92	0.79	1.77
2018	1.60	6.27	9.81	6.09	0.81	1.84
2019	1.63	6.52	10.09	6.26	0.83	1.92
Average Annual Escalation (%)	1.49%	3.45%	4.65%	4.65%	2.50%	2.24%

Table 1A.5-11
AEO 2001 Escalation Applied to 2000 OUC Fuel Prices ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.67	5.03	5.79	4.42	0.52	1.26
2001	1.69	5.23	6.32	4.82	0.53	1.28
2002	1.71	5.43	6.89	5.26	0.55	1.23
2003	1.74	5.65	7.52	5.74	0.56	1.20
2004	1.76	5.87	8.21	6.26	0.57	2.21
2005	1.78	6.06	8.58	6.55	0.59	2.23
2006	1.80	6.24	8.97	6.84	0.60	1.23
2007	1.81	6.44	9.37	7.15	0.62	1.26
2008	1.83	6.64	9.79	7.47	0.63	1.28
2009	1.85	6.85	10.24	7.81	0.65	1.32
2010	1.88	7.09	10.56	8.06	0.67	1.36
2011	1.92	7.33	10.89	8.31	0.68	1.40
2012	1.95	7.59	11.23	8.57	0.70	1.44
2013	1.98	7.85	11.58	8.83	0.72	1.51
2014	2.02	8.13	11.94	9.11	0.73	1.56
2015	2.05	8.47	12.28	9.37	0.75	1.62
2016	2.09	8.83	12.63	9.64	0.77	1.69
2017	2.13	9.20	12.99	9.91	0.79	1.77
2018	2.17	9.59	13.36	10.20	0.81	1.84
2019	2.21	10.00	13.74	10.49	0.83	1.92
Average Annual Escalation (%)	1.49%	3.68%	4.65%	4.65%	2.50%	2.24%

1A.5.3.2 Florida Gas Transmission Company

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 5,000 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation which, in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and El Paso Energy Corporation, one of the largest independent producers of natural gas in the United States.

The FGT pipeline system accesses a diversity of natural gas supply regions, including:

- Anadarko Basin (Texas, Oklahoma, and Kansas).
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana – Mississippi – Alabama Salt Basin.
- Mobile Bay.

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

1A.5.3.3 Florida Gas Transmission Market Area Pipeline System

The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

1A.5.3.4 Florida Gas Transmission Expansion Project

FGT filed for FERC approvals of the Phase IV expansion project December 2, 1998. The filing consists of expanding services to southwest Florida with 139 miles of underground pipelines. The $268 million Phase IV project will add more than 38,000 horsepower of compression, and associated facilities and will provide approximately 197 million cubic feet per day (MMcf/d) of incremental firm transportation service on an average annual basis. FGT announced in May of 2000 that construction related to the Phase IV had begun and is scheduled for service by the May 2001 target.

FGT's Phase V expansion project, filed with the FERC on December 1, 1999, will deliver natural gas to a variety of new and current FGT customers and make natural gas available to areas that have not previously had gas service. The Phase V expansion project is intended to add approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. The result of this expansion will be the addition of more than 428 MMcf/d of incremental mainline capacity to Florida. With an estimated cost of $466 million, the Phase V expansion plan has a target in-service date of April 1, 2002.

The Phase V expansion faced many changes that caused it to file an amended project application with FERC. After the Florida Supreme Court ruling that limited the ability of nonutility merchant plants to use the Florida Electrical Power Plant Siting Act, two major Phase V customers, Enron and Dynergy, withdrew from Phase V. However, FGT subsequently gained back some of the lost market by signing a long-term contract with Tampa Electric Company as a Phase V customer. FERC granted preliminary approval to the expansion in November of 2000. The Phase V expansion still requires final environmental approval.

FGT recently concluded an open season for Phase VI. FGT received what it defined as 'a positive response' to the open season. The intent of the project is to provide incremental firm transportation service to Florida. The new pipeline is proposed to extend from Savannah, Georgia, to Jacksonville, Florida, with access to Southern LNG Company's liquefied natural gas. Phase VI is scheduled for an in-service date of Spring 2003.

FERC approved in November of 2000 FGT's request for the purchase of an undivided interest in Koch Gateway Pipeline's Mobile Bay Lateral. This purchase will give FGT the right to an additional 300,000 MMcf/d of input capacity. The acquisition is set to become effective April 1, 2002.

1A.5.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida

There is currently one transportation company serving Peninsular Florida: FGT. Two additional pipelines, Buccaneer and Gulfstream, received preliminary approval from the Federal Energy Regulatory Commission (FERC) in April of last year. In September of last year, both pipelines also received one of the two required approvals from FERC.

In November of 2000, the developers of the Buccaneer gas pipeline, Williams Energy and Duke Energy, announced their intent to purchase the Gulfstream pipeline from Coastal Corporation. The purchase is subject to federal regulatory approvals and conditioned upon completion of the Coastal/El Paso Energy Corporation merger.

Duke Energy and Williams Energy will collaborate on the Gulfstream pipeline in lieu of the Buccaneer pipeline. Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities representing long-term commitments for the majority of its 1.1 billion cubic feet of gas per day capacity. The Gulfstream pipeline was designed primarily to serve Florida utilities and power generation facilities that plan on using high efficiency natural gas turbines to meet the incremental demand for electrical energy. The pipeline is discussed below. At this time, it is uncertain as to what effect the purchase will have on the pipeline configuration.

FGT, El Paso Merchant, and Gulfstream have all made competitive proposals to provide gas transportation to Stanton A.

1A.5.3.5.1 Gulfstream Pipeline. The Gulfstream pipeline is a 744 mile pipeline originally proposed by the Coastal Corporation. The pipeline will originate from the Mobile Bay region, crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline is expected to supply Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida.

The 1.6 billion dollar pipeline won FERC approval, subject to environmental review, on April 24, 2000. Final environmental and routing approvals by FERC are expected in March of 2001. Construction for the Gulfstream pipeline is scheduled to begin in June of 2001, with an estimated operation date of June of 2002. The first major acquisition of right-of-way occurred July 20, 2000, with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained the permanent right-of-way easement to cross through Port Manatee. In addition to a payment to Port Manatee, Coastal Corporation will lease up to 190 acres of vacant land at Port Manatee to serve as a logistics base during Gulfstream's construction phase.

1A.6.0 Methodology to Evaluate Power Supply Alternatives

In order to obtain the most cost-effective alternative, OUC, KUA, and FMPA considered three independent strategies. The first was the joint development of a natural gas fueled combined cycle generating unit at either the Stanton Energy Center or Cane Island Power Park sites. The second alternative was the solicitation of power supply proposals from third parties. This alternative included purchased power from existing or proposed units of any fuel or technology. The third alternative, a self-build option, considered the construction of a natural gas fired combined cycle generating unit at the Stanton Energy Center site. This unit would be jointly owned and operated by OUC, KUA, and FMPA.

1A.6.1 Joint Development RFP Summary

The Joint Development RFP contemplates the need for additional capacity and energy no later than October 1, 2003, and seeks proposals from qualified parties to jointly develop a 500 MW or 750 MW combined cycle power plant facility at Stanton Energy Center or a 500 MW combined cycle at Cane Island Power Park. Additionally, the Joint Development RFP requires that the proposed unit be capable of operating on natural gas and No. 2 fuel oil. Moreover, the RFP contained the following nonmonetary evaluation criteria:

- Respondent's capability to provide power generation equipment necessary to support the proposal.
- Respondent's registration to do business within the State of Florida.
- Respondent's experience in power plant development, procurement, and construction within the United States.
- Respondent's experience in combined cycle power plant development, procurement, and construction within the State of Florida.
- Respondent's ability to meet the RFP requirements of having generation available by the year 2003.

One objective of the Joint Development RFP for OUC, KUA, and FMPA is to obtain a purchase power agreement which is competitively priced, providing flexibility in managing the bulk power supply available to serve their customers. To accomplish this, the RFP requires that respondents make the following assumptions:

- OUC, KUA, and FMPA shall own a combined 35 percent of the project assets and shall be entitled to 35 percent of the project capacity.
- The respondent shall own 65 percent of the project assets and shall be entitled to 65 percent of the project capacity.

- OUC, KUA, and FMPA shall purchase, pursuant to the PPA, between 77 percent and 100 percent of the respondent's share of the capacity.
- OUC, KUA, and FMPA shall be responsible for the payment of 35 percent of project costs and ongoing project operation and maintenance costs.
- The respondent shall be responsible for the payment of 65 percent of project costs and ongoing project operation and maintenance costs.
- The respondent shall be responsible for the procurement of all project fuel.

The RFP was issued May 26, 2000, and proposals were due July 18, 2000. The Joint Development RFP is included in Appendix 1A.B. The RFP was issued to 39 parties, including all three investor-owned utilities in Peninsular Florida.

Proposals were received in response to the Joint Development RFP from Southern-Florida and four other developers. An independent consulting firm, WHH Enterprises, analyzed each of the responses. The complete WHH Enterprises evaluation and results are included in the Confidential Exhibit A.

The conclusion of the evaluation from WHH Enterprises indicated that the proposal from Southern-Florida contained the lowest levelized cost per megawatt-hour based on a 60 and 70 percent capacity factor.

In addition to having higher costs, the proposal from the second highest ranked respondent was not as responsive as the Southern-Florida proposal. Although required by the RFP, the second highest ranked respondent's proposal failed to price the extension options. Also, the second highest ranked respondent's proposal did not provide for combined cycle generation at the Stanton Energy Center site until October 2006. The second highest ranked respondent proposed providing capacity and energy from another proposed project from October 2003 until October 2006. Although the evaluation did not financially penalize the second highest ranked respondent's proposal for the above deficiencies, it was concluded that their proposal subjected OUC, KUA, and FMPA to more uncertainty.

1A.6.2 Power Supply RFP Summary

The second alternative solicited proposals for power supply from third parties. The Power Supply RFP states that OUC, KUA, and FMPA will consider proposals for the purchase of 500 MW or 750 MW of physically firm, base, intermediate, and/or peaking power from existing specified resources, a portfolio of supply resources with appropriate backup guarantees, and/or a generating facility to be constructed at the proposer's site for unit power sale. The proposals may come from any electric utility, independent power producer, qualifying facility, exempt wholesale generator, nonutility generator, or electric power marketer who has received certification as such by the Federal Energy

Regulatory Commission. The RFP was advertised locally and nationally and placed on the Internet. The RFP was issued on May 24, 2000, and bids were due on July 11, 2000. The Power Supply RFP is included, in its entirety, as Appendix 1A.C.

The issuance of the Power Supply RFP resulted in responses from five companies. The proposals were screened and evaluated by the independent consulting firm of R.W. Beck, Inc. Initial screening indicated that the proposal received from one of the respondents did not comply with the RFP minimum requirements. After attempts to obtain the additional information necessary to make that proposal complete were unsuccessful, it was not included in the subsequent evaluations. The remaining proposals were then compared against one another using a 10 year levelized cost evaluation process. The complete R.W. Beck, Inc. evaluation and results are included in the Confidential Exhibit A.

1A.6.3 Self-Build Alternative

In order to investigate the economics of the self-build alternative, OUC commissioned Black & Veatch to develop cost estimates for a 2 x 1 Siemens-Westinghouse 501F combined cycle in two configurations. One configuration represented a standard sized steam turbine and would have been an appropriate sized unit for OUC if KUA and FMPA had ultimately decided not to participate in the project. The other configuration included an oversized steam turbine that would accommodate the maximum duct firing possible and would be an appropriate size for the project. The cost estimates are summarized in Section 1A.7.6 and are presented in detail in Appendices 1A.D and 1A.E.

The cost estimates were developed to be consistent with the competitive plants being developed by the independent power producer (IPP) industry, but included reliability and redundancy features typical for utility power plants to represent a true self-build alternative for OUC, KUA, and FMPA. The cost estimates were developed without consideration of combustion turbine delivery dates even though the delivery schedule for combustion turbines ordered from Siemens-Westinghouse or General Electric was the beginning of 2004. This delivery schedule would obviously preclude an October 1, 2003 commercial operation date, but nevertheless, the cost estimates provided OUC with a benchmark against which it could evaluate respondents' proposals that utilized previously ordered equipment.

In addition, KUA was able to extend its option, obtained from the Cane Island 3 Project, for two General Electric 7FA combustion turbines. The option for these turbines had a delivery schedule that would have allowed the October 1, 2003, commercial operation date to be achieved. This allowed a direct comparison between a self-build alternative that would have the same output and performance as the project proposed by

Southern-Florida. The cost and performance of this self-build alternative is also provided in Section 1A.7.6.

1A.6.4 Results of RFPs and Self-Build Alternative Comparison

The Southern-Florida proposal was lower in cost on a levelized basis at 70 percent capacity factor than any of the other joint development proposals and power supply proposals. The Southern-Florida proposal also offered significant savings over the cost of the self-build unit. In addition to the Southern-Florida bid being the lowest cost, the bid offered a number of other favorable nonprice attributes, including the following:

- **Flexibility**: As OUC, KUA, and FMPA face both uncertainty and risk as the future electric markets develop, flexibility is critical to assuring an economic and reliable supply of electricity while mitigating long-term financial risk. The Southern-Florida joint development project offers significant flexibility over a self-built and owned power plant. Although OUC, KUA, and FMPA have the right to 100 percent of the unit's capacity for up to 30 years, they have the right to either maintain or reduce their capacity nomination over time should the following occur:
  - Other more economical options develop in response to competitive pressures in the marketplace.
  - Improvements in technology develop which may provide economic benefit or improvements in reliability.
  - The need to adjust fuel mix in response to long-term changes in fuel commodity prices develops.

  These advantages are obtained without compromising the day-to-day scheduling flexibility needed to respond to both inter-day customer demand as well as capture opportunities to buy more economical power when available in the hourly market.
- **Reliability of Supply**: Reliability of supply, critical in today's marketplace, is enhanced in the following ways:
  - The Southern-Florida proposal utilizes proven technology with demonstrable service reliability.
  - Power purchased under this joint development proposal carries financial guarantees based on reliability of supply. These guarantees help to mitigate financial cost for replacement power should a loss of capacity occur. With a self-owned plant, the owner bears all financial risk when a loss of capacity occurs.

- **Equipment Considerations**: The joint development project captures a number of benefits relating to both economics and availability:
  - The equipment utilized represents proven technologies with a historical record of reliability.
  - The configuration provides benefits of both baseload and peaking operation depending on the operating mode selected.
  - Equipment costs reflect the benefits of both procurement prior to significant cost increases as well as the economies of scale achieved by the procurement of multiple units at the same time.
  - The equipment is available to meet the desired commercial operation date.
- **Schedule Considerations:**
  - The Southern-Florida proposal is capable of achieving commercial operation 24 months after environmental and regulatory certification.
  - Commercial operation of the joint development project can be achieved earlier than if the unit was self-built.
  - Earlier commercial operation better matches the needs of OUC, KUA, and FMPA.
- **Joint Development Considerations**: The joint development of a unit at Stanton Energy Center offers a number of advantages for OUC, KUA, and FMPA:
  - Participation with a large partner allows an economy of scale for equipment procurement, fuel supply, and ongoing operation and maintenance.
  - As the project utilizes existing common facilities where appropriate, OUC, KUA, and FMPA, as existing joint owners of Stanton Energy Center, improve the recovery of original investments made in these common facilities and minimize the capital outlay required for a new unit.

  The additional flexibility and other advantages achieved through the joint development project approach provide significant financial benefit not currently quantified in the evaluation of alternatives, particularly when the uncertainties of the future electric markets are considered.

1A.6.5 Results of Contract Negotiations

As a result of contract negotiations, improvements were made to Southern-Florida's initial proposal. The negotiated Construction and Ownership Participation Agreement, PPAs, and Operations and Maintenance Agreement are summarized in Sections 1A.3.0 and 1A.4.0. Table 1A.6-1 summarizes the changes to the capacity charge resulting from the negotiations. The capacity charge decreased for the initial 10 year period, and three additional 5 year extension options were added to the original proposal.

The negotiation process also improved the [redacted] availability guarantee for purchase power for OUC, KUA, and FMPA. The availability guarantee contained in the PPA calls for a deadband between [redacted] for which there is no penalty or bonus. If availability of purchase power falls below [redacted], penalties are calculated from [redacted] which is higher than the proposed [redacted] availability guarantee. Detailed evaluations of the project based on the Construction and Ownership Participation Agreement and the PPAs compared to self-build alternatives are conducted for OUC, KUA, and FMPA on a system basis in Volumes 1B, 1C, and 1D, respectively.

Table 1A.6-1
Results of Contract Negotiations

Initial Base Proposal		Initial Proposal Option		Final PPA	
Term	Capacity Charge	Term	Capacity Charge	Term	Capacity Charge
Initial 5 years	[redacted]	Initial 7 years	[redacted]	Initial 10 years	[redacted]
Optional 5 year extension (years 6-10)	[redacted]				
Average (years 1-10)	[redacted]				
Optional 5 year extension (years 11-15)	[redacted]			Optional 5 year extension (years 11-15)	[redacted]
				Optional 5 year extension (years 16-20)	[redacted]
				Optional 5 year extension (years 21-25)	[redacted]
				Optional 5 year extension (years 26-30)	[redacted]

Note: Capacity charge for last three 5 year extensions in the final PPA will be the higher of the capacity charge shown or the market price if elected by Southern-Florida. Capacity charge comparison is based on base capacity. The adjustments to the capacity charge shown in Table 1A.4-1 actually further reduce the capacity charge and further increase the benefits of the final PPA compared to the initial proposal.

1A.7.0 Supply-Side Alternatives

Each of the applicants has unique system requirements and unique opportunities due to existing or lack of existing sites. Thus, the cost of the same alternative may vary by applicant due to existing site infrastructure or lack thereof. Generally, however, the performance characteristics will be similar for the same alternative regardless of where the alternative is located. This section generally discusses the characteristics of alternatives which will not change with the location of the alternative. Characteristics unique to an individual applicant are presented in Volumes 1B, 1C, and 1D. This section also develops a self-build alternative to be located at the Stanton Energy Center that is technically identical to the Southern-Florida proposal that is common to OUC, KUA, and FMPA.

This section presents a review of the renewable, advanced, and conventional energy resources screened as potential capacity addition alternatives. Although many technologies are not commercially viable at this time, cost and performance data were developed in as much detail as possible to provide an accurate resource planning evaluation. In addition, due to the dependent nature of some technologies on site characteristics and resources, it is difficult to accurately estimate performance and costing information. For this reason, some of the options have been presented with a typical range for performance and capital cost. For most technologies, the performance and costs are based on a specified size. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy production accounts for capital cost (including all direct and indirect costs), fuel, operations, maintenance, and other costs over the typical life expectancy of the unit. The assumptions used to develop the cost of the alternatives (e.g., financing cost, fuel cost) are the same as presented in Section 1A.5.0 of this report.

The following alternatives are addressed in the subsequent sections:

- Renewable technologies.
- Waste to energy technologies.
- Advanced technologies.
- Energy storage systems.
- Nuclear fission.
- Conventional technologies.

1A.7.1 Renewable Technologies

Renewable energy technologies are based on energy sources that are practically inexhaustible. Such technologies are sometimes favored by the public over conventional

fossil fuel technologies because of the perception that renewable technologies are more environmentally benign. Renewable technologies evaluated in this section include wind, solar thermal, solar photovoltaic, biomass, geothermal, hydroelectric, ocean wave, ocean tidal, and ocean thermal energy technologies.

1A.7.1.1 Wind

Wind power systems convert the movement of the air to power by means of a rotating turbine and generator. Wind power was the fastest growing energy source of the last decade in percentage terms and realized a 36 percent growth in worldwide capacity in 1999. Installed worldwide wind capacity at the end of 1999 is estimated by the American Wind Energy Association to be 13,400 MW[1]. The United States has a total installed capacity of about 2,500 MW. Germany is the leader with just over 4,000 MW installed; Denmark, Spain, and India are also active international markets. Domestic markets are no longer limited to California. In the past few years, large wind farms have been installed in Iowa, Minnesota, and Texas. Much of the recent growth in domestic capacity was spurred by expectation that the US federal production tax credit would not be renewed when it expired July 1, 1999. However, the application period for the credit has since been extended to January 1, 2002.

Utility scale wind energy systems consist of multiple wind turbines that range in size from 100 kW to 1,600 kW. Typically sized wind energy system installations may total 5 to 200 MW. Wind is an intermittent resource with average capacity factors ranging from 15 to 40 percent. The capacity factor of an installation depends on the wind regime in the area and energy capture characteristics of the wind turbine. To provide a peaking resource, wind energy systems may be coupled with battery energy storage to provide power when required, but this is uncommon. Table 1A.7-1 provides wind energy characteristics for a 10 MW wind farm with an average yearly wind speed of 18 miles per hour (8 meters per second).

In general, wind resources in the southeastern United States, including Florida, are limited and not economically recoverable. Average wind speeds in Florida are typically below 14 miles per hour (6.2 m/s) at a 50 meter hub height and are not sufficient to support economical wind power generation. Wind turbine power output rises with the cube of wind speed, making small differences in wind speed very significant. The central plains states offer the greatest potential for large scale wind development in the United States.

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[1]American Wind Energy Association, "Global Wind Energy Market Report," December 23, 1999, from: http:/www.awea.org/faq/global99.html.

Table 1A.7-1 Wind Energy Conversion - Performance and Costs	
Commercial Status	Commercial
Performance*	
Plant Capacity (MW)	10
Capacity Factor (percent)	35
Economics	
Capital Cost ($/kW)	1,000 - 1,380
Fixed O&M ($/kW-yr)	10.5
Variable O&M ($/MWh)	5.0
Levelized Cost (cents/kWh)	4.6 - 5.8

*Performance calculations based on a Rayleigh wind speed distribution with an average annual wind speed of 18 m/s at 50 m hub height. The Rayleigh wind speed distribution is a mathematical function in common use in the wind industry to provide a convenient, approximate method of summarizing wind regimes.

1A.7.1.2 Solar Thermal

Solar energy consists of capturing the sun's energy and converting it to either thermal energy (solar thermal) or electrical energy (photovoltaic). Solar thermal systems convert solar insulation to high temperature thermal energy, usually steam, which is then used to drive heat engines, turbine/generators, or other devices for electricity generation. Commercial solar thermal plants in the US currently generate more than 350 MW. Solar thermal technologies are appropriate for a wide range of intermediate and peak load applications including central power station power plants and modular power stations in both remote and grid-connected areas.

In order to achieve the high temperature needed for solar thermal power systems, the sunlight is usually concentrated with mirrors or lenses. Three concentrating solar thermal collector technologies have been developed. Each is characterized by the shape of the mirrored surface on which the sunlight is concentrated. The three technologies are:

- Parabolic trough
- Parabolic dish
- Central receiver

Of the three, parabolic trough represents the vast majority of installed capacity, primarily in the desert southwest. Small parabolic dish systems have been developed by a few companies and are now being actively marketed. These systems are typically below 50 kW in size. The US government has funded two utility scale central receiver power plants: Solar One and its successor/replacement, Solar Two. Solar Two is no longer operating due to reduced federal support.

Representative characteristics for an 80 MW parabolic trough solar thermal plant are represented in Table 1A.7-2.

Table 1A.7-2
Solar Thermal - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	80
Capacity Factor (percent)	34
Economics	
Capital Cost ($/kW)	2,700 - 4,600
Fixed O&M ($/kW-yr)	24 - 46
Variable O&M ($/MWh)	3 - 5
Levelized Cost (cents/kWh)	10.8 - 18.7

Note: Evaluation based on use of a parabolic trough system.

1A.7.1.3 Solar Photovoltaics

Solar photovoltaic cells convert sunlight directly into electricity by the interaction of photons and electrons within the semiconductor material. To create a photovoltaic cell, a material such as silicon is doped (i.e., mixed) with atoms from an element with one more or less electron than occurs in its matching substrate (e.g., silicon). A thin layer of each material is joined to form a junction. Photons striking the cell cause this mis-matched electron to be dislodged, creating a current as it moves across the junction. Through a grid of physical connections, the current is gathered. Various currents and voltages can be supplied through series and parallel cell arrays.

The direct current produced depends on the material involved and the intensity of the solar radiation incident on the cell. The single crystal silicon cell is the most widely used today. The source silicon is highly purified and sliced into wafers from single-crystal ingots or is grown as thin crystalline sheets or ribbons. Polycrystalline cells are

another alternative. These are inherently less efficient than single crystal solar cells, but are less expensive to produce. Gallium arsenide cells are among the most efficient solar cells and have many other technical advantages, but they are also more costly.

Thin film cells are another type of photovoltaic that shows great promise. Commercial thin films are principally made from amorphous silicon; however, copper indium diselenide and cadmium telluride also show promise as low cost solar cells. Thin film solar cells require very little material and can be manufactured on a large scale. Furthermore, the fabricated cells can be flexibly sized and incorporated into building components.

Current utility grid connected photovoltaic systems are generally below 1 MW. However, several larger projects ranging from 1 to 50 MW have been proposed. One of the more recent project announcements is a 2.5 MW installation to be constructed on an industrial brownfield site in Chicago.

Numerous variations in photovoltaic cells are available such as single crystalline silicon, polycrystalline, and thin films, and several support structures are available such as fixed tilt, one-axis tracking, and two-axis tracking. For representative purposes, a fixed tilt, single crystalline photovoltaic system is characterized in Table 1A.7-3.

Table 1A.7-3
Solar Photovoltaic - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	0.01 - 10
Capacity Factor (percent)	20 - 22
Economics	
Capital Cost ($/kW)	3,600 - 8,050
Fixed O&M ($/kW-yr)	5.7 - 8.2
Variable O&M ($/MWh)	0.5 - 1.5
Levelized Cost (cents/kWh)	19.4 - 47.4

Note: Evaluation based on use of a single crystalline, fixed tilt array.

1A.7.1.4 Biomass

Electricity generation from biomass, which is any material of recent biological origin, is the second most prolific source of renewable energy generation after hydro. Biomass includes diverse materials such as urban wood waste, agricultural residues, and

yard waste. Direct biomass combustion power plants in operation today essentially use the same steam Rankine cycle introduced into commercial use 100 years ago. Pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to combustion in the boiler, the biomass fuel may require some processing to improve the physical and chemical properties of the feedstock. Furnaces used in the combustion of biomass include spreader stoker-fired, suspension-fired, fluidized bed, cyclone, and pile burners. Advanced integrated biomass gasification combined cycles are under development.

The capacity of biomass plants is usually less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. Furthermore, biomass plants will commonly have lower efficiencies as compared to modern coal plants. The low efficiency is due to the lower heating value and higher moisture content of the biomass fuel compared to coal. Finding sufficient sources of fuel within an economical delivery radius (typically 100 miles) may also limit the size of the plant.

Wood is the most common biomass fuel. There are around 1,000 wood fired plants in the country, with typical sizes ranging from 10 to 25 MW. Only a third are commercially operated for electricity sales, with the balance owned and operated by the forest products industry for self-generation. Table 1A.7-4 provides typical characteristics of a 50 MW biomass plant using urban wood waste as fuel.

Table 1A.7-4
Biomass - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	13,500 - 15,000
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	2,000 - 3,450
Fixed O&M ($/kW-yr)	50 - 70
Variable O&M ($/MWh)	6 - 10
Levelized Cost (cents/kWh)*	6.3 - 11.8

*Assumes fuel cost of $0.75/MBtu.

1A.7.1.5 Geothermal

Geothermal power plants use heat from the earth to generate steam and drive turbine generators for the production of electricity. The production of geothermal energy in the US currently ranks third in renewable energy sources, following hydroelectric power and biomass energy. In the United States, the electrical generation industry has an installed capacity of 2,800 MW (electrical) from geothermal energy, and direct thermal applications have an installed capacity in excess of 2,100 MWt (thermal megawatts). Approximately 8,000 MW of electricity are currently being generated from geothermal sources in about 20 countries, and there are 12,000 MWt direct heat applications worldwide.[1]

Geothermal power is limited to locations where geothermal pressure reserves are found. In the United States, most of these reserves can be found in the western portion of the country. No known geothermal reservoirs suitable for power production are located in the state of Florida.

Four types of geothermal power conversion systems are in common use. They are dry steam, single-flash, double-flash, and binary cycle power plants. For representative purposes, a binary-cycle power plant is characterized in Table 1A.7-5. Capital costs of geothermal facilities can vary widely, as the drilling of individual wells can cost as much as 4 million dollars, and the number of wells drilled depends on the success of finding the resource. Variable O&M costs include the replacement of production wells.

1A.7.1.6 Hydroelectric

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable; however, construction techniques and costs continue to change. Capital costs are highly dependent on site characteristics and may vary widely. To be able to predict performance and cost, site and river resource data would be required. Table 1A.7-6 has typical ranges for performance and cost estimates.

New large domestic hydro installations are unlikely due to long construction times and environmental concerns.

[1] University of Utah Energy & Geoscience Institute, "Geothermal Energy Brochure," accessed June, 2000, from: http://www.egi.utah.edu/geothermal/brochure/brochure.htm.

Table 1A.7-5 Geothermal - Performance and Costs	
Commercial Status	Commercial
Performance	
Plant Capacity (MW)	25 - 50
Capacity Factor (percent)	85 - 93
Economics	
Capital Cost ($/kW)	1,800 - 4,600
Fixed O&M ($/kW-yr)	30 - 90
Variable O&M ($/MWh)	2 - 6
Levelized Cost (cents/kWh)*	3.1 - 8.0
Note: Evaluation based on use of a binary cycle geothermal plant.	

Table 1A.7-6 Hydroelectric - Performance and Costs	
Commercial Status	Commercial
Performance	
Plant Capacity (MW)	50 - 1,500+
Capacity Factor (percent)	60 - 80*
Economics	
Capital Cost ($/kW)	1,300 - 5,980
Fixed O&M ($/kW-yr)	5 - 20
Variable O&M ($/MWh)	0.25 - 2.0
Levelized Cost (cents/kWh)*	2.0 - 12.4*
*These values are for representative comparison purposes only. Capacity factors are highly resource dependent and can range from 10 to over 90 percent. Levelized cost will vary significantly based on actual capacity factor for a site.	

1A.7.1.7 Ocean Wave Energy

Ocean wave energy systems convert the kinetic and potential energy contained in the natural oscillations of ocean waves into electricity. A variety of proposed mechanisms for the utilization of this energy source exist, most of which are still in the demonstration or prototype testing stage. Wave energy research was intensive in 1970s and 1980s. Research funding has slowed and wave energy applications are not likely to be competitive in the near future. The optimal regions for wave power applications typically occur between 40 and 60 degrees latitude, although seas that consistently experience trade winds can also produce sufficient wave energy for power applications. The potential for offshore/deep wave plants is large, but the technical barriers and associated costs are also considerably high. Surge devices and oscillating water column devices are the primary technologies for converting wave energy to electricity.

The technical problems of dealing with adverse sea conditions, complexity and difficulty of electricity interconnection and transmission, and low reliability have kept wave energy systems from being developed commercially. Furthermore, the high capital costs of such systems have deterred the implementation of wave energy systems. Table 1A.7-7 presents typical performance and cost characteristics of wave energy systems.

Table 1A.7-7
Ocean Wave Energy - Performance and Costs

Commercial Status	Developmental
Performance	
Plant Capacity (MW)	0.1 - 1
Capacity Factor (percent)	25
Economics	
Capital Cost ($/kW)	2,600 - 6,900
Fixed O&M ($/kW-yr)	55 - 110
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)*	15.7 - 39.3

1A.7.1.8 Ocean Tidal Energy

The generation of electrical power from ocean tides is very similar to traditional hydroelectric generation. A tidal power plant consists of a tidal pond created by a dam, a powerhouse in the dam containing a turbogenerator, and a sluice gate in the dam to allow

the tidal flow to enter and leave. By opening the sluice gate in the dam, the rising tidal waters are allowed to fill the tidal basin. At high tide, these gates are closed and the tidal basin behind the dam is filled to capacity. After the ocean waters have receded, the tidal basin is released through a turbogenerator in the dam. Power may be generated during ebb tide, flood tide, or both. The capacity factor of such a facility may be expected to be up to 25 percent. Commercial tidal plants have been developed; a 240 MW plant in France and an 18 MW plant in Canada are the two largest plants in the world.

Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably from region to region. Economic studies suggest that tidal power will be most economical at sites where mean tidal range exceeds about 16 feet. In North America, the northeast and northwest coasts of Canada are generally considered the only regions where tidal energy plants could potentially be economically feasible. Tidal amplitudes as high as 50 feet are experienced on the east coast of Canada in the Bay of Fundy. It is unlikely that tidal energy plants are economically feasible in the coastal Florida region.

Utilization of tidal energy for power generation has the environmental advantage of a zero emission technology. However, the environmental and aesthetic impact that the facility has on the coastline must be carefully evaluated. The main barriers to the increased use of tidal energy are the high cost and long period for the construction of the tidal generating system. As noted previously, the economic viability of this option is highly dependent on the location chosen for application. Table 1A.7-8 presents typical performance and cost characteristics for tidal energy plants.

Table 1A.7-8
Ocean Tidal Energy - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	18 - 240
Capacity Factor (percent)	20 - 25
Economics	
Capital Cost ($/kW)	1,600 - 5,175
Fixed O&M ($/kW-yr)	5 - 25
Variable O&M ($/MWh)	0.5 - 2.5
Levelized Cost (cents/kWh)	7.8 - 32.4

1A.7.1.9 Ocean Thermal Energy

The temperature of the ocean may have a 40° F temperature differential from the surface to a depth of 3,000 feet. The idea of utilizing this temperature difference for energy production has existed for over a century. Ocean thermal energy conversion (OTEC) concepts have been developed by using three basic types of cycles: closed cycles, open cycles, and hybrid cycles. Closed cycle plants use a low boiling point working fluid such as ammonia. The working fluid is heated and vaporized by the warm surface water, expanded in a turbine generator, and condensed by the deep cold water. Open cycle plants use warm surface water itself as the working fluid. The water vaporizes in a near vacuum at surface water temperatures. The expanding vapor drives a low-pressure turbine generator and is condensed by the deep cold water. As the condensed vapor no longer contains salt, it may be used for drinking, irrigation, and mariculture (i.e., sea farming, which also benefits from the nutrient-rich deep ocean water). Hybrid OTEC cycles use parts of both the closed and open cycles to optimize production of electricity and fresh water.

In OTEC systems, the relatively small temperature difference between the warm and cold thermal reservoirs and the large pumping power required combine for a very low overall system efficiency. Commercial OTEC plants must be located in an environment that is suitable for efficient system operation. The temperature of the warm surface seawater should differ at least 36° F from that of the cold deep water, and the extraction depth should not be more than about 3,280 feet below the surface. The best thermal gradients for OTEC sites are in tropical and subtropical areas.

OTEC systems are still in the development stage, and current research efforts focus on cold water pipe technology, heat exchanger systems to improve heat transfer performance and decrease costs, and innovative turbine concepts for the large machines required for open cycle systems. A few 50 to 200 kW demonstration systems are being developed in Hawaii. The high capital costs of OTEC systems are expected to delay their implementation. Furthermore, some environmental questions remain regarding the effect of high pumping flow rates and local temperature changes on the surrounding aquatic environment. Because the current low prices of fossil fuels makes OTEC uneconomic, funding for OTEC research has been limited. Levelized costs for OTEC systems have been estimated at 10 to 22 cents/kWh.

1A.7.2 Waste to Energy Technologies

Waste to energy (WTE) technologies can utilize a variety of refuse types to produce electrical power. The use of municipal solid waste (MSW), refuse derived fuel (RDF), landfill gas (LFG), tire derived fuel (TDF), and sewage sludge to generate power

will be addressed in this section. Florida has grown from having one small WTE power plant in 1980 to 13 operating WTE facilities in 1997. These plants have a total capacity to burn nearly 19,000 tons of waste per day to generate about 500 MW of electrical power. Florida has established the largest capacity to burn MSW of any state in the US.[2]

Economic feasibility of WTE facilities is generally difficult to assess. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location. Values given in this section should be considered representative of the technology at a generic site.

1A.7.2.1 Municipal Solid Waste to Energy Conversion

Converting refuse or municipal solid waste (MSW) to energy can be accomplished by a variety of technologies. These technologies have been developed and implemented as a means of reducing the quantity of municipal and agricultural solid waste. The avoided cost of disposal is a primary component in determining whether a waste to energy facility is economically feasible.

The degree of refuse processing determines the method used to convert municipal solid waste to energy. Unprocessed refuse is typically combusted in a water wall furnace (mass burning). After only limited processing to remove noncombustible and oversized items, the MSW is fed on to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. Other furnaces used in mass burning applications are refractory furnaces and rotary kiln furnaces, which use other means to transfer the heat to the steam cycle or add a mixing process to the combustion. For smaller modular units, controlled air furnaces, which utilize two-stage burning for more efficient combustion, can be used in mass burning applications.

Large MSW facilities typically process 500 to 3,000 tons of MSW per day (the average amount produced by 200,000 to 1,200,000 residents). Table 1A.7-9 has typical ranges of performance and cost for a facility burning 2,000 tons of MSW per day.

1A.7.2.2 Refuse Derived Fuel to Energy Conversion

Refuse derived fuel (RDF) is preferred in many refuse to energy applications because it can be combusted with technology traditionally used for coal. Spreader stoker fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units

[2] Florida Division of Waste Management, "1999 Solid Waste Management in Florida Annual Report," 1999, from: http://www.dep.state.fl.us/dwm/documents.htm.

Table 1A.7-9
MSW Mass Burning Unit - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	16,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	2,500 - 4,600
Fixed O&M ($/kW-yr)	100 - 175
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)*	3.5 - 15.3*

*Includes tipping fee of $25/ton.

have all been utilized to generate steam from RDF. Fluidized bed combustors are often preferred for RDF energy applications due to their high combustion efficiency, capability to handle RDF with minimal processing, and inherent ability to effectively reduce nitrous oxide and sulfur dioxide emissions. In all boiler types, the combustion temperature for MSW or RDF must be kept at a temperature less than 800° F in order to minimize boiler tube degradation due to chlorine compounds in the flue gas. Table 1A.7-10 has typical ranges for performance and costs for a 50 MW RDF facility.

The City of Lakeland currently burns RDF as a supplemental fuel in McIntosh 3, in which OUC is a joint owner.

1A.7.2.3 Landfill Gas to Energy Conversion

Landfilled waste can be converted to energy by collecting the gases generated by the decomposition of waste in landfills. To reduce smog production and the risk of explosion, many landfills are currently required to collect landfill gas (LFG) and either flare or generate energy. The major constituents released from LFG wells are carbon dioxide and methane. The methane concentration is typically around 50 percent. To convert this clean burning, low heating value gas to electricity, the gas is piped from

Table 1A.7-10
RDF Stoker Fired Unit - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	17,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	3,000 - 4,830
Fixed O&M ($/kW-yr)	150 - 225
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)*	4.9 - 16.8*

*Includes tipping fee of $25/ton.

wells, filtered, compressed, and typically used in internal combustion engine generation sets. Depending on the scale of the gas collection facility, it may be feasible to generate power via a combustion turbine generator.

LFG was first used as a fuel in the late 1970s. Since then, there has been a steady development of the technology for its collection and use. LFG energy recovery is now regarded as one of the more mature and successful of the waste to energy technologies. There are more than 600 LFG energy recovery schemes in 20 countries, spanning five continents.

In general, LFG recovery may be economically feasible at sites that have over one million tons of waste, more than 30 acres available for gas recovery, a waste depth greater than 40 feet, and the equivalent of 25+ inches of annual precipitation. In many cases, the payback period of LFG energy facilities is between 2 and 5 years. The capital costs will be highly dependent on the conversion technology and landfill characteristics. Table 1A.7-11 has typical ranges for performance and costs.

OUC currently burns LFG from the Orange County Landfill as a supplemental fuel in Stanton 1 and 2.

Table 1A.7-11 Landfill Gas IC Engine - Performance and Costs	
Commercial Status	Commercial
Performance	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500 - 13,000
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	1,000 - 1,725
Fixed O&M ($/kW-yr)	1.0 - 1.35
Variable O&M ($/MWh)	6 - 20
Levelized Cost (cents/kWh)	2.4 - 6.3

1A.7.2.4 Tire Derived Fuel to Energy Conversion

The conversion of used tires to energy via combustion is attractive due to the high heating value (15,000 - 17,000 Btu/lb), low ash and sulfur content, and low cost of tire derived fuel (TDF). The co-firing of TDF with coal can be done in either a cyclone or conventional stoker boiler without system modification. TDF at co-firing percentages of 2 to 20 percent has been utilized by eight utilities in the US on a regular basis. In cyclone plants, the NO_x emissions and trace metal emissions have actually been reduced when burning TDF. On an energy basis, the cost of TDF (processed to 1 inch mesh) can be almost half that of coal. A new facility designed to co-fire TDF with coal would likely be a fluidized bed unit. Fluidized bed systems provide multi-fuel capability, in-situ sulfur removal, high combustion efficiencies, and low NO_x emissions. The estimated cost and performance of a 100 MW multi-fuel (10 percent TDF co-fire) circulating fluidized bed system are shown in Table 1A.7-12.

1A.7.2.5 Sewage Sludge to Energy Conversion

The disposal of sewage sludge is a significant environmental problem. The combustion of these materials to convert them into thermal energy is one solution that has been proposed. Dewatered sewage sludge has a heating value of up to 7,000 Btu/lb. Typically, the sludge has been co-fired with coal in a fluidized bed combustor. Some problems of fluidized bed agglomeration have been realized when utilizing large amounts of sludge. In addition to this operational problem, the low heating value of this waste has

Table 1A.7-12
TDF Multi-Fuel CFB (10 Percent Cofire) - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	13,300
TDF Tons per Day	100
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	1,800 - 2,530
Fixed O&M ($/kW-yr)	40 - 75
Variable O&M ($/MWh)	3.0 - 6.5
Levelized Cost (cents/kWh)	3.9 - 8.0

impeded the development of sludge combustion. Dewatered sewage sludge can also be burned with municipal solid waste (MSW), but the kinetics of combustion require that the ratio of sludge to MSW remain low (2 percent to 3 percent). A research project of the US Department of Energy shows that the combination of enhanced combustion kinetics and combustion temperature control could increase the sludge/MSW ratios to 10 percent.[3] Other waste to energy methods are currently being investigated that involve digestion, fermentation, or gasification of the sludge to produce a higher grade fuel or gas for energy conversion. There are also a number of sewage recycling methods that convert sludge to soil, fertilizer, or building materials. These applications compete with energy conversion methods.

1A.7.3 Advanced Technologies

Advanced technologies include developmental and near commercial technologies that offer significant potential for cost and efficiency improvements over conventional technologies. These include advanced gas and coal technologies, magnetohydrodynamics, fuel cells, and nuclear fusion.

[3] National Renewable Energy Laboratory, "Oxygen-Enriched Co-combustion of Sewage Sludge and Municipal Solid Waste," Advances in Industrial Energy-Efficiency Technologies, from: http://es.epa.gov/techinfor/facts/kocmbust.html.

1A.7.3.1 Advanced Gas Technologies

Combined cycle combustion turbines have many advantages, including low capital cost, high efficiency, and short construction periods. Operation of an actual combustion turbine approaches that of an idealized thermodynamic cycle called the air-standard Brayton cycle. The Brayton cycle is based on an all gas cycle that uses air and combustion gases as the working fluid, as opposed to the Rankine cycle, which is a vapor-based cycle. Three Brayton cycles show promise as advanced technologies: the humid air cycle, Kalina cycle, and Cheng cycle. These cycles are discussed in this section.

1A.7.3.1.1 Humid Air Cycle. The humid air turbine (HAT) cycle is an intercooled, regenerative cycle burning natural gas with a saturator that adds considerable moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Table 1A.7-13 presents typical performance and cost characteristics for the HAT cycle.

Table 1A.7-13
Humid Air Turbine Cycle - Performance and Costs

Commercial Status	Development
Performance	
Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	600 - 920
Fixed O&M ($/kW-yr)	5.0 - 9.0
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	4.6 - 6.0

1A.7.3.1.2 Kalina Cycle. The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages based on the nonisothermal boiling and condensing behavior of the working fluid's two-component mixture, coupled with the ability to alter

the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters a heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger where it is heated with vapor turbine exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG, where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the high-pressure vapor turbine where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. Table 1A.7-14 presents typical performance and cost characteristics for the Kalina cycle.

Table 1A.7-14
Kalina Cycle - Performance and Costs

Commercial Status	Development
Performance	
Plant Capacity (MW)	50 - 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	600 - 860
Fixed O&M ($/kW-yr)	4 - 10
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	4.7 - 6.1

1A.7.3.1.3 Cheng Cycle. The Cheng cycle, which is similar to the steam-injected gas turbine, increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a compressor, combustor, turbine, generator, and heat recovery steam generator (HRSG). The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

The typical application of the Cheng cycle is in a cogeneration plant where increased power can be produced during low cogeneration demand and/or peak demand periods. Since 1984, over 50 small cogeneration plants have applied the Cheng cycle in California, Japan, Australia, and Europe. The Cheng cycle has also been proposed as a retrofit for simple cycle combustion turbines. Table 1A.7-15 presents typical performance and cost characteristics for the Cheng cycle.

Table 1A.7-15
Cheng Cycle - Performance and Costs

Commercial Status	Development (larger units)
Performance	
Plant Capacity (MW)	25 - 250
Net Plant Heat Rate (Btu/kWh)	8,000 - 9,000
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	700 - 1,270
Fixed O&M ($/kW-yr)	6 - 10
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	5.6 - 8.0

1A.7.3.2 Advanced Coal Technologies

Coal fired plants continue to supply a large portion of the energy requirements in the US. Current research is focused on making the conversion of energy from coal more clean and efficient. Supercritical pulverized coal boilers and pressurized fluidized bed systems are two systems that have been developed to improve coal conversion efficiency.

1A.7.3.2.1 Supercritical Pulverized Coal Boilers. New generation pulverized coal boilers can be designed at supercritical steam pressures of 3,000 to 4,500 psig, compared to the conventional 2,400 psig subcritical boilers. This increase in pressure can bring the overall efficiency of the unit from below 40 percent to nearly 45 percent. This efficiency increase, coupled with the latest in emissions control technologies, is expected to keep pulverized coal systems environmentally and economically competitive with other generation technologies. Further significant advances in supercritical steam conditions depend on the availability of fully tested and approved advanced steel alloys. It is currently envisaged that advanced supercritical power plants with an efficiency of

48 percent might be in operation by 2005, with 50 percent possible by 2015.[4] Table 1A.7-16 presents typical performance and cost characteristics of supercritical pulverized coal power plants.

Table 1A.7-16
Supercritical Pulverized Coal - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	300 - 1,000
Net Plant Heat Rate (Btu/kWh)	7,500 - 9,500
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	1,200 - 1,670
Fixed O&M ($/kW-yr)	18 - 24
Variable O&M ($/MWh)	3.0 - 4.0
Levelized Cost (cents/kWh)	4.3 - 6.7

1A.7.3.2.2 Pressurized Fluidized Bed Combustion. Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atm. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations, PFBC exhaust is expanded to drive both the compressor and gas turbine generator. Heat recovery steam generators transfer heat from this exhaust to generate steam in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. These second generation PFBC systems are in the development stage. Table 1A.7-17 presents typical performance and cost characteristics for pressurized fluidized bed combustion.

[4] International Energy Agency, "Competitiveness of Future Coal-Fired Units in Different Countries," January 1999.

Table 1A.7-17 Pressurized Fluidized Bed Combustion - Performance and Costs	
Commercial Status	Development
Performance	
Plant Capacity (MW)	150 - 350
Net Plant Heat Rate (Btu/kWh)	8,000 - 9,000
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	1,350 - 1,840
Fixed O&M ($/kW-yr)	20 - 35
Variable O&M ($/MWh)	3.8 - 5.0
Levelized Cost (cents/kWh)	4.8 - 7.4

1A.7.3.3 Magnetohydrodynamics

Magnetohydrodynamic (MHD) generators produce electrical power by passing a high velocity conducting fluid through a very strong magnetic field. The conducting fluid is an ionized gas (plasma) or a liquid metal. Current prototypes and conceptual designs typically use the high temperature combustion of coal to produce a partially ionized flue gas, which can be passed through a magnetic field. When this highly conductive, plasma-like flue gas is accelerated in a nozzle and then passed through a channel perpendicular to a magnetic field, an electric field is induced. To successfully ionize the flue gas, the combustion temperatures must be around 5,000° F. A seed material such as potassium is added to the flue gas flow to increase gas conductivity.

An MHD system in simple cycle configuration only converts a portion of the flue gas energy to electricity. To optimize the performance of an MHD system, the energy in the hot flue gas exiting the MHD generator can be utilized to generate steam for additional power generation. This combined cycle configuration can result in an efficiency increase of 15 to 30 percent over conventional steam plant efficiencies. The overall thermal efficiency could potentially be as high as 60 percent.

Emission levels can be effectively controlled in MHD systems. NO_x levels are controlled by designing time-temperature profiles within the radiant boiler that promote the decomposition of NO_x formed in the combustion process. The potassium seed in the flue gas reacts with the sulfur compounds to produce a solid potassium sulfate. The spent

seed is regenerated and converted to nonsulfur containing potassium species. Particulate emissions can be controlled by an electrostatic precipitator.

Currently, MHD power generation technology is still in the development stage and, therefore, cost estimates are highly speculative. Although a variety of the individual subcomponents of this technology have been developed and tested, the operation of a fully integrated system has not been demonstrated. The driving force behind MHD combined cycle technology is improved performance. Currently, there are no commercial applications of MHD that demonstrate that this improved performance is feasible. The disadvantages of MHD power plants are their complexity compared to standard steam plants, longer construction times, higher capital costs, and their generation of direct current, which must be converted to alternating current to be compatible with most grid systems. Further development work is required.

1A.7.3.4 Fuel Cells

Fuel cells convert hydrogen-rich fuel sources directly to electricity through an electrochemical reaction. Fuel cell power systems have the capability of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Commercial stationary fuel cell plants are fueled by natural gas. There are four major fuel cell types under development: phosphoric acid, molten carbonate, solid oxide, and proton exchange membrane. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). Currently PAFC plants have efficiencies on the order of 40 percent. Fuel cells can sustain high efficiency operation even under part load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements. Current PAFC plants range from around 200 kW to 11 MW in size. PAFC cogeneration facilities can attain efficiencies approaching 88 percent when the thermal energy from the fuel cell is utilized. Also, the potential development of solid oxide fuel cell/gas turbine combined cycles could reach electrical conversion efficiencies of 60 to 70 percent.

In addition to the potential for low heat rates and low O&M costs, the environmental benefits of fuel cells remain one of the primary reasons for their development. With natural gas as the fuel source, carbon dioxide and water are the only emissions. High capital costs are the primary disadvantage of fuel cell systems. These costs are expected to drop significantly in the future as development efforts continue, partially spurred on by interest by the transportation sector. Fuel cell plants are typically less than 10 MW in size. The performance and costs of a 200 kW unit are shown in Table 1A.7-18.

Table 1A.7-18
Fuel Cell - Performance and Costs

Commercial Status	Development/Commercial
Performance	
Plant Capacity (MW)	0.20 - 13
Net Plant Heat Rate (Btu/kWh)	7,000 - 9,500
Capacity Factor (percent)	60 - 80
Economics	
Capital Cost ($/kW)	3,200 - 5,750
Fixed O&M ($/kW-yr)	275 - 325
Variable O&M ($/MWh)	0.78 - 0.84
Levelized Cost (cents/kWh)	14.2 - 25.4

1A.7.3.5 Nuclear Fusion

Theoretically, the potential for nuclear fusion power is enormous. It involves the release of energy when two light nuclei such as deuterium and tritium undergo fusion to form heavier nuclei such as helium. This new nuclei has less mass than the total of the two original nuclei, resulting in a release of energy. Large amounts of energy are released if this fusion reaction can be sustained, but fusion also has high initiation energy requirements. A temperature greater than 50 million Kelvin is required to sustain a deuterium-tritium reaction.

The concept of a fusion power plant is appealing not only because huge amounts of energy can be produced from relatively small amounts of readily available resources (water and lithium), but also because the fusion process has only a very limited impact on the environment. In contrast to conventional nuclear fission, the fusion power plant is not likely to undergo an uncontrolled meltdown situation. Furthermore, the minimal amount of radioactive fusion waste does not emit strong radiation during its moderate half-life of approximately 12 years.

Despite the attractive theoretical benefits of fusion, the technology has yet to yield a net energy output. At the current level of development, the energy required to sustain the fusion reaction is still over twice the amount produced. Recently, fusion research funding has been cut dramatically in the US. The Princeton Tokamak Fusion Test Reactor was decommissioned in the spring of 1997 due to cuts in federal funding of the program. Alternative basic research on various aspects of fusion continues and the

international effort to develop a viable fusion power facility is still significant. Nonetheless, it is likely to be well into this century before fusion develops to the point of commercial viability.

1A.7.4 Energy Storage Systems

Energy storage technologies convert and store electricity to help alleviate disparities between electricity supply and demand. Energy storage systems increase the value of power by allowing better utilization of off-peak baseload generation and through mitigation of instantaneous power fluctuations. Different types of technologies are available to provide for a variety of storage durations. Durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (batteries, compressed air, and pumped hydro). These technologies are discussed in this section.

1A.7.4.1 Pumped Hydro Energy Storage

Pumped hydro energy storage is the oldest and most prevalent of the central station energy storage options. More than 22 GW of pumped storage generation is installed in the United States.[5] A pumped storage hydroelectric facility requires a reservoir/dam system similar to a conventional hydroelectric facility. Excess energy from the grid (available at low cost) is used to pump water from a lower reservoir to an upper reservoir above a dam. When this energy is required during high electrical demand periods, the potential energy of the water in the upper reservoir is converted to electricity as the stored water flows through a turbine to the lower reservoir.

Capital cost and lead time are the primary considerations in implementing this storage technology. Furthermore, without careful siting, planning, and construction, the environmental impact of this technology can be significant. Geographic and geologic conditions largely preclude many areas, including Florida, from consideration of this technology. Table 1A.7-19 presents typical performance and cost estimates for pumped hydro energy storage.

1A.7.4.2 Battery Energy Storage

A battery energy storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and a building to house the components. During peak power demand periods, the battery system can discharge power to the utility

[5] US Department of Energy, EPRI, "Renewable Energy Technology Characterizations," December 1997.

Table 1A.7-19
Pumped Hydro Energy Storage - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	30 - 1,500+
Capacity Factor (percent)	10 - 25
Economics	
Capital Cost ($/kW)	800 - 1,840
Fixed O&M ($/kW-yr)	3 - 8
Variable O&M ($/MWh)	0.5 - 2.0
Levelized Cost (cents/kWh)	7.3 - 26.3

system for about 4 to 5 hours. The batteries are then recharged during nonpeak hours. In addition to the high initial cost, a battery system will require replacement every 4 to 10 years, depending on the duty cycle.

Currently, the only commercially available utility size battery systems are lead-acid systems. Research to develop better performing and lower cost batteries such as sodium-sulfur and zinc-bromine batteries is currently underway. More than 70 MW of battery energy storage systems have been installed by utilities in ten states.[6] The largest facility is a 21 MW lead-acid system with 140 MWh of storage capability. The overall efficiency of battery systems averages 72 percent from charge to discharge. The cost and performance of a 5 MW (15 MWh) system is provided in Table 1A.7-20.

1A.7.4.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) is a technique used to supply electrical power to meet peak loads within an electric utility system. This method uses the power surplus from baseloaded coal and nuclear plants during off-peak periods to compress and store air in an underground formation. The compressed air is later heated (with a fuel) and expanded through a gas turbine expander to produce electrical power during peak power demand. A simple compressed air storage plant consists of an air compressor, turbine, motor/generator unit, and a storage vessel, typically underground. Exhaust gas heat recuperation may be added to increase cycle efficiency.

[6] US Department of Energy, EPRI, "Renewable Energy Technology Characterizations," December 1997.

Table 1A.7-20
Lead-Acid Battery Energy Storage - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	5
Energy Capacity (MWh)	15
Capacity Factor (percent)	10 - 25
Economics	
Capital Cost ($/kW)	800 - 1,610
Fixed O&M ($/kW-yr)	13.5
Variable O&M ($/MWh)	50 - 100*
Levelized Cost (cents/kWh)	15.5 - 39.2

*Included battery replacement costs.

The theoretical basis associated with the thermodynamic cycle for a compressed air storage facility is that of a simple gas turbine system. Typically, gas turbines will consume 50 to 60 percent of their net power output to operate the air compressor. In a compressed air storage generating plant, the air compressor and the turbine are not connected and the total power generated from the gas turbine is supplied to the electrical grid. By using off-peak energy to compress the air, the need for expensive natural gas or imported oil is reduced by as much as two-thirds compared with conventional gas turbines.[7] This results in a very attractive heat rate for CAES plants, ranging from 4,000 to 5,000 Btu/kWh. Because fuel (typically natural gas) is supplied to the system during the energy generation mode, CAES plants actually provide more electrical power to the grid than was used during the cavern charging mode.

The location of a CAES plant must be suitable for cavern construction or for the reuse of an existing cavern. However, suitable geology is widespread throughout the United States with over 75 percent of the land area containing appropriate geological formations.[8] There are three types of formations that can be used to store compressed gases: solution mined reservoirs in salt, conventionally mined reservoirs in salt or hard rock, and naturally occurring porous media reservoirs (aquifers).

[7] Nakhamkin, M., Anderson, L., Swenson, E., "AEC 110 MW CAES Plant: Status of Project," Journal of Engineering for Gas Turbines and Power, October 1992, Vol. 114.
[8] Mehta, B., "Compressed Air Energy Storage: CAES Geology," EPRI Journal, October/November 1992.

The basic components of a CAES plant are proven technologies and CAES units have a reputation for achieving good availability. The first commercial scale CAES plant in the world is a 290 MW plant in Huntorf, Germany. This plant has been operated since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility in McIntosh, Alabama, began operation. This plant remains the only US CAES installation, although several new plants have been recently announced. Table 1A.7-21 shows the performance and cost characteristics of a CAES system.

Table 1A.7-21
Compressed Air Energy Storage - Performance and Costs

Commercial Status	Commercial
Performance	
Plant Capacity (MW)	100 - 500
Net Plant Heat Rate (Btu/kWh)	4,000 - 5,000
Capacity Factor (percent)	10 - 25
Economics	
Capital Cost ($/kW)	450 - 690
Fixed O&M ($/kW-yr)	3 - 6
Variable O&M ($/MWh)	3 - 6
Levelized Cost (cents/kWh)	7.1 - 14.7

1A.7.4.4 Flywheel Energy Storage

The flywheel provides a means to store energy in the form of rotational inertia. Flywheels have a number of advantages as an energy storage device. First, compared to other storage technologies, such as lead-acid batteries or pumped storage hydro systems, they are very compact, have a high energy density, and can transfer large amounts of energy very quickly. They have very long life cycles and low operating and maintenance costs. These advantages make flywheel systems particularly advantageous to the transportation industry, where weight reduction and quick energy transfer (fast acceleration) are important parameters.

Although high tech prototype flywheels can exceed 80 percent efficiency from storage to release, they are still in the research and development stage. In order for flywheels to be economically viable for general purpose energy storage, the capital cost must be reduced, performance must be enhanced with new materials and low friction bearings, and motor/generator controls need to be enhanced to better utilize flywheel

energy under the always changing flywheel speed. Current research is focusing on the development of magnetic bearings using high temperature superconductor technology. At this point in flywheel development, flywheels cannot compete against battery systems, particularly in the power industry. Conventional battery energy storage systems have significantly lower costs on a price per unit of stored energy.

1A.7.4.5 Superconducting Magnetic Energy Storage

Superconducting magnetic energy storage (SMES) stores energy by allowing a current to pass through a "zero resistance" toroidal winding, storing the energy in a magnetic field. SMES systems for power industry storage applications are still in the research and development stage. The cost of these high tech systems must be reduced significantly before they will become commercially viable for large energy storage. Smaller SMES systems are commercially available. Such systems are practical for eliminating power surges and dips in industries where these brief discontinuities can be harmful to sensitive equipment and processes. Typically, they can store only a few seconds of energy at full load.

1A.7.5 Nuclear (Fission)

As of May 2000, there were 103 nuclear units in more than 30 states supplying roughly 20 percent of the nation's power needs. The majority of nuclear power plants in the United States use uranium as a fuel source. Once inside a nuclear reactor, uranium atoms are bombarded by neutrons. Each time a neutron is absorbed by a uranium atom, the atom becomes unstable and splits, a process known as fission. During this process, the atom produces additional neutrons, usually two and a half for each fission, which go on to split more uranium atoms, creating more neutrons. This scenario perpetuates, resulting in a chain reaction. The fission process generates heat and occurs in the reactor core, where the fuel transfers its heat to water that is then circulated to the steam generator.

Currently, nuclear power in the United States faces obstacles related to public perception and capital costs. It also has resulted in environmental concerns related to the disposal of spent fuel since the onsite disposal areas at some plants are filling up and the excess must be transported to an offsite nuclear waste storage facility. Combined, these factors explain why nuclear plants have fallen out of favor as a generating resource.

1A.7.6 Conventional Technologies

Conventional alternatives selected for generation expansion planning analysis were chosen for each utility. The size of the additional conventional alternatives selected

considers the unique needs for capacity and the suitability of those units at selected applicant sites. Table 1A.7-22 exhibits the conventional alternatives analyzed for each applicant. These generating unit alternatives include the following:

- Pulverized Coal (PC).
- Circulating Fluidized Bed (CFB).
- Combined Cycle.
- Simple Cycle Combustion Turbine.

Also included in this section are the assumptions associated with a self-build alternative to Stanton A, a General Electric 2 x 1 7FA combined cycle unit that is technically identical to Southern-Florida's proposed unit. This unit was evaluated to prove that Stanton A as a joint development project is the most cost-effective alternative. The assumptions for the 2 x 1 7FA are included in the combined cycle assumptions section with the other candidate units.

Table 1A.7-22
Utility Generation Expansion Candidates

	OUC	KUA	FMPA
Simple Cycle	7FA (156 MW)	7FA (156 MW) 7FA (78 MW) (50% share) LM6000 (39 MW)	7FA (156 MW)
Combined Cycle	501F 2 x 1 Standard (514 W) 501F 2 x 1 Oversized (610 W)	501F 1x1 (125MW) (50% share)	501F 2 x 1 (257 MW) (50 % share) 501F 1x1 (125 MW) (50% share)
Solid Fueled Unit	PC (446 MW) CFB (267 MW)	PC (111.5 MW) (25% share)	PC (223 MW) (50 % share)

Table 1A.7-22 reflects partial unit ownership of large capacity units for KUA and FMPA. The joint ownership portions are based on reasonable assumptions based on KUA's and FMPA's history of joint ownership and their general capacity requirements. KUA and FMPA units are assumed to be installed at the Cane Island or at generic greenfield sites. Some of these units could also be assumed to be installed by FMPA at FMPA member sites. OUC alternatives are assumed to be installed at Stanton Energy Center. Solid fueled units are assumed to be installed at Stanton Energy Center. This section presents information common to all alternatives regardless of ownership. Information specific to ownership for OUC, KUA, and FMPA is contained in Volumes 1B, 1C, and 1D.

1A.7.6.1 Performance Estimates

Performance estimates have been compiled for each of the conventional capacity alternatives listed above. The estimates provide representative values for each generation alternative and show expected trends in performance within a given technology as well as between technologies. Actual unit performance and availability will vary based on site conditions, regulatory requirements, and operation practices. The economic evaluation of an option involves consideration of a number of performance criteria. These criteria are explained below.

1A.7.6.1.1 Net Plant Output. Net plant output (NPO) is equal to the gross plant output less the plant auxiliary power. In this analysis, net plant output estimates are provided for summer (97° F ambient), annual average (70° to 72° F ambient), and winter (30° F ambient).

1A.7.6.1.2 Equivalent Availability (EA). Equivalent availability is a measure of the ability of a generating unit to produce power over a period of time, taking into account limitations such as equipment failures, unit deratings, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

1A.7.6.1.3 Equivalent Forced Outage Rate (EFOR). The equivalent forced outage rate is a reliability index which reflects the probability that a unit will not be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours plus equivalent forced outage hours by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

1A.7.6.1.4 Planned Maintenance Outage. This measure is an estimate of the time required each year to perform scheduled maintenance.

1A.7.6.1.5 Startup Fuel. Estimates for startup fuel, where applicable, in millions of Btu (MBtu), are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operating conditions.

1A.7.6.1.6 Net Plant Heat Rate. The net plant heat rate is a measure of generating station thermal efficiency, generally expressed in Btu/kWh. It can be computed by dividing the total Btu content of the fuel burned for electric generation by the resulting net kWh generation. Estimates for net plant heat rates are based on the higher heating values of the fuel. In this analysis, heat rate estimates are provided for average annual temperature conditions for combustion turbines and combined cycle units. Heat rates

may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, hours of operation, and local site conditions.

1A.7.6.1.7 Degradation. Power plant output and heat rate performance can degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance from the new and clean performance.

Approximations for performance degradation applied to the new and clean performance estimates of the combined cycle and simple cycle alternatives vary from unit to unit. Table 1A.7-23 presents the degradation factors used for simple and combined cycle units. Performance for solid fuel units was developed incorporating degradation.

Table 1A.7-23
Degradation Factors

Unit	Net Output (%)	Heat Rate (%)
7FA Simple Cycle	-4.04	2.87
LM 6000 Simple Cycle	-3.00	1.50
1x1 F Combined Cycle	-3.82	1.94
2 x1 F Combined Cycle	-3.72	1.84

1A.7.6.2 Pulverized Coal

The pulverized coal unit is developed to be identical to Stanton 2 and considers the existing infrastruction included in the Stanton 1 project to incorporate future pulverized coal unit additions.

OUC, KUA, and FMPA evaluated the pulverized coal unit as an alternative, with KUA and FMPA being joint owners with an assumed ownership share.

1A.7.6.2.1 Pulverized Coal Capital Cost Estimates. Interest during construction (IDC) is not included in these estimates. Capital costs were developed based on escalating the actual Stanton 2 costs.

The estimated capital cost is presented in Table 1A.7-24.

1A.7.6.2.2 Pulverized Coal O&M Costs and Performance Estimates. Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Staffing estimates provided are based on Stanton 2 experience with modern facilities. Variable operations costs include an assumed reagent cost for flue gas desulfurization (FGD), waste disposal, and ammonia. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the

operating time of the plant, such as steam turbine inspection costs and catalyst replacement. The estimated O&M cost and performance are presented in Table 1A.7-24.

Table 1A.7-24
Generating Unit Characteristics
446 MW Pulverized Coal Unit

Total Capital Cost,* 2000 ($000)	512,163
O&M Cost - Baseload Duty	
Fixed O&M Cost, 2000 ($/kW-yr)	14.17
Variable O&M Cost, 2000 ($/MWh)	3.73
Equivalent Forced Outage Rate (percent)	3.00
Planned Maintenance (days/year)	30
Construction Period (months)	42
kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	446,000/9,979
	329,710/10,125
	187,430/10,911
	117,060/12,463

*Includes site-specific costs as well as permitting and licensing.
Note: Capital cost does not include interest during construction.

1A.7.6.3 Circulating Fluidized Bed

Typical atmospheric circulating fluidized bed units consist of a large boiler burning a variety of solid fuels including coal, petroleum coke, or biomass. Typically, the fuel and limestone are fluidized in a bed in the boiler with air. The fuel burns and turns water into steam. Like the PC unit, the steam created is run through a steam turbine connected to a generator to produce power. A 267 MW CFB unit with a dry scrubber and selective noncatalytic reduction (SNCR) burning petroleum coke or coal was selected as a solid fuel alternative. Petroleum coke was selected as the primary fuel based on its low market price. The CFB is assumed to be located at Stanton Energy Center and take advantage of existing infrastructure.

1A.7.6.3.1 Circulating Fluidized Bed Capital Cost Estimates. Cost estimate was based on a recent bid to a Florida municipal utility for a unit at an existing site.

The estimated capital costs are presented in Table 1A.7-25.

1A.7.6.3.2 Circulating Fluidized Bed O&M Costs and Performance Estimates. O&M and performance estimates for the petroleum coke fueled CFB were based on the following assumptions.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Fixed maintenance costs contain the maintenance staff salary costs and the costs of supplies associated with periodic maintenance. Staffing estimates provided are based on recent utility experience with modern facilities.

Variable operations costs include an assumed lime cost for flue gas desulfurization (FGD), waste disposal, and ammonia. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs. The estimated O&M cost and performance are presented in Table 1A.7-25.

Table 1A.7-25
Generating Unit Characteristics
267 MW Circulating Fluidized Bed Unit

Total Capital Cost, 2000 ($000)	366,076	
O&M Cost - Baseload Duty		
Fixed O&M Cost, 2000 ($/kW-yr)	23.55	
Variable O&M Cost, 2000 ($/MWh)	5.53	
Equivalent Forced Outage Rate (percent)	3.00	
Planned Maintenance (days/year)	28	
Construction Period (months)	36	
kW Output / Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	Petroleum Coke	Coal
	267,000/9,831	10,087
	200,250/10,050	10,308
	133,500/10,885	11,163
	93,450/12,184	12,495

Note: Capital cost does not include interest during construction.

1A.7.6.4 Combined Cycle Units

The combined cycle units selected by the applicants as generating unit alternatives are as follows:

- 1 x 1 Siemens-Westinghouse 501F.

- 2 x 1 Siemens-Westinghouse 501F – Standard size.
- 2 x 1 Siemens-Westinghouse 501F – Oversized.
- 2 x 1 General Electric 7FA – Self-Build Alternative.

The standard size unit is based on a steam turbine sized to utilize all steam produced during normal cool weather conditions and includes duct burners sized to fully load the steam turbine during hot weather conditions. The oversized unit is based on a steam turbine sized to accommodate the maximum duct firing possible. The 2 x 1 General Electric 7FA self-build alternative represents a plant that is technically identical to Stanton A. The capital cost, however, represents current equipment costs and utilizes combustion turbine pricing and delivery schedules from options that KUA has on two General Electric 7FA combustion turbines.

Typical combined cycle units consist of one or more combustion turbine generators (CTGs), an equal number of heat recovery steam generators (HRSGs), and normally a single steam turbine generator (STG). Fuel is supplied to the CTG where it is mixed with compressed air and combusted. The combustion gases flow through a turbine that turns a generator to produce power. The CTG exhaust gas flows through the HRSG where water is turned into steam. The steam created is run through the STG to produce power. The total power output of the unit is the combination of the power from the CTG(s) and the STG.

The combined cycle units all utilize conventional, heavy-duty, industrial type combustion turbines. This application limited the alternatives reviewed to "F" class CTGs based on size and because F class turbines are a proven technology. Several vendors provide combustion turbines with similar performance characteristics. The combined cycle units would be dual fueled with natural gas as the primary fuel and No. 2 oil as the secondary fuel. Specifications for performance and operating costs are based on natural gas fuel and baseload operation. The combined cycles assume that emission requirements will be met with dry low NO_x combustors on the CTGs and SCR on the HRSGs. Various units could be located at the OUC Stanton, KUA Cane Island, or FMPA member sites and would utilize existing common facilities to the extent possible. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate. The combined cycles include bypass stacks and dampers to allow simple cycle operation. The combined cycles also include fuel oil and demineralized water storage tanks.

Two Siemens-Westinghouse 501F 2 x 1 combined cycle capital and O&M cost estimates were developed for comparison with the bids received from the Joint Development RFP. The two different Siemens-Westinghouse 501F 2 x 1 configurations consisted of a standard sized steam turbine and an oversized steam turbine sized to

accommodate the maximum duct firing possible. The standard sized configuration would be appropriate if KUA and FMPA did not participate in the project, while the oversized steam turbine configuration would be appropriate if KUA and FMPA did participate in the project. Because these estimates were to be used to compare costs from bids received from the Joint Development RFP, they were developed in greater detail than estimates used for generic generating unit alternatives. The estimates were also developed for installation specifically at Stanton Energy Center and take advantage of existing infrastructure. The detailed estimates are contained in Appendices 1A.C and 1A.D. The estimates were developed for an October 1, 2003, commercial operation date to correspond to the end of OUC's purchase power contract with Reliant, which is also the commercial operation date requested in the RFPs. The estimates include an allowance for the current market price of combustion turbines, but do not consider constraints on the delivery dates for combustion turbines. The current delivery date schedule for Siemens-Westinghouse 501F combustion turbines and General Electric 7F combustion turbines is the beginning of 2004, which would make an October 1, 2003, commercial operation date impossible unless OUC could obtain someone else's delivery slot. Nevertheless, the estimate was prepared on the basis of an October 1, 2003, commercial operation date to allow comparison with bids that OUC anticipated would utilize previously purchased combustion turbines and delivery slots. The specific estimates are presented in this section. The 2 x 1 F combined cycles are also appropriate as alternatives for subsequent additions at Stanton Energy Center for OUC and for KUA and FMPA sites after site specific adjustments are made. Specific estimates for other sites are presented in Volumes 1C and 1D.

In addition to the Siemens-Westinghouse 2 x 1 501F alternatives, a General Electric 2 x 1 7FA alternative was developed using an option for two General Electric 7FA combustion turbines that KUA obtained as part of their Cane Island Unit 3 project. The option with specific combustion turbine pricing and delivery schedule allows a 2 x 1 combined cycle unit to be constructed for an October 1, 2003 commercial operation date. The unit is technically identical to the Southern-Florida unit with respect to output and performance to enable a direct comparison of the Southern-Florida project and an identical self-build alternative. The self-build alternatives, however, have increased redundancy to provide for greater reliability since the self-build option would not have the benefit of being backed up by other Southern-Florida capacity.

1A.7.6.4.1 Siemens-Westinghouse 2 x 1 501F Combined Cycle Units. Cost estimates were based on standard plant arrangements for similar units and include adjustments for site-specific costs. Cost estimates include capital costs and operation and maintenance (O&M) costs. Capital cost and O&M cost estimate assumptions for

alternatives to Stanton A are included below. Utility and site-specific cost estimates for other sites can be found in Sections 1C.6 and 1D.6 of this application.

1A.7.6.4.1.1 Siemens-Westinghouse 2 x 1 501F Combined Cycle Capital Costs. The scope upon which the cost estimate is based for the standard size and the oversized steam turbine alternatives is presented in Appendices 1A.D and 1A.E, respectively. Table 1A.7-26 summarizes the cost estimates provided to OUC for comparison with costs contained in the proposal bids.

Table 1A.7-26
Siemens-Westinghouse 2 x 1 F Combined Cycle Cost Estimates

Item	Standard Turbine ($1,000)	Oversized Turbine ($1,000)
Basic EPC Plant Costs	233,000	242,000
Scope Additions Above Basic Plant	11,119	11,974
Natural Gas Pipeline Lateral	5,508	5,508
Condensate Polisher	1,200	1,200
Rehabilitate Waste Water Treatment	2,600	2,600
Subtotal	253,427	263,282
Transmission Interconnection	11,524	11,524
Need for Power and Site Certification Permitting	2,176	2,176
Total (10/01/03 Commercial Operation)	267,127	276,982

As the project has progressed, additional engineering and evaluations have been conducted which further refine some of the cost estimates. Among the refinements are the cost estimates for interconnecting the unit to the existing services at Stanton Energy Center. It has been determined that the cost of providing two of these services (ammonia and sanitary sewer) would be lower with stand-alone systems rather than by interconnecting them to the existing services at Stanton Energy Center. The estimated cost savings from providing these services independently rather than through interconnecting to the Stanton Energy Center services is $310,000. In addition, more refined estimates for interconnection costs indicate an additional savings of $253,000 based on the refined

estimates rather than the initial estimates. Negotiations with natural gas transportation suppliers have indicated that the most likely event will be that the natural gas transportation supplier will provide service to the Stanton A site and, therefore, the $5,508,000 included for the natural gas pipeline lateral will not be necessary. Finally, further investigation has indicated that rehabilitating the existing A and B brine crystalizer trains will not provide adequate wastewater treatment capacity. The additional cost for adding a new 600 gpm train identical to Train C installed for Stanton 2 is $17,300,000. Table 1A.7-27 summarizes the revised capital cost estimates for the Siemens-Westinghouse 2 x 1 combined cycle units.

Table 1A.7-27
Revised Siemens-Westinghouse 2 x 1 F Combined Cycle Cost Estimates

Item	Standard Turbine ($1,000)	Oversized Turbine ($1,000)
Original Estimate	267,127	276,982
Savings from Independently Supplied Services	(310)	(310)
Savings from Refined Estimates	(253)	(253)
Natural Gas Pipeline Lateral	(5,508)	(5,508)
Additional Costs for New Brine Concentrator	17,300	17,300
Total (10/01/03 Commercial Operation)	278,356	288,211

1A.7.6.4.1.2 Siemens Westinghouse 2 x 1 501F Combined Cycle O&M Costs and Performance Estimates. For consistency purposes, total plant fixed O&M costs are considered to be the same as those presented in Southern-Florida's proposal, and variable O&M costs are also assumed to be the same as those presented in Southern-Florida's proposal. The O&M costs along with the performance estimates for the Siemens-Westinghouse 2 x 1 501F combined cycle units are presented in Table 1A.7-28.

1A.7.6.4.2 General Electric 2 x 1 7FA Combined Cycle Units. As discussed previously, a technically identical self-build alternative was developed using KUA's General Electric 7FA combustion turbine option obtained from KUA's and FMPA's Cane Island 3 project. This option specifies the price and delivery schedule for the combustion turbines such that an October 1, 2003, commercial operation date can be achieved. The scope of the unit is identical to the Siemens-Westinghouse 2 x 1 combined cycle with the oversized steam turbine presented in Appendix 1A.E. The unit also incorporates power augmentation identical to Southern-Florida's proposal.

Table 1A.7-28
Estimated O&M Costs and Performance
Siemens-Westinghouse 501F Combined Cycle Units

	Standard Turbine	Oversized Turbine
O&M Cost – Baseload Duty		
Fixed O&M Cost, 2003 ($/kW-yr)	[redacted]	[redacted]
Variable O&M Cost, 2003 ($/MWh)	[redacted]	[redacted]
Equivalent Forced Outage Rate (percent)	4.00	4.00
Planned Maintenance (days/year)	[redacted]	[redacted]
Construction Period (months)	[redacted]	[redacted]
kW Output / Net Plant Heat Rate (NPHR), at 70° F, HHV (Btu/kWh)	513,830/7,074	609,730/7,542
	504,570/7,039	498,990/7,118
	316,110/7,512	311,450/7,625
	251,900/7,215	299,120/7,687
	247,160/7,186	243,740/7,287
	150,990/7,863	149,350/7,950

1A.7.6.4.2.1 General Electric 2 x 1 7FA Combined Cycle Capital Costs. The capital cost for the General Electric 2 x 1 7FA combined cycle is $2 million more than the Siemens-Westinghouse 2 x 1 501F combined cycle with the oversized steam turbine, or a total of $290,211,000. The $2 million additional cost represents KUA's $39 million option price for each of the General Electric combustion turbines compared to the $38 million allowance for each of the combustion turbines in the Siemens-Westinghouse 2 x 1 501 F combined cycle cost estimate.

1A.7.6.4.2.2 General Electric 2 x 1 7FA Combined Cycle O&M Costs and Performance Estimates. The estimated O&M costs and performance for the General Electric 2 x 1 7FA combined cycle is assumed to be the same as OUC's, KUA's, and FMPA's ownership share of Stanton A as described in Section 1A.3.

1A.7.6.4.3 Siemens-Westinghouse 1 x 1 501F Combined Cycle Unit. Cost estimates were based on standard plant arrangements for similar units and include adjustments for site-specific costs. Cost estimates include capital costs and O&M costs. Capital cost and O&M cost estimates that do not vary by site are included below. Utility

and site-specific cost estimates can be found in Sections 1C.6 and 1D.6 of this application.

1A.7.6.4.3.1 Siemens-Westinghouse 1 x 1 501F Combined Cycle Capital Costs. The total capital cost of a plant is the summation of direct and indirect costs. Interest during construction (IDC) is not included in these estimates. Capital costs were developed on the basis of the current costs observed in the competitive generation market.

Common general cost assumptions for the Siemens-Westinghouse 1 x 1 combined cycle include the following:

- The plant will contain:
  - One dual fueled combustion turbine.
  - One heat recovery steam generator.
  - One condensing steam turbine.
- No consideration was given to possible future expansion.
- Spread footing assumed for all foundations except turbine and HRSG area, which has an allowance for piling included. Stabilization of existing subgrade is not included.
- The combustion turbines will be capable of firing natural gas or No. 2 fuel oil.
- The HRSG duct burners will be capable of burning natural gas only.
- Fuel gas with adequate pressure, quantity, and suitable temperature to be provided at the site boundary.
- All permitting, fuel supplies, and interconnections supplied by the utility and others shall be in place to support the schedule.
- Land and rights-of-way are to be provided.
- Costs of unloading and delivery to the project site are included.
- Raw and makeup water are assumed to be provided.
- A sanitary sewer treatment connection is assumed to be provided.
- Construction power is assumed to be provided.
- Natural gas is available at the site boundary at the required pressure.
- Shipping for equipment and materials is included.
- Transmission hookup costs are included.
- Permitting and licensing costs are included.

Common direct cost assumptions for the Westinghouse 1 x 1 combined cycle include the following:

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
- Direct costs are based upon an overnight commercial operation date.
- Construction costs are based upon an engineer, procure, and construct (EPC) contracting philosophy.
- Includes dry low NO_x burners.
- Estimate includes SCR.
- Mechanical draft cooling tower included.
- An allowance is included for startup spare parts.
- The central control/electrical building will include:
  - Adequate space to support a control room.
  - Battery room.
  - Motor control center.
  - Meal room, toilets.
  - One office.
  - Building will be a preengineered metal structure.
- The service water building consists of:
  - Cooling pumps.
  - Chemical conditioning system.
  - Service water system.
  - Building will be a preengineered metal structure.
- Automatic fire protection of combustion turbine includes:
  - Standard CO_2 fire suppression system.
  - Water deluge of the transformers.
  - Hydrant protection of the cooling tower and site.
  - Wet pipe sprinkler system in the buildings except the control room.
  - Control room will have fire detection equipment only.
- Field erected tanks include:
  - Fuel oil storage.
  - Service/fire water storage.
  - Demineralized water.
  - Neutralization.
  - Condensate storage.

The following lists the common indirect costs included in the capital cost estimates for the Siemens-Westinghouse 1 x 1 combined cycle:

- General indirects include:
  - Relay checkouts and testing.
  - Instrumentation and control equipment calibration and testing.
  - Systems and plant startup.
  - Operating crew during test and initial operation period.
  - Operating crew training.
  - Electricity and water and fuel used during construction.
- Insurance costs include:
  - General liability.
  - Builder's risk.
  - Liquidated damages.
- Engineering and related services include:
  - A/E services.
  - Outside consultants and other related costs incurred in the permit and licensing process.
- Field construction management services include:
  - Field management staff including supporting staff personnel.
  - Field contract administration.
  - Field inspection and quality assurance.
  - Project control.
  - Technical direction.
  - Management of startup and testing.
  - Cleanup expense for the portion not included in the direct cost construction contracts.
  - Safety and medical services.
  - Guards and other security services.
  - Insurance premiums.
  - Other required labor insurance.
  - Telephone and other utility bills associated with temporary services.
  - Shipping for equipment and materials.

The following costs are not included in the estimates:

- Other owner costs.
- Federal, state, county, or local taxes.

- Acquisition of lands.
- Operating spare parts.

1A.7.6.4.3.2 Siemens-Westinghouse 1 x 1 501F Combined Cycle O&M Costs. For simple and combined cycle units, O&M estimates are based on a maintenance cycle of 25 years. A baseload capacity factor of 90 percent was assumed for combined cycle units.

Fixed O&M costs are those that do not directly vary according to plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Variable O&M costs change as a function of plant generation. Variable O&M costs include consumables such as chemicals, lubricants, water, and maintenance repair parts.

Fuel costs typically are determined separately and are not included in either fixed or variable O&M. The assumptions for fixed and variable O&M are as follows:

- Assumed maintenance cycle of 25 years.
- Primary fuel is natural gas.
- Unit will run at baseload operation with a capacity factor of 90 percent.
- Annual number of starts for the combustion turbine is 25.
- NO_x control method – Dry low NO_x combustors for combustion turbine generation (CTG) with SCR.
- CTG estimated maintenance costs provided by manufacturer.
- CTG specialized labor cost estimated at $38/hour, provided by manufacturer.
- CTG initial operational spares, combustion spares, and hot gas path spares are not included.
- HRSG annual inspection costs are estimated based on manufacturer input and Black & Veatch experience.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch experience. Annual inspections occur every 8,000 hours of operation, minor occur every 24,000 hours of operation, and major occur every 48,000 hours of operation.
- Balance-of-plant costs are estimated based on Black & Veatch experience.
- SCR uses anhydrous ammonia.
- Demineralized, raw, and wastewater costs are included.
- Estimated additional staff requirements are 16.
- Staff supplies and material are estimated to be 10 percent of staff salary.

- Rental equipment and contract labor costs are estimated by Black & Veatch. Rental equipment includes costs for heavy mobile equipment required for specific maintenance activities.
- Routine maintenance costs are estimated based on Black & Veatch experience. Routine maintenance includes maintenance costs for services not included in balance-of-plant costs or maintenance that is not directly part of power production.
- Contract services includes costs for services not directly related to power production.
- Insurance, training fees, and bonuses are not included.
- Fuel costs are not included.
- Employee training costs are not included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and takes into account the replacement and refurbishment costs.
- The fixed O&M analysis assumes that the fixed costs will remain constant over the life of the plant.

1A.7.6.5 Simple Cycle Combustion Turbine Generator

Two simple cycle combustion turbines were selected as generating unit alternatives as follows.

- General Electric LM6000.
- General Electric 7FA.

Simple cycle combustion turbine generators are supplied with fuel where it is mixed with compressed air and combusted. The combustion gases flow through a turbine that turns a generator to produce power.

The General Electric 7FA is heavy-duty, industrial combustion turbine generator. The General Electric LM6000 is an aeroderivative combustion turbine generator. Several vendors provide combustion turbine generators with similar performance characteristics. The combustion turbine generators are dual fueled with specifications for performance and operating costs based on natural gas operation. Part load performance information is also indicated. The simple cycle combustion turbines assume that emission requirements will be met with dry low NO_x combustors on the CTGs. Various units could be located at the OUC Stanton, KUA Cane Island, or FMPA member sites and would utilize existing common facilities to the extent possible. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate.

Cost estimates were based on standard plant arrangements for similar units and include adjustments for site-specific costs. Cost estimates include capital costs and O&M costs. Capital cost and O&M cost estimates that do not vary by site are included below. Utility and site-specific cost estimates can be found in Sections 1B.7, 1C.7, and 1D.7 of this application.

1A.7.6.5.1 Combustion Turbine Generator Capital Costs. The total capital cost of a plant is the summation of direct and indirect costs. Interest during construction (IDC) is not included in these estimates. Capital costs were developed on the basis of the current costs observed in the competitive generation market.

Common cost assumptions for the combustion turbine generators include the following:

- The plant will contain:
  - One dual fueled combustion turbine.
- No consideration was given to possible future expansion.
- Spread footing assumed for all foundations except the combustion turbine, which has an allowance for piling included. Stabilization of existing subgrade is not anticipated.
- The combustion turbines will be capable of firing natural gas or No. 2 fuel oil.
- Fuel gas with adequate pressure, quantity, and suitable temperature to be provided at the site boundary.
- All permitting, fuel supplies, and interconnections supplied by the utility and others shall be in place to support the schedule.
- Land and rights-of-way are to be provided.
- Costs of unloading and delivery to the project site are included.
- Raw water is assumed to be provided.
- A sanitary sewer treatment connection is assumed to be provided.
- Construction power is assumed to be provided.
- Natural gas available at the site boundary at the required pressure.
- Transmission hookup costs are included.
- Permitting and licensing costs are included.

Common direct cost assumptions for the combustion turbine generator include the following:

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
- Direct costs are based upon an overnight commercial operation date.

- Construction costs are based upon an engineer, procure, and construct (EPC) contracting philosophy and are based on utilizing union labor.
- Direct costs include sitework, concrete, architectural, metals, piping, insulation, mechanical equipment, electrical, and controls as identified in the detail listings.
- Direct costs include necessary substation modifications.
- Direct costs for the simple cycle alternatives include dry low NO_x burners.
- Direct costs for natural gas alternatives include a 3 day supply fuel oil storage tank for backup fuel.
- Direct costs include an allowance for startup spares.
- Buildings include:
  - General services building.
  - Maintenance shop.
  - Both are preengineered metal structures.
- Fire protection includes:
  - Standard CO_2 fire suppression system.
  - Water deluge of the transformers.
  - Hydrant protection of the cooling tower and site.

The following lists the common indirect costs included in the capital cost estimates for the combustion turbine generator:

- General indirects include:
  - Relay checkouts and testing.
  - Instrumentation and control equipment calibration and testing.
  - Systems and plant startup.
  - Operating crew during test and initial operation period.
  - Operating crew training.
  - Electricity and water and fuel used during construction.
- Insurance costs include:
  - General liability.
  - Builder's risk.
  - Liquidated damages.
- Engineering and related services include:
  - A/E services.
  - Outside consultants and other related costs incurred in the permit and licensing process.

- Field Construction Management services include:
  - Field management staff including supporting staff personnel.
  - Field contract administration.
  - Field inspection and quality assurance.
  - Project control.
  - Technical direction.
  - Management of startup and testing.
  - Cleanup expense for the portion not included in the direct cost construction contracts.
  - Safety and medical services.
  - Guards and other security services.
  - Insurance premiums.
  - Other required labor insurance.
  - Performance bond and liability insurance for equipment and tools.
  - Telephone and other utility bills associated with temporary services.
  - Shipping for equipment and materials.

The following costs are not included in the estimates:

- Other owner costs.
- Federal, state, county, or local taxes.
- Acquisition of lands.
- Operating spare parts.

1A.7.6.5.2 Combustion Turbine Generator O&M Costs. For simple cycle units, O&M estimates are based on a maintenance cycle of 25 years. A peak load capacity factor of 10 percent was assumed for simple cycle units.

Fixed O&M costs are those that do not directly vary according to plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Variable O&M costs change as a function of plant generation. Variable O&M costs include disposal of combustion wastes and consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts.

O&M and performance estimates for the simple cycle units were based on the following assumptions:

- Assumed cycle life of 25 years.
- Primary fuel is natural gas.
- Unit will run at peak load operation with a capacity factor of 10 percent.
- Annual number of starts for the combustion turbine is 200.

- NO_x control method – dry low NO_x combustors for combustion turbine generation (CTG).
- CTG maintenance estimated costs provided by manufacturer.
- CTG specialized labor cost estimated at $35/man-hour, provided by manufacturer.
- CTG initial operational spares, combustion spares, and hot gas path spares are not included.
- Balance-of-plant costs based on Black & Veatch experience.
- Estimated additional staff is four for the LM 6000 and five for the 7FA.
- Staff supplies and materials are estimated to be 10 percent of staff salary.
- Rental equipment and contract labor costs are estimated by Black & Veatch. Rental equipment includes costs for heavy mobile equipment required for specific maintenance activities.
- Routine maintenance costs are estimated based on Black & Veatch experience. Routine maintenance includes maintenance costs for services not included in balance-of-plant costs or maintenance that is not directly part of power production.
- Contract services includes costs for services not directly related to power production.
- Insurance, training fees, and bonuses are not included.
- Fuel costs are not included.
- Employee training costs are not included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and takes into account the replacement and refurbishment costs.
- The fixed O&M analysis assumes that the fixed costs will remain constant over the life of the plant.

1A.7.7 Supply-Side Screening

Previous sections and details included in Volumes 1B, 1C, and 1D present cost and performance information for many supply-side alternatives that could potentially fit the future capacity needs of OUC, KUA, and FMPA. Once these options were identified, the next step was to identify those technologies that will be modeled in detail. In order to arrive at an acceptable number of alternatives to be modeled, a two-phase screening process was used. The first phase of the screening process, Phase I Screening, eliminated alternatives that were not technically or commercially viable for OUC, KUA, or FMPA.

The second phase, Phase II Screening, screened options based upon a busbar cost analysis. Details of the screening process are outlined below.

1A.7.7.1 Phase I Screening

The initial screening is intended to eliminate alternatives that are not technically feasible or are still under commercial development at this time. Below is a discussion of each of the alternatives.

1A.7.7.1.1 Renewable Technologies. The nine renewable technologies identified in Section 1A.7.1, including wind, solar thermal, solar photovoltaics, biomass, geothermal, hydroelectric, ocean wave, ocean tidal, and ocean thermal were reviewed to determine technical feasibility and if the resources needed to operate these alternatives were available. Insufficient wind conditions are available to provide cost-effective generation, and thus wind energy is eliminated from further consideration. Biomass, consisting of wood fired plants, was deleted from consideration due to environmental emission concerns and lack of raw materials for baseload operation. Geothermal and hydroelectric alternatives were eliminated due to a lack of natural resources to support these technologies. Ocean wave, tidal, and thermal technologies were eliminated from consideration due to environmental and technological concerns. Thus, the only renewable energy technologies that are considered for the busbar cost analysis are solar thermal and solar photovoltaics.

1A.7.7.1.2 Waste to Energy Technologies. Waste energy technologies evaluated include municipal solid waste (MSW), refused derived fuel (RDF), landfill gas, tire derived fuel, and sewage sludge. A sufficient volume of fuel is not available to provide a waste to energy plant comparable in size to Stanton A. Although there is insufficient volume of wastes to supplant all of Stanton A, the possibility exists that a smaller waste energy technology plant could be cost-effective and reduce the size of Stanton A. The location of the Stanton Energy Center adjacent to the Orange County Landfill makes the idea of waste utilization especially attractive. Tire derived fuel and sewage sludge technologies are eliminated due to their relatively smaller volumes. Municipal solid waste (MSW) and refuse derived fuel (RDF) represent more promise from a volume standpoint. MSW and RDF are relatively expensive, with the midpoint of the range of estimated levelized costs to be 9.4 and 10.8 cents/kWh, respectively. Furthermore, there are significant environmental concerns with MSW and RDF technologies. Landfill gas represents a generally cost-effective technology. OUC is currently burning landfill gas from the Orange County Landfill in Stanton 1 and 2. Since OUC is currently obtaining the benefits from waste through the use of landfill gas and because of cost and environmental concerns relative to MSW and RDF, both MSW and RDF are eliminated from

further analysis. Neither KUA or FMPA have adequate waste resources available to consider MSW and RDF technologies.

1A.7.7.1.3 Advanced Technologies. Advanced technologies evaluated include advanced gas technologies (humid air turbine (HAT), Kalina, and Cheng cycles), advanced coal technologies (supercritical pulverized coal boilers and pressurized fluidized bed combustion (PFBC)), magnetohydrodynamics (MHD), fuel cells, and nuclear fusion. Only fuel cell and supercritical coal technologies are considered commercially viable at this time. Therefore, the other advanced alternatives were eliminated from further consideration.

1A.7.7.1.4 Energy Storage Systems. Energy storage systems evaluated include pumped hydro, battery, compressed air, flywheel, and superconducting magnetic. Pumped hydro and compressed air are commercially proven resources, but site topography and natural resources will not accommodate these technologies. Battery, flywheel, and superconducting magnetic were also eliminated from further consideration since the status of these alternatives is experimental.

1A.7.7.1.5 Nuclear (Fission). Nuclear power was not included for the next level of screening due to cost, environmental, and public perception considerations.

1A.7.7.1.6 Conventional Technologies. Conventional generating unit alternatives initially considered for capacity expansion include pulverized coal, circulating fluidized bed, combined cycle, and simple cycle combustion turbines. Each of these alternatives was carried forward to the detailed economic analysis.

1A.7.7.2 Phase II Screening

The Phase II screening is intended to eliminate alternatives based on a busbar analysis. Table 1A.7-29 shows the peaking and intermediate alternatives that passed the initial screening and were considered for the Phase II busbar analysis. For comparison purposes, a 7FA SC was chosen with a capacity factor equivalent to what the solar alternatives would likely operate at. It is clearly shown in Table 1A.7-29 that the solar alternatives are not cost-effective on a levelized busbar basis.

The fuel cell and supercritical coal advanced technologies represent baseload technologies. The conventional pulverized coal unit at an 85 percent capacity factor is chosen for a busbar comparison to them. Table 1A.7-30 indicates that fuel cell and supercritical coal are not cost-effective compared to conventional pulverized coal.

Table 1A.7-29
Levelized Busbar Comparison-Peaking and Intermediate

Alternative	Levelized Busbar Cost (cents/kWh)
7FA SC (30% capacity factor)	7.58
Solar Thermal	10.8 - 18.7
Solar Photovoltaic	19.4 - 47.4
Note: Levelized cost based on OUC economic criteria.	

Table 1A.7-30
Levelized Busbar Comparison-Base Load

Alternative	Levelized Busbar Cost (cents/kWh)
Conventional Pulverized Coal	4.41
Fuel Cell	14.2 - 25.4
Supercritical Coal	4.3 - 6.7
Note: Levelized cost based on OUC economic criteria.	

1A.8.0 Demand-Side Programs

According to Section 403.519, Florida Statutes, in a determination of need proceeding, the Florida Public Service Commission (FPSC) must take into consideration conservation measures that could mitigate or delay the need for the proposed plant. Based on this requirement, OUC, KUA, and FMPA have tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the FPSC approved Florida Integrated Resource Evaluator (FIRE) model, which provides output in the form of the Rate Impact Test, the Total Resources Cost Test, and the Participant Test.

The cost-effectiveness of DSM measures has decreased over the years, especially for municipal utilities, which are subject to lower cost tax exempt financing. This reduction in cost-effectiveness is attributed to a number of factors, one of which is the increase in the efficiency of new generation units. In addition, the cost of installing new generation has decreased. Moreover, government mandates have forced appliance manufacturers to increase the efficiencies of their products. These reasons combine to result in it becoming more difficult for DSM measures to be cost-effective.

Results of the DSM analysis for OUC, KUA, and FMPA can be found in Sections 1B.5.0, 1C.5.0, and 1D.5.0. Description and details of existing DSM programs can be found in those sections as well.

This section discusses the FIRE model methodology which is common to OUC, KUA, and FMPA.

1A.8.1 FIRE Model Methodology

The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

1A.8.1.1 FIRE Model Assumptions

Assumptions inherent in the FIRE model include:

- System demand is growing. Demand reductions due to DSM will result in reduced need for system expansion.
- Individual demand reductions can be related to reduced need for system generation expansion.
- The generation reduction will be evaluated with respect to specified generation.

- Decreases or increases in revenue due to demand-side programs will impact rate levels and will be passed on to all customers.
- Additional conservation taking place after the next deferred generating unit will affect subsequent units.

1A.8.1.1.1 FIRE Model Inputs. There are two types of FIRE Model input files. The first input file contains data specific to the utility's next proposed unit, the avoided unit. The second input file contains data specific to the DSM measure being tested for cost-effectiveness. Input data for the avoided unit is placed on a per kW basis. Because the avoided unit data is input on a per kW basis, the potential DSM measures can be tested individually to determine cost-effectiveness.

1A.8.1.1.2 Avoided Unit. The avoided unit used in the DSM analysis is the proposed Southern-Florida 633 MW 2 x 1 combined cycle unit. Stanton A is unique because it entails 35 percent ownership by OUC, KUA, and FMPA, which have a right to the remaining 65 percent of Stanton A capacity pursuant to PPAs with Southern-Florida. Therefore, the 35 percent ownership capacity will be considered the avoided unit since it is lower in cost than the capacity under the PPAs. If DSM measures are not cost-effective compared to the ownership capacity, they will also not be cost-effective compared to the PPA capacity.

1A.8.1.1.3 DSM Measures. Potential DSM measures for cost-effective analyses were selected based on the potential to be cost-effective. OUC, KUA, and FMPA did not model each possible DSM measure; instead, OUC, KUA, and FMPA focused on alternatives that were expected to have the highest potential for being cost-effective.

The DSM measures analyzed were compiled from measures deemed cost-effective in the 2000 Demand-Side Management Plan of Florida Power & Light (FPL). By testing the most cost-effective measures from FPL, the assumption was made that if the most cost-effective measure for FPL did not prove cost-effective for OUC, KUA, and FMPA, then FPL's lesser cost-effective measures would also fail the analysis. Using this methodology, OUC, KUA, and FMPA have effectively screened all of FPL's measures.

FPL's most cost-effective residential measure is Direct Load Control and its most cost-effective commercial/industrial measure is Off-Peak Battery Charging. OUC, KUA, and FMPA separately tested both FPL measures. The FIRE Model results for OUC, KUA, and FMPA can be found in Volumes 1B, 1C, and 1D, respectively.

1A.8.1.2 FIRE Model Outputs

FIRE Model results are presented in the form of three cost-effectiveness tests. All the DSM cost-effectiveness tests are based on the comparison of discounted present

worth benefits to costs for a specific DSM measure. Each test is designed to measure costs and benefits from a different perspective.

The Total Resource Cost Test measures the benefit/cost ratio by comparing the total program benefits (both the participant's and utility's) to the total program costs (equipment costs, supply costs, participant costs).

The Participants Test measures the impact of the DSM program on the participating customer. Benefits to the participant may include bill reductions, incentives paid, and tax credits. Participants' costs may include equipment costs, operation and maintenance expenses, equipment removal, etc. The Participants Test is important because customers will not participate in a program if it is not beneficial to them.

The Rate Impact Test is a measure of the expected impact on customer rates resulting from a DSM program. The test statistic is the ratio of the utility's benefits (avoided supply costs and increased revenues) compared to the utility's costs (program costs, incentives paid, increased supply costs and revenue losses). A value of less than one indicates an upward pressure on electricity rates as a result of the DSM program. OUC, KUA, and FMPA view the Rate Impact Test as the primary test for determining the cost-effectiveness of a DSM measure on their systems.

1A.9.0 Peninsular Florida Needs

The Florida Reliability Coordinating Council (FRCC) is responsible for coordinating power supply reliability in Peninsular Florida for the North American Reliability Council (NERC). As part of its reliability coordination activities, the FRCC provides an annual summary and report of Peninsular Florida Ten-Year Site Plans. The annual summary is then analyzed by FPSC staff and utility members during annual workshops. The most recent planning summary conducted by FRCC is the 2000 Load and Resource Plan for the State of Florida. Published in July 2000, this Load and Resource Plan summarizes utility loads and resources, by type of capacity, through the year 2009. The summary also includes utility load forecast data and proposed generation expansion plans, retirements, and capacity re-rates. The following section summarizes the results of the FRCC's reliability analysis in the determination of future capacity requirements for Peninsular Florida according to the State of Florida 2000 Load and Resource Plan.

1A.9.1 Peninsular Florida Capacity and Reliability Needs

Table 1A.9-1 represents the peak demand and available capacity for summer and winter as presented by FRCC. As Table 1A.9-1 indicates, reserve margins are projected to exceed the 15 percent criteria required by FRCC. Closer inspection, however, indicates that reserve margins before exercising load management and interruptible loads only range between 7 to 14 percent.

Table 1A.9-2 represents the summer and winter peak demand and available capacity by excluding the capacity required to be approved under the Florida Electrical Power Plant Siting Act, but not yet approved. The available capacity consists of existing capacity, capacity changes that have been approved under the Florida Electrical Power Plant Siting Act, and capacity changes not requiring certification under the Florida Electrical Power Plant Siting Act. Planned capacity changes which are not approved under the Florida Electrical Power Plant Siting Act have not been included in the available capacity shown in Table 1A.9-2. Figure 1A.9-1 shows the curves of peak demand, available capacity, and peak demand plus 15 percent reserve margin. Table 1A.9-2 and Figure 1A.9-1 show that, beginning with the winter period of 2003/04, there is insufficient capacity to meet the required 15 percent reserve margin.

Table 1A.9-1
2000 Load and Resource Plan--Peninsular Florida Peak Demand and Available Capacity

Summer Peak Demand

Calendar Year	Installed Capacity	Net Contracted Firm Interchange	Projected Firm Net to Grid from NUG	Total Available Capacity	Total Peak Demand	Reserve Margin w/o Load Management & Int.		Load Management	Interruptible Load	Firm Peak Demand	Reserve Margin w / Load Management & Int.	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	(MW)	(MW)	% of Peak
2000	36,033	1,697	2,653	40,383	37,728	2,655	7%	1,584	1,312	34,832	5,551	16%
2001	38,244	1,699	2,653	42,596	38,445	4,151	11%	1,565	1,320	35,560	7,036	20%
2002	38,903	1,675	2,906	43,484	39,282	4,202	11%	1,517	1,333	36,432	7,052	19%
2003	41,007	1,583	3,221	45,811	40,157	5,654	14%	1,485	1,359	37,313	8,498	23%
2004	42,138	1,583	2,768	46,489	41,004	5,485	13%	1,464	1,376	38,164	8,325	22%
2005	42,734	1,583	2,658	46,975	41,905	5,070	12%	1,445	1,395	39,065	7,910	20%
2006	44,174	1,583	2,525	48,282	43,190	5,092	12%	1,430	1,413	40,347	7,935	20%
2007	44,887	1,583	2,220	48,690	44,097	4,593	10%	1,416	1,426	41,255	7,435	18%
2008	45,916	1,583	2,205	49,704	44,926	4,778	11%	1,408	1,424	42,094	7,610	18%
2009	46,623	1,583	2,096	50,302	45,810	4,492	10%	1,400	1,430	42,980	7,322	17%

Winter Peak Demand

Calendar Year	Installed Capacity	Net Contracted Firm Interchange	Projected Firm Net to Grid from NUG	Total Available Capacity	Total Peak Demand	Reserve Margin w/o Load Management & Int.		Load Management	Interruptible Load	Firm Peak Demand	Reserve Margin w / Load Management & Int.	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	(MW)	(MW)	% of Peak
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7%	2,864	1,216	36,814	7,031	19%
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7%	2,835	1,223	37,753	7,012	19%
2002/03	42,943	1,583	3,365	47,891	42,739	5,152	12%	2,812	1,248	38,679	9,212	24%
2003/04	44,759	1,583	2,912	49,254	43,663	5,591	13%	2,810	1,261	39,592	9,662	24%
2004/05	45,311	1,583	2,802	49,696	44,638	5,058	11%	2,814	1,273	40,551	9,145	23%
2005/06	46,275	1,583	2,669	50,527	45,694	4,833	11%	2,823	1,286	41,585	8,942	22%
2006/07	47,607	1,583	2,324	51,514	46,668	4,846	10%	2,831	1,296	42,541	8,973	21%
2007/08	48,950	1,583	2,309	52,842	47,573	5,269	11%	2,839	1,289	43,445	9,397	22%
2008/09	49,559	1,583	2,200	53,342	48,531	4,811	10%	2,850	1,295	44,386	8,956	20%
2009/10	50,746	1,583	1,778	54,107	49,478	4,629	9%	2,858	1,304	45,316	8,791	19%

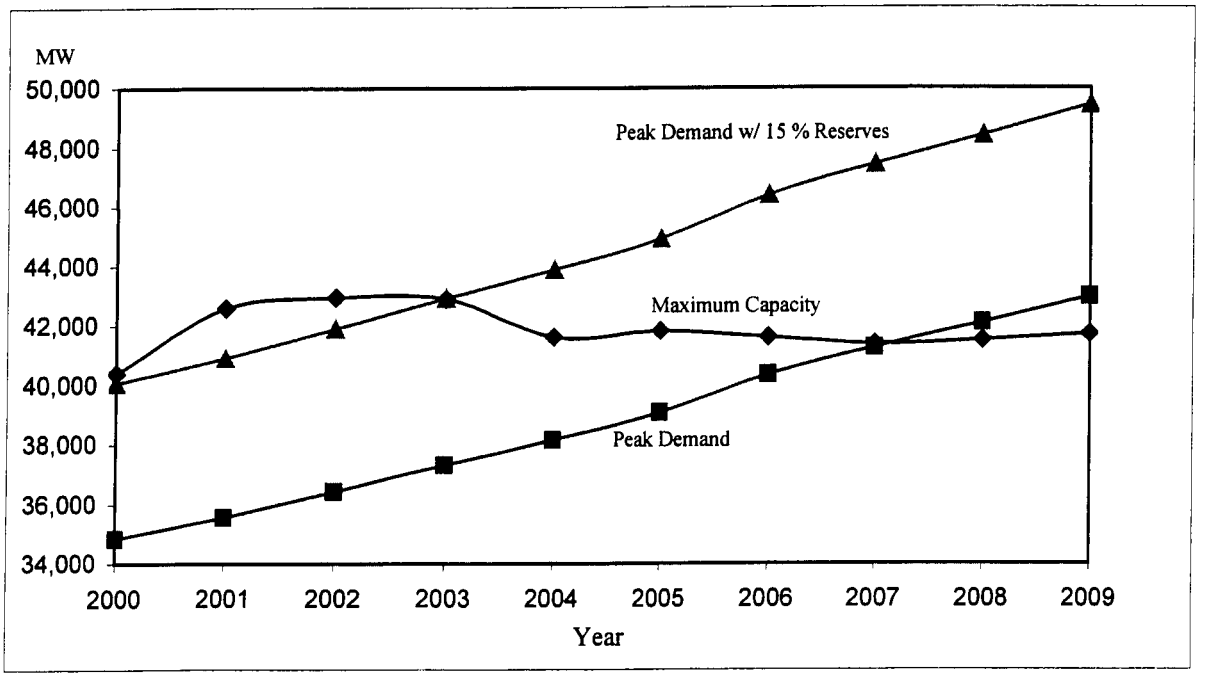
Table 1A.9-2
2000 Load and Resource Plan -- Peninsular Florida Peak Demand and Available Capacity
Excluding Capacities Pending Approval Under the Florida Electrical Power Plant Siting Act but Not Yet Approved

Summer Peak Demand

Calendar Year	Installed Capacity	Net Contracted Firm Interchange	Projected Firm Net to Grid from NUG	Total Available Capacity	Total Peak Demand	Reserve Margin w/o Load Management & Int.		Load Management	Interruptible Load	Firm Peak Demand	Reserve Margin w / Load Management & Int.	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	(MW)	(MW)	% of Peak
2000	36,033	1,697	2,653	40,383	37,728	2,655	7%	1,584	1,312	34,832	5,551	16%
2001	38,244	1,699	2,653	42,596	38,445	4,151	11%	1,565	1,320	35,560	7,036	20%
2002	38,373	1,675	2,906	42,954	39,282	3,672	9%	1,517	1,333	36,432	6,522	18%
2003	38,097	1,583	3,221	42,901	40,157	2,744	7%	1,485	1,359	37,313	5,588	15%
2004	37,278	1,583	2,768	41,629	41,004	625	2%	1,464	1,376	38,164	3,465	9%
2005	37,586	1,583	2,658	41,827	41,905	-78	0%	1,445	1,395	39,065	2,762	7%
2006	37,503	1,583	2,525	41,611	43,190	-1,579	-4%	1,430	1,413	40,347	1,264	3%
2007	37,578	1,583	2,220	41,381	44,097	-2,716	-6%	1,416	1,426	41,255	126	0%
2008	37,718	1,583	2,205	41,506	44,926	-3,420	-8%	1,408	1,424	42,094	-588	-1%
2009	38,031	1,583	2,096	41,710	45,810	-4,100	-9%	1,400	1,430	42,980	-1,270	-3%

Winter Peak Demand

Calendar Year	Installed Capacity	Net Contracted Firm Interchange	Projected Firm Net to Grid from NUG	Total Available Capacity	Total Peak Demand	Reserve Margin w/o Load Management & Int.		Load Management	Interruptible Load	Firm Peak Demand	Reserve Margin w / Load Management & Int.	
	(MW)	(MW)	(MW)	(MW)	(MW)	(MW)	% of Peak	(MW)	(MW)	(MW)	(MW)	% of Peak
2000/01	39,342	1,786	2,717	43,845	40,894	2,951	7%	2,864	1,216	36,814	7,031	19%
2001/02	40,075	1,688	3,002	44,765	41,811	2,954	7%	2,835	1,223	37,753	7,012	19%
2002/03	40,677	1,583	3,365	45,625	42,739	2,886	7%	2,812	1,248	38,679	6,946	18%
2003/04	40,439	1,583	2,912	44,934	43,663	1,271	3%	2,810	1,261	39,592	5,342	13%
2004/05	39,903	1,583	2,802	44,288	44,638	-350	-1%	2,814	1,273	40,551	3,737	9%
2005/06	40,012	1,583	2,669	44,264	45,694	-1,430	-3%	2,823	1,286	41,585	2,679	6%
2006/07	39,916	1,583	2,324	43,823	46,668	-2,845	-6%	2,831	1,296	42,541	1,282	3%
2007/08	40,263	1,583	2,309	44,155	47,573	-3,418	-7%	2,839	1,289	43,445	710	2%
2008/09	40,443	1,583	2,200	44,226	48,531	-4,305	-9%	2,850	1,295	44,386	-160	0%
2009/10	40,634	1,583	1,778	43,995	49,478	-5,483	-11%	2,858	1,304	45,316	-1,321	-3%



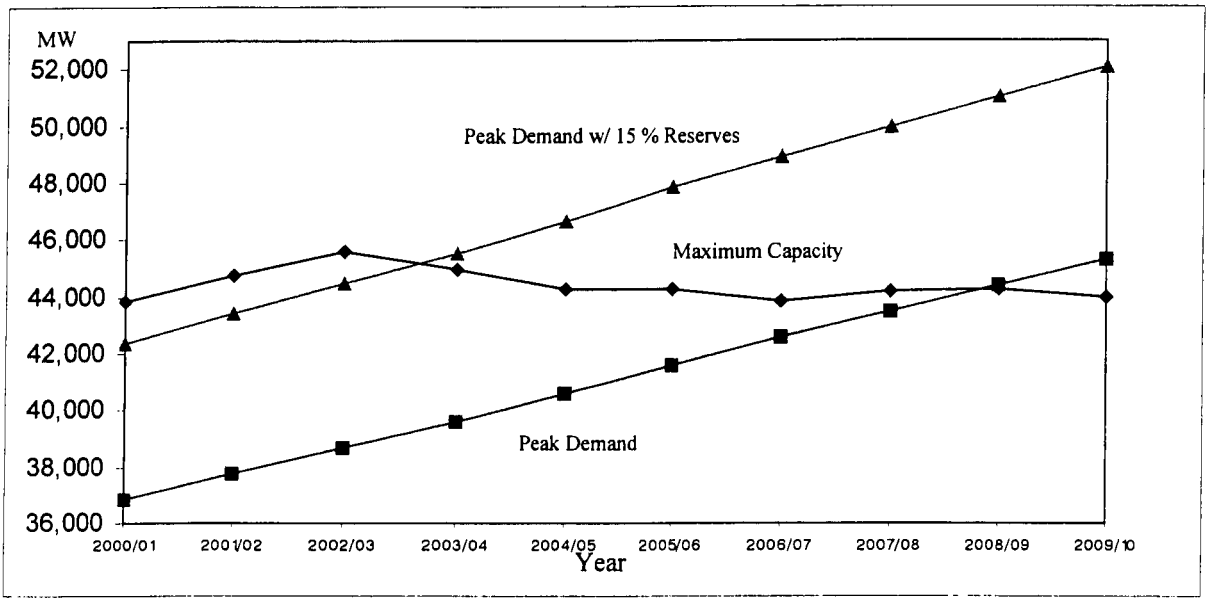


Figure 1A.9-1
2000 Load and Resource Plan – Peak Demand and Reserve Margin
Excluding Capacity Required to be Approved Under the Florida Electrical Power Plant
Siting Act but Not Yet Approved

1A.9.2 Impact to Transmission System

The addition of Stanton A will not have a negative impact on OUC's, KUA's, and FMPA's or the State of Florida's Electric Transmission System. OUC's internal transmission system will be upgraded to accommodate the addition of the combined cycle project by adding onsite interconnection expansions and offsite circuit breaker upgrades to improve the interrupting capability of selected circuits. Details of the required transmission upgrades are provided in Section 1A.3.8.

1A.10.0 Analysis of 1990 Clean Air Act Amendments

While the Florida Electrical Power Plant Siting Act carefully bifurcates the need for the power plant from the environmental impacts of the facility, the Clean Air Act requirements have a great impact on the power plant's cost and performance.

1A.10.1 History of the Clean Air Act

The Clean Air Act of 1970 was designed to protect human health and the environment by regulating the amount of pollutants released to the atmosphere. The major regulated air pollutants include carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO_2), hydrocarbon compounds (or volatile organic compounds, VOC), ozone, lead, and suspended particulates (PM/PM_{10}). The listed pollutants, commonly referred to as criteria pollutants, have been regulated primarily through National Ambient Air Quality Standards (NAAQS) and the respective state implemented programs that support the NAAQS.

In the late 1980s, as it came time for Congress to reauthorize the Clean Air Act, air quality had improved, but it was clear that continuing the improvement was becoming more costly per unit of pollution removed. Under the 1990 Clean Air Act amendments, Congress required the EPA to establish an emissions trading program that would cut the emissions of sulfur dioxide in half by the year 2000. Under the program established by the EPA, existing power plants were allocated sulfur dioxide allowances with a given number of additional allowances auctioned each year. An allowance holder can emit 1 ton of sulfur dioxide for each allowance. Firms holding the allowances can use the allowances to emit pollutants, bank the allowances for the next year, or sell the allowances to other firms. Total emissions will fall because the sulfur dioxide emissions associated with the number of allowances available are less than existing emissions.

1A.10.2 Authority to Construct

Stanton A is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. One aspect of the ATC permit is the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are NO_x, SO_2, VOC, CO, and PM/PM_{10}.

Stanton A is also subjected to the New Source Performance Standards (NSPS) requirements for a stationary gas turbine used for electricity generation as defined in 40 CFR Part 60, Subpart GG. NSPS Subpart GG places restrictions on emission of SO_2 and NO_x from combustion turbines. NO_x concentrations in the flue gas for combustion turbines with heat inputs greater than 100 MBtu/h are limited to a nominal value of

75 ppmvd (corrected to 15 percent O_2). Upward corrections to NO_x emission limits are allowed for fuel bound nitrogen content and thermal efficiencies greater than 25 percent.

Stanton A's proposed maximum NO_x emissions of 3.5 ppmvd (corrected to 15 percent O_2) for natural gas firing are well below the nominal NSPS Subpart GG limit of 75 ppmvd. Incorporating the fuel bound nitrogen corrections would result in the Project's NO_x emissions being even further below the NSPS Subpart GG limit. When operating on No. 2 oil, Stanton A will emit 10 ppmvd at 15 percent O_2.

NSPS Subpart GG also limits SO_2 emissions from combustion turbines to 150 ppmvd (corrected to 15 percent O_2) and restricts fuel sulfur content to less than 0.8 percent by weight. The sulfur content in the natural gas will be approximately 0.2 gr/100 scf. As a result, SO_2 emissions from Stanton A will be less than 0.2 ppm (corrected to 15 percent O_2) when operating on natural gas.

Stanton A will therefore satisfy the NSPS Subpart GG requirements.

1A.10.3 Title V Operating Permit

Along with the ATC, each new unit is required to obtain an operating permit under Title V of the Clean Air Act.

Requirements under the Title V permit for Stanton A will require similar emissions control and operations to those required under the ATC and BACT determination.

1A.10.4 Title IV Acid Rain Permit

In addition to the construction and operating permit requirements of the new units, the regulations implementing the Acid Rain provisions of the Clean Air Act Amendments require that electric utility units obtain acid rain permits requiring SO_2 allowances. The maximum annual projected SO_2 emissions from Stanton A at 70° F with 1,000 hours of operation on No. 2 oil are 123.8 tons/year, which corresponds to an annual allowance requirement of 124 tons/year. These allowances can be obtained from excess allowances available for OUC, KUA, and FMPA through their participation in Stanton 1. Alternatively, they could be purchased on the open market. At an allowance cost of $200, the cost of purchasing allowances would be less than $25,000 per year.

1A.11.0 Consequences of Delay

The consequences of delaying the Site Certification or the commercial operation of Stanton A are significant from a cost and reliability standpoint for OUC, KUA, and FMPA.

1A.11.1 Economic Consequences

If the Site Certification of Stanton A is delayed, the commercial operation of the project will be delayed and OUC, KUA, and FMPA would incur additional costs to replace the capacity and energy available from Stanton A. There have been no generating unit alternatives identified that could be placed into commercial operation to replace Stanton A's commercial operation other than the LM6000 simple cycle combustion turbine identified as an alternative for KUA. Although it has been assumed for evaluation purposes that the LM6000 could be available for a commercial operation date of October 1, 2003, actual delivery schedules may preclude that commercial operation date. Even if it is available, the estimate capital cost is over twice the cost of Stanton A on a $/kW basis and the heat rate is over 30 percent higher than Stanton A. If delivery schedules preclude the installation of generating units, OUC, KUA, and FMPA would be subject to purchasing power. The availability of purchase power is uncertain, and the price is even more uncertain. In either event, the economic consequences of a delay in the commercial operation of Stanton A would have a significant adverse economic impact on OUC, KUA, and FMPA.

1A.11.2 Reliability Consequences

If the Site Certification of Stanton A is delayed, the commercial operation of the project will be delayed and OUC, KUA, and FMPA will not be able to meet their reserve margin criteria. Without Stanton A and assuming an extension of the full 500 MW available from the Reliant Agreement, OUC, KUA, and FMPA collectively would be 17 MW short of meeting their required reserves for the 2003-04 winter and 214 MW short of the required reserves for the summer of 2004. If the Reliant Contract is not extended, these short falls would be 517 MW for the 2003-04 winter and 714 MW for the summer of 2004. Capacity shortfalls of this magnitude potentially can have significant adverse impacts on system reliability. While the capacity short fall does not appear very significant for the winter of 2003-04, it is based on the base case forecast assuming normal weather. A severe weather event would result in substantially greater short falls and would likely either require very heavy dependence on the statewide reserves or result in the inability of OUC, KUA, and FMPA to serve their customers. Historically, statewide reserves have often not been available during severe winter weather events.

Appendix 1A.A
Power Purchase Agreement
Between
Orlando Utilities Commission,
Kissimmee Utility Authority,
Or
Florida Municipal Power Agency
(All Requirements Power Supply Project)
and
Southern Company-Florida LLC

CONFIDENTIAL PROPRIETARY BUSINESS INFORMATION – TRADE SECRET

SOUTHERN DRAFT - 01/23/01

POWER PURCHASE AGREEMENT

BETWEEN

ORLANDO UTILITIES COMMISSION,

KISSIMMEE UTILITY AUTHORITY,

OR[1]

FLORIDA MUNICIPAL POWER AGENCY (ALL REQUIREMENTS POWER SUPPLY PROJECT)

AND

SOUTHERN COMPANY - FLORIDA LLC

Dated as of January ___, 2001

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[1] Each separate contract will list the appropriate entity.

TABLE OF CONTENTS

Section		Page
SECTION 1	DEFINITIONS AND EXPLANATION OF TERMS	1
SECTION 2	TERM OF AGREEMENT	14
SECTION 3	CONDITIONS PRECEDENT	15
SECTION 4	SALE AND PURCHASE	16
SECTION 5	SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY	32
SECTION 6	REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE	35
SECTION 7	INTERCONNECTION AND TRANSMISSION	36
SECTION 8	RISK OF LOSS; METERING	38
SECTION 9	METHOD OF PAYMENT	39
ARTICLE 10	CHANGE IN LAW; MODIFICATION OF AGREEMENT	41
SECTION 11	FORCE MAJEURE	42
SECTION 12	EVENTS OF DEFAULT; TERMINATION	43
SECTION 13	WAIVER	46
SECTION 14	REPRESENTATIONS AND WARRANTIES	46
SECTION 15	PERFORMANCE ASSURANCE	50
SECTION 16	LIABILITY OF PARTIES	52
SECTION 17	ASSIGNMENT	56
SECTION 18	DISPUTE RESOLUTION	57

SECTION 19 AMENDMENT 58

SECTION 20 NOTICES 58

SECTION 21 APPLICABLE LAW 59

SECTION 22 SEVERABILITY 60

SECTION 23 ENTIRE AGREEMENT 60

SECTION 24 NO THIRD PARTY BENEFICIARIES 60

SECTION 25 COUNTERPARTS 60

SECTION 26 INFORMATION AND CONFIDENTIALITY 61

SECTION 27 PUBLIC STATEMENTS 62

SECTION 28 INSURANCE 62

SECTION 29 TAXES 63

APPENDIX A TECHNICAL LIMITS

APPENDIX B REQUESTS FOR ENERGY

APPENDIX C CAPACITY TESTING PROCEDURE

APPENDIX D EXAMPLE CALCULATIONS

APPENDIX E AFFILIATE GUARANTEE

CONFIDENTIAL PROPRIETARY BUSINESS INFORMATION – TRADE SECRET

SOUTHERN DRAFT - 01/23/01

POWER PURCHASE AGREEMENT

This Power Purchase Agreement (this "Agreement") is made and entered into as of the ___ day of January, 2001, by and between [_____], a [_____] existing under the laws of the State of Florida ("Purchaser"), and Southern Company - Florida LLC, a limited liability company organized and existing under the laws of the State of Delaware ("Seller"). Purchaser and Seller are hereinafter each referred to individually as a "Party" and collectively as the "Parties."

RECITALS

Seller, Purchaser, ____, and ____[2] intend to construct, own, operate and maintain a 633 MW combined cycle electric generating facility (the "Facility") to be located at the existing Stanton Energy Center of the Orlando Utilities Commission in Orlando, Florida.

Seller intends to sell to Purchaser, and Purchaser intends to purchase from Seller, a portion of Seller's share of the Capacity and Energy generated by the Facility in accordance with the terms and conditions of this Agreement.

Seller and Purchaser acknowledge that this Agreement is one of three substantially similar contracts through which Seller will sell and the three Purchasers will individually purchase their respective designated shares of Seller's share of the Capacity and Energy generated by the Facility.

In consideration of the mutual covenants and agreements set forth herein, the Parties, intending to be legally bound, hereby agree as follows:

SECTION 1
DEFINITIONS AND EXPLANATION OF TERMS

1.1 Definitions. When used in this Agreement, the following capitalized terms shall have the meanings set forth below:

1.1.1 "Actual Availability" has the meaning given such term in Section 4.3.3 or 4.3.4, as applicable.

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[2] We need to define in this space the names OUC, FMPA and KUA depending on which of them is signing the contract. The signatory company is defined in the preamble, and the other two should be defined here.

1.1.2 "Actual Capability" means the amount of Capacity the Facility is capable of producing in any given hour.

1.1.3 "AGC" means automatic generation control, which is the capability to make automatic adjustments to load change by generation through the use of a digital computer. This control is based on such factors as frequency, cost and tie line flows.

1.1.4 "Agreement" means this Power Purchase Agreement, including all appendices attached hereto and all amendments hereto that may be made from time to time.

1.1.5 "Alternate Resources" has the meaning given such term in Section 4.4.

1.1.6 "Ancillary Services" means ancillary services customarily provided by an electric generating facility, including voltage/VAR control, load following, regulation and frequency response, spinning reserve and non-spinning reserve.

1.1.7 "Annual Capacity Charge" means (i) [redacted] per kilowatt per month for that portion of the Initial Term before the end of the day of May 31, 2014 , (ii) [redacted] per kilowatt per month for that portion of the Initial Term after the beginning of the day June 1, 2014 and during the Extended Term, (iii) with respect to the first Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), (iv) with respect to the second Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), and (v) with respect to the third Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3); *provided, however,* that the Annual Capacity Charge shall be (i) increased by [redacted] per kilowatt per month for every [redacted] increase in the BOP Capital Cost Range that occurs pursuant to Sections 6.7.2(b) or 6.7.2(c) of the Ownership Agreement, (ii) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the BOP Capital Costs Range that occurs pursuant to Sections 6.7.2(b) and 6.7.2(c) of the

Ownership Agreement, (iii) increased by [redacted] per kilowatt per month for every [redacted] increase in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement, and (iv) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement.

1.1.8 "Annual Purchaser's Capacity Nomination" of the Purchaser means, during the first five Contract Years, [__] percent [__%][3] of the Demonstrated Capability, and thereafter, [__] percent [__%] of the Demonstrated Capability reduced by those amounts, if any, that Purchaser elects to subtract from the Capacity available to Purchaser pursuant to the process provided in Section 4.1.4 for the Customers jointly to make such elections.

1.1.9 "Availability Guarantee" has the meaning given such term in Section 4.3.1.

1.1.10 "Availability Incentive Payment" has the meaning given such term in Section 4.3.2.

1.1.11 "Bankruptcy" means, with respect to a Party, (i) an adjudication of bankruptcy or insolvency, or the entry of an order for relief, under any Bankruptcy Law with respect to such Party; (ii) the making by such Party of an assignment for the benefit of its creditors; (iii) the filing by such Party of a petition in bankruptcy or for relief under any Bankruptcy Law; (iv) the filing by such Party of an answer or pleading admitting or failing to contest the material allegations of any such petition; (v) the filing against such Party of any petition in bankruptcy or for relief under any Bankruptcy Law (unless such petition is dismissed within 90 days from the date of filing thereof); (vi) the appointment of a trustee, conservator or receiver for such Party or for all or substantially all of its assets (unless such appointment is vacated or stayed within 90 days of such appointment); or (vii) the taking by such Party of any action for its winding up or liquidation, or

[3] This percentage will be different for each Purchaser, being for OUC 80% of 65% and for each of KUA and FMPA 10% of 65%. The total of all percentages is 65%.

the consent by such Party to any of the actions described in clauses (i) through (vi) being taken against it.

1.1.12 "Bankruptcy Law" means any applicable bankruptcy or insolvency statute.

1.1.13 "Bond Legislation" shall mean the Junior Lien Resolution, the Senior Lien Resolution and the Master Note Resolution.

1.1.14 "BOP Capital Cost Range" has the meaning ascribed to the term in Section 6.7.1 of the Ownership Agreement.

1.1.15 "Business Day" means any day other than Saturday or Sunday on which commercial banks are authorized to open for business in Orlando, Florida.

1.1.16 "Capacity" means electric capacity

1.1.17 "Capacity Emergency" means, with respect to any hour, that any one or more of Purchaser's resources is unavailable due to a forced outage and the summation of such Purchaser's firm Capacity obligations exceeds the summation of such Purchaser's available resources.

1.1.18 "Capacity Payment" has the meaning given such term in Section 4.1.1.

1.1.19 "Change in Law" has the meaning given such term in Section 10.1.3.

1.1.20 "Collateral Documents" means, collectively, the Ownership Agreement, the Operating Agreement, the Interconnection Agreement, the Power Purchase Agreements of the other Customers, the long term lease of the Facility Site by OUC to and for the benefit of the Participants, the guarantee to be provided by an affiliate of Seller as contemplated in Section 16.3, and the agreement(s) pursuant to which Purchaser and/or the other Customers provide station service and other support services (including but not limited to demineralized water and cooling water supply) to Seller.

1.1.21 "Commencement Date" has the meaning given such term in Section 5.2.

1.1.22 "Commercial Operation Date" has the meaning ascribed to such term in Section 1.1.14 of the Operating Agreement.

1.1.23 "Confidential Information" has the meaning given such term in Section 26.

1.1.24 "Contract Year" means (i) the period commencing on the Commencement Date or, if Seller elects the option under Section 4.5(ii)(a), the later of the Commencement Date or Scheduled Commencement Date, and ending on the last day of the month in which the first anniversary date of the Commencement Date falls, and (ii) each 12-month period thereafter, except that for the 12-month period during which the expiration or termination date of this Agreement occurs, Contract Year shall mean the period commencing on the first day of such 12-month period and ending on such expiration or termination date.

1.1.25 "Customers" means collectively all of OUC, Kissimmee Utility Authority and Florida Municipal Power Agency (All Requirements Power Supply Project), or their permitted assigns.

1.1.26 "Delivered Energy" means, in respect of a period of time, the amount of Energy from the Facility or from Alternate Resources delivered by Seller to Purchaser at the Delivery Point for sale to Purchaser pursuant to this Agreement.

1.1.27 "Delivery Point" means (a) with respect to Energy delivered from the Facility, the high side of generator step-up transformer, as further described in the Interconnection Agreement, and (b) with respect to Energy delivered from Alternate Resources, any unconstrained point on the Grid.

1.1.28 "Demonstrated Capability" means the net Capacity of the Facility, determined by a periodic Capacity test, adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity.

1.1.29 "Dispute" has the meaning given such term in Section 18.

1.1.30 "Eastern Prevailing Time" or "EPT" means the time prevailing in the Eastern time zone of the United States of America.

1.1.31 "Effective Date" has the meaning given such term in Section 3.1.

1.1.32 "Eligible Collateral" has the meaning given such term in Section 15.1.1.

1.1.33 "Energy" means electric energy (expressed in megawatt-hours).

1.1.34 "Energy Payment" has the meaning given such term in Section 4.2.

1.1.35 "Equipment Breakdown" means a mechanical breakdown of equipment at the Facility that is not the result of a Force Majeure that is an act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted]; storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under Section 1.1.42 if such failure were directly experienced by the applicable Party.

1.1.36 "Equity Capacity" with respect to each Participant means that Participant's percentage share of the Capacity of the Facility corresponding to such Participant's ownership interest in the Facility.

1.1.37 "Event of Default" means any of the events listed in Sections 12.1 and 12.2.

1.1.38 "Facility" means the gas fired combined cycle electric generating unit to be located on the Facility Site and owned by the Participants, as further described in the Ownership Agreement.

1.1.39 "Facility Site" means the parcel of land in Orlando, Florida on which the Facility is to be located, as further described in Appendix A.

1.1.40 "FDEP" means the Florida Department of Environmental Protection or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.41 "FERC" means the Federal Energy Regulatory Commission or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.42 "Firm Transmission Service" means (a) electric transmission service designated firm under the open access transmission tariff of a transmission provider having an open access transmission tariff or (b) if purchased from a transmission provider that does not have an open access transmission tariff, electric transmission service sold by such transmission provider as firm transmission service and generally considered, pursuant to Prudent Utility Practice and FRCC requirements, to be substantially equivalent to the firm transmission service referenced in item (a) of this definition.

1.1.43 "Fixed Amount" has the meaning ascribed to such term in Section 6.7.1 of the Ownership Agreement.

1.1.44 "Force Majeure" as to a Party means each of the following events as affects the Facility: act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted] storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; shutdown of the Facility by a court order or Governmental Body not resulting from any action or inaction by the applicable Party; strike, lockout or labor difficulty affecting the SEC Site generally [redacted]; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under this provision if such failure were directly experienced by the applicable Party; or any other occurrence, nonoccurrence or set of circumstances, whether or not foreseeable, that is beyond the reasonable control of the applicable

Party and is not caused or exacerbated by the applicable Party's failure to follow Prudent Utility Practices.

1.1.45 "FRCC" means the Florida Reliability Coordinating Council or any successor organization.

1.1.46 "Fuel Supply Agent" has the meaning given such term in the Operating Agreement.

1.1.47 "Further Extension" has the meaning given such term in Section 2.3.

1.1.48 "Gas Delivery Point" shall have the meaning assigned to it in the Operating Agreement.

1.1.49 "Governmental Body" means any federal, state, local, municipal or other government; any governmental, regulatory or administrative agency, commission or other authority lawfully exercising or entitled to exercise any administrative, executive, judicial, legislative, police, regulatory or taxing authority or power; any court or governmental tribunal and any RTO, or any other entity, having control over the security and reliability of the Grid; NERC; and FRCC; *provided, however,* that Governmental Body shall not include any of OUC, KUA or FMPA, or any agency, court, commission, department or other such entity acting in its capacity as lender, guarantor or mortgagee.

1.1.50 "Grid" means (i) OUC's electric transmission system, or (ii) if ownership or control of and jurisdiction over OUC's electric transmission system is succeeded to by an RTO or other entity, the portion of the electric transmission system of that RTO or other successor entity that most closely resembles the OUC electric transmission system as it existed on the effective date of this Agreement.

1.1.51 "Guaranteed Output" means in any given hour the amount of Capacity (in MWh per hour) determined by adjusting the Demonstrated Capability to the prevailing ambient conditions in such hour and adjusting for degradation. The degradation adjustment shall be [redacted]

[redacted] The degradation adjustment shall [redacted]

1.1.52 "Indemnified Parties" has the meaning given such term in Section 16.1.1.

1.1.53 "Indemnifying Party" has the meaning given such term in Section 16.1.1.

1.1.54 "Interconnection Agreement" means that certain Interconnection Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.55 "Interconnection Meters" has the meaning given such term in Section 8.2.

1.1.56 "Junior Lien Resolution" shall mean the OUC resolution duly adopted on May 16, 1998, as supplemented and amended, authorizing the issuance of OUC's Water and Electric Subordinate Revenue Bonds.

1.1.57 "Lender" has the meaning such term in Section 12.3.

1.1.58 "Law" means any constitution, charter, act, statute, law, ordinance, code, rule, regulation or other applicable judicial, legislative or administrative action of any Governmental Body or any judicial or administrative interpretation thereof.

1.1.59 "Market Price" shall mean the price established by Seller, or negotiated and agreed upon by the Parties, as the case may be, upon Seller's election pursuant to Section 2.3 with respect to any Further Extension, which shall become the Annual Capacity Charge for Capacity to be delivered by Seller during such Further Extension consistent with all other terms and conditions of this Agreement.

1.1.60 "Master Note Resolution" shall mean the OUC resolution duly adopted on August 25, 1998, as supplemented and amended, authorizing the issuance of OUC's Water and Electric Revenue Application Notes.

1.1.61 "Meters" means the Interconnection Meters and/or Customers' check-meters, as applicable.

1.1.62 "Minor Maintenance" shall mean maintenance events lasting not greater than [redacted] per occurrence, which have been scheduled and for which Purchaser and the other Customers have given consent in accordance with Section 6.4.

1.1.63 "MMBtu" means one million British thermal units, where one British thermal unit is the amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit from sixty (60) degrees Fahrenheit.

1.1.64 "MW" means megawatt.

1.1.65 "MWh" means megawatt-hour.

1.1.66 "NERC" means the North American Electric Reliability Council or successor organization.

1.1.67 "Non-Performing Party" has the meaning given such term in Section 11.1.

1.1.68 "Notice of Intent to Terminate" has the meaning given such term in Section 12.3.

1.1.69 "Off-Peak Period" means all the days of any given Contract Year other than the Peak Period days.

1.1.70 "Operating Agreement" means that certain Operating Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.71 "Operating Period" means the period from the beginning of the first Contract Year until the end of the last Contract Year.

1.1.72 "OUC" means Orlando Utilities Commission.

1.1.73 "OUC Interconnection Facilities" means the modifications to the Stanton Substation reasonably required for the receipt and

delivery of Energy from the Facility onto the Grid consistent with Prudent Utility Practice.

1.1.74 "Ownership Agreement" means that certain Stanton Energy Center Combined Cycle Unit Construction and Ownership Participation Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.75 "Participant" or "Participants" mean individually or collectively Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency (All Requirements Power Supply Project) and Seller.

1.1.76 "Parties" has the meaning given such term in the first paragraph of this Agreement.

1.1.77 "Peak Period" means for any given Contract Year the periods that include the days from January 1 through March 15, inclusive, May 15 through September 15, inclusive, and December 15 through December 31, inclusive.

1.1.78 "Permit" means any permit, license, approval, consent, waiver, authorization or other requirement in connection with the Project required from any Governmental Body under applicable Law.

1.1.79 "Person" means any individual, partnership, corporation, limited liability company, association, business, trust, Governmental Body or other entity.

1.1.80 "Planned Major Maintenance" means the Gas Turbine (GT) Combustor Inspection, the GT Hot Gas Path Inspection, and the GT Major Inspection, as these inspections are defined in the maintenance agreement with the GT vendor.

1.1.81 "Power Purchase Agreements" means this Agreement and those certain similar power purchase agreements between Seller and the other Customers respecting the delivery of Capacity and Energy from Seller's ownership share of the Capacity and Energy of the Facility.

1.1.82 "Prime Rate" means the prime rate of interest as published from time to time in the Wall Street Journal or such other comparable successor publication as the Participants may agree upon. The Prime Rate shall be calculated on the basis of a 365-day year for the actual number of days that a payment, reimbursement or adjustment, as the case may be, has not been made.

1.1.83 "Project" means the Facility, the Facility Site and all other appliances, parts, instruments, appurtenances, accessories and other property that may be incorporated or installed in, or otherwise become part of, any of the foregoing.

1.1.84 "Prudent Utility Practice" means any of the practices, methods and acts engaged in, or approved by, a significant portion of the electric utility industry in the United States [redacted] or any of the practices, methods and acts, which, in the exercise of reasonable judgment in light of the facts known, or that reasonably should have been known, at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with applicable Laws, reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods and acts generally accepted in the United States and having due regard for current editions of the National Electrical Safety Code, the National Electric Code and other applicable electrical, safety and maintenance codes and standards, manufacturers' warranties and applicable Laws.

1.1.85 "Request for Energy" or "Schedule" means a request for the delivery of Energy made by Purchaser and the other Customers in accordance with the process provided in Section 6 and Appendix B for the Customers jointly to Schedule Energy, and any adjustments thereto made in accordance with Appendix B.

1.1.86 "RTO" means a regional transmission organization.

1.1.87 "Scheduled Commencement Date" means the date that is twenty-four (24) months after the receipt of the Site Certification and all other Permits to be obtained by Purchaser that are necessary for Seller to commence construction, as such date may be extended under the provisions of Section 5.1, but in no event earlier than October 1, 2003.

1.1.88 "Scheduled Maintenance" means the removal of the Facility or a component thereof from service (which removal reduces the capability of the Facility to operate) to perform maintenance, overhaul, inspection, testing or repair work, as contemplated in Section 6.4.

1.1.89 "SEC Site" means the parcel of land in Orlando, Florida on which the fossil fired generating stations Stanton Unit # 1 and Stanton Unit #2 are located, including the parcel of land on which the Facility is to be located.

1.1.90 "Seller" has the meaning given such term in the first paragraph of this Agreement.

1.1.91 "Senior Lien Resolution" shall mean the OUC resolution duly adopted on June 3, 1993, as supplemented and amended, authorizing the issuance of OUC's Water and Electric Revenue Bonds.

1.1.92 "Site Certification" means (i) the final approval by the applicable Governmental Body of the initial need for power determination and site certification permit applications pursuant to the Florida Electrical Power Plant Siting Act, and (ii) the receipt of the air construction (Prevention of Significant Deterioration) permit by OUC issued by FDEP pursuant to the delegated authority of the United States Environmental Protection Agency under the Clean Air Act Amendments of 1977.

1.1.93 "Technical Limits" means the limits and constraints relating to the operation and maintenance of the Facility, as described in Appendix A.

1.1.94 "Termination Payment" means the payment to be paid by a Defaulting Party to the Non-Defaulting Party under in Section 12.5.1.

1.1.95 "Test Energy" means (i) Energy produced by the Facility during testing of the Facility prior to the Commencement Date; and (ii) Energy produced by the Facility during periodic tests of the Facility's Capacity output capability following the Commencement Date.

1.2 Rules of Construction. In this Agreement, unless the context otherwise requires, the singular shall include the plural, the masculine shall include the feminine and neuter, and vice versa. The terms "include," "includes" and "including" shall be deemed to be followed by the words "without limitation." The term "month" refers to a calendar month, and any period measured by a "month" from a reference date refers to the period beginning on such reference date and ending on the same date of the next succeeding calendar month or, if no such date exists in the next succeeding calendar month, the last day of such next succeeding calendar month. References to a Section, Table or Appendix shall be references to a Section of, Table of or Appendix to this Agreement unless specifically stated otherwise. A reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented and restated through the date as of which such reference is made. The term "or" is not exclusive, the term "shall" is mandatory and the term "may" is permissive. In the event that any index or publication referenced in this Agreement ceases to be published, each such reference shall be deemed to be a reference to a successor or alternate index or publication reasonably agreed by the Parties. Both Parties acknowledge that each was actively involved in the negotiation and drafting of this Agreement and that no law or rule of construction shall be raised or used in which the provisions of this Agreement shall be construed in favor of or against either Party because one is deemed to be the author thereof.

1.3 Consents. Whenever the consent or approval of either Party is required under this Agreement, such consent or approval shall not be unreasonably withheld, unless this Agreement provides that such consent or approval is to be given by such Party at its sole or absolute discretion or is otherwise qualified.

SECTION 2
TERM OF AGREEMENT

2.1 Initial Term.

2.1.1 This Agreement shall become effective as set forth in Section 3.1, and shall remain in full force and effect, subject to the early termination provisions set forth herein, through the later of (i) the last day of the month in which the tenth (10^{th}) anniversary of the Scheduled Commencement Date occurs or (ii) the last day of the month in which the tenth (10^{th}) anniversary of the Commencement Date occurs (the "Initial Term").

2.1.2 Notwithstanding the provisions of Section 2.1.1, the Initial Term shall terminate on (a) November 30, 2013 if Section 2.1.1 yields an end date falling between December 1, 2013 and April 30, 2014, inclusive, or (b) November 30, 2014 if Section 2.1.1 yields an end date that falls on or after May 1, 2014.

2.2 Extension of Initial Term. The Initial Term shall be automatically extended an additional five (5) years from the end of the Initial Term ("Extended Term"); *provided, however*, that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of the Initial Term by providing written notice of such election to Seller no later than the date that is three (3) years prior to the end of the Initial Term.

2.3 Extensions of Extended Term. The Extended Term shall be automatically extended three (3) successive periods of five (5) years each from the end of the Extended Term (the "Further Extensions"); *provided, however*, that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of any of (i) the Extended Term, (ii) the first Further Extension, or (iii) the second Further Extension, by providing written notice of such election to Seller no later than the date that is, respectively, three (3) years prior to the end of the Extended Term, three (3) years prior to the end of the first Further Extension, or three (3) years prior to the end of the second Further Extension, as the case may be; *provided, further*, that with respect to each Further Extension, Seller shall have the right to establish the Annual Capacity Charge for such Further Extension based on Seller's then-current assessment of market conditions by providing Purchaser written notice of the new proposed Annual Capacity Charge no later than the date that is three and one-half (3 1/2) years prior to the date that such Further Extension period is scheduled to begin, subject to Purchaser's right to request that Seller negotiate in good faith to agree on any other price that Purchaser believes in good faith reflects current market conditions.

2.4 Survival. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to satisfy the terms and conditions of this Agreement and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing either Party pursuant to this Agreement, repayment of principal and interest associated with security funds, and the indemnifications specified in this Agreement.

SECTION 3
CONDITIONS PRECEDENT

3.1 Condition Precedent to Effectiveness. The Parties agree and acknowledge that this Agreement shall be effective only upon: (i) the execution and delivery of the Ownership

Agreement and the Operating Agreement and all other Collateral Documents; and (ii) the acknowledgment of the Participants' satisfaction of the foregoing condition and the accuracy of the cross-references to the Collateral Documents contained in this Agreement.

3.2 Conditions Precedent to Obligations. Notwithstanding any provisions of this Agreement to the contrary, the obligations of the Parties to this Agreement shall be subject to the fulfillment of each of the conditions (or the waiver in writing of such conditions by the respective Party or Parties) set forth in Article 8 of the Ownership Agreement.

SECTION 4
SALE AND PURCHASE

4.1 Capacity Delivery and Payment. Subject to the terms and conditions of this Agreement, during the Operating Period, Seller agrees to deliver and sell to Purchaser and Purchaser agrees to receive and purchase from Seller up to __ percent [__%][4] of the Actual Capability of the Facility in accordance with the following provisions:

4.1.1 The Capacity payment (the "Capacity Payment" or "CP") in respect of each month during the Operating Period shall be an amount equal to: the product of the Annual Purchaser's Capacity Nomination (expressed in kilowatts) multiplied by the Annual Capacity Charge. For any partial month during the Operating Period, the Capacity Payment shall equal the amount determined pursuant to the formula set forth in the preceding sentence multiplied by a fraction, the numerator of which is the number of days of such partial month within the Operating Period, and the denominator of which is the total number of days in such month. If the Annual Purchaser's Capacity Nomination changes during a month, then the Capacity Payment for such month shall be equal to the product of the Annual Capacity Charge multiplied by the sum of the two results obtained: (i) first by multiplying the old Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) prior to the time of the change over the total number of days in the month; and (ii) second by multiplying the new Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) after the time of the change over the total number of days in the month. The Capacity Payment shall be paid by Purchaser to Seller in

[4] This percentage will vary among Customers. For OUC, it will be 80% of 65%, and for each of KUA and FMPA it will be 10% of 65%. The total will be 65%.

accordance with Section 9.1. Notwithstanding the above, if during the first three (3) months of the Operating Period any Governmental Body shall prohibit the Facility from operating because of Seller's failure to obtain, prior to the Commencement Date any Permit required by Law for Seller to operate the Facility, then Purchaser's obligation to make Capacity Payments shall be suspended until the earlier of: (i) the lifting of such prohibition; or (ii) the date that is three (3) months after the Commencement Date.

4.1.2 The initial Demonstrated Capability of the Facility shall be established in accordance with the Capacity testing procedure set forth in Appendix C. Following the first anniversary of the Commencement Date, Seller shall perform Capacity tests [redacted], pursuant to the testing procedures set forth in Appendix C, during the Summer and Winter periods as defined by FRCC; *provided, however*, that Seller shall be entitled to a [redacted] period of maintenance that does not affect calculation of Actual Availability of the Facility (which period shall be prior to any such Capacity test from 9 p.m. Friday to 7 a.m. Monday, unless OUC, in its sole discretion, agrees otherwise). In addition, Seller may retest when a repair or modification of the Facility, or a corrected or improved operational or maintenance activity, results in an increase in the Capacity of the Facility (including adjustments made during initial shakedown), provided that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) is at least one hundred and one percent (101%) of the last Demonstrated Capability test amount. Should any test or retest conducted pursuant this Section 4.1.2 indicate that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) has changed by an amount equal to or greater than one percent (1%) of the last Demonstrated Capability test amount, the Demonstrated Capability shall be reset at such actual full load output for purposes of determining the Capacity Payment as of the time the test is completed; *provided, however*, that if the test is performed during a Force Majeure event and such Force Majeure event resulted in the reduction of the Demonstrated Capability, the Capacity Payment shall not be reduced thereby until the end of the [redacted] period described in the last paragraph of Section 4.1.

4.1.3 Seller shall conduct additional tests as required by the FRCC or as requested by Purchaser pursuant to Purchaser's legal or contractual obligations with third parties; *provided, however*, such additional tests shall

be for informational purposes and shall not be used to reset the Demonstrated Capability or otherwise determine the Capacity Payment under this Agreement.

4.1.4 Beginning with the sixth (6^{th}) Contract Year and ending with the tenth (10^{th}) Contract Year, the Customers shall have the irrevocable right to jointly reduce the total of their combined Annual Purchaser's Capacity Nominations, for the remainder of the Initial Term and any Extended Term or Further Extensions, by either twenty-five (25) MW or fifty (50) MW (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) per year; *provided, however*, that such combined total of the Annual Purchaser's Capacity Nominations may not be reduced by more than 200 MW in the aggregate. Purchaser must give Seller notice of any such reduction elected by Purchaser not later than three (3) years prior to the commencement of the Contract Year in which such reduction shall occur; *provided, however*, that such notice shall be effective if and only if either it is made jointly with the other Customers or the other Customers give Seller a similar notice under their respective Power Purchase Agreements with all such notices together satisfying the above criteria; *provided, further*, that such notices shall specify any changes in the percentage of the Annual Purchaser's Capacity Nomination to be purchased by Purchaser under Section 4.1.1 and by the other Customers under the corresponding provisions of their respective Power Purchase Agreements.

Notwithstanding the foregoing provisions of this Section 4.1, if and to the extent that a Force Majeure event affects Seller's ability to deliver and sell to Purchaser the Capacity of the Facility or any portion thereof, Seller shall be excused from any delay in performing or failure to perform any or all of such obligations (and in this regard, the Parties shall follow the procedures contemplated in Section 11.1); *provided, however*, that notwithstanding such reduction or elimination of the Actual Capability of the Facility, Purchaser shall continue to pay Seller the full Capacity Payment attributable to the [redacted] following the date of Seller's notification to Purchaser of any such Force Majeure effect; *provided, further*, that if the effect of a Force Majeure event lasts for longer than [redacted], then Purchaser shall not be required to make Capacity Payments attributable to any continued period of Force Majeure declaration after the end of such [redacted] period, but Purchaser must resume making Capacity Payments when Seller declares the Force Majeure period over and resumes its obligation for delivery of Energy under this Agreement; *and provided, further*, that the Capacity Payment relief contemplated in the immediately preceding clause shall not apply if the Force Majeure event affecting Seller resulted from a failure of Purchaser or another Customer to fulfill its obligations under this Agreement or

any of the Collateral Documents; *and provided, further,* that a Force Majeure event that affects Purchaser's ability to receive Energy from the Facility shall not excuse Purchaser's obligation to make Capacity Payments, except solely to the extent provided for in Section 5.1.3 if and to the extent such provision is applicable.

4.2 Energy Delivery and Payment. Subject to the terms and conditions of this Agreement and, in particular, subject to the provisions of Section 6 and Appendix B, Seller shall sell and deliver, and Purchaser shall purchase and receive, during the Operating Period, Energy requested by Purchaser in a Request for Energy, as well as Energy generated by associated ramp up and ramp down of the Facility and Test Energy; *provided, however,* that Purchaser shall not be required to make any payments for Test Energy produced prior to the Commencement Date. The Customers shall pay for and supply all fuel associated with the Customers' Request for Energy in accordance with the provisions of Section 3.2 of the Operating Agreement. The Energy payment (the "Energy Payment" or "EP") in respect of each month shall be the sum of four (4) components: a variable O&M component for operation on natural gas, a variable O&M component for operation on fuel oil, a start-up component, and a fuel component for Energy delivered from Alternate Resources. The components of the Energy Payment shall be calculated as follows:

4.2.1 Variable O&M Component—Natural Gas. The variable O&M component for operation on natural gas shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} [(DENG_{ij} \times VOMR) + HVOM_{ij}]$$

Where:

$DENG_{ij}$ is Delivered Energy in MWh (other than Test Energy prior to the Commencement Date) from the Facility produced with natural gas during hour j of day i; *provided, however,* that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with natural gas; and

VOMR is the variable O&M rate (in $/MWh), which shall be [redacted]; and

HVOM is the hourly variable O&M rate (in $ per hour) as determined from Table A and its accompanying Notes applicable

for hour j of day i during which the Facility is operating on natural gas and which is applicable only when $DENG_{ij}$ is > 0.

Table A

Hourly Variable O&M Charges for Operation on Natural Gas

Annual On-Line Factor	Combined Hourly Variable O&M Rate (in $ per hour) for all Customers (see Notes below)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table A:

1) The Hourly Variable O&M Rate in Table A represents the rate applicable for the Annual Purchaser's Capacity Nominations of all Customers. The actual Hourly Variable O&M Rate for Purchaser for an hour in a particular Contract Year shall equal the product of the applicable rate from the table for such Contract Year multiplied by the ratio of Purchaser's portion of the Request for Energy for such hour over the total Request for Energy for such hour.

2) The Hourly Variable O&M Rate for a Contract Year shall be interpolated between the values shown in Table A when the Annual On-Line Factor for the previous Contract Year falls between the specific

percentages shown on Table A. For example, with respect to an Annual On-Line Factor of [redacted] the Hourly Variable O&M Rate shall be [redacted].

3) The dollar amounts shown in Table A are expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

4) The dollar amounts in Table A represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Customers under the Power Purchase Agreements. If Purchaser and the other Customers elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table A shall be proportionately reduced commensurate with such Capacity reduction.

5) The Annual On-Line Factor shall be calculated for each Contract Year, as follows:

Annual On-Line Factor = SH/ (PH – OH)

Where:

SH is the number of hours that the Customers Schedule and Seller delivers Energy in a Contract Year; and

PH is the number of hours in a Contract Year; and

OH is the number of hours in a Contract Year during which (i) the Facility is unavailable due to a forced outage or due to a maintenance outage that Seller has scheduled pursuant to Section 6.4 or, if applicable, that is a [redacted] under Section 4.1.2, and (ii) Seller does not deliver from an Alternate Resource.

6) For the first Contract Year, all monthly Energy billings will be made assuming an Annual On-Line Factor of [redacted]. The rate shall be determined annually for each Contract Year based on the Annual On-Line Factor for the previous Contract Year. At the end of each Contract Year, the Annual On-Line Factor for such Contract Year shall be calculated and the Hourly Variable O&M charges for such

Contract Year shall be recalculated using such Annual On-Line Factor for such Contract Year. A true-up payment or refund shall be made to adjust the amounts collected by Seller from Purchaser during each Contract Year to the amount computed by Seller using such Annual On-Line Factor for such Contract Year. Any true-up payments shall be included on an invoice as soon as reasonably practicable following the end of the applicable Contract Year.

4.2.2 Variable O&M Component—Fuel Oil. The variable O&M component for operation on fuel oil when firing the gas turbines shall be calculated as follows:

$$\sum_{i=\text{ Days in the Month}} \sum_{j=\text{ Hours in the Day}} [(DEFO_{ij} \times VOMRFO) + HVOMFO_{ij}]$$

Where:

$DEFO_{ij}$ is Delivered Energy (other than Test Energy prior to the Commencement Date) produced with fuel oil during hour j of day i; provided that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with fuel oil; and

VOMRFO is the variable O&M rate (in $/MWh) for Energy produced with fuel oil, which shall be [redacted] subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations); and

HVOMFO is the hourly variable O&M rate (in $ per hour) for hour j of day i during which the Facility is Operated on fuel oil, which rate shall be [redacted], subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations), and which is applicable only when $DEFO_{ij}$ is > 0.

4.2.3 Start-up Component. The start-up component shall be calculated as follows:

GTS x SUR

Where:

GTS is the number of gas turbine starts required to meet a Request for Energy (other than for Test Energy prior to the Commencement Date) where the amount of Energy delivered from any single gas turbine increases from zero to an amount greater than zero; *provided, however*, that the calculation of GTS shall not include: (i) any starts required to resume delivery to Purchaser due to an interruption caused by a forced outage, or (ii) any starts initiated by Seller in order to make third party sales in any given hour where the Facility would otherwise not have been started in such hour to meet a Request for Energy.

SUR is the Start-up Rate (in $ per start) for each gas turbine as determined from Table B below and its accompanying Notes:

TABLE B

Start-Up Rates

Cumulative Number of Start-ups per Gas Turbine per Contract Year	Combined Start-up Rate per Start per Gas Turbine for all Customers (see Notes)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table B:

1) The SUR in Table B represents the rate applicable to all Customers for each start-up during a Contract Year. [redacted]

[redacted] and the combined rate among all Customers participating in each subsequent start-up during such Contract Year shall be as identified in the Table B. The actual SUR for Purchaser (in $ per start) for any such start-up shall equal the quotient of the applicable rate from the Table B divided by the number of Customers participating in the Request for Energy that requires the start-up (and in which Purchaser is one of those Customers); *provided, however,* Purchaser will not have to pay for start-ups in which it does not participate.

2) The SUR is expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

3) The dollar amounts in Table B represent the charge for sixty-give percent (65%) of the Facility's Capacity being sold to Participants under the Power Purchase Agreements. If the Participants elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table B shall be proportionately reduced commensurate with such Capacity reduction.

4.2.4 O&M Rate Adjustment. The rates in Sections 4.2.1, 4.2.2 and 4.2.3 shall be increased or decreased based on good faith negotiation of the Parties (in accordance with Section 18) to reflect and include any actual increase or decrease in Seller's costs of operating the Facility that is caused by any mutually agreed-upon modification or design change or any actual increase or decrease in Purchaser's or another Customers' charges for providing any services to Seller.

4.2.5 Energy Payment for Delivery from Alternate Resources.

4.2.5.1 If Seller elects to deliver Energy from Alternate Resources pursuant to Section 4.4, then the variable O&M component and the start-up component of the Energy Payment shall be calculated in accordance with Sections 4.2.1 and 4.2.3, respectively, for such Alternate Resource Energy as if it were delivered from the Facility. In addition, the fuel component for the Energy delivered from Alternate Resources shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} (MDE_{ij} \times HR_{ij} \times FRP_{ij})$$

Where:

MDE_{ij} = Scheduled Energy in MWhs delivered from an Alternate Resource during hour j of day i;

when the Facility is unavailable, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs,

when the Facility is available, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs; and

FRP_{ij} = the fuel rate proxy for an hour calculated in dollars per MMBtus in accordance with the applicable provisions of either Section 4.2.5.2 or 4.2.5.3.

4.2.5.2 If the Fuel Supply Agent has not already scheduled the transportation of gas to the Facility to meet the Customers' Schedules for the hour during which Seller elects to deliver the Scheduled Energy from Alternate Resources, then following notification from Seller of its election to deliver the Scheduled

Energy from Alternate Resources, Seller shall be obligated to obtain the necessary quantities of gas and necessary gas transportation capacity to accommodate any portion of the Schedule that Seller has elected to satisfy from Alternate Resources. During periods that Seller elects to deliver Energy from Alternate Resources, the Fuel Supply Agent shall make available transportation capacity, within constraints of the pipeline tariffs and operational procedures in effect at the time and at no additional cost to the Fuel Supply Agent, in the amount determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtus) shall be equal to the sum of: (i) [redacted]; and (ii) the applicable firm gas transportation variable cost associated with deliveries to the Facility under such Participant's firm transportation agreement(s). All risks of gas supply and transportation interruption to accommodate deliveries of Energy from Alternate Resources shall be borne by Seller.

4.2.5.3 If the Fuel Supply Agent has already scheduled the transportation of gas to the Facility to meet the Customers' Schedules by the time Seller notifies Purchaser of Seller's election to deliver the Scheduled Energy from Alternate Resources, then at Seller's election:

(i) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to revise its scheduled transportation of gas to the Facility to provide for the delivery of the gas to Seller at any alternate delivery point designated by Seller that is available under the Customers' firm transportation agreement(s). The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time, and the Fuel Supply Agent shall not be required to incur any additional cost as a result of the revision of the schedule of

transportation of gas to the alternate delivery point. The amount of scheduled transportation of gas to be delivered to the alternate delivery point shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtu) shall [redacted]; or

(ii) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to remarket to third parties the gas that has been scheduled for delivery to the Facility on the best terms possible under the circumstances. The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time. The amount of scheduled transportation of gas to be remarketed to third parties shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in from paragraph 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has directed the Fuel Supply Agent to remarket the gas under these circumstances, the FRP (in $ per MMBtu) shall be [redacted].

4.3 Availability Guarantee.

4.3.1 Seller guarantees that the Actual Availability of the Facility for [redacted] of each Contract Year will equal or exceed [redacted] ("Availability Guarantee"); *provided, however*, that (i) the [redacted] of operation following the Commencement Date shall be excluded from the Availability Guarantee, (ii) if and to the extent that a Force Majeure event affects Seller's ability to achieve the Availability Guarantee, other than in the case of Equipment Breakdown, Seller shall be excused from the Availability Guarantee (and in this regard the Parties shall follow the procedures contemplated in Section 11), and (iii) to the extent that the Facility is fired with fuel oil in excess of [redacted] per combustion turbine unit in any Contract Year in order to meet Purchaser's Request for Energy, then for every additional [redacted] that the Facility is fired using fuel oil, the lower end of the Availability Guarantee range, and the factors [redacted] in Sections 4.3.5.1 and 4.3.5.2, shall be reduced by [redacted] each, which reductions shall remain in effect until the next Planned Major Maintenance occurs. If either combustion turbine is not fired on oil during any Contract Year for the same number of hours as the other combustion turbine, then for purposes of calculating the adjustment to the Availability Guarantee, each combustion turbine will be deemed to have been fired on oil during such Contract Year for a number of hours that is equal to one half of the summation of the number of hours that each combustion turbine was actually fired on oil during such Contract Year.

4.3.2 In each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, Seller shall be entitled to an availability incentive payment from Purchaser ("Availability Incentive Payment") equal to (a) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Peak Period, and/or (b) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Off-Peak Period.

4.3.3 The Actual Availability for the Peak Period of each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted]

[redacted] or the last Contract Year, shall be calculated as follows and then rounded up or down to the nearest tenth of a percentage point [redacted]; *provided, however*, that such Actual Availability shall not exceed one (1.00):

Actual Availability = (PH-OH -EDH+EMH+ARDH)/PH

Where: "PH" (or "Period Hours") shall equal the hours in the Peak Period of such calendar year;

"OH" (or "Outage Hours") in the Peak Period of such Contract Year means all hours the Facility is unavailable for operation; *provided, however*, that OH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day;

"EDH" (or "Equivalent Derated Hours") in the Peak Period of such Contract Year means the summation of EDH for each hour during the Peak Period; *provided, however*, that EDH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day. In each hour for which the EDH of such hour must be calculated, EDH for the hour will equal (Guaranteed Output - Actual Capability)/Guaranteed Output;

"EMH" (or "Excused Maintenance Hours") shall equal hours that Seller has scheduled maintenance on the Facility in the Peak Period of such calendar year pursuant to Section 6.4 and, if applicable, the [redacted] of pre-testing maintenance allowed prior to a Capacity test under Section 4.1.2; *provided, however*, that in any hour EMH must be zero if there is no Outage Hour in such hour; and

"ARDH" (or "Alternate Resource Delivery Hours") shall equal the number of hours that Seller delivers Energy to Purchaser from Alternate Resources in the Peak Period of such Contract Year to fully or partially make up for shortfalls caused by Facility outages or derates. Seller will not receive any credit for ARDH in any entire day unless Seller is able to deliver at least partial Energy in

each hour of such day that Purchaser Schedules Energy, in which case Seller will receive ARDH credit for each hour of the day based on the lowest ratio during any hour of such day of Delivered Energy to Scheduled Energy.

4.3.4 The Actual Availability for the Off-Peak Period of each Contract Year shall be calculated in a fashion similar to Section 4.3.3, substituting "Off-Peak Period" for "Peak Period" where it appears in Section 4.3.3.

4.3.5 In the event that the Actual Availability during the Peak Period or Off-Peak Period, or both, of any given Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, is less than the lower end of the Availability Guarantee range, then Purchaser shall be entitled to receive availability damages ("Availability Damages") from Seller as Purchaser's sole and exclusive remedy for Seller's failure to delivery Capacity and Energy from the Facility due to the unavailability of the Facility.

4.3.5.1 The Availability Damages for the Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Peak Period of any Contract Year = [redacted]

4.3.5.2 The Availability Damages for the Off-Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Off-Peak Period of any Contract Year = [redacted]

4.3.5.3 In both of Sections 4.3.5.1 and 4.3.5.2, the factors [redacted] and [redacted] shall be adjusted for the use of fuel oil pursuant to Section 4.3.1(iii), if applicable.

4.3.6 As soon as reasonably practicable after the first month following the Commencement Date, and each month thereafter, Seller shall submit to

Purchaser a statement setting forth in reasonable detail the actual availability of the Facility during the prior month, including the underlying availability data.

4.3.7 As soon as reasonably practicable following each Contract Year, Seller shall submit to the Purchaser a statement setting forth the Actual Availability for the preceding Contract Year together with a calculation of the net amount of any Availability Incentive Payment due to Seller or Availability Damages due to the Purchaser for the preceding Contract Year based on the foregoing calculations, as applicable, with respect to the Peak Period and Off-Peak Period of such Contract Year. Within ten (10) Business Days of (a) receipt of such statement, Purchaser shall pay any Availability Incentive Payment due to Seller by wire transfer in immediately available funds, or (b) transmittal of such statement, Seller shall pay any Availability Damages due to Purchaser by wire transfer in immediately available funds.

4.4 Alternate Resources. In any hour in which the Facility is unavailable, Seller may continue to make deliveries of Energy in the full amount Scheduled by Purchaser from non-Facility sources (including, but not limited to, generating units on Seller's or its Affiliates' systems and Energy purchases available to Seller) ("Alternate Resources") to replace the Energy that would have been provided by the unavailable Facility. In any hour in which the Facility is available, Seller may choose to make deliveries of Energy in the full amount Scheduled by Purchaser, or any portion thereof, from Alternate Resources to replace the Energy that would have been provided by the available Facility; *provided, however*, that if the Facility is available, Seller must maintain the Facility on-line and committed at least at the Facility's minimum load, and Purchaser may Schedule spinning reserves from the Facility, all in accordance with Appendix B. Seller must deliver Energy from Alternate Resources to Purchaser at an unconstrained point on the Grid, and if Seller is making such delivery at a time when the Facility is unavailable, then Seller will purchase Firm Transmission Service for such delivery to the extent that such Firm Transmission Service is available for the Alternate Resource Energy from the point of its acquisition by Seller to the unconstrained point on the Grid. In utilizing Alternate Resources, Seller shall comply with the notice requirements of Section 3 of Appendix B.

4.5 Purchaser's Right to Capacity and Energy. During the Operating Period, Purchaser shall have the first call to purchase Seller's share of the Capacity and Energy generated by, and Ancillary Services associated with, the Facility (other than the reductions in Capacity elected jointly by the Customers pursuant to Section 4.1.4); *provided, however*, that (i) subject to Purchaser's right to Capacity and Energy under this Agreement and the Operating Agreement, Seller may make sales of any Capacity and Energy generated by, and Ancillary Services associated

with, Seller's Equity Capacity when such Capacity and Energy is not Scheduled by Purchaser, and (ii) in the event that Seller determines that the Facility is capable of delivering Energy to the Grid prior to the Scheduled Commencement Date, Seller shall have the option of either (a) utilizing the Capacity and Energy generated by, and Ancillary Services associated with, its percentage ownership share of the Facility prior to the Scheduled Commencement Date for sales to third parties by delivering written notice of its election of this option thirty (30) days prior to the anticipated Commercial Operation Date, in which event Purchaser shall not make Capacity Payments until the later of the Scheduled Commencement Date or the Commencement Date, or (b) initiating delivery of Capacity and Energy to Purchaser under this Agreement on the Commencement Date. If Seller makes sales of either or both Capacity and Energy to third parties under Section 4.5(ii)(a) at a time when the Scheduled Commencement Date has passed but the Commencement Date has not yet occurred, then Seller will pay to Purchaser the portion, if any, of the proceeds of such sales that Seller actually receives.

SECTION 5
SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY

5.1 Scheduled Delivery.

5.1.1 Seller anticipates that, the Facility will achieve the Commencement Date by the Scheduled Commencement Date and shall be fully capable of reliably producing the power and Energy to be provided under this Agreement to Purchaser at the Delivery Point; *provided, however*, that if and to the extent that a Force Majeure event affects Seller's ability to timely comply with the foregoing guarantee, the Scheduled Commencement Date shall be extended by the amount of time Seller reasonably needs to remedy the effects of the Force Majeure that prevented Seller's performance (and in this regard, the Parties shall follow the procedures contemplated in Section 11).

5.1.2 In the event that Seller fails to achieve the Commencement Date by the date that is two (2) years after the Scheduled Commencement Date, then either (i) Seller shall have the right to simultaneously terminate all of the Power Purchase Agreements by delivering written notice of such election to Purchaser and the other Customers ("Seller's Termination Notice"), or (ii) Purchaser may terminate this Agreement, if and only if each of the other Customers also terminates contemporaneously its respective Power Purchase Agreement for the same reason, by delivering written notice of such election to Seller (collectively, together with the other Customers' similar notices, "Purchasers' Termination Notices"). Within ten (10)

Business Days of the date of Seller's Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Seller's Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2. Within ten (10) Business Days of the date of Purchasers' Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Purchasers' Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2.

5.1.3 In the event that Seller's failure to achieve the Commencement Date by the Scheduled Commencement Date is attributable to, in whole or in part, the failure of any Customer to meet any of their respective obligations under this Agreement or their respective Power Purchase Agreements or the Collateral Documents, then (a) the Scheduled Commencement Date shall be extended for such period of Purchaser's or such other Customer's failure, and (b) Purchaser shall make Capacity Payments (assuming a Demonstrated Capability of [redacted] MW and an Availability Performance of [redacted] for the period affected by the delay) beginning as of the initial Scheduled Commencement Date (without any extension); *provided, however*, that Purchaser shall not be required to make any Capacity Payments under this Section 5.1.3 to the extent the delay in achieving the Scheduled Commencement Date is attributable to the concurrent failure of Purchaser or such other Customers and Seller (where such concurrent failures are not co-extensive, such relief from Capacity Payments shall apply only during the period of time that Seller's failure to meet its obligations contributed to the delay); *provided, further*, that in the event Purchaser's failure to meet its obligation was the result solely of a Force Majeure event that prevented Purchaser's timely completion of such obligation, then Purchaser will be excused from having to make Capacity Payments as contemplated in Section 5.1.3(b) for [redacted] after the Scheduled Commencement Date (without benefit of any extension thereof allowed under this Agreement), but if the Commencement Date does not occur within such [redacted]

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[5] This number will vary among Participants, but all numbers will together total [redacted].

[6] This number will vary among Participants, but all numbers will together total [redacted].

period, then Purchaser shall recommence making Capacity Payments starting at the beginning of the [redacted] after the Scheduled Commencement Date and thereafter continue making Capacity Payments as contemplated in Section 5.1.3(b).

5.2 Conditions to Commencement. Seller will notify Purchaser of the date when the Facility has achieved the following criteria (the "Commencement Date"), which notice will be accompanied by reasonable documentation evidencing satisfaction or occurrence of each of the following; *provided, however,* that Seller shall not be precluded from making third-party sales, in accordance with Section 4.5, of its percentage ownership share of Capacity and Energy from the Facility notwithstanding whether any or all of the following criteria have been met in whole or in part:

5.2.1 successful completion of required testing of the Facility has occurred for purposes of financing, project operation, air permitting, Purchaser's planning and reporting, and manufacturers' warranties, including establishment of the initial Demonstrated Capability of the Facility as contemplated in Section 4.1.2;

5.2.2 the Facility has completed [redacted] successful start-ups without experiencing any abnormal operating conditions and has generated continuously for a period of not less than [redacted] while synchronized to the Grid at a net Capacity output of at least [redacted] of the Demonstrated Capability (adjusted for ambient conditions) without experiencing any abnormal operating conditions;

5.2.3 the Facility is in compliance with the Interconnection Agreement, either is capable of operation in the AGC mode or is capable of responding to manual load change instructions, has achieved initial synchronization with the Grid, and has demonstrated the reliability of its communications systems and communications with the Florida Municipal Power Pool Energy Control Center located in the OUC Pershing Operations Building (or the replacement for such control center if the Customers decide to have their generation control performed at a different location); and

5.2.4 certificates of insurance coverages and/or insurance policies required of Seller have been obtained and submitted to Purchaser as required by Section 28.

5.3 Test Energy. Seller shall coordinate the production and delivery of Test Energy with Purchaser. Purchaser shall cooperate with Seller to facilitate Seller's testing of the Facility, provide the fuel necessary to conduct testing, and shall accept Test Energy delivered to Purchaser in accordance with the provisions of Section 4.2.

SECTION 6
REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE

6.1 Communicating Requests for Energy. Purchaser shall have the right to request deliveries of Energy by providing a Request for Energy to Seller in accordance with this Section 6 and Appendix B; *provided, however*, that Purchaser and the other Customers shall coordinate their Scheduling requirements by jointly submitting a single Request for Energy that covers all of their respective requirements on any given day.

6.1.1 The Customer's joint Requests for Energy may request the full output of the Facility, reduced by those amounts, if any, that Customers jointly elect to subtract from the Capacity available to Customers pursuant to the process provided in Section 4.1.4 of this Agreement and the other Power Purchase Agreements. If the Customer's joint Request for Energy is for less than the full output of the facility, then the request shall be deemed to be a Request for Energy first from Purchaser's Equity Capacity and, if such Equity Capacity is not sufficient, then from Purchaser's purchased Energy under this Agreement.

6.1.2 The Parties hereby consent to the recording of all conversations on the telephone lines used for communicating Requests for Energy and related notices and instructions in accordance with customary industry practice. The contents of such recordings shall be definitive.

6.2 Limitations on Requests for Energy. Notwithstanding anything to the contrary in this Agreement, any Request for Energy, operation in the AGC mode or operation in response to a Capacity Emergency that would require the Facility to operate in a manner inconsistent with the Technical Limits, Prudent Utility Practice or applicable Law and Permit requirements shall be deemed not to comply with the requirements and limitations set forth in this Section 6. If and when a Customers' Request for Energy does not comply with the requirements and limitations of this Section 6 by reason of the previous sentence, Seller will notify Customers of such noncompliance promptly after Seller realizes that the Request for Energy is noncompliant and will modify Customer's Request for Energy to make it consistent with the Technical Limits, Prudent Utility Practice and all applicable Laws and Permits to the extent it is reasonably possible to do so consistent with such standards.

6.3 Operation of the Facility. Seller shall operate and maintain the Facility in accordance with this Agreement, Prudent Utility Practice, the Technical Limits and all applicable Laws and Permit requirements. Any emission allowances required for operation of the Facility as contemplated in this Agreement shall be provided in accordance with the applicable provisions of the Operating Agreement.

6.4 Scheduled Maintenance. Seller agrees to schedule Planned Major Maintenance during the Off-Peak Period, or to obtain Purchaser's consent to schedule such maintenance during the Peak Period. Seller will submit to Purchaser an annual maintenance projection and will make reasonable efforts to coordinate the scheduling of such Planned Major Maintenance with Purchaser, including estimated start dates and return to service dates. Seller must seek the consent of OUC, acting for itself and on behalf of the other Customers (which Purchaser hereby authorizes) in scheduling of any Minor Maintenance; *provided, however*, that Purchaser guarantees Seller will be afforded a minimum of [redacted] such Minor Maintenance events distributed approximately evenly over the Off-Peak Period, with a maximum of [redacted] such Minor Maintenance events during any year; *provided, further*, that requests for Minor Maintenance events during the period from May 15 through September 15 may be granted or withheld in [redacted].

6.5 Transmission Operator. Coordination with an RTO regarding security and reliability of the Grid as it relates to the Facility, or any other entity, having control over the security and reliability of the Grid shall be the responsibility of Seller as the operator of the Facility. Coordination with an RTO, or other entity, having balancing authority or scheduling authority over the Facility should be handled by Purchaser for any schedules to Purchaser from the Facility and by Seller for any other schedules from the Facility. Any orders, directives or operating requirements that Seller is required to follow by Law imposed on Seller by an RTO, or any other entity, having control over the security and reliability of the Grid shall take precedence over this Agreement. To the extent the requirements of such order, directive or operating requirement necessarily prevent Seller from fulfilling its obligations under this Agreement, Seller shall be relieved of its obligations hereunder. To the extent the requirements of such order, directive or operating requirement conflict with Seller's fulfillment of its obligations hereunder, the rights and obligations of the Parties hereunder shall be adjusted as necessary to comply with such orders, directives or operating requirements.

SECTION 7
INTERCONNECTION AND TRANSMISSION

7.1 Interconnection Facilities. The Parties shall execute an Interconnection Agreement pursuant to applicable interconnection policies and procedures of OUC. The

Interconnection Agreement shall contain terms and conditions governing the interconnection and parallel operation of the Facility with the Grid.

7.2 Delay in Interconnection. Purchaser shall provide 230 kV service for purposes of energizing and testing the Facility 230 kV and collector bus systems by the date that is [redacted] prior to the anticipated Commercial Operation Date. Purchaser shall complete the OUC Interconnection Facilities and ensure that the 230kv Grid is capable of providing and receiving Energy by the date that is [redacted] prior to the anticipated Commercial Operation Date, but in no event earlier than [redacted]. Without limiting OUC's obligation under the previous sentence, if at any time from the date that is [redacted] prior to the anticipated Commercial Operation Date until the date that is [redacted] prior to the anticipated Commercial Operation Date, Seller has completed the collector bus and the 230kv line to the OUC Interconnection Facilities, then OUC shall provide service to the Facility for the purposes of engineering and testing the collector bus and other systems by either providing 230kv service at the Interconnection Point or by providing 4160V service to the Facility at the 4160V SWGR bus.

If for any reason, other than the fault of Seller, OUC fails to complete the OUC Interconnection Facilities and/or if the Grid is not capable of providing and receiving Energy (as determined by OUC and as supported by reasonable documentation) in accordance with the preceding sentences and, as a result, OUC cannot accommodate Seller's start-up and testing of the Facility (such a delay, an "IF/Grid Delay"), then the Scheduled Commencement Date shall be extended until such time that the OUC Interconnection Facilities are complete and the Grid is capable of so providing and receiving Energy to accommodate start-up and testing of the Facility (as determined by OUC and as supported by reasonable documentation); *provided, however*, that Purchaser shall make the Capacity Payments as provided in Section 5.1.3(b); *provided, further*, that if, at the time of the original anticipated Commercial Operation Date, Seller is not capable of delivering Energy from the Facility to the OUC Interconnection Facilities, then the extension of the Scheduled Commencement Date as provided above shall not commence, and Purchaser shall not be required to make Capacity Payments, until Seller is capable of delivering Energy from the Facility to the OUC Interconnection Facilities (and if, at that time, all of the causes of the IF/Grid Delay have been remedied, there shall be no extension at all).

7.3 Transmission.

7.3.1 Purchaser shall be responsible for all costs associated with and for making all necessary transmission arrangements for Delivered Energy, including tagging and any required Ancillary Services, with the transmission service provider for delivery from and beyond the Delivery Point.

7.3.2 Seller shall bear all costs and losses and shall be responsible for making all arrangements for transmission service, including tagging and any required

ancillary services, with respect to delivery of Capacity and Energy from an Alternate Resource to an unconstrained point on the Grid.

SECTION 8
RISK OF LOSS; METERING

8.1 Risk of Loss. Delivered Energy sold pursuant to this Agreement shall be made available to Purchaser at the Delivery Point. Risk of loss with respect to all such Energy shall pass to Purchaser when such Delivered Energy is made available to Purchaser at the Delivery Point. Risk of loss with respect to the natural gas supply utilized to deliver Energy pursuant to this Agreement shall pass to Seller when such natural gas supply is made available to Seller at the Gas Delivery Point. For purposes of this Agreement, and except to the extent expressly limited in this Agreement, Purchaser shall bear all risk of all occurrences of any nature (including Force Majeure or any other event beyond the reasonable control of either Party) affecting any interconnection facilities, substations, transmission lines and other facilities on Purchaser's side of the applicable Delivery Point and the Gas Delivery Point.

8.2 Place of Measurement. All Energy from the Facility shall be measured by the Facility's meters (such meters collectively, the "Interconnection Meters"), and the Energy delivered from the Facility shall be the Interconnection Meters' readings of the quantities of Energy, reduced by an amount equal to the applicable Energy quantity necessary to compensate for the loss, if any, between the Interconnection Meters and the Delivery Point.

8.3 Testing and Calibration of Interconnection Meters. Seller shall inspect and calibrate the Interconnection Meters at least once a year. Seller shall give Purchaser reasonable advance notice of any inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to have a representative present at such inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to require, at Purchaser's expense except as set forth in Section 8.4, a test of any of the Interconnection Meters not more often than once every twelve (12) months. If any Interconnection Meter is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such Interconnection Meter shall be deemed accurate, but Seller shall use its reasonable efforts to adjust such Interconnection Meter immediately and accurately. In the event that any Interconnection Meter is found to be inaccurate by more than one half of a percent (0.5%), Energy delivered at the corresponding Delivery Point shall be measured by reference to Customers' check-meters, if installed and registering accurately, or the meter readings at the Delivery Point for the period of inaccuracy shall be adjusted as far as can be reasonably ascertained by Seller from the best available data from both Parties. If the period of the inaccuracy cannot be ascertained reasonably, any such adjustment shall be for a period equal to one half of the time elapsed since the preceding test. Customers' check meters, if installed, shall be subject to Seller's right to require, at Seller's expense except as set forth in

Section 8.4, a test of any of the check-meters not more often than once every twelve (12) months. If any of Customers' check meters is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such check meter shall be deemed accurate, but Customers shall use their reasonable efforts to adjust such check meter immediately and accurately.

8.4 Delivered Energy Adjustments. In the event that, due to correction for inaccurate Interconnection Meters with an inaccuracy in excess of one half of a percent (0.5%) (determined in accordance with Section 8.3), the amount of Delivered Energy is increased or decreased, the revised quantity of Delivered Energy shall be used for purposes of calculating the Energy Payment pursuant to Section 4.2. If any Energy Payment has already been calculated using the previous quantity of Delivered Energy, the Energy Payment shall be recalculated using the revised quantity of Delivered Energy. If the recalculation (i) increases the Energy Payment, Purchaser shall pay to Seller the amount of such increase, or (ii) decreases the Energy Payment, Seller shall refund to Purchaser the amount of such decrease. In any such case, the required payment shall be included on the next invoice to be issued and shall be paid at the time payment of such invoice is required pursuant to Section 9. Any payment required under this Section 8.4 shall bear interest in accordance with Section 9.3 from the original due date (or from the date paid in the case of a refund) until the date paid (or until the date refunded in the case of a refund). In the case of inaccurate Meters with an inaccuracy in excess of one half of a percent (0.5%), the Party which owns such Meters shall promptly cause such Meters to be corrected and, where such inaccuracy was determined pursuant to a test required by the other Party, the Party which owns such Meters shall bear the expense of any such test.

SECTION 9
METHOD OF PAYMENT

9.1 Invoicing and Payment. As soon as reasonably practicable after the first day of each month commencing with the second month or portion thereof during which Test Energy is delivered to Purchaser and continuing for each month until the first month after the end of the Operating Period, Seller shall submit to Purchaser an invoice as described in Section 9.2. If such invoice indicates a net amount payable to Seller, Purchaser shall pay such invoice within ten (10) Business Days of Purchaser's receipt of the invoice. Such payment shall be made in U.S. dollars by wire transfer of immediately available funds prior to 3:00 p.m. Eastern Prevailing Time, on the date of payment in accordance with the invoice instructions. Payments made after 3:00 p.m. Eastern Prevailing Time or on a day that is not a Business Day shall be deemed to be made on the next subsequent Business Day. If such invoice indicates a net amount payable to Purchaser, Seller shall pay such amount within ten (10) Business Days of Purchaser's receipt of the invoice.

9.2 Monthly Invoices. Each monthly invoice shall show the amount and calculation of the following, as applicable: (i) the Capacity Payment and Energy Payment payable by Purchaser

to Seller for the preceding month net of any amounts to be credited by Seller to Purchaser for such month; (ii) following each Contract Year, the net amount payable by Purchaser or Seller pursuant to Section 4.3 respecting the Availability Incentive Payment and Availability Damages, as the case may be; and (iii) payments, refunds, credits and reductions, if any, payable by either Party pursuant to Sections 9.3 or 9.4.

9.3 Late Payments. Any amount due from either Party hereunder not paid in full on or before the date such payment is due will incur a delayed payment charge on the unpaid amount from the original due date until the date paid at an annual rate equal to the then current Prime Rate plus six (6) percentage points (or such lesser annual rate as is the maximum rate permitted by applicable Law).

9.4 Billing Disputes. In the event of any dispute as to all or any portion of any monthly invoice, Purchaser shall give notice of the dispute to Seller but shall pay the full amount of the invoiced charges when due (or if applicable, Seller shall give notice to Purchaser of Seller's dispute regarding any information provided by Purchaser that was a factor in any calculation supporting invoiced amounts). Such notice shall state the amount in dispute and set forth a full statement of the grounds on which such dispute is based. Purchaser and Seller shall give all due and prompt consideration to any such dispute. Upon final determination (whether by agreement, dispute resolution pursuant to Section 18 hereof, or otherwise) of the dispute, any amounts due to Purchaser or Seller, together with interest from the date due until the date paid at the rate specified in Section 9.3, shall be paid no later than thirty (30) days following such final determination. Purchaser and Seller shall have until the end of one hundred eighty (180) days after its receipt of any invoice, statement or information supporting invoice calculations to question or contest the correctness of any charge or credit on such invoice or statement.

9.5 Audit Rights. Until the end of one hundred eighty (180) days after Purchaser's receipt of any invoice, Seller and Purchaser will make available to the other upon written request, and the Purchaser or Seller may audit, such books and records of the other (or other information to which Purchaser or Seller has access) as are reasonably necessary for Purchaser or Seller to calculate and determine the amounts shown on such invoice and thereby to verify the accuracy and appropriateness of the amounts billed or credited to Purchaser or Seller hereunder; *provided, however,* that Purchaser shall coordinate its rights under this section with the other Customers in order to conduct joint, rather than individual, audits pursuant to this provision. The Parties shall maintain their respective books and records in accordance with generally accepted accounting principles applicable from time to time.

ARTICLE 10
CHANGE IN LAW; MODIFICATION OF AGREEMENT

10.1 Change in Law.

10.1.1 The Parties acknowledge that a Change in Law may increase or decrease Seller's costs in providing service under this Agreement. In the event of such a Change in Law, Seller may give notice to Purchaser that Seller's costs of providing service under this Agreement have changed (which notice will include reasonably detailed information about such cost changes) and, in the event such notice is given, this Agreement shall be modified to reflect such changes in costs, subject to Section 18, *provided, however*, that in the event Seller provides notice of such an increase, then Purchaser may provide documentation to Seller of other Changes in Law that have decreased the cost of providing service under this Agreement and Seller shall set-off any such decrease in cost against the increase in cost identified in the Seller's notice.

10.1.2 Purchaser shall pay the adjusted amount calculated pursuant to Section 10.1.1 for the period commencing with the notice of changed cost through the date of termination of this Agreement. The Parties shall make such payments as are appropriate to adjust all prior billings or payments to reflect the adjustments described herein.

10.1.3 A "Change in Law" shall mean a change in Law which constitutes a new environmental or tax Law or a new interpretation of such Law (not including a change in tax Laws that assess taxes only on Seller's net income) or a change in the provisions contained in the Site Certification permits and which generally affects the cost of, or restricts, operation of the Facility.

10.2 Modification of Agreement. In the event the FERC modifies this Agreement, the Parties agree to make all changes necessary to preserve as nearly as possible the bargain contained in this Agreement, including but not limited to, the total amounts of Capacity and Energy delivered to Purchaser and the total amount of revenues to be received by Seller hereunder; *provided, however*, that Seller shall have the right to terminate this Agreement without further obligation to Purchaser in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Seller; *provided, further*, that Purchaser shall have the right to terminate this Agreement without further obligation to Seller in the event that modifications to this Agreement by FERC cause a material adverse effect on the

economic value of this Agreement to Purchaser; *and provided, further*, that in the event Seller elects to terminate this Agreement pursuant to this Section 10.2, then Purchaser and Seller agree to expeditiously proceed with a sale [redacted] to Purchaser and the other Customers in accordance with the provisions of the Ownership Agreement. Seller agrees to use good faith efforts, consistent with Prudent Utility Practice, to resist any changes to this Agreement proposed by the FERC or any other Governmental Body or their respective staffs, and Purchaser agrees not to seek, request, promote or support any changes to this Agreement before the FERC or any other Governmental Body.

SECTION 11
FORCE MAJEURE

11.1 Force Majeure Notice and Obligations. With respect to those obligations of the Parties set forth in this Agreement that expressly excuse performance in the event of a Force Majeure, the existence of Force Majeure that causes a Party (the "Non-Performing Party") to delay performance or fail to perform such obligations shall excuse the Non-Performing Party's delay in performing, or failure to perform, such obligations, subject to any express limitations on such excuse provided or referenced in the Section invoking the excuse. In the event of Force Majeure that causes the Non-Performing Party to delay performance or fail to perform its obligations under this Agreement and that excuses such delay or failure:

11.1.1 the Non-Performing Party shall give the other Party written notice and full details as soon as practicable after learning of the Force Majeure;

11.1.2 the Non-Performing Party shall use reasonable dispatch to remedy its inability to perform (except that this provision shall not impose a requirement on either Party to deliver or receive Energy at a delivery point other than a Delivery Point), and, if Seller is the Non-Performing Party, Seller shall use reasonable efforts to provide Energy from the Facility at a Delivery Point; and

11.1.3 when the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

SECTION 12
EVENTS OF DEFAULT; TERMINATION

12.1 Events of Default of Seller. Except when excused due to a Force Majeure event pursuant to the provisions of Section 11 hereof, an Event of Default shall be deemed to have occurred with respect to Seller upon the occurrence and during the continuance of any of the following events:

12.1.1 The Bankruptcy of Seller;

12.1.2 Seller fails to pay any invoiced amount or undisputed non-invoiced amount when due under this Agreement within five (5) Business Days after receiving notice of such failure;

12.1.3 Seller fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than obligations addressed in Section 12.1.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Purchaser demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot be reasonably accomplished within such 30-day period and Seller diligently commences such cure in such period and continues such cure to completion); or

12.1.4 Any representation or warranty made by Seller herein, in the Ownership Agreement or in any document or certificate furnished by Seller hereunder shall have been false when made and such false representation or warranty has a material and adverse effect on Purchaser and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Purchaser.

12.2 Events of Default of Purchaser. An Event of Default shall be deemed to have occurred with respect to Purchaser upon the occurrence and during the continuance of any of the following events:

12.2.1 The Bankruptcy of Purchaser;

12.2.2 Purchaser fails to pay any invoiced amount or any undisputed non-invoiced amount when due under this Agreement within five (5) Business Days after receiving notice of such failure;

12.2.3 Purchaser fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than payment obligations, which are addressed in Section 12.2.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Seller demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot reasonably be accomplished within such 30-day period and Purchaser diligently commences such cure in such period and continues such cure to completion);

12.2.4 Any representation or warranty made by Purchaser herein, in the Ownership Agreement or in any document or certificate furnished by Purchaser shall have been false when made and such false representation or warranty has a material and adverse effect on Seller and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Seller; or

12.2.5 Purchaser fails to comply with any of the requirements of Section 15 within thirty (30) days of receipt of Seller's written notice of such failure.

12.3 Remedies; Notice of Intent to Terminate. Subject to the provisions of this Agreement providing for limitations on damages and for exclusive remedies under certain circumstances, upon the occurrence and during the continuation of any Event of Default, the Party not in default (the "Non-Defaulting Party") shall have the right to pursue all remedies available at law or in equity, suspend its performance under this Agreement to the extent of the Event of Default and/or to deliver a notice of intent to terminate ("Notice of Intent to Terminate") this Agreement to the Party in default ("Defaulting Party"). Any Notice of Intent to Terminate shall specify the Event of Default giving rise to such Notice of Intent to Terminate. Following the giving of a Notice of Intent to Terminate, the Parties shall negotiate pursuant to the provisions of Section 18 hereof, following which, unless the Parties shall have otherwise mutually agreed on a remedy or the Defaulting Party or any lender or financing party ("Lender") to the Defaulting Party or its affiliate, or agent on behalf of a Lender, shall have cured such default or is diligently pursuing a remedy to cure the Event of Default, the Non-Defaulting Party having given the Notice of Intent to Terminate may terminate this Agreement by giving written notice thereof to the Defaulting Party, whereupon this Agreement shall immediately terminate. Except as provided in Sections 2.2, 2.3, 5.1.2, 10.2, 12.4, and 12.5 or in this Section 12.3, or in Section 4.3.2 of the Ownership Agreement, neither Party shall have any right to terminate this Agreement.

12.4 Notice to Lenders. Any and all notices given by Purchaser to Seller under this Section 12 shall also be given at the same time by Purchaser to any Lender for which Seller

provides written notice to Purchaser of the need to provide such notice and the address to which such notice must be sent. No termination of this Agreement by Purchaser will be effective until and unless Purchaser shall have given Seller's Lenders notice of Seller's Event of Default and an opportunity to cure such Event of Default, which notice and cure period shall be as set forth in any consent executed by Purchaser with Seller's Lenders but in any event such notice and cure period shall be at least concurrent with that provided to Seller under this Agreement.

12.5 Termination Payment.

12.5.1 Subject to Section 12.5.2 below, in the event that a Non-Defaulting Party terminates this Agreement pursuant to Section 12.3 and provided an Event of Default shall not have occurred and be continuing as to such Non-Defaulting Party, the Defaulting Party shall pay the Non-Defaulting Party the Termination Payment, as defined below, within thirty (30) days of the effective date of the termination. Except for payment of the Termination Payment (if applicable), neither Party shall have any liability or obligation to the other Party arising out of a termination of this Agreement pursuant to Section 12.3. The Defaulting Party's Termination Payment (if applicable) to the Non-Defaulting Party resulting from an Event of Default under this Agreement shall be calculated as follows:

Termination Payment = TPR * APCN

Where:

TPR = a termination payment rate in dollar per kilowatt, which is equal to: (i) [redacted] if the Notice of Intent to Terminate is given between the date of this Agreement's execution and the end of the twelfth (12th) month after the date Purchaser gives notice under Section 2.2 or 2.3 that it has elected to terminate this Agreement; (ii) [redacted] if the Notice of Intent to Terminate is given between the end of such twelfth (12th) month and the end of the twenty-fourth (24th) month after the date Purchaser gives such notice; or (iii) [redacted] if the Notice of Intent to Terminate is given between the end of such twenty-fourth (24th) month and the expected termination of this Agreement twelve (12) months later; and

APCN = the Annual Purchaser's Capacity Nomination, in kilowatts, that is in effect on the date of the Notice of Intent to Terminate.

Delivery of a Notice to Terminate or calculation or payment of the Termination Payment shall not relieve the Defaulting Party of its obligation to pay all other amounts that became or have become due and payable by the Defaulting Party hereunder prior to the effective date of termination.

12.5.2 Notwithstanding the provisions of Section 12.5.1, in the case of an Event of Default under Section 12.2.2 by Purchaser at a time when Purchaser is able to pay its debts as they come due, Seller shall be entitled to recover the actual damages of Seller. In determining actual damages, any amounts actually recovered from Seller's reasonable efforts to mitigate such damages shall be taken into account. Also notwithstanding Section 12.5.1, in the case of an Event of Default by Seller under Section 12.1.3 that results from a failure by Seller to deliver Energy from the Facility to Purchaser as required by this Agreement at a time when (i) the Facility was capable of delivering such Energy to Seller as required by this Agreement consistent with Prudent Utility Practice, the Technical Limits and applicable Law and Permit requirements, and (ii) Seller sold such Energy to a third party, then Purchaser shall be entitled to recover the actual damages of Purchaser. In determining actual damages, the actual results of Purchaser's reasonable efforts to mitigate such damages shall be taken into account. In receiving a Termination Payment or recovering actual damages, the Non-Defaulting Party shall also be entitled to recover its reasonable attorney fees in enforcing this provision.

SECTION 13
WAIVER

Failure by either Party to exercise any of its rights under this Agreement shall not constitute a waiver of such rights. Neither Party shall be deemed to have waived any right resulting from any failure to perform by the other Party unless it has made such waiver specifically in writing, and no such waiver shall operate as a waiver of any future failure to perform whether of a like or different character. No single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege hereunder.

SECTION 14
REPRESENTATIONS AND WARRANTIES

14.1 Representations and Warranties of Seller. Seller hereby represents and warrants to Purchaser as follows:

14.1.1 Organization and Existence. Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware and has sufficient power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Seller has full power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.1.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Seller has been duly and effectively authorized by all requisite action on the part of Seller. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Seller, enforceable against Seller in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.1.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Seller's knowledge, threatened against Seller or Seller's Affiliate guarantor by or before any Governmental Body having jurisdiction over Seller or Seller's Affiliate guarantor which, if adversely determined, would have a material adverse effect upon Seller's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents. Neither Seller nor Seller's Affiliate guarantor are subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Seller or Seller's Affiliate guarantor which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents.

14.1.4 No Violation or Conflict. The execution, delivery and performance by Seller of this Agreement and the Collateral Documents do not violate or conflict with Seller's operating agreement, any existing Law applicable to Seller, or any note, bond, indenture, agreement or instrument to which Seller is a party or by which it is bound.

14.1.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment C of the Ownership Agreement, there are no approvals or consents other than those referenced in or incorporated by reference into Section 3 hereof, the absence of which would materially impair Seller's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2 Representations and Warranties of Purchaser. Purchaser hereby represents and warrants to Seller as follows:

14.2.1 Organization and Existence. Purchaser is a statutory utility authority duly organized, validly existing and in good standing under the laws of the State of Florida and has sufficient statutory power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Purchaser has full statutory power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.2.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Purchaser has been duly and effectively authorized by all requisite action on the part of Purchaser's governing board. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Purchaser, enforceable against Purchaser in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.2.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Purchaser's knowledge, threatened against Purchaser by or before any Governmental Body having jurisdiction over Purchaser which, if adversely determined, would have a material adverse effect upon Purchaser's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents. Purchaser is not subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Purchaser which would materially and adversely affect its ability to enter into and perform its

obligations under this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents.

14.2.4 No Violation or Conflict. The execution, delivery and performance by Purchaser of this Agreement and the Collateral Documents do not violate or conflict with Purchaser's [charter or bylaws], any existing Law applicable to Purchaser, or any note, bond, resolution, indenture, agreement or instrument to which Purchaser is a party or by which it is bound.

14.2.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment C of the Ownership Agreement, there are no approvals or consents other than those referenced in or incorporated by reference into Section 3 hereof, the absence of which would materially impair Purchaser's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2.6 No Immunity. With respect to its contractual obligations hereunder and performance thereof, Purchaser is not entitled to claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from: (a) suit; (b) jurisdiction of any Florida court; or (c) relief by way of injunction, order for specific performance or attachment of property that is subject to execution or levy under Florida Law (including the Eligible Collateral).

14.2.7 Unsubordinated Obligations. Payments made by Purchaser hereunder constitute "Operating Expenses", as defined in the Senior Lien Resolution, and are payable from "Revenues", as that term is defined in the Senior Lien Resolution. Such Revenues are not subject to any material prior claim under the Bond Legislation or other bond resolutions adopted by Purchaser or indentures to which Purchaser is a party and such Revenues are available without limitation or deduction, except as may be provided herein, to satisfy all of Purchaser's obligations hereunder. Such obligations to make payments hereunder may be limited by applicable bankruptcy, insolvency or similar laws or by limitation upon the availability of equitable remedies.

14.3 Warranties Regarding Energy, Capacity and Ancillary Services. Seller warrants that the Energy, Capacity and Ancillary Services provided under this Agreement (i) shall have been delivered in accordance with applicable Law, and (ii) meets the requirements set forth in this

Agreement. **THE FOREGOING IS IN LIEU OF ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, IN FACT OR BY LAW WITH RESPECT TO THE ENERGY, CAPACITY AND ANCILLARY SERVICES PROVIDED HEREUNDER. SELLER HEREBY DISCLAIMS ANY AND ALL OTHER WARRANTIES WHATSOEVER.**

SECTION 15
PERFORMANCE ASSURANCE

15.1 In the event that Purchaser experiences a Material Adverse Change, as defined below, as security for Purchaser's payment obligations under this Agreement, Purchaser shall deliver to Seller within [redacted] of Seller's written request therefor, Eligible Collateral in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period.

15.1.1 As used in this Section 15.1: (i) a "Material Adverse Change" shall occur either (A) when Purchaser's credit rating on its senior securities falls below the lower of (x) [redacted] (Standard & Poors) or [redacted] (Moody's) and (y) the lowest credit rating of Southern Guarantor's senior securities under either Moody's or Standard & Poors, or (B) upon an Event of Default by Purchaser under Section 12.2.2; and (ii) "Eligible Collateral" means cash deposited into an operating reserve account from "Revenues", as that term is defined in the Senior Lien Resolution, or an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller. Costs of a letter of credit shall be borne by Purchaser.

15.1.2 If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Purchaser, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when a "Material Adverse Change" has occurred.

15.2 In the event that legislation is enacted in the State of Florida which contains provisions that will cause an Event of Default by Purchaser at any time during the term of this Agreement, Seller will have the right, from and after the date of enactment of such legislation, to provide Purchaser with written notice requesting Eligible Collateral, as defined above, in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period. Upon receipt of

such notice, in addition to Purchaser's other payment obligations under this Agreement, Purchaser shall within [redacted] provide such Eligible Collateral.

15.3. To the extent Purchaser delivers Eligible Collateral in the form of cash to be held in an operating reserve account pursuant to Sections 15.5 or 15.6, Purchaser hereby grants to Seller a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, such Eligible Collateral, and any and all proceeds resulting therefrom or from the liquidation thereof, and Purchaser agrees to take such action as Seller reasonably requires in order to perfect Seller's first-priority security interest in, and lien on (and right of setoff against), such Eligible Collateral and any and all proceeds resulting therefrom or from the liquidation thereof. This Agreement is intended to, and does, constitute a security agreement between Seller and Purchaser with regard to any cash which may constitute Eligible Collateral.

15.4. Upon or any time after the occurrence and during the continuation of an Event of Default of Purchaser, Seller may (i) exercise any of the rights and remedies of a secured party with respect to the Eligible Collateral, including any such rights and remedies under Law then in effect, such as but not limited to the Uniform Commercial Code, and (ii) liquidate and/or draw on any outstanding Eligible Collateral issued for its benefit (free from any claim or right of any nature whatsoever of Purchaser including any equity or right of purchase or redemption by Purchaser) with respect to Purchaser's obligations under this Agreement. In the event that Seller liquidates or draws on any of the Eligible Collateral, Purchaser shall within [redacted] of notice from Seller of such liquidation or draw, deliver additional cash or increase the amount of the letter of credit, as the case may be, in order to replenish the amount of the Eligible Collateral to the extent of the liquidation or draw.

15.5. If the trigger of a Material Adverse Change was occurrence of the circumstances in Sections 15.1.1(i)(A) or the circumstances described in Section 15.2 occur, then: (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as the circumstances described in Sections 15.1.1(i)(A) and 15.2 no longer apply (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire at such time as the circumstances described in Sections 15.1 and 15.2 no longer apply and Seller shall return such letter of credit to Purchaser (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.6 If the trigger of a Material Adverse Change was occurrence of the circumstances described in Section 15.1.1(i)(B), then (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as Purchaser shall have (A) cured the Event of Default under Section 12.2.2 that triggered the Material Adverse Change and (B) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire (and Seller shall return such letter of credit) at such time as Purchaser shall have (C) cured the Events of Default under Section 12.2.2 that triggered the Material Adverse Change and (D) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.7 In the event that the Purchaser exercises its right to elect an Extended Term or any Further Extension of this Agreement pursuant to Sections 2.2 and 2.3, and on any day of such Extended Term or Further Extensions the circumstances of either Sections 15.1.1 or 15.2 apply, then, Purchaser shall deliver to Seller within [redacted] of the date of such occurrence, Eligible Collateral, as defined above, in an amount equal to [redacted] of Capacity Payments, and the provisions of Sections 15.3, 15.4, 15.5 and 15.6 shall apply to such Eligible Collateral.

SECTION 16
LIABILITY OF PARTIES

16.1 INDEMNITIES.

16.1.1 **TO THE EXTENT PERMITTED BY LAW, EACH PARTY (THE "INDEMNIFYING PARTY") SHALL FULLY INDEMNIFY AND DEFEND THE OTHER PARTY AND EACH OF THE OTHER PARTY'S SUBSIDIARIES AND AFFILIATES, AND THE PARTNERS, MEMBERS, PARTICIPANTS, PRINCIPALS, REPRESENTATIVES, SHAREHOLDERS, DIRECTORS, OFFICERS, AGENTS, EMPLOYEES, SUCCESSORS AND**

ASSIGNS OF EACH OF THEM (THE "INDEMNIFIED PARTIES") FROM AND AGAINST ANY AND ALL LOSSES, COSTS, DAMAGES, INJURIES, LIABILITIES, CLAIMS, DEMANDS, PENALTIES AND INTEREST, INCLUDING REASONABLE ATTORNEYS' FEES, RESULTING FROM THIRD PARTY CLAIMS DIRECTLY OR INDIRECTLY RELATED TO THIS AGREEMENT, TO THE EXTENT CAUSED OR CONTRIBUTED TO BY THE FAULT, INTENTIONAL ACT, NEGLIGENCE OR STRICT LIABILITY OF THE INDEMNIFYING PARTY OR ITS SUBSIDIARIES, AFFILIATES, CONTRACTORS OR SUBCONTRACTORS OR ANY OF THE OFFICERS, PARTNERS, MEMBERS, PARTICIPANTS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, EMPLOYEES, AGENTS, REPRESENTATIVES, SUCCESSORS OR ASSIGNS OF ANY OF THEM OR BY BREACH BY THE INDEMNIFYING PARTY OF THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT ANY LIABILITY TO THIRD PARTIES INCURRED BY SELLER IN PERFORMANCE OF ITS AGENCY FUNCTIONS PURSUANT TO THE OWNERSHIP AGREEMENT OR THE OPERATING AGREEMENT SHALL BE APPORTIONED IN ACCORDANCE WITH ARTICLE 9 OF THE OWNERSHIP AGREEMENT OR ARTICLE 7 OF THE OPERATING AGREEMENT.

16.1.2 **IF ANY INDEMNIFIED PARTY INTENDS TO SEEK INDEMNIFICATION UNDER THIS SECTION 16.1 FROM AN INDEMNIFYING PARTY WITH RESPECT TO ANY ACTION OR CLAIM, THE INDEMNIFIED PARTY SHALL GIVE THE INDEMNIFYING PARTY WRITTEN NOTICE OF SUCH CLAIM OR ACTION PROMPTLY FOLLOWING THE RECEIPT OF ACTUAL KNOWLEDGE OR INFORMATION BY THE INDEMNIFIED PARTY OF A POSSIBLE CLAIM OR OF THE COMMENCEMENT OF A CLAIM OR ACTION, WHICH WRITTEN NOTICE SHALL IN NO EVENT BE DELIVERED LATER THAN THE FIRST TO OCCUR OF (A) 15 DAYS PRIOR TO THE LAST DAY FOR RESPONDING TO SUCH CLAIM OR ACTION OR (B) THE EXPIRATION OF THE FIRST HALF OF THE PERIOD ALLOWED FOR RESPONDING TO SUCH CLAIM OR ACTION. THE INDEMNIFYING PARTY SHALL HAVE NO LIABILITY UNDER THIS SECTION FOR ANY CLAIM OR ACTION FOR WHICH SUCH NOTICE IS NOT PROVIDED TO**

THE EXTENT THAT THE FAILURE TO GIVE SUCH WRITTEN NOTICE MATERIALLY PREJUDICES THE INDEMNIFYING PARTY. UPON ACKNOWLEDGMENT OF ITS OBLIGATIONS UNDER THIS SECTION 16.1, THE INDEMNIFYING PARTY SHALL HAVE THE RIGHT TO ASSUME THE DEFENSE OF ANY CLAIM OR ACTION, AT ITS SOLE COST AND EXPENSE, WITH COUNSEL DESIGNATED BY THE INDEMNIFYING PARTY AND REASONABLY SATISFACTORY TO THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE DEFENDANTS IN ANY SUCH ACTION INCLUDE BOTH THE INDEMNIFIED PARTY AND THE INDEMNIFYING PARTY, AND THE INDEMNIFIED PARTY SHALL HAVE REASONABLY CONCLUDED THAT THERE MAY BE LEGAL DEFENSES AVAILABLE TO IT WHICH ARE DIFFERENT FROM OR ADDITIONAL TO THOSE AVAILABLE TO THE INDEMNIFYING PARTY, THE INDEMNIFIED PARTY SHALL HAVE THE RIGHT TO SELECT SEPARATE COUNSEL, AT THE INDEMNIFYING PARTY'S EXPENSE, TO ASSERT SUCH LEGAL DEFENSES AND TO OTHERWISE PARTICIPATE IN THE DEFENSE OF SUCH ACTION ON BEHALF OF SUCH INDEMNIFIED PARTY.

16.1.3 **EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFIED PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT HAS SOUGHT OR INTENDS TO SEEK INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFYING PARTY. SHOULD ANY INDEMNIFIED PARTY BE ENTITLED TO INDEMNIFICATION UNDER THIS SECTION 16.1 AS A RESULT OF A CLAIM OR ACTION BY A THIRD PARTY, AND SHOULD THE INDEMNIFYING PARTY FAIL TO ASSUME THE DEFENSE OF SUCH CLAIM OR ACTION, THE INDEMNIFIED PARTY MAY, AT THE EXPENSE OF THE INDEMNIFYING PARTY, CONTEST (OR, WITH OR WITHOUT THE PRIOR CONSENT OF THE INDEMNIFYING PARTY, SETTLE) SUCH CLAIM OR ACTION. EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFYING PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT MAY BE LIABLE TO PROVIDE INDEMNIFICATION PURSUANT TO THIS AGREEMENT**

WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE INDEMNIFYING PARTY HAS REACHED A BONA FIDE SETTLEMENT AGREEMENT WITH THE PLAINTIFF(S) IN ANY SUCH ACTION AND THE INDEMNIFIED PARTY DOES NOT CONSENT TO SUCH SETTLEMENT AGREEMENT, THEN THE AMOUNT SPECIFIED IN THE SETTLEMENT AGREEMENT, PLUS THE INDEMNIFIED PARTY'S REASONABLE ATTORNEY FEES INCURRED PRIOR TO THE DATE OF SUCH SETTLEMENT AGREEMENT, SHALL ACT AS AN ABSOLUTE MAXIMUM LIMIT ON THE INDEMNIFICATION OBLIGATION OF THE INDEMNIFYING PARTY WITH RESPECT TO THE CLAIM, OR PORTION THEREOF, THAT IS THE SUBJECT OF SUCH SETTLEMENT AGREEMENT TO THE EXTENT SUCH SETTLEMENT AGREEMENT FULLY RELEASES THE INDEMNIFIED PARTY AND DOES NOT REQUIRE ANY PAYMENT FROM, OR IMPOSE ANY RESTRICTION ON, THE INDEMNIFIED PARTY.

16.2 **LIMITATION ON DAMAGES. NEITHER PARTY NOR ITS SUBSIDIARIES OR AFFILIATES NOR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, SUCCESSORS OR ASSIGNS OF ANY OF THEM SHALL IN ANY EVENT BE LIABLE TO THE OTHER PARTY OR ITS SUBSIDIARIES OR AFFILIATES OR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS OR DIRECTORS OF ANY OF THEM FOR CLAIMS FOR INCIDENTAL, PUNITIVE, CONSEQUENTIAL OR INDIRECT DAMAGES OF ANY NATURE, ARISING AT ANY TIME, FROM ANY CAUSE WHATSOEVER, WHETHER ARISING IN TORT, CONTRACT, WARRANTY, STRICT LIABILITY, BY OPERATION OF LAW OR OTHERWISE, CONNECTED WITH OR RESULTING FROM PERFORMANCE OR NON-PERFORMANCE UNDER THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT THIS SECTION 16.2 IS NOT INTENDED, NOR SHALL IT BE CONSTRUED, TO LIMIT OR ELIMINATE A PARTY'S OBLIGATION TO PAY LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR MAKE ANY OTHER PAYMENTS EXPRESSLY CONTEMPLATED HEREIN, OR IN ANY COLLATERAL DOCUMENT, EVEN IF IT MAY BE POSSIBLE TO CHARACTERIZE SUCH LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR OTHER PAYMENTS AS INCIDENTAL, PUNITIVE, CONSEQUENTIAL OR INDIRECT DAMAGES.**

16.3 Seller Affiliate Guarantee. Seller shall at all times following the Effective Date of this Agreement cause an Affiliate of Seller to maintain in place a guarantee of Seller's obligations under this Agreement. For purposes of the previous sentence, an "Affiliate" of Seller shall be any entity controlling, under common control with or controlled by Seller, which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's). If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Seller's affiliates, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when an entity controlling, under common control with or controlled by Seller has sufficient credit-worthiness to qualify as an "Affiliate."

16.4 No Penalty. The Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by Purchaser due to Seller's failure to meet the Availability Guarantee or achieve the schedule provided under Section 5.1.1, that the Availability Damages set forth in Section 4.3 and the liquidated damages set forth in Section 5.1.2 are fair and reasonable determinations of the amount of actual damages which would be suffered by Purchaser or Seller, as the case may be, by reason of such failure, and that the Availability Damages and other liquidated damages do not constitute a penalty. Similarly, the Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by either Party in case of an Event of Default and a termination of this Agreement by the Non-defaulting Party, that the Termination Payment set forth in Section 12.5.1 is a fair and reasonable determination of the amount of actual damages which would be suffered by the Non-defaulting Party in such event, and that the Termination Payment does not constitute a penalty.

SECTION 17
ASSIGNMENT

17.1 Agreement Binding. This Agreement shall be binding upon, and shall inure to the benefit of, the Parties and their successors and permitted assigns.

17.2 Permitted Assignment. This Agreement shall not be assignable by Seller without the prior written consent of Purchaser, except that this Agreement (a) may be assigned by Seller without the requirement for such consent (but with notice to Purchaser) (i) to any affiliate of Seller who has succeeded to all of Seller's rights and obligations as a Participant under the Ownership Agreement, (ii) as collateral to any Lender from time to time providing financing to Seller or its affiliate with respect to all or any portion of the Project or (iii) to any Lender or its designee in connection with a foreclosure or other exercise of remedies, and (b) may be assigned by Seller without the requirement for such consent (but with notice to Purchaser) in the event of a sale by Seller of all or a substantial portion of Seller's interest in the Facility. This Agreement shall not be assignable by Purchaser without the prior written consent of Seller, *provided,*

however, that Purchaser may assign this Agreement to another Customer without the requirement for such consent (but with notice to Seller) so long as such Customer has not experienced a Material Adverse Change under its PPA. Any such transferee, assignee or purchaser (other than a Lender through collateral assignment in connection with a lease or other financing transaction permitted under Section 6.2.9 of the Ownership Agreement) shall confirm its willingness to accept all of the assigning Party's obligations under this Agreement by writing reasonably acceptable to the non-assigning Party. Any such assignee, transferee or purchaser (other than a Lender through collateral assignment in connection with a lease or other financing transaction permitted under Section 6.2.9 of the Ownership Agreement) must be sufficiently creditworthy and otherwise capable of performing all of the assigning Party's obligations under this Agreement. No assignment or transfer of this Agreement by a Party shall be permitted during any period in which an Event of Default of such Party shall have occurred and be continuing and not cured, unless the other Party shall agree. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement, except that the assignor shall be released from its obligations under this Agreement at such time as all future obligations of the assignor hereunder shall have been assumed by the assignee in a written agreement delivered to the other Party. Any assignment that does not comply with the provisions of this Section 17 shall be null and void.

SECTION 18
DISPUTE RESOLUTION

18.1 Good-Faith Negotiations. The Parties shall first negotiate in good faith to attempt to resolve any dispute, controversy or claim arising out of, under, or relating to this Agreement (a "Dispute"), unless otherwise mutually agreed to by the Parties. In the event that the Parties are unsuccessful in resolving a Dispute through such negotiations, either Party may proceed immediately to litigation concerning the Dispute.

18.1.1 The process of "good-faith negotiations" requires that each Party set out in writing to the other its reason(s) for adopting a specific conclusion or for selecting a particular course of action, together with the sequence of subordinate facts leading to the conclusion or course of action. The Parties shall attempt to agree on a mutually agreeable resolution of the Dispute. A Party shall not be required as part of these negotiations to provide any information which is confidential or proprietary in nature unless it is satisfied in its discretion that the other Party will maintain the confidentiality of and will not misuse such information or any information subject to attorney-client or other privilege under applicable Law regarding discovery and production of documents.

18.1.2 The negotiation process shall include at least two (2) meetings to discuss any Dispute. Unless otherwise mutually agreed, the first meeting shall take place within ten days after either Party has received notice from the other of the desire to commence formal negotiations concerning the Dispute. Unless otherwise mutually agreed, the second meeting shall take place no more than ten days later. In the event a Party refuses to attend a negotiation meeting, either Party may proceed immediately to litigation concerning the Dispute.

18.2 Confidentiality and Non-Admissibility of Statements Made in, and Evidence Specifically Prepared for, Good Faith Negotiations. Each Party hereby agrees that all statements made in the course of good faith negotiations, as contemplated in Section 18.1, shall be confidential and shall not be disclosed to or shared with any third parties (other than any person whose presence is necessary to facilitate the negotiation process). Each Party agrees and acknowledges that no statements made in or evidence specifically prepared for good faith negotiations under Section 18.1 shall be admissible for any purpose in any subsequent litigation.

SECTION 19
AMENDMENT

This Agreement cannot be amended, modified or supplemented except by written agreement making specific reference hereto executed by both Parties.

SECTION 20
NOTICES

Other than telephonic notices required or permitted under Section 6.1 or Appendix B, any notice required or permitted to be given hereunder shall be in writing and shall be: (i) personally delivered; (ii) transmitted by postage prepaid registered mail; (iii) transmitted by a recognized overnight courier service; or (iv) transmitted by facsimile to the receiving Party as follows, as elected by the Party giving such notice:

20.1 In the case of Purchaser:

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Attention: Vice-President of Power Resources
Telephone: 407-244-8372
Facsimile: 407-275-4120

With a copy to:

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Attention: Legal Department
Telephone: 407-423-9100
Facsimile: 407-423-9198

20.2 In the case of Seller:

Southern Company Services, Inc.
270 Peachtree Street, Bin 935
Atlanta, Georgia 30303
Attention: Manager of Contract Administration
Telephone: 404-506-5100
Facsimile: 404-506-0304

With a copy to:

Troutman Sanders LLP
Bank of America Plaza
600 Peachtree Street N.E.
Atlanta, Georgia 30308
Attention: Robert H. Forry, Esq.
Telephone: 404-885-3142
Facsimile: 404-962-6559

All notices and other communications shall be deemed to have been duly given on (i) the date of receipt if delivered personally, (ii) five (5) days after the date of posting if transmitted by mail, (iii) the Business Day following delivery to the courier if transmitted by overnight delivery service, or (iv) the date of transmission with confirmation if transmitted by facsimile, whichever shall first occur. Any Party may change its address for purposes hereof by notice to the other Party.

SECTION 21
APPLICABLE LAW

This Agreement shall be governed by, and construed in accordance with, the laws of the State of Florida, exclusive of any conflict of laws provisions thereof that would apply the laws of

another jurisdiction. The Parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Middle District of Florida, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Circuit Court of the State of Florida sitting in Orange County, Florida, and the Parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

SECTION 22
SEVERABILITY

The invalidity or unenforceability of any provision or portion of this Agreement will not affect the validity of the remainder of this Agreement. If any provision of this Agreement is determined to be invalid or unenforceable, the Parties will negotiate in good faith to agree upon substitute provisions to carry out the purpose and intent of the invalid or unenforceable provision. If the economic or legal substance of the transactions contemplated hereby is affected in any manner adverse to any Party as a result thereof, the Parties shall negotiate in good faith in an effort to agree upon a suitable and equitable substitute provision to effect the original intent of the Parties.

SECTION 23
ENTIRE AGREEMENT

This Agreement and the Collateral Documents contain the complete agreement of the Parties hereto with respect to the matters contained herein and supersede all other agreements, understandings and negotiations, whether written or oral, with respect to the matters contained herein.

SECTION 24
NO THIRD PARTY BENEFICIARIES

This Agreement is intended to be solely for the benefit of Purchaser and Seller and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any Person not a signatory hereto.

SECTION 25
COUNTERPARTS

This Agreement may be executed in one or more counterparts, each of which shall constitute an original but all of which, when taken together, shall constitute only one legal instrument.

SECTION 26
INFORMATION AND CONFIDENTIALITY

Where a Party makes any calculation of costs or damages under this Agreement, such Party shall provide, upon the reasonable request of the other Party, documentation supporting such calculation. Neither Party shall disclose or otherwise make available to any other party any information of a technical, commercial or business nature regarding the Project or this Agreement that has been marked or identified as confidential or proprietary ("Confidential Information") without the prior written consent of the other Party, except that (a) Seller or its affiliate may provide Confidential Information to its or any such affiliate's prospective Lenders, underwriters, investors, affiliates, advisors, employees, officers and directors to the extent reasonably required in connection with the administration of this Agreement, the issuance of debt or equity or other financing activities of Seller or its affiliate, or the performance of any duties relating to this Agreement; (b) Purchaser may provide Confidential Information to its advisors, employees and officers to the extent reasonably required in connection with the administration of this Agreement or the performance of any such Person's duties relating to this Agreement; (c) any Party may disclose any such Confidential Information in any litigation or proceeding to enforce or recover damages under this Agreement; (d) any Party (or its affiliate) may disclose any such Confidential Information as may be required by any applicable Law, regulation or governmental order; and (e) any Party (or its affiliate) may disclose such Confidential Information to any person or entity succeeding to all or substantially all the assets of such Party (or its affiliate) or all or a substantial portion of its interest in the Facility; *provided*, that in the case of (e), any such successor shall agree to be bound by the provisions of this Section 26. Confidential Information shall not include information that: (i) the receiving Party can demonstrate was known to it prior to its disclosure by the other Party; (ii) is, or later becomes, public knowledge without breach of this Agreement by the receiving Party; (iii) was received by the receiving Party from a third party without obligation of confidentiality; or (iv) is developed by the receiving Party independently from Confidential Information received from the other Party, as evidenced by appropriate documentation. In the event that disclosure is required by a valid order of a court or Governmental Body, the Party subject to such requirement may disclose Confidential Information to the extent so required, but shall promptly notify the other Party and shall cooperate with the other Party's efforts to obtain protective orders or similar restraints with respect to such disclosure. The provisions of this Section 26 shall continue in effect until three years after the end of the Operating Period.

The Parties understand that under the Florida Public Records Law (Section 119.10, Florida Statutes), any Party or all of them may be subject to statutory fines and penalties, including but not limited to a requesting Party's costs and attorney's fees for failure to make public records available for public inspection upon request (Chapter 119, Florida Statutes). In addition, each Party may be subject to its own costs and expenses of litigation. With this understanding in mind, the Parties agree that in the event Purchaser in an attempt to comply with this Agreement, refuses to honor a public records

request under Chapter 119, Florida Statutes, for examination or inspection of a confidential document of Seller or any Affiliate of Seller and is forced to defend its actions in a court of competent jurisdiction, Seller shall indemnify, defend, and hold Purchaser harmless from and against any fines, penalties, costs, attorney's fees and expenses, including, but not by way of limitation, attorney's fees, expert fees, court costs and other costs arising from or related to defending any lawsuit bought pursuant to Chapter 119, Florida Statutes; *provided, however,* Seller's consent with such refusal shall be obtained before Seller can be liable under this Section *26*. In addition, the Parties shall cooperate to provide witnesses to support the Parties' declarations and certification that the Confidential Information is a valid trade secret under the above cited Florida law and meets all definitional requirements therein or is exempt from disclosure under other applicable Florida law.

SECTION 27
PUBLIC STATEMENTS

Seller and Purchaser shall consult with each other and neither of them shall issue a press release or make a statement intended for release to the general public with respect to the transactions contemplated hereby without the consent of the other Party, which consent shall not be unreasonably withheld, unless the Party desiring to make such statement or press release is advised by legal counsel that a statement or press release is required by applicable Law (including information provided pursuant to a request for public information under the Florida Public Records Law, Section 119.10, Florida Statutes); *provided, however,* that in this event the Party making the public statement or press release shall notify the other Party in advance of such statement or press release and allow the other Party reasonable time to comment on such statement or press release. Notwithstanding the immediately preceding sentence, the Parties acknowledge that certain meetings of the Orlando Utilities Commission and the City of Orlando are open to the public, and nothing in this Agreement shall be deemed to require that the proceedings of such meetings not be made public or to restrict the reporting by the media of such proceedings.

SECTION 28
INSURANCE

Seller and Purchaser, and all contractors and subcontractors performing any services in connection with the operation or maintenance of the Facility, shall obtain and maintain in force comprehensive general liability insurance, and property insurance for injury to persons and property, automobile liability insurance and workman's compensation insurance, all in amounts and under terms as required by the Operating Agreement.

SECTION 29
TAXES

Purchaser shall pay all sales, use, personal property and other taxes of every kind, if any, that are not currently levied and are hereafter levied on the purchase, sale or use of fuel consumed by the Facility to provide Energy or Ancillary Services in accordance with this Agreement or the purchase, sale or use of Capacity, Energy or Ancillary Services under this Agreement, but excluding any taxes levied on Seller's net income. In the event Seller, on behalf of Purchaser, pays any taxes that are the responsibility of Purchaser under this Section *29*, the amount so paid shall be added to the next monthly invoice submitted by Seller to Purchaser under Section 9, and Purchaser shall pay such amount in accordance with Section 9. Upon the reasonable request of Purchaser, Seller agrees to (i) provide documents related to taxes or assessments to be paid by Purchaser under this Agreement and (ii) cooperate in tax contests or proceedings involving Purchaser at Purchaser's expense.

IN WITNESS WHEREOF, the Parties, intending to be legally bound, have caused this Agreement to be executed by their duly authorized representatives as of the day and year first written above.

ORLANDO UTILITIES COMMISSION[7]

By: _____

Name: _____

Title: _____

SOUTHERN COMPANY - FLORIDA LLC

By: _____

Name: _____

Title: _____

[7] Will be different for each entity.

APPENDIX A

TECHNICAL LIMITS

Unit Operating Modes

1. **Definition of Operating Modes**.

The Facility will have several different operating modes.

- Mode 1: Normal Operation—both gas turbines (CTs) operating with no supplemental firing of the Heat Recovery Steam Generator (HRSG) and no gas turbine power augmentation.

- Mode 2: Supplemental Firing Operation—both gas turbines operating at full load with supplemental firing of the HRSG.

- Mode 3: Power Augmentation Operation—both gas turbines operating at full load with supplemental firing of the HRSG's (Mode 2 Supplemental Firing Operation) to produce both steam for full steam turbine-generator output with the maximum allowed continuous throttle flow at the maximum allowed continuous throttle pressure and steam for full gas turbine power augmentation (steam injection.)

- Mode 4: Part-load Operation—one or both gas turbines operating at less than full load.

2. **Natural Gas Requirements**.

The Facility will require "pipeline quality gas" meeting the requirements of GE fuel specification "GEI 41040E - Process Specification Fuel Gases for Combustion in Heavy Duty Gas Turbines".

Natural gas is to be delivered to the Facility by pipeline and the pipeline and gas must meet the following equipment characteristics and requirements:

- Nominal Maximum N.G. Flow (HHV) per Block (2x1) [redacted] MMBtu/hr*
- Nominal N.G. Higher Heating Value [redacted] Btu/lb
- Minimum Fuel Supply Temperature (after PRV) [redacted] °F
- Fuel Pressure at Gas Control Valve** [redacted] PSIG (nominal)

[redacted] PSIG maximum

* Based on Winter Peaking [redacted] Power during Full Pressure Operation.

** Reference GE Pub. GEI 41040E.

3. **Fuel Oil Requirements**.

The Facility will require fuel oil that is in compliance with ASTM Standard Specification D-2880 (as revised) and "GE Gas Turbine Liquid Fuel Specifications" (document number GEI 41047H). This No. 2 GT Grade Gas Turbine Fuel Oil must be in compliance with the specifications and procedures for No. 2 Fuel Oil as defined in ASTM D396.

Note that environmental permitting may create conditions for sulfur, fuel bound nitrogen and other specifications which could affect or add minimum specifications, such as, but not limited to, those identified in the following table:

	SPECIFICATIONS	**ASTM TEST METHOD**
Sulfur, % Wt., Max.	0.05	D – 1266
Fuel Bound Nitrogen	0.050% Max.	

4. **Dispatch and Operational Requirements**.

- The Facility will be capable of operating with fuel oil. The Facility may fire oil in the gas turbines only and not in the HRSG duct burners. During these periods, the Facility shall operate in Mode 1 (Normal Operation) only.

- The Facility will require shutdown for a minimum of one hour prior to switching from natural gas to oil firing. The fuel oil forwarding system will not be operated during normal gas firing, but operation of the fuel forwarding system will be initiated upon proper notice of a requirement for fuel switching. The Facility will be capable of switching from oil to natural gas without shutdown; however, the Facility may be required to decrease to a minimum load and stabilize prior to ramping to full load.

- The Facility will be capable of being controlled via Automatic Generation Control (AGC) in Mode 1 (Normal Operation). The AGC load range and ramp rate will be set by the Facility's operator based on the actual capability of the CTs as determined through testing. With the

duct burners firing (Mode 2 – Supplemental Firing Operation), the load range and ramp rate will be set and manually controlled by the Facility's operator based on the capabilities of the duct burners. No load following capability is available in Mode 3 (Power Augmentation Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) only at ambient temperatures of [redacted] and higher.

- The Facility will require [redacted] of de-mineralized water for Mode 1 (Normal Operation).

- The expected maximum allowable rate of load increase for the Facility will be [redacted]. Actual maximum load increase rate will be determined by actual testing and in light of final permit restrictions and emissions tests.

- The Facility will be expected to be capable of operating minimum load with one CT at [redacted] load or two CTs each at part of [redacted] load. Actual minimum load will be determined in light of final NOx emissions and permit restrictions and testing.

- Required startup times for the Facility shall be as follows:

  Mode 1 (Normal Operation): refer to Attachment 1 – Time to Dispatch Curve. Note: Actual Curve to be determined by testing.

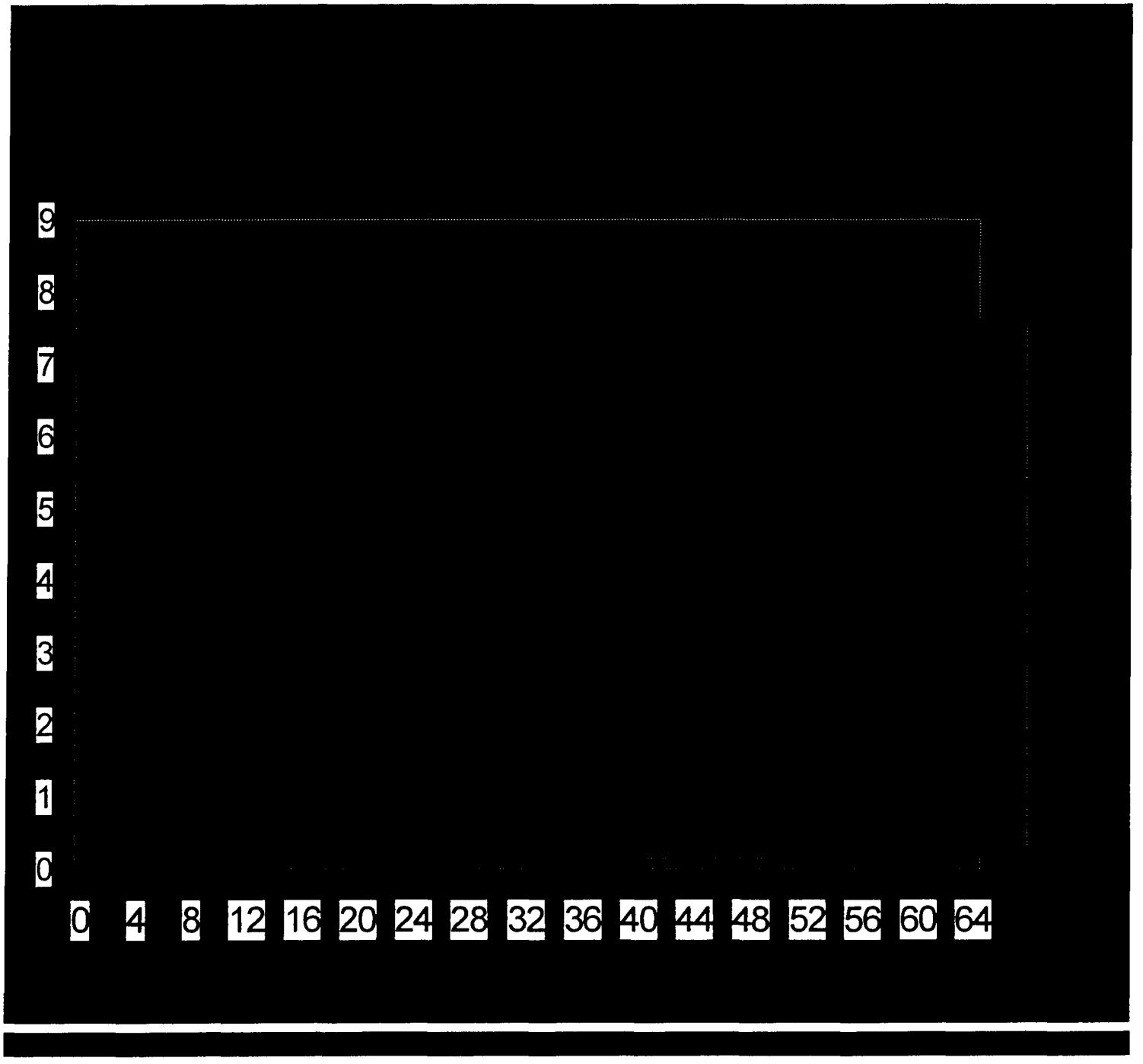
  Mode 2 (Supplemental Firing Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation).

  Mode 3 (Power Augmentation Operation [redacted] from one hundred percent (100%) Mode 1 (Normal Operation) or [redacted] from one hundred percent (100%) Mode 2 (Supplemental Firing Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) a maximum of [redacted] based on the LTSA contract with GE.

- The Facility will not be allowed to operate in a traditional CT only mode (no simple cycle operation, *i.e.*, no bypass stack). However, the CTs will be capable of operating independently of the steam turbine utilizing the steam bypass systems for a limited time. Most major plant equipment (such as HRSG BFP's, condenser, cooling tower and circulating water pumps) will be required during operation in this mode. The HRSG duct burners will not be available in this mode. The maximum generation capability of the Facility operating in this mode will be [redacted] CT load.

- The Facility's CT evaporative coolers should not be operated at ambient temperatures less 7than [redacted] to prevent freezing at the CT compressor inlet.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APPENDIX B

REQUESTS FOR ENERGY

1.1 Schedules for Requested Quantities of Energy. Purchaser and each other Customer shall provide Seller with a single Request for Energy in order to schedule requested quantities of each category of unit output as follows:

1.1.1 Day Ahead Daily Schedule. Customers shall communicate the day ahead Request for Energy for each day to Seller at or before [redacted] Eastern Prevailing Time of the immediately preceding day before delivery is to be made, or such other earlier time that may be required by an RTO.

1.1.1.1 When AGC mode is available, during each hour the unit is scheduled to be in AGC mode, the Request for Energy shall specify the maximum amount of Energy desired for each of the twenty-four (24) hours. During each hour the unit is in AGC mode, the Customers shall not be permitted to reduce the Request for Energy to an amount less than [redacted] MW of the maximum Energy scheduled during that hour in the Request for Energy from the Customers' aggregate Equity Capacity and the Customers' aggregate capacity available under the Power Purchase Agreements (Customers' "PPA Capacity"). If in any hour, should the Customers reduce the Request for Energy amount by more than [redacted] MW, the Customers shall pay Seller [redacted] for the difference between the amount of the Delivered Energy and the amount that is [redacted] MW below the Request for Energy amount.

1.1.1.2 During each hour the Facility is not scheduled to be in AGC mode or the AGC mode is unavailable, the Request for Energy shall specify the amount of Energy from the Customers' aggregate PPA Capacity and aggregate Equity Capacity for each of the twenty-four (24) hours. Requests for Energy shall be submitted in [redacted] MW increments in a total amount that falls between the Facility's minimum capability and its maximum capability as described in the Technical Limits.

1.2. Hourly Changes to the Daily Schedule. The Customers jointly shall be entitled to make changes to a Request for Energy by communicating such changes to Seller no later than [redacted] prior to the beginning of the hour in which such changes are to become effective. The Customers shall

be responsible for any costs associated with OASIS notifications and NERC tagging requirements.

1.3. Capacity Emergency. During any periods in which the Customers experience a Capacity Emergency, the Customers shall be entitled to increase the Request for Energy on shorter notice than that provided in paragraph 1.2 above by an amount not to exceed the Customers' unavailable resources that were the cause of the Capacity Emergency and Seller shall endeavor to comply with the request consistent with the Technical Limits, Prudent Utility Practice, applicable Law and Permit requirements.

1.4. Minimum Start-up Time. If the Customers have scheduled a zero amount of Capacity in any hour and the Facility is not on-line, the Customers shall provide notice consistent with the Technical Limits prior to scheduling any Request for Energy.

1.5. Load Following Service. The Customers shall have the ability to control the output of the Facility using the AGC mode, if available, only to the extent that the Facility has the ability to operate in the AGC mode consistent with the Technical Limits, Prudent Utility Practice, and applicable Law and Permit requirements.

1.6 Electronic Scheduling. The Customers shall use electronic scheduling for Requests for Energy under this Agreement, if and to the extent that Seller's electronic scheduling capability is operational. To the extent it is not, the Parties will use other mutually agreed-upon communication procedures (such as fax).

2.1 Shortfall Conditions; Oversupply Conditions.

2.1.1 If the Facility is in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the Facility is not within [redacted] MW of the Request for Energy, OUC shall communicate to Seller the amount of error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the Request for Energy within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.1.1 If the actual output of the Facility is greater than the Request for Energy (an "Oversupply Condition"), the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the Facility equals the Request for Energy. OUC, acting for itself and on behalf of the other Customers, shall coordinate with Seller during the period that the actual output of the Facility exceeds the Request for Energy. The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition. Seller shall compensate OUC, on its own behalf and as agent for KUA and FMPA, for any such Oversupply Condition.

2.1.1.2 If the actual output of the unit is less than the Request for Energy (an "Undersupply Condition"), the provisions of Section 4.3 will apply if applicable.

2.1.2 If the Facility is not in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the unit is not within [redacted] MW of the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy pursuant to Section 4.5 of this Agreement), then OUC shall communicate to Seller the amount of the error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.2.1 If an Oversupply Condition exists, the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the unit equals the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy). The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition.

2.1.2.2 If an Undersupply Condition exists, the provisions of Section 4.3 will apply if applicable.

3.1 Notification Requirements for Delivery of Energy from Alternate Resources.

3.1.1 When the Facility is available and running at minimum load and spinning reserves are available, Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of Customers' Schedule at least [redacted] (or the amount of time in which an RTO has determined that the Physical Transmission Rights ("PTRs") may be recalled) prior to the scheduled commencement of delivery of such Energy. For purposes of Section 3.1, the phrase "has scheduled delivery" means that Seller has scheduled and arranged the OASIS, tagging, and any transmission rights required by an RTO. If an RTO is established in Florida, and under such condition the RTO determines that Physical Transmission Rights (PTRs) may be recalled if not utilized, then Seller will notify OUC if Seller has so scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.2 When the Facility is unavailable and is not scheduled to return to service in time for Seller to serve the Customers' Schedule, Seller will notify OUC within [redacted] after Seller's receipt of Customers' Schedule if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customers' Schedule. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.3 When the Facility becomes unavailable while Seller is serving Customers' Schedule, Seller will notify OUC within [redacted] after the Facility is deemed unavailable if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of the remainder of Customers' Schedule. If Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than the top of the next full hour following the hour that Seller notified OUC of Seller's election. (Example: The Facility becomes unavailable at [redacted] Seller gives notice no later than [redacted] if Seller will arrange to deliver Energy from Alternate

Resources. Delivery from Alternate Resources should begin no later than [redacted]) At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.4 When the Facility is expected to return from an outage, but does not, Seller will notify OUC within [redacted] of Seller's realization that the Facility will not be available as expected to meet the start of a Customer's Schedule. If the start of such Customer's Schedule is to begin within [redacted] or less from the time of such notice, Seller will notify OUC at the same time if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule. Otherwise Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule at least [redacted] prior to the start of such Schedule and preferably at least [redacted]. If Seller notifies OUC that Seller has scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than [redacted] that Seller notified OUC of Seller's election (but not earlier than the original start of such Customers' Schedule). If an RTO develops in Florida, and under such condition the RTO determines that PTRs may be recalled if not utilized, then Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

APPENDIX C

CAPACITY TESTING PROCEDURE

The capability of the Facility will be required to be demonstrated prior to the Commencement Date. The demonstration of the capability of the Facility following the Commencement Date shall be scheduled in accordance with the provisions of Section 4.1.2. As provided in Section 4.1.3, Participants may also request additional tests of the Facility which shall not be used as the basis for determining the Demonstrated Capability of the Facility. Purchaser shall have the right to monitor (either on-Site or otherwise) all performance tests.

All Capacity testing will be adjusted to the Rated Conditions using correction curves supplied by Seller. "Rated Conditions" means seventy (70) degrees Fahrenheit (°F) and forty five percent (45%) relative humidity. The demonstrated net output of the Facility will be as measured by the Meters.

On the date of the Capacity test, Seller shall bring the Facility to maximum full load capability within the Technical Limits of the Facility for the ambient conditions for that day. The test shall be scheduled between the weekday hours of [redacted] (prevailing Eastern Time) and will be conducted over [redacted] period (or a lesser period if mutually agreed upon). Seller must notify Customers when the Facility is at maximum full load capability, at which time the Capacity test shall begin. The Demonstrated Capability will be the average net hourly output over the test period corrected to Rated Conditions.

APPENDIX D

Example Calculations of Quantities of Gas Transportation and/or Commodity Required for Delivery from Alternate Resources

Listed below are examples of the determination of the amount of gas transportation and/or commodity that the Fuel Supply Agent shall provide to Seller pursuant to Section 4.2.5.2 or 4.2.5.3 when Seller elects to deliver Energy from Alternate Resources.

Example 1

The facility is unavailable. The Customers have Scheduled 400 MWh of Energy in an hour. Seller notifies OUC that Seller will supply the 400 MWh of Energy for the subject hour from Alternate Resources.

In Example 1, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 2

The facility is unavailable. The Customers have Scheduled 610 MWh of Energy in an hour. Seller notifies OUC that Seller will supply 550 MWh of Energy for the subject hour from Alternate Resources.

In Example 2, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 3

The facility is available. The Customers have Scheduled 450 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 100 MWh of Energy for the subject hour from Alternate Resources and 350 MWh from the Facility.

In Example 3, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 4

The facility is available. The Customers have Scheduled 600 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 200 MWh of Energy for the subject hour from Alternate Resources and 400 MWh from the Facility.

In Example 4, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

APPENDIX E

AFFILIATE GUARANTEE

Appendix 1A.B
Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency Request for Detailed Proposals for the Joint Development of the Stanton Energy Center and/or The Cane Island Power Park May 26, 2000

Orlando Utilities Commission
500 South Orange Avenue
P.O. Box 3193
Orlando Florida 32802
Phone: 407.423.9100
Administrative Fax: 407.236.9616
Purchasing Fax: 407.384.4141
Website: www.ouc.com

OUC
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ORLANDO UTILITIES COMMISSION

KISSIMMEE UTILITY AUTHORITY AND

FLORIDA MUNICIPAL POWER AGENCY

REQUEST FOR DETAILED PROPOSALS

FOR THE JOINT

DEVELOPMENT OF THE

STANTON ENERGY CENTER AND / OR

THE CANE ISLAND POWER PARK

MAY 26, 2000

SECTION 1. PURPOSE AND SCOPE

The Orlando Utilities Commission ("OUC"), acting on its own behalf and as agent for the Kissimmee Utility Authority ("KUA") and the Florida Municipal Power Agency ("FMPA") (with OUC, KUA and FMPA referred to together as the "Participants") is issuing this Request for Detailed Proposals for the Joint Development of power generation facility on the Stanton Energy Center to a short listed group of interested parties that submitted Letters of Interest in response to OUC's earlier solicitation of interest letters of March 20, 2000 and May 11, 2000 ("Initial Solicitations"). The Initial Solicitations requested for pre-qualified parties to submit letters of interest in entering into an agreement with OUC to jointly develop a 500 MW, combined cycle power plant facility at OUC's Stanton Energy Center ("SEC") in Orlando, Florida, with an expanded capacity option to facilitate the participation of the KUA and FMPA in a 750MW combined cycle project at the SEC site. Having reviewed the letters of interest in response to the Initial Solicitations, OUC is now issuing this request for detailed proposals from a group of those respondents to the Initial Solicitations whose responses OUC deemed potentially most beneficial to the Participants and their customers ("Respondent(s)"). This request for detailed proposals ("RFP") will be used to rank the proposals of the Respondents and will form the basis for subsequent contract negotiations with the Respondent whose proposal has the best value to the Participants out of all of the detailed responses from the Respondents. This RFP further offers a potential development opportunity for a 500 MW combined cycle power plant on the KUA/FMPA Cane Island Power Park Site (with the resultant project or projects being referred to hereafter as the "Project"). The objectives of OUC in soliciting the joint development proposals are as follows:

A. To identify a means for satisfying the electric load requirements of OUC and the City of St. Cloud.
B. To assist KUA and FMPA in meeting their future power supply needs.
C. To obtain an ownership interest in a reliable and efficient generating resource that will provide competitively priced electric energy.
D. To obtain a purchase power agreement that is competitively priced with a term that provides the Participants flexibility in managing the bulk power supply available to the Participants to serve their customers.
E. To enter into a joint development relationship with an entity having resources that will assist the Participants in providing economical electric service in a deregulated utility environment.
F. To accomplish all of these objectives while preserving for OUC as much flexibility in any future development at the Stanton Energy Center site as possible.
G. To assure that KUA and FMPA make the best use of the Cane Island Power Park Site.

SECTION 2. DEFINITIONS

"**750 MW Option**" shall mean the optional project configuration to be proposed by each Respondent pursuant to Section 12 of this RFP.

"**Cane Island Option**" shall mean the potential 500 MW combined cycle power project located on the KUA Cane Island Power Park site.

"**FMPA**" shall mean the Florida Municipal Power Agency.

"**Initial Solicitations**" shall mean the solicitation for letters of interest in the joint development of the Stanton Energy Center issued by OUC on March 20, 2000 and May 11, 2000.

"**KUA**" shall mean the Kissimmee Utility Authority.

"**Minimum Requirements**" means the minimum of information which must be addressed in any proposal in order to be considered by OUC as being responsive to this RFP.

"**Negotiation Security**" shall mean the two hundred and fifty thousand ($250,000) security to be provided by the Respondent under this RFP (as applicable) prior to OUC entering into negotiations on that party's proposal.

"**OUC**" shall mean the Orlando Utilities Commission.

"**Participants**" shall mean OUC, FMPA and KUA together as joint participants in the Project with the successful Respondent.

"**Project**" shall mean the jointly owned combined cycle electrical generating facility constructed on the Project Site pursuant to this RFP.

"**Project Cost(s)**" shall mean the costs associated with the permitting development, construction, testing and commissioning of the Project, some or all of which will be shared by OUC and the successful Respondent based on a percentage basis which corresponds to the relative ownership interest of each party.

"**Proposal Fee**" shall mean the non-refundable five thousand dollar ($5,000.) fee required to be submitted by each Respondent in order to have its detailed proposal be considered by OUC under this RFP.

"**Project Site(s)**" shall mean the property on the Stanton Energy Site or the Cane Island Power Park Site, or both (as applicable) designated by the Respondent as the minimum acreage required to construct, operate and maintain the Project.

"**Purchase Power Solicitation**" means the solicitation for the purchase capacity and energy for a term of at least five (5) years from an existing or new power resources not located on the Stanton Energy Center site issued by OUC on May 24, 2000.

"**Respondent(s)**" shall mean those respondents to the Initial Solicitations whose proposals OUC deemed potentially beneficial to the Participants and their customers.

"**RFP**" shall mean this Request for Detailed Proposals for the Joint Development of the Stanton Energy Center dated May 26, 2000.

"**Submission Deadline**" means July 18, 2000, the date by which OUC must receive a Respondent's proposal in order for such proposal to be evaluated under this RFP.

SECTION 3. PROJECT SITE INFORMATION

The following is information related to the potential Project Sites which is provided for the Respondents' information:

I. Stanton Energy Center Site

The Stanton Energy Center ("SEC") site is located in Orange County, Florida, approximately fourteen (14) miles east-southeast of the City of Orlando. The Site encompasses three thousand two hundred eighty (3,280) acres. Approximately nine hundred sixty (960) acres of the site have been developed. Certain portions of the remaining site have been reserved as a wildlife sanctuary for the Red Cockaded Woodpecker. Main site access is an entry off of State Highway 50 and Alafaya Trail. The site has rail access from CSX Railroad. It is anticipated that the proposed Project units will be located just north of the existing power blocks. This area is suitable for siting the proposed unit without any additional site preparation. A schematic drawing of the SEC Site is attached as Attachment 7. Major features of the developed portions of the site include the following:

A. Existing Steam Generating Units.

Currently located on the site is a power block of two (2) virtually identical coal fueled steam turbine units. SEC Unit Number One commenced commercial operation in 1987 and SEC Unit Number 2 commenced commercial operation in 1996. Each unit has a gross output rated at 460 MW.

B. Make-up Water Storage.

The site includes a ninety-three (93) acre makeup water supply storage pond. This pond supplies cooling tower makeup water for SEC Units 1 and 2 and is sized to accommodate the anticipated cooling tower makeup storage requirements for the Project.

C. Coal Storage.

The site has a coal storage area and a combustion waste storage area of approximately fifteen (15) acres and three hundred twelve (312) acres respectively.

D. Substation

The site has one 230 kV substation. The substation is connected to six (6) 230 kV transmission lines that interconnect the existing generating units to the OUC transmission grid and a seventh 230kV line that interconnects to the Florida Power Corporation transmission system is under construction.

E. Cooling Water Supply

The site is a zero discharge site which receives treated wastewater from Orange County's Eastern Subregional Water Treatment Facility. The water quality from that water treatment facility is as follows:

	Guaranteed Max Annual Average Concentration	Guaranteed Max Monthly Average Concentration
Calcium, mg/l as Ca CO3	88	125
Magnesium, mg/l as Ca CO3	41	62
M-Alkalinity mg/l as Ca CO3	115	165
Sulfate, mg/l as SO4	45	75
Chloride, mg/l as Cl	70	90 (prior to Chlorination)
Silica, mg/l (SiO2)	16	24
Nitrate Nitrogen, mg/l (as N)	2	6
Total Nitrogen, mg/l (as N)	5	6
BOD5, mg/l	8	10
Suspended Solids, mg/l	8	10
Total Phosphorus, mg/l	1	1
Sodium, mg/l (as P)	60	80
Total Dissolved Solids, mg/l	400	500
PH at 25 *C	6.0-8.5	6.0-8.5

F. Gas Transmission

An existing Florida Gas Transmission natural gas transmission line passes three (3) miles south of the site boundary contiguous to the OUC railroad corridor. The gas transmission line is twenty-six (26) inches in diameter and transmits gas at a pressure of eight hundred and fifty (850) psig.

II. Cane Island Power Park Site

The Cane Island Power Park consists of a 1,027 acre site owned by KUA. The existing power plant units are located on an island in the middle of the site with the remainder of the site comprised mainly of wetlands providing buffer. 876 acres of the site have been deeded as conservation easement which resulted in KUA obtaining mitigation credits available for use to mitigate other development on the site. The site was designated for at least 1,000 MW of combined cycle generating capacity. Existing power plant Units 1 and 2 began commercial operation in 1995. Unit 1 is a 42 MW General Electric LM 6000 simple cycle combustion turbine. Unit 2 is a 120 MW, 1 x 1 General Electric 7EA combined cycle power plant. Unit 3, currently under construction, will be a 250 MW, 1 x 1 General Electric 7FA combined cycle power plant which will begin commercial operation on June 1, 2001. All Units have dual fuel capability and will operate on natural gas with No. 2 fuel oil as backup. Unit 3 will be fitted with a selective catalytic reduction ("SCR") system for NOx control.

KUA constructed and operates the Units under the terms of a Participation Agreement with FMPA. FMPA is a fifty percent (50%) joint owner of Units 1 – 3. KUA has a very good construction and operating record. Units 1 and 2 were constructed under budget and have been operating efficiently with a high level of reliability. Ease of licensing is one of the biggest advantages of the Cane Island Project Site enjoys.. There were no intervenors in any of the site certification hearings and no members of the public appeared in opposition. KUA feels that the lack of opposition in the permitting of a 250 MW power plant in today's environment is a due to the quality of the site and KUA's reputation in the community.

A. Gas Transmission

The site is served by a 20 inch natural gas pipeline with capacity to serve more than 1,000 MW of combined cycle generation.

B. Cooling Water Supply

The site obtains cooling water through a treated sewage effluent pipeline, which runs adjacent to the southern boundary of the site. Wastewater discharge is permitted back to the treated sewage effluent pipeline.

C. Make-up Water Storage.

Groundwater from onsite wells is used for service water and is permitted as a backup source for cooling water.

SECTION 4. SCHEDULE FOR SOLICITATION

The following is the proposed schedule by OUC for the RFP and Project development:

Event	Scheduled Date
Issuance of RFP	May 26, 2000
Submission Date for Respondent to File Intent to Provide Detailed RFP Proposal Form	June 15, 2000
Receipt of Responses to Joint Development RFP	July 18, 2000
Ranking of Joint Development Respondents	August 15, 2000
Negotiation of Joint Development & Purchased Power Contracts	August 21 – September 29, 2000
Receipt of Site Certification	October 1, 2001
Commencement of Construction	October 15, 2001
Commercial Operation	October 1, 2003

SECTION 5. PROPOSAL INSTRUCTIONS

Each Respondent must provide OUC with written notice of its intent to provide a detailed proposal in the form attached as Attachment 10 and such notice must be received by OUC on or before 5:00 p.m. on June 15, 2000. Respondents must submit along with such notice of intent, the Proposal Fee as further described in Section 8. Following the notice of intent, Respondents must provide their detailed proposals along with supporting documentation and fully completed proposal data sheets attached hereto as Attachments 2 - 6 on or before July 18, 2000 (the "Submission Deadline"). Three (3) hard copies of the proposal package must be submitted to the following address on or before 5:00 p.m. on the Submission Deadline date:

Frederick F. Haddad, Jr.
Vice President
Power Resources Business Unit,
Orlando Utilities Commission
500 South Orange Avenue
Orlando, FL 32801

All proposal packages must be signed by an authorized representative of each Respondent. Some of the information requested of each Respondent under this RFP has been requested solely to allow OUC to evaluate each proposal on the same terms as the proposals of the other Respondents, but the final contract as negotiated with the chosen Respondent will ultimately be tailored to that which brings the best value to the Participants.

SECTION 6. EVALUATION OF PROPOSALS

A. Evaluation Process

(i) Acting in its capacity as the negotiating agent for the Participants, OUC and its independent consultants will verify that each proposal received on or before the Submission Deadline includes all required information and supporting documentation. Any proposal which is not received by the Submission Deadline will be deemed non-responsive and will not be considered. OUC will perform an initial screening evaluation of each timely proposal to identify and eliminate any proposals which (a) are not responsive to this RFP, (b) do not meet the Minimum Requirements set forth in this RFP, or (c) fail to include an executed confidentiality agreement in the form attached hereto as Attachment 1 . No additional information will be accepted from a Respondent after the Submission Deadline, except for clarification requested by OUC and any transmission study results (if applicable).

(ii) The proposals that pass the initial evaluation screening will be evaluated against the remaining proposals to determine which, if any, in OUC's sole judgement, provides the best value to the Participants and their customers. Information provided by each Respondent in its proposal will be used by OUC to select the highest ranked Respondents. OUC will evaluate the proposals and rank the three (3) best proposals considering monetary and non-monetary factors. In addition to this RFP, the Participants have issued a Purchase Power Solicitation for capacity. The Purchase Power Solicitation is a solicitation for the purchase power for a term of at least five (5) years from existing or new power resources not located on the SEC or Cane Island Power Park site. The Participants will not have an ownership position in this resource. The proposals from the Purchase Power Solicitation will be ranked and the proposals from this RFP will be ranked, and then the highest ranking proposals from each solicitation will be ranked against each other. Upon ranking of the proposals from each of the solicitations, OUC on behalf of the Participants will commence negotiations on behalf of the Participants with the highest ranked

proposal from either the Purchase Power Solicitation or this RFP (as applicable). These negotiations with the highest ranked respondent may result in a project structure different than that originally proposed. OUC will continue negotiations with the highest ranked respondent under the applicable solicitation in an attempt to reach agreement. If no agreement is reached with the highest ranked respondent, OUC will terminate those negotiations and initiate negotiations with the second highest ranked respondent from the applicable solicitation and so on until either a negotiation is completed or OUC abandons the solicitation.

(iii) Upon the selection of the highest ranked proposal and prior to the start of negotiations, the respondent under the applicable solicitation will be required to provide further security, equal to two hundred and fifty thousand ($250,000) dollars. Such additional security must be in form and substance reasonably acceptable to OUC ("Negotiation Security"). The Negotiation Security shall be returned only if:

(a) OUC abandons the solicitation prior to the termination of negotiations; or

(b) The parties successfully execute a contract for the Joint Development of a generation unit on the SEC and/or Cane Island Power Park site.

(c) The laws of Florida or interpretations thereof by Florida courts preclude the joint ownership of the Project by the Respondent and the Participants and neither the Participants nor the Respondent, after the exercise of their best reasonable efforts, are able to identify an mutually acceptable alternate joint development plan.

B. Reservation of Rights.

(i) The Participants reserve the right, without qualification and in their sole discretion, to accept or reject any or all proposals for any reason or to make an award to that Respondent, who, in the opinion of OUC, will provide the most value to the Participants and their customers as a joint development partner.

(ii) The Participants reserve the right to reject any, all, or portions of the proposals received for failure to meet any criteria set out in this RFP. The Participants may also decline to enter into any

agreement proposed by or negotiated with a Respondent, or to abandon the RFP effort in its entirety.

(iii) The Participants reserve the right to reject proposals submitted by any Respondent which (a) is incomplete, inaccurate, conditional, deceptive, misleading, ambiguous, exaggerated, or non specific in its offer; or (b) is not in conformance with the requirements and instructions contained in this RFP; or (c) Respondents that submit proposals due so without recourse against the Participants, the City of Orlando or the City of Kissimmee for either rejection of such proposals or for failure of the Participants to enter into any agreement with the Respondent in association with the proposal and this RFP.

C. Disqualification of Respondents

Each Respondent must direct any questions or comments in writing with respect to its proposal to:

Frederick F. Haddad, Jr.
Vice President
Power Resources Business Unit
Orlando Utilities Commission
500 South Orange Avenue
Orlando, FL 32801

Failure of any Respondent to direct communications to OUC in this manner may result in such Respondent's proposal being rejected from consideration by OUC.

D. Acknowledgement of Law

Each Respondent to this RFP, by submitting its proposal to this RFP, acknowledges that it is aware of the April 20, 2000, ruling by the Florida Supreme Court on the Duke Power/ New Smyrna Power Plant need application published in Tampa Electric Co., et. al. v. Joe Garcia, et. al. as the Florida Public Service Commission, and understands that in so ruling, the Florida Supreme Court has created some question as to the viability of merchant plant siting in Florida under the Electrical Power Plant Siting Act. A copy of the ruling is attached hereto as Attachment 9.

SECTION 7. PROPOSAL PRESENTATION

Each Respondent is encouraged to visit the SEC and the Cane Island Power Park sites prior to the submission of its proposal. In addition, each Respondent may schedule a presentation time with OUC during the week of June 26, 2000 prior to Submission Deadline. This presentation will provide the Respondent the opportunity to introduce the proposed project personnel and present any other information the Respondent believes may be relevant to the evaluation process.

SECTION 8. PROPOSAL FEE

Respondents are required to submit the Proposal Fee with the Notice of Intent to Provide a Detailed Proposal Form, in the form of a non-refundable check payable to OUC for each proposal submitted. The Proposal Fee is non-refundable and will only be returned to a Respondent that withdraws its proposal prior the Submission Deadline.

SECTION 9. NO LIABILITY

Neither OUC the City of Orlando, KUA, the City of Kissimmee nor FMPA will be liable for any expenses incurred by Respondents in connection with the preparation of its proposals or negotiations with OUC, or for any costs, fees, or lost or foregone profits of an unsuccessful Respondent.

SECTION 10. EXPANDED PROJECT OPTIONS

The Participants wish to evaluate the potential benefits that may accrue from the joint development of expanded project options at the SEC Project Site or the Cane Island Power Park Project Site or both and therefore the Participants are soliciting information from the Respondents in order to evaluate two (2) potential expanded Project options.

A. 750 MW Option. The first option is to increase the SEC Project capacity of 500 MW to 750 MW (the "750 MW Option"). Proposal data forms include columns to price this option. All assumptions provided for the base case of 500 MW case shall be assumed to apply to the 750 MW Option case for purposes of this RFP.

B. Cane Island Option. The second option is the joint development of a combined cycle unit on the Cane Island Power Park site shown in the diagrams attached as Attachment 8. (the "Cane Island Option") To the extent that sufficient benefits are available, the Participants are prepared to commit to the successful Respondent the first right to negotiate a Joint Ownership and Power Purchase Agreement for a unit on the Cane Island Power Park Project Site. To

the extent that sufficient benefits do not exist, then the Participants will pursue the development of the Cane Island site independently of the SEC Project Site development.

It is anticipated that the Cane Island Option will consist of the development of a two-on-one combined cycle unit. It is proposed that the Cane Island Power Park Project Site units will be jointly owned with the successful Respondent and the Participants. OUC and KUA will support the Need for Power Application and generally be responsible for the permitting of the unit as proposed for the SEC Project Site. Respondents are requested to fill out the information shown for the Cane Island Option on the attached data forms if interested in the Cane Island Option .

SECTION 11. BASE PROPOSAL ASSUMPTIONS

The following is a list of base assumptions which should be considered by all Respondents in calculating the Project Costs for its proposal:

I. SEC Project Site

A. Site Costs

Each Respondent should indicate the minimum total acreage needed to support the construction and operation of a minimum 500 MW combined cycle plant in the configuration set out in its proposal. Respondents should assume that a site sufficient for that purpose will be offered to the joint Project by OUC at the SEC site based on a long term lease. Respondents should specify a site large enough that all proposed structures and equipment for the Project, unless otherwise noted in this RFP as being provided from existing OUC facilities or third party sources, will be located on the Project Site.

B. OUC Provided Equipment/Project Cost

For purposes of the proposal evaluation, each Respondent should assume that OUC will provide for the Project the following materials and services for a one (1) time Project Cost of five million five hundred thousand dollars ($5,500,000), for which payment is due October 1, 2000. The actual cost for these materials and services will be determined during negotiations with the successful Respondent:

(i) Project Need for Power Permitting and Site Certification Permitting- OUC will take the lead in the Project Need for Power Permitting and Site Certification Permitting, including preparation of permit applications, arranging for the services of outside consultants, and

arranging for expert testimony. Respondent shall at its own cost support OUC in the permitting process from internal resources as required.

(ii) Transmission Related Systems – The following transmission system equipment:

(a) Necessary 230 kV breakers to tie the Project to the existing SEC substation;
(b) All Transmission system equipment to connect the high side of the Project generator step-up transformers to the SEC substation;
(c) All generator and generator transformer protective relaying for the Project;
(d) Reserve station power at 6.9kv to the Project site boundary.

(iii) Natural Gas Supply - Natural gas piping from the FGT transmission line to the Project Site boundary. Metering shall be on the Project Site. Respondent's estimation of the size of Project Site necessary to support its proposal should include the space necessary to install a meter station and the costs associated with the installation of a meter station should be included in the Respondents proposal.

C. Ongoing OUC Commodities and Services

Each Respondent should include in its proposal a eight hundred thousand dollar ($800,000) annual cost, escalating annually with the Gross Domestic Product Deflator, for the following ongoing Project materials and services and should further assume such costs will be shared costs for the operation of the Project.

(i) Long term lease of the land sufficient for siting and operation of the Project;
(ii) Potable water for the Project;
(iii) Deionized water for the Project;
(iv) Site security services for SEC Site (including the Project Site); and,
(v) Grounds maintenance services for the Project Site.

The Project would pay to OUC such annual costs based on an agreed monthly payment schedule.

D. Cooling Water

The Project will receive cooling water make-up from Orange County's Eastern Subregional Wastewater Treatment Facility. The Respondent

shall assume a cost of forty-five cents per thousand ($0.45/1000) gallons for cooling water make-up .

The Project would pay to OUC such annual costs based on an agreed monthly payment schedule.

E. Cooling Tower Blowdown Treatment

Each Respondent shall include in its proposal sufficient capital costs and operation and maintenance costs to construct and operate on the Project Site a treatment facility sufficient to treat any additional cooling tower blowdown water generated by the Project to a level sufficient to permit such treated water to be used as cooling water makeup for the Project.

The Project would pay to OUC such annual costs based on an agreed monthly payment schedule.

F. Tax Exempt Financing

Each Respondent must assume that no tax exempt financing will be available from OUC for the benefit of the Project. Each Respondent should assume that any portion of the financing required of the Respondent for its ownership share of the proposed Project will be arranged by the Respondent by whatever normal means each Respondent would otherwise use to finance a power generation project.

G. Emission

For purposes of this RFP, Respondents should assume that the Project must meet the air emissions requirements established in the site certification for the Kissimmee Utility Authority Cane Island 3 Site. The Cane Island 3 site certification requires the use of Selective Catalytic Reduction (SCR) technology to reduce NO_x emissions. Each Respondent must provide or arrange for applicable Project emissions credits in proportion to its ownership interest in the Project.

H. Transmission Availability

OUC has determined that sufficient transmission capacity exists to support the addition of 500 MW of generating capacity on the SEC site. Respondents shall assume that costs for transmission service for its ownership share in the Project will be consistent with OUC open access tariff available at the Florida OASIS website.

Certain transmission system improvements will be necessary in order support the 750 MW Option. At the present time, the cost of any such improvements have not been determined. For purposes of this RFP, Respondent's proposal should assume that no additional costs associated with those improvements should be included.

I. Operation and Maintenance Costs

Respondents pricing should include all operation and maintenance costs for the proposed Project. These costs shall include without limitation costs for labor, equipment parts, outside services, supplies, station service power, and costs for OUC provided materials and services set forth in Section 11 (c) above. Costs should be estimated for the duration of the Project.

J. Dual Fuel Capability/ Fuel Storage

The Project shall be capable of operating on natural gas and No. 2 Fuel Oil. The Project shall have sufficient fuel oil storage capability on the Project Site to store a minimum of forty thousand (40,000) barrels of fuel oil.

K. Project Ownership Structure/ Cost Sharing

Each Respondent should assume the following with respect to the ownership of the Project, the Project output and Project cost sharing:

(i) the Participants shall own thirty-five percent (35%) of the Project assets and shall be entitled to thirty-five percent (35%) of the Project capacity;
(ii) the successful Respondent shall own sixty five percent (65%) of the Project assets and shall be entitled to sixty five percent (65%) of the Project capacity;
(iii) the Participants shall purchase, pursuant to the PPA, between seventy seven percent (77%) and one hundred percent (100%) of the Respondent's share of the Project capacity;
(iv) the Participants shall be responsible for the payment of thirty-five percent (35%) of Project Costs and ongoing Project operation and maintenance costs;
(v) the Respondent shall be responsible for the payment of sixty-five percent (65%) of Project Costs and ongoing Project operation and maintenance costs;
(vi) Respondent shall be responsible for the procurement of all Project fuel.

II. Cane Island Power Park Project Site

A. Site Costs

Each Respondent should indicate the minimum total acreage needed to support the construction and operation of a nominal 500 MW combined cycle plant in the configuration set out in its proposal. Respondents should assume that a site sufficient for that purpose will be offered to the joint Project by KUA at the Cane Island site based on a long term lease. Respondents should specify a site large enough that all proposed structures and equipment for the Project, unless otherwise noted in this RFP as being provided from existing facilities or third party sources, will be located on the Project Site.

B. KUA Provided Equipment/Project Cost

For purposes of the proposal evaluation, each Respondent should assume that for the opportunity to utilize the Cane Island Power Park site, that KUA will provide for the Cane Island Power Park Project Site the following materials and services for a one (1) time Project Cost of five million dollars ($5,000,000), for which payment is due October 1, 2000. The actual cost for these materials and services will be determined during negotiations with the successful Respondent:

(i) Project Need for Power Permitting and Site Certification Permitting- OUC (on behalf of the Participants) will take the lead in the Project Need for Power Permitting and Site Certification Permitting, including preparation of permit applications, arranging for the services of outside consultants, and arranging for expert testimony. Respondent shall at its own cost support OUC in the permitting process from internal resources as required.

(ii) Transmission Related Systems – The Cane Island Power Park site has direct access to the transmission system of Florida Power Corporation ("FPC"), OUC, Tampa Electric Company ("TECO") and KUA. Some transmission and substation infrastructure which is already in place for the existing Cane Island Units 1 - 3 may be shared by the Project Site. In addition to the existing transmission infrastructure, it is anticipated that additional substation and transmission facilities will be required. For the purpose of this RFP, Respondent's proposal should assume that no additional costs associated with those improvements should be included.

(iii) Natural Gas Supply – The Cane Island Power Park site is connected to Florida Gas Transmission's ("FGT") St. Petersburg lateral line through a 20" pipeline owned by KUA/FMPA. The cost

of any gas line extension shall be assumed to be part of the one time fee set forth above. Respondent's estimation of the size of Project Site necessary to support its proposal should include the space necessary to install a meter station and the costs associated with the installation of a meter station should be included in the Respondents proposal.

C. Annual User Fees for Certain Common Facilities

Each Respondent should include in its proposal an eight hundred thousand dollars ($800,000.00), annual cost, escalating annually with the Gross Domestic Product Deflator, for the following ongoing Project materials and services and should further assume such costs will be shared costs for the operation of the Project.

(i) Long term lease of the land sufficient for siting and operation of the Project;
(ii) Potable water for the Project;
(iii) Deionized water for the Project;
(iv) Site security services for Cane Island Power Park Project Site and,
(v) Grounds maintenance services for the Project Site.

The Project would pay to KUA/FMPA such annual costs based on an agreed monthly payment schedule for the life of the Project.

D. Cooling Water

The Project will receive wastewater from the City of Kissimmee for cooling water make-up. The Respondent shall assume a cost of twenty-five cents per thousand ($0.25/1000) gallons plus a flat fee of eight thousand dollars ($8,000) for cooling water make-up. These fees should be included in the Project operation and maintenance cost assumptions. The water quality of the wastewater effluent from the City of Kissimmee is treated to meet the treatment levels required for public access as defined in Rule 17.610, Florida Administrative Code.

E. Cooling Tower Blowdown Treatment

Cooling tower blowdown water generated by the Cane Island Power Park Site operations is currently sent back to the City of Kissimmee via the City's wastewater pipeline near the site

F. Operation and Maintenance Costs

Respondents pricing should include all operation and maintenance costs for the proposed Project. These costs shall include without limitation costs for labor, equipment parts, outside services, supplies, station service power, and the annual fees associated with the use of the site common facilities set forth in Section 11 (A), Cane Island Power Park Project Site, above. Costs should be estimated for the duration of the Project.

G. Dual Fuel Capability/ Fuel Storage

The Project shall be capable of operating on natural gas and No. 2 Fuel Oil. The Project shall have sufficient fuel oil storage capability on the Project Site to store a minimum of forty thousand (40,000) barrels of fuel oil.

H. Project Ownership Structure/ Cost Sharing

Each Respondent should assume the following with respect to the ownership of the Project, the Project output and Project cost sharing:

(i) the Participants shall own thirty-five percent (35%) of the Project assets and shall be entitled to thirty-five percent (35%) of the Project capacity;
(ii) the successful Respondent shall own sixty five percent (65%) of the Project assets and shall be entitled to sixty five percent (65%) of the Project capacity;
(iii) the Participants shall purchase, pursuant to the PPA, between seventy seven percent (77%) and one hundred percent (100%) of the Respondent's share of the Project capacity;
(iv) the Participants shall be responsible for the payment of thirty-five percent (35%) of Project Costs and ongoing Project operation and maintenance costs;
(v) the Respondent shall be responsible for the payment of sixty-five percent (65%) of Project Costs and ongoing Project operation and maintenance costs;
(vi) Respondent shall be responsible for the procurement of all Project fuel.

SECTION 12. POWER PURCHASE AGREEMENT (PPA)

A. Term of Agreement

Each Respondent shall propose terms for the sale of capacity and energy from the Respondent's ownership share of the Project. The term of the PPA

shall be a minimum of five (5) years with the unilateral right of the Participants to extend the agreement for two (2) additional five (5) year terms. For the purpose of this RFP evaluation, it shall be assumed that the Participants will purchase between fifty percent (50%) and sixty-five percent (65%) of the Project capacity under the terms of the PPA.

B. Pricing

The pricing of energy under the PPA may be explicitly priced or tied to a fuel index. If the Respondent proposes an explicit energy price, the price in dollars per MWHR at the high side of the generator terminal should be provided, effective as of July 1, 2000. Any proposed escalation of this price should be detailed. Actual fuel cost pass-through provisions are not acceptable. The energy price should be escalated with readily available third party indices such as a fuel price index or government inflation index.

If the pricing of energy is based on a fuel price index, then it is the preference of OUC that the index for natural gas be based on Gas Daily Henry Hub mid-point posting for such flow date. For example, the fuel component of the energy price for calendar day, Monday, April 24 for a flow date of April 24 was three dollars, seven and one-half cents ($3.075). The energy price for April 22 and April 23 shall be based on the April 22 and 23 flow dates which was also three dollars, seven and one-half cents ($3.075). It is also the preference of OUC that the gas transportation component of the energy price shall be a specified price with, if necessary, escalation provisions.

Pricing of energy under the proposed PPA shall be detailed by each Respondent in the PPA data form attached hereto as Attachment 6. To insure that the Respondent understands the desired energy pricing designation, the following example is provided as an acceptable response on the energy price data form:

Fuel Price Index	Gas Daily Henry Hub Mid-Point
Adjustment to Index	Minus $0.03
Fuel Transportation Component	$0.55
Fuel Transportation Escalation Index	10% of GDP Deflator

To insure proper understanding of the Respondent's proposed energy pricing, the Respondent is encouraged to provide an example of the energy pricing determination for a known date.

C. Nomination and Scheduling

The Participants value flexibility in the nomination of capacity and proposals offering this flexibility will be evaluated favorably. The following applies to information requested in the PPA data form:

"Minimum Take Provision" is the minimum energy that the Participants must schedule during each hour that the Project units are on line. OUC will assume for the purposes of this evaluation that the Participants have complete scheduling flexibility between the Minimum Take Load and the maximum load available under the PPA. The respondent can assume that the Participants will have day ahead scheduling obligations and that capacity not scheduled by OUC will be available to the Respondent for its purposes.

The "Annual Capacity Nomination" provision is the amount that the Participants may, on an annual basis, reduce capacity obligation under the PPA. The amount may be expressed in percent of PPA or in megawatts. The Respondent may propose a maximum amount that the capacity obligation under the PPA may be reduced.

D. Availability

The "Guaranteed Annual Availability" is the minimum equivalent availability as defined by the NERC GADS, that the Respondent is guaranteeing from the operation of the Project units. OUC will expect to negotiate financial penalties for the failure of the Respondent to provide PPA capacity with an availability less than the specified guaranteed level.

SECTION 13. NON-MONETARY EVALUATION CRITERIA

The following is a non-exclusive list of the non-monetary evaluation criteria which will be considered by OUC in evaluating the proposal of the Respondents.

A. Financial Criteria

(i) Respondent's willingness and capability to provide equity funding in support of its proposal.

(ii) Capability of Respondent to provide power generation equipment necessary to support its proposal.

(iii) The overall credit rating of the Respondent.

B. Licensing and Permits

(i) Registration of Respondent to do business within the State of Florida.

(ii) Non-utility generator status of Respondent from the Federal Energy Regulatory Commission.

(iii) Any other necessary permits which could be provided by Respondent in support of its proposal.

C. Experience

(i) Respondent's experience in power plant development, procurement, and construction within the United States.

(ii) Respondent's experience in combined cycle power plant development, procurement, and construction within the State of Florida.

(iii) Respondent's experience and power sales and brokering in the wholesale market nationally.

(iv) Respondent's experience in power sales and brokering in the wholesale market within the State of Florida.

(v) Respondent's experience in local government and state permitting within the State of Florida.

D. Asset Diversity

(i) Diversity of Respondent's generating assets within the United States.

(ii) Diversity of Respondent's generating assets within the State of Florida, including existing assets and assets for which the development efforts have begun.

(iii) Diversity of products or services which Respondent may offer to the Participants not only those of value in conjunction with its proposal, but also those which may be available from Respondent in an ongoing relationship with the Participants, including the following:

(a) retail customer billing services;

(b) information systems;

(c) supply of fuel and swap capability; and,

(d) purchasing and materials management.

E. Procurement Advantages

(i) A current inventory of combustion turbines, steam turbines, or heat recovery steam generators for use in support of the proposal.

(ii) Combustion turbine, steam turbine and/or heat recovery steam generators currently under manufacturing contracts with equipment vendors which can be used in support of the proposal.

(iii) Combustion turbine, steam turbine and/or heat recovery steam generators currently not being manufactured but under contract and secured with monetary down payment with equipment vendors.

F. Miscellaneous Criteria

(i) The ability of Respondent to meet the proposed Project requirements for having generation available by the year 2003.

(ii) Ability of Respondent to offer other unrelated project opportunities for the Participants.

14. CONFIDENTIALITY.

Each Respondent must execute and return to OUC a copy of the Confidentially Agreement attached to this RFP as Attachment 1. Failure of any Respondent to execute and transmit along with its proposal the attached Confidentially Agreement will cause that Respondent's proposal to be deemed non-responsive. OUC will take reasonable precautions and use all reasonable efforts to protect any proprietary and confidential information contained in a proposal provided by each Respondent. Pages of a proposal which contain any information which Respondent deems to be proprietary should be marked clearly as "proprietary and confidential". Any such information marked as "proprietary and confidential" shall be treated as confidential by OUC and shall not be disclosed to third parties except as may be required by law. OUC may disclose confidential information of Respondents as necessary under state or federal law to regulatory commissions, their staff, or other governmental agencies having an interest in the matter covered by this RFP. OUC further reserves the right to release such information to those of its independent consultants and agents as necessary for the purposes of evaluating the proposal that agree to protect confidential information in the

same manner as OUC. Under no circumstances will OUC or the City of Orlando be liable for any damages resulting from any disclosure of confidential information during or after the evaluation of each Respondents proposal before or after the evaluation period.

LIST OF ATTACHMENTS

Attachment 1 - Confidentiality Agreement

Attachment 2 – Respondent Data

Attachment 3 – Equipment Data

Attachment 4 – Project Performance Data

Attachment 5 – Project Cost Data

Attachment 6 – PPA Data

Attachment 7 – SEC Site Drawing

Attachment 8 – Cane Island Site Drawing

Attachment 9 – Florida Supreme Court Ruling

Attachment 10 – Notice of Intent to Provide Detailed Proposal Form

Attachment 1 - Confidentiality Agreement

CONFIDENTIALITY AGREEMENT

THIS CONFIDENTIALITY AGREEMENT (this "Agreement"), is made and entered into this ____ day of _____, 2000, by and between the ORLANDO UTILITIES COMMISSION (hereafter "OUC") a governmental entity created under the laws of Florida, and _____ a _____ whose address is _____ (hereafter "Respondent").

RECITALS

1. The parties hereto intend to enter into confidential discussions with regard to the evaluation and possible undertaking of a business relationship (the "Proposed Transactions"). Further, the parties each understand that other third parties will or may be also entering into discussions with OUC regarding business relationships and the proposed transactions.

2. It will be necessary for the parties or their Affiliates (as defined in Section 9) to share certain confidential information with each other for the sole purpose of enabling OUC to evaluate its interest in entering into the Proposed Transactions.

3. The parties have entered into this Agreement in order to assure the confidentiality of all such information and to prevent the disclosure of same to third parties except as permitted herein.

4. The parties understand that under the Florida Public Records Law (Section 119.10, Florida Statutes), they may be subject to statutory fines and penalties, including but not limited to a requesting party's costs and attorney's fees for not making public records available for public inspection upon request (Sections 119.10 and 119.12, Florida Statutes). In addition, both parties will be subject to their own costs and expenses of litigation. The parties shall cooperate with each other protect confidential information which is a trade secret or which is otherwise exempt from disclosure under Sections 119.10 and 119.12, Florida Statutes, and to provide witnesses to support the declarations and certification that the confidential information is a valid trade secret under the above cited Florida law and meets the definitial requirements therein or is exempt from disclosure under other applicable Florida law. Further, Respondent

shall not be liable to OUC for any disclosure of OUC's confidential information which was or is disclosed pursuant to and in compliance with Florida law.

5. The parties have also entered into this Agreement to ensure that the Proposed Transaction or any other action taken with respect to each other shall be done with mutual agreement and in the best interest of each party.

ACCORDINGLY, for and in consideration of the Recitals, the mutual undertakings and agreements herein contained and assumed, and other good and valuable consideration the receipt and sufficiency are acknowledged by the parties, and the parties hereby covenant and agree as follows:

SECTION 1. RECITALS. The above Recitals are true and correct, and form a material part of this Agreement.

SECTION 2. CONFIDENTIAL INFORMATION. The term "Confidential Information" as used in this Agreement shall mean any and all written materials provided by either party or their Affiliates to the other or ascertained through due diligence investigation or discussions between employees or agents of the parties or their Affiliates; such Confidential Information shall include but not be limited to, all marketing, technical, engineering, operational, economic or financial knowledge, information or data of any nature whatsoever relating to the future, present or past business, operations, plans or assets of OUC, including any Affiliates, which is disclosed (either directly or through their agents) by Respondent or OUC or their Affiliates to the other in connection with the Proposed Transaction; provided, however, that Confidential Information shall not include the following:

(1) information which at the time of disclosure by a party or its Affiliate (the "Disclosing Party") is in the public domain, or information which later becomes part of the public domain through no act or omission of the recipient (the "Receiving Party");

(2) information which the Receiving Party can demonstrate was legally in its possession prior to disclosure by the Disclosing Party;

(3) information received by the Receiving Party from a third party who, to the best of the Receiving Party's knowledge, did not acquire such information on a confidential basis either directly or indirectly from the Disclosing Party.

SECTION 3. DISCLOSURE AND USE OF CONFIDENTIAL INFORMATION. The parties agree to keep confidential all Confidential Information, and shall not, without the other party's prior written consent, disclose to any third party, firm, corporation or entity such Confidential Information. The parties shall limit the disclosure of the Confidential Information to only those officers, employees, directors, and agents (including attorneys, accountants, investment bankers and similar consultants) of the party or its Affiliate reasonably necessary to evaluate the Proposed Transaction. To the extent that any such persons are not employees of the party or its Affiliate, the party shall obtain a signed writing evidencing the acceptance by such persons of the terms of this Agreement. Each party shall use the Confidential Information only for the purpose of its internal evaluation of the Proposed Transaction. Neither party shall make any other use, in whole or in part, of any such Confidential Information without the prior written consent of the other.

SECTION 4. REQUIRED DISCLOSURE. In the event that either party or any of their Affiliates (as the case may be) are requested or required by oral questions, interrogatories, requests for information or documents, subpoena, civil investigation, demand or similar process or by law or regulation (1) to disclose any Confidential Information of the other or (2) to disclose the possibility of any Proposed Transaction or the discussions pertaining thereto, it is agreed that it will provide prompt notice of such potential disclosure so that an appropriate protective order may be sought and/or a waiver of compliance with the provisions of this Agreement may be granted. If, in the absence of a protective order or the receipt of a waiver hereunder, **Respondent** and/or any of their Affiliates (as the case may be) are nonetheless, in the written opinion of their counsel, legally required to disclose Confidential Information of the other, then in such event, **Respondent** or the Affiliate (as the case may be) may disclose such information without liability hereunder, provided that **OUC** has been given a reasonable opportunity to review the text of such disclosure before it is made.

SECTION 5. RETURN OF DOCUMENTS. Upon written request from the Disclosing Party or upon termination of the confidential discussions contemplated hereunder, **Respondent** shall return any and all written Confidential Information as well as any other information disclosed to it by the other party, including all originals, copies, translations, notes, or any other form of paid material.

SECTION 6. SURVIVAL OF OBLIGATIONS. The obligations and commitments established by this Agreement shall remain in full force and effect for two (2) years from the date of this Agreement or until such time as the parties have entered into an agreement providing otherwise.

SECTION 7. NATURE OF INFORMATION. The parties each hereby accepts the representations of the other party that the other party's Confidential Information is of a special, unique, unusual, extraordinary, and intellectual character. Each acknowledges that the other party's interests in such Confidential Information may be irreparably injured by disclosure of such Confidential Information. Each acknowledges and agrees that money damages would not be a sufficient remedy for any breach of this Agreement by it and that in addition to all other remedies the other party shall be entitled to specific performance and injunctive or other equitable relief as a remedy for any such breach and each further agrees to waive any requirement for the securing or posting of any bond in connection with such remedy.

SECTION 8. GOVERNING LAW. The validity and interpretation of this Agreement and the legal relations of the parties to it shall be governed by the laws of the State of Florida. In the event that a court of competent jurisdiction determines that any portion of this Agreement is unreasonable because of this term or scope, or for any other reason, **Respondent** and **OUC** agree that such court may reform such provision so that it is reasonable under the circumstances and that such provision, as reformed, shall be enforceable. We each hereby irrevocably and unconditionally consent to submit to the exclusive jurisdiction of the courts of the State of Florida for any actions, suits or proceedings arising out of or relating to this Agreement and we each agree not to commence any action, suit or proceeding relating hereto except in such courts. We further agree that service of any process, summons, notice or document by

U.S. registered mail to our respective executive offices will be effective service of process for any action, suit or proceeding brought in any such court.

SECTION 9. AFFILIATE. The term "Affiliate" shall mean any corporation, partnership, or other entity or association that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, Respondent or OUC (as the case may be).

SECTION 10. NO OTHER AGREEMENT. It is expressly understood that this Agreement is not and shall not be construed as any obligation or form of a letter of intent or agreement to enter into the Proposed Transaction. Neither party may rely on this Agreement or the negotiations or exchange of Confidential Information or other documentation between the parties as a commitment to enter into binding definitive agreements.

SECTION 11. NO REPRESENTATIONS OR WARRANTIES. With respect to any information, including but not limited to Confidential Information, which either party furnishes or otherwise discloses to the other party for the purpose of evaluating any Proposed Transaction, it is understood and agreed that the party disclosing such information does not make any representations or warranties as to the accuracy, completeness or fitness for a particular purpose thereof. It is further understood and agreed that neither party nor their representatives or Affiliates shall have any liability or responsibility to the other party or to any other person or entity resulting from the use of any information so furnished or otherwise provided.

SECTION 12. MODIFICATION AND WAIVER. The provisions of this Agreement may be modified or waived only by a separate writing signed by Respondent and OUC expressly so modifying or waiving the same. No failure or delay by Respondent or OUC in exercising any right, power or privilege hereunder shall operate as a waiver thereof, nor shall any partial exercises thereof preclude any other or further exercise thereof or of any other right, power or privilege.

SECTION 13. AFFILIATE BOUND. Respondent or OUC each agree to cause its Affiliates to be bound hereby as if each were a party to this Agreement.

SECTION 14. SEVERABILITY. If any provision of this Agreement is declared void, or otherwise unenforceable and cannot be reformed as provided in Section 8 hereof, such provision shall be deemed to have been severed from this Agreement, which shall otherwise remain in full force and effect.

IN WITNESS WHEREOF, OUC and Respondent have caused this Agreement to be executed in duplicate in their names by their respective duly authorized officials, as of the day and year first above written.

ATTEST:

By:_____
Assistant Secretary

ORLANDO UTILITIES COMMISSION

By:_____
Robert C. Haven, PE
General Manager, CEO

WITNESSES:

RESPONDENT

By:_____
Print Name:_____
Title:_____

Print Name:_____

[AFFIX CORPORATE SEAL HERE]

Print Name:_____

Attachment 2 – Respondent Data

PROPOSAL DATA SHEETS

RESPONDENT DATA

1. Company/Respondent _____

2. Name of Contact _____

3. Mailing Address _____
_____
_____

4. Telephone/Fax _____
_____

5. Certification: Respondent hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the Respondent's knowledge and belief. Respondent agrees to be bound by its proposal representations and the terms and conditions of this RFP.

Signed: _____

Title: _____

Date: _____

Attachment 3 – Equipment Data

SEC PROPOSAL DATA SHEETS

INFORMATION REQUESTED	SEC BASE PROPOSAL (500 MW)	SEC 750 MW OPTION
Combustion Turbine Manufacturer		
Combustion Turbine Model		
Earliest Possible Combustion Turbine Delivery Date(s)		
Steam Turbine Manufacturer		
Steam Turbine Model		
Earliest Possible Steam Turbine Delivery Date(s)		
HRSG Manufacturer		
Earliest Possible HRSG Delivery Date(s)		
Project Site Estimate (Acres)		

Attachment 3 – Equipment Data

CANE ISLAND POWER PARK PROPOSAL DATA SHEETS

INFORMATION REQUESTED	DATA
Combustion Turbine Manufacturer	
Combustion Turbine Model	
Earliest Possible Combustion Turbine Delivery Date(s)	
Steam Turbine Manufacturer	
Steam Turbine Model	
Earliest Possible Steam Turbine Delivery Date(s)	
HRSG Manufacturer	
Earliest Possible HRSG Delivery Date(s)	
Project Site Estimate (Acres)	

Attachment 4 – Project Performance Data

SEC PROPOSAL DATA SHEETS

PROJECT PERFORMANCE DATA

	BASE 500 MW	750 MW OPTION
Unit Summer Net Rating		
95 F Ambient Temperature Sea Level Pressure Natural Gas Fuel	_____	_____
Unit Winter Net Rating 45 F Ambient Temperature Sea Level Pressure Natural Gas Fuel	_____	_____
Unit Net Heat Rate HHV Summer Conditions, Full Load Summer Conditions, Half Load Winter Conditions, Full Load Winter Conditions, Half Load	_____	_____
Project Minimum Load Under Automatic Generator Control	_____	_____
Project Maximum Load Change Rate	_____	_____
Cooling Water Consumption at Full Load Summer Conditions and 80% RH and 80% Capacity Factor	_____	_____
Project Estimated Annual Deionized Water Consumption 80% Capacity Factor	_____	_____

Attachment 4 – Project Performance Data

CANE ISLAND POWER PARK PROPOSAL DATA SHEETS

PROJECT PERFORMANCE DATA

Unit Summer Net Rating _____
95 F Ambient Temperature
Sea Level Pressure
Natural Gas Fuel

Unit Winter Net Rating _____
45 F Ambient Temperature
Sea Level Pressure
Natural Gas Fuel

Unit Net Heat Rate HHV _____
Summer Conditions, Full Load
Summer Conditions, Half Load
Winter Conditions, Full Load
Winter Conditions, Half Load

Project Minimum Load Under Automatic Generator Control _____

Project Maximum Load Change Rate _____

Cooling Water Consumption at Full Load _____
Summer Conditions and 80% RH and 80% Capacity Factor

Project Estimated Annual Deionized Water Consumption _____
80% Capacity Factor

Attachment 5 – Project Cost Data

SEC PROJECT DATA SHEETS

PROJECT COST DATA

	Base 500 MW	750 MW Option
Total Project Capital Cost including KUA provided materials and services as per Section II (I)(B)	$_____	$_____
Total Project Quarterly Cash Flow Statement		
4th Quarter 2000	$_____	$_____
1st Quarter 2001	$_____	$_____
2nd Quarter 2001	$_____	$_____
3rd Quarter 2001	$_____	$_____
4th Quarter 2001	$_____	$_____
1st Quarter 2002	$_____	$_____
2nd Quarter 2002	$_____	$_____
3rd Quarter 2002	$_____	$_____
4th Quarter 2002	$_____	$_____
1st Quarter 2003	$_____	$_____
2nd Quarter 2003	$_____	$_____
3rd Quarter 2003	$_____	$_____
4th Quarter 2003	$_____	$_____
1st Quarter 2004	$_____	$_____
Annual Operating Labor Costs 1st year of operation	$_____	$_____
Annual Maintenance Labor Costs 1st year of operation	$_____	$_____
Total Annual Operations Maintenance Costs 1st year of operation including non-labor components (excluding fuel cost)	$_____	$_____
Non-Fuel O&M Cost Escalation Index	_____	_____
Average Annual Capital Expenditures (Per Year) For First Ten (10) Years Of Project	$_____	$_____

Attachment 5 – Project Cost Data

CANE ISLAND POWER PARK PROJECT DATA SHEETS

PROJECT COST DATA

Total Project Capital Cost including KUA provided materials and services as per Section II (II)(B) $_____

Total Project Quarterly Cash Flow Statement

4th Quarter 2000	$_____
1st Quarter 2001	$_____
2nd Quarter 2001	$_____
3rd Quarter 2001	$_____
4th Quarter 2001	$_____
1st Quarter 2002	$_____
2nd Quarter 2002	$_____
3rd Quarter 2002	$_____
4th Quarter 2002	$_____
1st Quarter 2003	$_____
2nd Quarter 2003	$_____
3rd Quarter 2003	$_____
4th Quarter 2003	$_____
1st Quarter 2004	$_____

Annual Operating Labor Costs 1st year of operation $_____

Annual Maintenance Labor Costs 1st year of operation $_____

Total Annual Operations Maintenance Costs 1st year of operation including non-labor components (excluding fuel cost) $_____

Non-Fuel O&M Cost Escalation Index $_____

Average Annual Capital Expenditures (Per Year) For First Ten (10) Years Of Project $_____

Attachment 6 – PPA Data

SEC PROJECT DATA SHEETS

PURCHASE POWER AGREEMENT DATA

		Base 500 MW	750 MW Option
Capacity Price Fourth Quarter 2003		_____	_____
Annual Capacity Price Escalation Index (if any)		_____	_____
Heat Rate to be used for Energy Pricing		_____	_____
Fuel Price Index		_____	_____
Adjustment to Index		_____	_____
Fuel Transportation Component		_____	_____
Fuel Transportation Escalation Index		_____	_____
Minimum Must Take Obligation (if any)		_____	_____
Guaranteed Annual Availability of PPA Capacity		_____	_____
Annual Capacity Nomination Flexibility	Plus	_____	_____
	Minus	_____	_____
Maximum Range Over The Term Of PPA	Plus	_____	_____
	Minus	_____	_____

Example of Energy Price Determination (Attach Additional Sheets if Necessary):

Attachment 6 – PPA Data

CANE ISLAND POWER PARK PROJECT DATA SHEETS

PURCHASE POWER AGREEMENT DATA

		Cane Island Option
Capacity Price Fourth Quarter 2003		_____
Annual Capacity Price Escalation Index (if any)		_____
Heat Rate to be used for Energy Pricing		_____
Fuel Price Index		_____
Adjustment to Index		_____
Fuel Transportation Component		_____
Fuel Transportation Escalation Index		_____
Minimum Must Take Obligation (if any)		_____
Guaranteed Annual Availability of PPA Capacity		_____
Annual Capacity Nomination Flexibility	Plus Minus	_____ _____
Maximum Range Over The Term Of PPA	Plus Minus	_____ _____

Example of Energy Price Determination (Attach Additional Sheets if Necessary):

ATTACHMENT 7

SEC SITE DRAWING

ATTACHMENT 8

CANE ISLAND SITE DRAWINGS

ATTACHMENT 9

SUPREME COURT RULING

ATTACHMENT 10

NOTICE OF INTENT TO PROVIDE DETAILED PROPOSAL FORM

(A separate form must be completed for each proposed alternative)

The undersigned intends to respond to OUC's Request for Detailed Proposals for the Joint Development of the Stanton Energy Center and/or the Cane Island Power Park by submitting a proposal as follows:

Project Respondent: Company: _____

Name: _____

Title: _____

Address: _____

_____

_____

Telephone: _____

Fax: _____

E-Mail: _____

Respondent's Signature: _____
(Duly Authorized)

Date: _____

Appendix 1A.C
Orlando Utilities Commission Request for Power Supply Proposals
May 24, 2000

ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

MAY 24, 2000

ORLANDO UTILITIES COMMISSION
Request for Power Supply Proposals
Table of Contents

1 INTRODUCTION 1

2 RFP SCHEDULE 2

3 DESCRIPTION OF THE PARTICIPANTS 2

3.1 Orlando Utilities Commission 2

3.1.1 Existing Generation Facilities 3

3.1.2 Participation Agreements 5

3.1.3 Existing Transmission Facilities 6

3.2 Florida Municipal Power Agency 7

3.2.1 Organization and Management 8

3.2.2 Agency Projects 8

3.2.3 Transmission System and Arrangements 12

3.3 Kissimmee Utility Authority 13

3.3.1 Generation Resources 13

3.3.2 Purchase Power Resources 16

3.3.3 Transmission and Interconnections 16

3.3.4 Service Area 17

4 PROPOSAL REQUIREMENTS 17

5 NOTICE TO PROPOSERS 19

6 RIGHT OF REJECTION 22

7 INTERPRETATIONS AND ADDENDA 22

8 ERRORS, MODIFICATIONS OR WITHDRAWAL OF PROPOSAL 23

9 CONFIDENTIALITY AND PROPERTY RIGHTS 23

10 PROPOSER QUALIFICATIONS 24

11 COLLUSION 25

12 INDEMNITY 25

13 EQUAL EMPLOYMENT OPPORTUNITY CLAUSE 26

14 EVALUATION PROCESS 26

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14.1 Minimum Requirements *28*

14.2 Price Criteria *30*

14.3 Non-Price Criteria *30*

15 FINAL CONTRACT 32

16 RFP FORMS AND ATTACHMENTS 32

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1 INTRODUCTION

The Orlando Utilities Commission ("OUC") is issuing this request for proposals ("RFP") as an invitation to qualified companies to submit proposals for a project to supply electric capacity and energy (the "Project") as a part of a plan to secure economical generating resources for the OUC, Florida Municipal Power Agency ("FMPA") and Kissimmee Utility Authority ("KUA") collectively (the "Participants"). OUC will act as the agent for FMPA and KUA in all matters relating to this RFP process including contract negotiations. The successful "Proposer(s)" will enter into a single agreement with the Participants. OUC is requesting proposals for an aggregate of 750 MW of physically firm, dispatchable capacity in the form of base, intermediate or peaking resources, beginning on or before October 1, 2003 for a minimum period of five years. The nomination of capacity among the three Participants in the Project is as follows:

Project Participant	Nominated Capacity (MW)
OUC	600
FMPA	75
KUA	75

In addition to this RFP, OUC is pursuing the following power supply option on behalf of the Participants:

- Joint development of a combined cycle power plant at the OUC Stanton and/or KUA/FMPA Cane Island sites. OUC will issue a separate solicitation for this option ("Joint Development Solicitation").

The due date for proposals in response to this RFP is July 11, 2000.

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2 RFP SCHEDULE

OUC has developed a preliminary timetable of events that it intends to follow during the RFP process. All times are shown in prevailing Eastern Time . However, the dates on the schedule that is shown below are estimates only and are subject to change at the sole discretion of OUC.

Issue RFP	May 24, 2000
Pre-Proposal Conference (Mandatory)	June 1, 2000 (10:00 A.M.)
Deadline for Proposers' Questions	June 5, 2000 (5:00 P.M.)
Response to Proposers' Questions	June 12, 2000 (5:00 P.M.)
Notice of Intent to Propose	June 15, 2000 (5:00 P.M.)
Proposal Due Date	July 11, 2000 (5:00 P.M.)
Commence Negotiations	August 21, 2000
Contract Approved	October 31, 2000
Commence Power Supply Services	October 1, 2003

3 DESCRIPTION OF THE PARTICIPANTS

3.1 ORLANDO UTILITIES COMMISSION

OUC is a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City of Orlando. OUC has the full authority over the management and control of the electric and water plants in the City of Orlando and has been approved by the Florida Legislature to offer these services in portions of Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission and distribution systems, water production, and transmission and distribution systems in order to meet the requirements of its customers.

OUC's electric system provides power to customers within Orange County encompassing approximately 244 square miles. As of December 31, 1999, the electric system had 141,242 active services. Of these, 121,767 are residential services, 15,547 are

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general service non-demand services, and the remaining 3,928 are general service demand services. An interlocal agreement signed with the City of St. Cloud, Florida ("St. Cloud") in 1997 allowed OUC to add an additional 150 square miles of service area as well as additional 17,725 active services.

3.1.1 EXISTING GENERATION FACILITIES

OUC presently has ownership interests in the following five electric generating plants which are further described below.

- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Stanton Energy Center Units 1 and 2
- Florida Power Corporation ("FPC") Crystal River Unit 3 Nuclear Generating Facility
- City of Lakeland McIntosh Unit 3
- Florida Power & Light Company ("FPL") St. Lucie Unit 2 Nuclear Generating Facility.

Stanton Energy Center. The Stanton Energy Center (SEC) is located 14 miles southeast of Orlando, Florida. The 3,280 acre site contains SEC Units 1 and 2, and the necessary supporting facilities. SEC 1 was placed in operation on July 1, 1987 followed by SEC Unit 2, which was placed in operation on June 1, 1996 . Both units are fueled by pulverized coal and operate at emission levels that are better than the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection requirement standards for SO_2, NO_x and particulates.

SEC Unit 1 is a 440 MW net coal-fired facility of which OUC has a 68.6 percent ownership share providing 304 MW of capacity to the OUC system. SEC Unit 2 is a 444 MW net coal-fired generating facility. OUC's ownership share in this facility is 71.6 percent, or 319 MW.

Indian River Combustion Turbine Units A, B, C and D. The Indian River Plant is located four miles south of Titusville, Florida, on U.S. Highway 1 and consists of four combustion turbine units, A, B, C, and D. The three steam turbine units at the site

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were sold to Reliant Energy Indian River, LLC in 1999. As part of the sale, OUC has signed a power purchase agreement ("PPA") with Reliant. The combustion turbine units are primarily fueled by natural gas with No. 2 fuel oil as an alternative.

OUC has a partial ownership share of 48.8 percent, or 47 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent, or 201 MW, in Indian River Units C and D.

McIntosh Unit 3. McIntosh Unit 3 is a 340 MW net coal-fired unit operated by the City of Lakeland. McIntosh Unit 3 has supplementary oil and refuse fuel-burning capability and also is capable of burning up to 20 percent petroleum coke. OUC has a 40 percent ownership share in this unit providing approximately 136 MW of capacity to the OUC system.

Crystal River Unit 3. Crystal River Unit 3 is a net 830 MW nuclear generating facility operated by the FPC. OUC has a 1.6015 percent ownership share in this facility providing approximately 13 MW to the OUC system.

St. Lucie Unit 2. St. Lucie Unit 2 is a net 855 MW nuclear generating facility operated by the FPL. OUC has a 6.08951 percent ownership share in this facility providing approximately 52 MW to the OUC system.

Table 3-1-1 summarizes OUC's generating facilities including the capacity, commercial operation date, and ownership share.

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TABLE 3-1-1
SUMMARY OF OUC GENERATION FACILITIES

Generating Facility	Date in Service Mo/Yr	Net Capability for Total Facility[1]	Ownership Share - %	Net Capability Available for OUC		Unit Type[2]	Fuel[3]	
				Summer MW	Winter MW		Primary	Alternate
Stanton Energy Center (SEC)								
Unit No. 1	07/87	440	68.55	301.6	303.7	FS	C	-
Unit No. 2	06/96	444	71.59	319.3	319.3	FS	C	-
Total SEC		884		620.9	623			
Indian River Combustion Turbine								
Unit A	06/89	48	48.8	18	23.4	CT	NG	LO
Unit B	07/89	48	48.8	18	23.4	CT	NG	LO
Unit C	08/92	127	79	85.3	100.3	CT	NG	LO
Unit D	10/92	127	79	85.3	100.3	CT	NG	LO
Total Indian River		350		206.6	247.4			
Crystal River Unit No. 3	03/77	830	1.6015	13	13	N	N	-
C.D. McIntosh Jr. Unit No. 3	09/82	340	40	133	136	FS	C/R	HO
St. Lucie Unit No. 2[4]	08/83	853	6.089	51	52	N	N	-
Total		3,257		1,024.5	1071.4			

1. Actual net capacity varies with auxiliary power consumption.
2. FS = Fossil Steam; N = Nuclear; CT = Combustion Turbine
3. C = Coal; C/R = Coal and Refuse; HO = Heavy Oil (#6); LO = Light Oil (#2); NG = Natural Gas; N = Nuclear
4. OUC receives 50 percent of this capacity from St. Lucie Unit No. 1 pursuant to a reliability exchange agreement with FPL

3.1.2 PARTICIPATION AGREEMENTS

OUC has entered into a series of participation agreements, which convey an undivided ownership interest in units constructed and operated by OUC. Table 3-1-2 is a summary of those participation agreements.

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Table 3-1-2

Summary of Generation Facility Participation Agreements

Utility	Unit	Amount of Ownership (MW)	Percent of Ownership
FMPA	SEC 1	117	26.6
KUA	SEC 1	21	4.8
FMPA	SEC 2	126	28.4
FMPA	IRP CT A&B	37	39.0
KUA	IRP CT A&B	12	12.2
FMPA	IRP CT C&D	53	21.0

FMPA – Florida Municipal Power Agency
KUA – Kissimmee Utility Authority
SEC – Stanton Energy Center
IRP – Indian River Plant

3.1.3 EXISTING TRANSMISSION FACILITIES

OUC's existing transmission system consists of 26 substations, approximately 302 miles of 230 kV and 115 kV transmission lines and cables. OUC is fully integrated into the state transmission grid through its twelve 230 kV interconnections with other generating utilities which are members of the Florida Reliability Coordinating Council ("FRCC") as summarized in Table 3-1-3.

In addition, OUC is also now responsible for approximately 50 miles of St. Cloud's transmission system including the 69 kV interconnection from St. Cloud's Central Substation to KUA's Carl Wall Substation, and a 230 kV interconnection from the St. Cloud's East Substation to FPC's Holopaw Substation.

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TABLE 3-1-3 OUC Transmission Interconnections		
kV	**Utility**	**Number of Interconnections**
230	FPL (2 circuits)	1
230	FPC	5
230	KUA	2
230	KUA/FMPA	1
230	Lakeland	1
230	TECO	1
230	TECO/RCID	1

FPL – Florida Power & Light Company
FPC – Florida Power Corporation
KUA – Kissimmee Utility Authority
TECO – Tampa Electric Company
RCID – Reedy Creek Improvement District
FMPA – Florida Municipal Power Agency

Proposers may refer to OUC's Internet Web Page at www.ouc.com to learn more about OUC.

3.2 FLORIDA MUNICIPAL POWER AGENCY

FMPA was created on February 24, 1978, by the signing of the Interlocal Agreement among its 29 members, which agreement specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution; the Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

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3.2.1 ORGANIZATION AND MANAGEMENT

Each city commission, utility commission, or authority which is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of FMPA. The Board of Directors has the responsibility of developing and approving the Agency's budget, hiring a General Manager, and establishing both bylaws which govern how FMPA operates and policies which implement such bylaws. At its annual meeting, the Board of Directors elects a Chairman, Vice Chairman, Secretary, Treasurer and an Executive Committee. The Executive Committee consists of nine representatives elected by the Board of Directors plus the then-current Chairman and Vice Chairman of the Board of Directors. The Executive Committee meets regularly to control FMPA's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

3.2.2 AGENCY PROJECTS

FMPA currently has five power supply projects in operation: (i) the St. Lucie Project; (ii) the Stanton Project; (iii) the Tri-City Project; (iv) the All-Requirements Project and (v) the Stanton II Project.

St. Lucie Project: On May 12, 1983, FMPA purchased from FPL an 8.806 percent undivided ownership interest in St. Lucie Unit No. 2 (the "St. Lucie Project"), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie Unit No. 2 was declared in commercial operation on August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the FMPA's members are participants in the St. Lucie Project.

Stanton Project: On August 13, 1984, FMPA purchased from the OUC a 14.8193 percent undivided ownership interest in Stanton Unit No. 1, a coal-fired electric generation unit with a nominally-rated net high dispatch capacity of 428 MW.

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Stanton Unit No. 1 went into commercial operation July 1, 1987. Six of FMPA's members are participants in the Stanton Project.

Tri-City Project: On March 22, 1985, the FMPA Board of Directors approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton Unit No. 1. Three of FMPA's members are participants in the Tri-City Project.

All-Requirements Project: Under the All-Requirements Project, FMPA currently serves all the power requirements (above certain excluded resources) for eleven of its members. In 1997, the Cities of Vero Beach and Starke joined the All-Requirements Project. In January 1998, the Fort Pierce Utilities Authority became an All-Requirements member. The Key West City Electric System joined the All-Requirements Project in April 1998 and the City of Ft. Meade joined in February 2000. The City of Lake Worth is anticipated to be included in the All-Requirements Project sometime in 2001. The current supply resources of the Project include: (i) the purchase of a 6.5060 percent undivided ownership interest in Stanton Unit No. 1 from OUC; (ii) the purchase from OUC of a 5.1724 percent undivided ownership interest in OUC's Stanton Unit No. 2; (iii) capacity and energy from FMPA's 39 percent undivided ownership interest in two 37 MW combustion turbines (Units A and B) at the OUC Indian River Plant; (iv) capacity and energy from FMPA's 21 percent undivided ownership interest in two 129 MW combustion turbines (Units C and D) at the OUC Indian River Plant; (v) capacity and energy from FMPA's 50 percent undivided ownership interest in a 30 MW combustion turbine (Cane Island Unit 1) and a 120 MW combined cycle (Cane Island Unit 2) at KUA's Cane Island Power Park; (vi) capacity and energy purchases from other utilities including OUC, FPL, FPC, Tampa Electric Company (TECO), the City of Lake Worth, Gainesville Regional Utilities and others; (vii) necessary transmission arrangements; and (viii) required dispatching services. Additional capacity now available includes two reconditioned combustion turbines that have been installed in the Key West City Electric System. FMPA assumed ownership of these two 17.5 MW (each) units in

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June 1999. With the addition of the four cities that joined the All-Requirements Project in 1997 and 1998, the supply resources of the All-Requirements Project include capacity and energy purchases from each of these cities for city-owned generation and/or firm power resources. FMPA will serve capacity and energy requirements of the City of Ft. Meade via the full-requirements TECO agreement currently in place. When the Ft. Meade/TECO agreement terminates, FMPA will serve Ft. Meade from the All-Requirements Project's portfolio of power-supply resources.

Stanton II Project: On June 6, 1991, FMPA, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton Unit No. 2, a coal-fired unit virtually identical to Stanton Unit No. 1. The unit commenced commercial operation in June 1996. Seven of FMPA's members are participants in the Stanton II Project.

In partnership with the KUA, FMPA will dedicate a new natural gas-fueled combined-cycle generating unit at the Cane Island Power park. Expected to be in service in June 2001, each utility will be entitled to 50% of the new Cane Island 3, a 250 MW unit.

In another joint venture, FMPA and the City of Lakeland plan to share in the capacity of a petroleum coke/coal-fired combined-cycle generating unit that will reside in the Lakeland Electric system. Expected to be in service in 2005, FMPA will be entitled to up to 100 MW of the 288 MW MacIntosh Unit 4. A separate Request for Proposals process is being initiated in connection with the FMPA/City of Lakeland joint venture project.

Table 3-2-1 gives a summary of member participation by project as of April 1, 2000.

Table 3-2-2 provides details on existing FMPA generating facilities.

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Table 3-2-1: FMPA Member Participation by Project

FMPA Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bartow					
City of Bushnell				X	
City of Chattahoochee					
City of Clewiston	X			X	
City of Ft Meade	X			X	
Ft Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana					
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X			X
City of Lakeland Electric & Water					
City of Lake Worth	X	X		P (2001)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt Dora					
City of Newberry	X				
City of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utilities Commission					
City of Quincy					
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X
City of Wauchula					
City of Williston					

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Table 3-2-2

SUMMARY OF FMPA GENERATING FACILITIES

Facility		Commercial In-Service Month/Year	Gen Max Nameplate kW	Net Capability		Unit Type (1)	Fuel (1)	
				Summer MW	Winter MW		Primary	Alternate
St. Lucie	2	8/83	839,000	74.0	75.0	N	N	---
Stanton Energy Center	1	7/87	464,580	115.0	115.0	FS	C	---
	2	6/96	464,580	122.0	122.0	FS	C	---
Indian River	CT A	6/89	41,400	14.5	18.5	CT	NG	LO
Indian River	CT B	7/89	41,400	14.5	18.5	CT	NG	LO
Indian River	CT C	8/92	112,040	22.0	27.0	CT	NG	LO
Indian River	CT D	10/92	112,040	22.0	27.0	CT	NG	LO
Cane Island	1	11/94	40,000	15.2	15.2	CT	NG	LO
Cane Island	2	6/95	122,000	54.4	60.2	CC	NG	LO
Stock Island	CT 2	6/99	21,000	17.5	17.5	CT	LO	---
Stock Island	CT 3	6/99	21,000	17.5	17.5	CT	LO	---

Note (1)

FS	Fossil Steam	N	Nuclear
CC	Combined Cycle	NG	Natural Gas
CT	Combustion Turbine	LO	Light Oil (#2)
C	Coal		

3.2.3 TRANSMISSION SYSTEM AND ARRANGEMENTS

FMPA jointly owns 17 miles of 230 kV transmission circuit that connects the Cane Island power plant into the surrounding grid. Additionally, FMPA purchases transmission services from several different investor-owned utilities and from one municipal electric utility. These transmission contracts provide FMPA access to all systems interconnected with these utilities thus enabling the delivery of electric power to each of FMPA's participating members.

FMPA's All-Requirements Project has seven of the existing eleven All-Requirements Project participants geographically located within FPL's service area and the other four All-Requirements Project participants located within FPC's service area. All eleven All-Requirements Project participants are supplied their full-requirements

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power supply from FMPA and such power is delivered to the All-Requirements Project participants over the transmission systems of FPL or FPC, respectively. Transmission agreements are currently in place that enable FMPA to provide transmission service over both FPL's and FPC's systems.

FMPA's All-Requirements Project capacity needs are provided on a system basis; however, the utilization of FMPA's transmission agreements with FPL and FPC must be separately planned.

Proposers may refer to FMPA's Internet Web Page at www.fmpa.com to learn more about FMPA.

3.3 KISSIMMEE UTILITY AUTHORITY

KUA is a body politic organized and legally existing as part of the government of the City of Kissimmee. On October 1, 1985, the City of Kissimmee transferred ownership and operational control of the electric generation, transmission, and distribution system to KUA. KUA has all the powers and duties of the City of Kissimmee to construct, acquire, expand, and operate the system in an orderly and economic manner.

3.3.1 GENERATION RESOURCES

KUA owns and operates or has ownership interest in generating units comprising several technologies, including nuclear, coal-fired, diesel, simple cycle, and combined cycle. Table 3-3-1 provides a summary of KUA's existing generating resources. The following paragraphs describe KUA's generating assets and ownership interests in detail.

KUA owns and operates eight diesel generating units ranging in age from 17 to 41 years. Each of these diesel units is located at the Roy B. Hansel Generating Station in Kissimmee. Six of these diesel units are fueled by natural gas while the remaining two burn No. 2 oil. The total nameplate capacity of the eight diesels is 18.35 MW. In addition, KUA owns and operates a natural gas fired (with No. 2 oil as backup)

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combined cycle plant, which is also located at the Hansel site. This plant consists of a 35 MW (nameplate) combustion turbine which provides waste heat for two 10 MW (nameplate) steam turbine generators. The total nameplate generating capability at the Hansel site is approximately 73.35 MW.

KUA and FMPA are both 50 percent joint owners of Cane Island Units 1 and 2. Unit 1 is a simple cycle General Electric LM6000 aero-derivative combustion turbine with a nameplate rating of 42 MW. Unit 2 is a one-on-one General Electric Frame 7EA combined cycle with a nameplate rating of 120 MW. KUA and FMPA have also committed to build Cane Island 3, which is a nominal 250 MW combined-cycle unit. This unit is currently under construction and is expected to be on-line in mid-2001. KUA's 50 percent ownership share of the Cane Island Units is 206 MW (nameplate).

KUA owns a 0.6754 percent interest, or 6 MW (nameplate), in the FPC's Crystal River Nuclear Unit 3, located in Citrus County, Florida. KUA also has a 4.8193 percent ownership interest, or 22,300 kW (nameplate), in the OUC's Stanton Energy Center Unit 1 and a 12.2 percent, or 10 MW (nameplate), of OUC's Indian River Combustion Turbine Project Units A and B.

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Table 3-3-1
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Hansel	8	Osceola County 27,T25S/R29E	IC	NG	FO2	02/59	Unknown	3.00	3	3	PL	TK
	14		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	15		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	16		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	17		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	18		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	19		IC	FO2	---	02/83	Unknown	2.50	3	3	TK	---
	20		IC	FO2	---	02/83	Unknown	2.50	3	3	TK	---
	21		CT	NG	FO2	02/83	Unknown	35.00	28	32	PL	TK
	22		ST	WH	---	02/83	Unknown	10.00	10	10	---	---
	23		ST	WH	---	02/83	Unknown	10.00	10	10	---	---
Plant Total								73.35	67	71		
Crystal River	3	Citrus County 33,T17S/R16E	N	UR	---	03/77	Unknown	890.46	6[1]	6[1]	TK	---
Plant Total								890.46	6	6		
Stanton Energy Center	1	Orange County 13,14,23,24 /R31E/T23S and 18,19 /T23S/R32E	ST	BIT	---	07/87	Unknown	464.58	21[2]	21[2]	RR	---
Plant Total								464.58	21	21		
Indian River	A	Brevard County 12/T23S/R35E	CT	NG	FO2	06/89	Unknown	41.40	4.5[3]	5.5[3]	PL	TK
	B		CT	NG	FO2	07/89	Unknown	41.40	4.5[3]	5.5[3]	PL	TK
Plant Total								82.80	9	11		
Cane Island	1	Osceola County 29,32/R28E /T25S	CT	NG	FO2	11/94	Unknown	42.00	15[4]	20[4]	PL	TK
	2		CT	NG	FO2	06/95	Unknown	80.00	34[4]	40[4]	PL	TK
	2		ST	WH	---	06/95	Unknown	40.00	20[4]	20[4]	---	---
Plant Total								162	69	80		
							System Total as of January 1, 2000		172	189		

Notes:
(1)KUA's 0.6754 percent portion of joint ownership.
(2)KUA's 4.8193 percent ownership portion.
(3)KUA's 12.2 percent portion of joint ownership.
(4)KUA's 50 percent ownership portion.

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3.3.2 Purchase Power Resources

KUA is a member of the FMPA, a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 15 other members of the FMPA. KUA's entitlement share of this unit, based on a power purchase contract and adjusted for transmission losses, is 6.9 MW. FMPA has also entered into a Reliability Exchange Agreement with FPL under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit No. 1 and half from Unit No. 2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has a contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases up to an additional 50 MW if the capacity is available from OUC. KUA also has a contract with OUC to purchase up to 40 MW from the Stanton 2 power plant. The contract ends in December 2000. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton 1 Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton 2 Project. The Stanton 2 percentage includes recently acquired Homestead and Lake Worth shares totaling 3.8314 percent.

3.3.3 Transmission and Interconnections

KUA is a member of the FRCC. The FRCC has established an energy broker system, which provides economic interchange of electric energy between member utilities, including KUA. KUA has purchased and sold energy through this broker system, and intends to continue such transactions whenever conditions are favorable.

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KUA has direct transmission interconnections with: (i) FPC, delivered at 69 kV from the FPC Lake Bryan substation and at 230 kV at OUC's Taft substation; (ii) OUC (two transmission lines and an auto-transformer), delivered at 230 kV at OUC's Taft substations; (iii) the City of St. Cloud, Florida, at KUA's 69 kV interconnection with St. Cloud's transmission facilities; and (iv) TECO, one 230 kV circuit through the interconnection with the Osceola and Lake Jewell circuits. A second interconnection with FPC between the Cane Island Power Plant Switchyard, and FPC's Intercession Power Plant Switchyard is being constructed. This 230 kV circuit is scheduled for completion by May 2001.

Electric power and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to eight distribution substations. KUA provides electric service to retail customers primarily by 13.2 kV feeder circuits from the distribution substations.

3.3.4 Service Area

KUA serves a total area of approximately 85 square miles, including the City's ten square mile area near the center. As of March 1, 2000, KUA served approximately 47,390 electric customers. Of these, 39,378 were residential, 7,346 were general service non-demand, and the remaining 666 were general service demand.

Proposers may refer to KUA's Internet Web Page at www.kua.com to learn more about KUA.

4 PROPOSAL REQUIREMENTS

OUC will consider proposals for the sale of up to 750 MW in minimum blocks of 150 MW of physically firm, base, intermediate and/or peaking power from (i) existing specified resources, (ii) a portfolio of supply resources with appropriate back-up guarantees, and/or (iii) a generating facility to be constructed at the Proposer's site for unit power sale. Such proposals must include ancillary services. All unit supply proposals must identify the

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specific generating units and the contribution that each unit will make to the proposed sale. For system supply proposals, the reliability of the sale to the Participants must be equivalent to native load. Proposals that require transmission services must identify the transmission path that will be used for the delivery of power to OUC's systems. OUC has issued a separate solicitation on behalf of the Participants for joint development of a combined cycle power plant at the OUC Stanton site and/or FMPA's/KUA's Cane Island site and will not consider such proposals as a part of this RFP process.

Proposals involving a unit or power plant power sale to the Participants should include all available data including equivalent availability factor ("EAF"), maintenance schedules, net capacity, heat rate, fuel type, and other pertinent data for the specific unit(s). Proposals involving a system or portfolio capacity and energy sale to the Participants should include information for all generating units and purchase contracts required to make the sale to the Participants. All proposals for power sale must be on a first call, non-recallable basis delivered to the transmission grid of OUC. Details of the information required for each proposal is specified in Attachment A.

If the power sale proposal is not based on a guaranteed energy price, the applicable fuel price indices provided in Attachment B shall be used by the Proposer to demonstrate how the cost of energy will be calculated. The starting price must be clearly identified. If the proposal is based on a guaranteed total energy cost, the proposal must include all information pertinent to the pricing and its escalation. If any of this information is Proprietary Confidential Business Information, it should be clearly noted and OUC will maintain confidentiality per Section 9.

All proposals shall include scheduling provisions of the sale. The schedule should be established no more than one day in advance with the ability to change the schedule within one to three hours before the schedule commences except under the Participants'

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emergency conditions when changes may be required as soon as physically possible if the resource is available. Any 'Must Take' energy provision must not exceed 25% of the total proposed sale capacity on an annual basis. As part of the scheduling provisions, the supplier will be required to fax daily to the Participants' dispatchers a schedule of estimated prices for the energy to be delivered for that day and the next day. It should be noted that the Participants and others are members of the Florida Municipal Power Pool, which provides resource dispatching services for its members.

While OUC has established a commencement date of October 1, 2003 for the commencement of power supply services requested in this RFP, OUC will consider proposals that offer commencement dates that are earlier or within 12 months later than the established date. The agreement term for proposals must extend at least five (5) years and a provision must be included that permits OUC the sole option to extend the agreement for at least an additional five (5) years. OUC values flexibility in the annual nomination of capacity and proposals offering this flexibility will be evaluated favorably.

Proposers should provide backup information that would verify the reasonableness of assumptions and cost data associated with transmission service required for delivery of the proposed capacity and energy from the source(s) of supply to the high voltage transmission system of OUC.

5 NOTICE TO PROPOSERS

OUC has scheduled a Pre-Proposal Conference for Thursday, June 1, 2000 at 10:00 A.M. at the OUC Pershing Facility, 6113 Pershing Avenue, Orlando, Florida 32822. Attendance at the Pre-Proposal Conference is mandatory for companies that intend to submit a Proposal. Proposals from Proposers that fail to attend the Pre-Proposal Conference will not be evaluated. The purpose of the Pre-Proposal Conference is for OUC to receive questions

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that Proposers may have about this RFP Process. Proposers are requested to use this forum to raise questions about the RFP and the form of the response to the RFP. Proposers should register for the Pre-Proposal Conference via facsimile to the attention of Mr. Selvin Dottin at (407) 648-8382, on or before May 30, 2000. To encourage a meaningful dialog, unofficial answers to verbal questions will be provided at the Pre-Proposal Conference. However, Proposers are reminded that only written responses to questions submitted on or before June 5, 2000 will be considered official.

All Proposers are required to provide written notification of their intent to submit a proposal no later than 5:00 P.M. on Thursday, June 15, 2000. A Notice of Intent to Propose Form is attached at the end of the RFP as RFP Form 1.

Sealed proposal packages will be received until 5:00 P.M. on Tuesday, July 11, 2000 ("Proposal Due Date") at the offices of R. W. Beck in Orlando. Each Proposer is required to submit a Proposal Summary (RFP Form 2), a Checklist (RFP Form 7), and other completed forms as applicable (RFP Form 3 to RFP Form 6) as part of the proposal package. The forms are included at the end of this RFP. Registered Proposers will be notified through addenda to the RFP of any change to the Proposal Due Date as well as other changes, if any. Only a Proposer that received a copy of the RFP from OUC will be considered a registered Proposer. After the deadline for the Notice of Intent to Propose, the list of registered Proposers will be modified to include only those Proposers that also submit a Notice of Intent to Propose. OUC reserves the right to reject all proposals received after the Proposal Due Date.

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One Original plus four (4) copies of the proposal response package should be delivered to the following address:

Mr. Selvin H. Dottin
Consulting Engineer
R. W. Beck, Inc.
800 North Magnolia Avenue, Suite 300
Orlando, FL 32803-3274
P. O. Box 538817
Orlando, FL 32853-8817
e-mail: sdottin@rwbeck.com

The name of the company submitting the proposal should be clearly marked on the outside of each package. In addition, each package should be marked as follows: "Proposal for Supply of Electric Power to OUC."

An electronic copy of the entire proposal including completed proposal pricing forms and all other spreadsheets included in the proposal should be submitted in Microsoft Word and Microsoft Excel Office 97 or compatible format on a CD ROM or $3^1/_2$ inch diskette.

The proposal offer must remain in effect until December 31, 2000. Each proposal package must be accompanied by a non-refundable Proposal Fee in the amount of $5,000 for each proposal alternative. The Proposal Fee must be in the form of a cashiers check made payable to OUC.

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6 RIGHT OF REJECTION

This RFP is not an offer establishing any contractual rights. This solicitation is solely an invitation to submit proposals.

- OUC reserves the right, without qualification and in its sole discretion, to accept or reject any or all proposals for any reason or to make an award to that Proposer, who, in the opinion of OUC, will provide the most value to the Participants and their customers as a supplier of electric power.
- OUC reserves the right to reject any, all, or portions of the proposals received for failure to meet any criteria set out in this RFP. The Participants may also decline to enter into any agreement proposed by or negotiated with a Proposer, or to abandon the RFP effort in its entirety.
- OUC reserves the right to reject proposals submitted by any Proposer which (a) is incomplete, inaccurate, conditional, deceptive, misleading, ambiguous, exaggerated, or non specific in its offer; or (b) is not in conformance with the requirements and instructions contained in this RFP.
- Proposers that submit proposals due so without recourse against OUC, the City of Orlando or the Participants for either rejection of such proposals or for failure of the Participants to enter into any agreement with the Proposers in association with the proposal and this RFP.

7 INTERPRETATIONS AND ADDENDA

All questions regarding interpretation of this RFP, technical or otherwise, must be submitted in writing to the following:

By Fax: Mr. Selvin H. Dottin
(407) 648-8382

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By Mail: Mr. Selvin H. Dottin
Consulting Engineer
R. W. Beck, Inc.
800 North Magnolia Avenue, Suite 300
Orlando, FL 32803-3274
P. O. Box 538817
Orlando, FL 32853-8817

E-mail: sdottin@rwbeck.com

Written questions and requests for interpretations will be accepted from Proposers up to the Deadline for Questions as established in Section 2. Questions and requests received after this date will not be addressed by OUC. No telephone inquires will be accepted. Written responses to all questions will be provided to all Proposers that attended the Pre-Proposal Conference. Copies of all addenda issued in connection with this RFP will be sent to all registered Proposers that obtained the RFP from OUC and submitted a Notice of Intent to Propose.

8 ERRORS, MODIFICATIONS OR WITHDRAWAL OF PROPOSAL

Proposers should carefully review the information provided in the RFP prior to submitting a response. The RFP contains instructions which should be followed by all Proposers. Modifications to proposals already received by OUC will only be accepted prior to the Proposal Due Date. Proposals may be withdrawn by giving written notice to OUC prior to the Proposal Due Date. In such cases, a full refund of the Proposal Fee will be provided by OUC.

9 CONFIDENTIALITY AND PROPERTY RIGHTS

OUC will take reasonable precautions and use all reasonable efforts to protect any proprietary and confidential information contained in a proposal provided by each

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Proposer. Pages of a proposal which contain any information which Proposer deems to be proprietary should be marked clearly as "proprietary and confidential". Any such information marked as "proprietary and confidential" shall be treated as confidential by OUC and shall not be disclosed to third parties except as may be required by law. OUC may disclose confidential information of Proposer as necessary under state or federal law to regulatory commissions, their staff, or other governmental agencies having an interest in the matter covered by this RFP. OUC further reserves the right to release such information to other Participants and those of its independent consultants and agents as necessary for the purposes of evaluating the proposal that agree to protect confidential information in the same manner as OUC. Under no circumstances will OUC or the City of Orlando be liable for any damages resulting from any disclosure of confidential information during or after the evaluation of each Proposer's proposal before or after the evaluation period.

Prior to commencing negotiations, a Proposer will be required to enter into a Confidentiality Agreement with OUC.

10 PROPOSER QUALIFICATIONS

OUC will accept proposals from any electric utility, independent power producer, qualifying facility, exempt wholesale generator, non-utility generator, or electric power marketer who has received certification as such by the Federal Energy Regulatory Commission. Proposers that are unfamiliar to OUC may be required to provide proof of experience. Proposers that propose to develop a power generating project to provide power to the Participants must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers proposing to provide the Participants with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

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Proposers offering power sales proposals from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract. OUC may require proof of such contracts as well as proof of contracts for sales from a portfolio of resources. Any contracts submitted with the proposal may have the price and other sensitive information deleted before submittal to OUC.

Electric power plant operators of a unit, plant or system capacity proposal must provide proof of operating experience as requested in RFP Attachment A.

Proposers are requested to provide the following information with their proposals: most recent audited financial statement; Form 10 K of parent company, where appropriate; most recent Dunn & Bradstreet report; description of any pending litigation; summary of project experience; and Annual Report.

11 COLLUSION

Each Proposer must execute and return to OUC a copy of the Non-Collusive Affidavit attached to this RFP as Attachment C. Failure of any Proposer to execute and transmit along with its proposal the attached Non-Collusive Affidavit will cause that Proposer's proposal to be deemed non-responsive.

12 INDEMNITY

In the event of a contract award, the successful Proposer shall defend, indemnify, and hold harmless the Participants, their officers, directors, and employees from and against all claims, damages, losses, and expenses, direct, in-direct, or consequential (including but not limited to fees and charges of attorneys or other professionals and court and arbitration or other dispute resolution costs) arising out of or resulting from the performance of the work

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by the Proposer, any subcontractor, supplier, and any person or organization directly or indirectly employed by any of them to perform or furnish any of the work or anyone for whose acts any of them may be liable, regardless of whether or not it is caused in part by any negligence, active or passive, or omission of a party indemnified hereunder or whether liability is imposed upon such indemnified party by law or regulation.

13 EQUAL EMPLOYMENT OPPORTUNITY CLAUSE

OUC has adopted a minority and women business enterprise policy (M/WBE) to encourage broad-based participation in all contracts with OUC. Qualified M/WBE firms are encouraged to respond to this RFP. All firms responding to this RFP shall demonstrate a commitment to diversity in the workplace.

14 EVALUATION PROCESS

(i) OUC and its independent consultants will verify that each proposal received on or before the Proposal Due Date includes all required information and supporting documentation. Any proposal which is not received by the Proposal Due Date will be deemed non-responsive and will not be considered. For each proposal alternative received by the Proposal Due Date, OUC will perform an initial screening evaluation to identify and eliminate any proposals which: (a) are not responsive to this RFP, (b) do not meet the Minimum Requirements set forth in this RFP. No additional information will be accepted from a Proposer after the Proposal Due Date, except for clarifications requested by OUC and any transmission study results (if applicable).

(ii) The proposals that pass the initial evaluation screening will be evaluated against each other to determine which, if any, in OUC's sole judgement, provides the best value to the Participants and their customers. Information provided by each Proposer in its proposal will be used by OUC to select the

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highest ranked Proposers. OUC will evaluate the proposals and rank the three (3) best proposals considering price and non-price factors. In addition to this RFP, OUC has issued a Joint Development Solicitation for a combined cycle project in which OUC will take an ownership position. Proposals may be combined to meet the capacity requirements of the Project. The proposals from the Joint Development Solicitation will be ranked and the proposals from this RFP will be ranked, and then the highest-ranking proposals from each solicitation will be ranked together against each other. Upon ranking of the proposals from each of the solicitations together, OUC will commence negotiations with the highest ranked Proposer(s). The negotiations with the highest ranked Proposer(s) may result in a project structure different than that originally proposed. OUC will continue negotiations with the highest ranked Proposer(s) in an attempt to achieve an agreement. If no agreement is reached with the highest ranked Proposer(s), OUC will terminate the negotiations and initiate negotiations with the next highest ranked Proposer(s) until either an agreement is completed or OUC abandons the solicitation process.

(iii) Prior to the start of negotiations, the Proposer(s) will be required to provide further security, equal to two hundred fifty thousand dollars ($250,000). Such additional security must be in form and substance reasonably acceptable to OUC ("Negotiation Security"). The Negotiation Security shall be returned only if:

(a) OUC abandons the solicitation process prior to the conclusion of negotiations; or

(b) The Participants successfully execute a contract with the Proposer(s) for the power supply project.

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14.1 MINIMUM REQUIREMENTS

Each proposal must meet certain minimum requirements before it will receive any evaluation or consideration. The Proposer must demonstrate in its submittal that the following minimum requirements have been met:

1. The Proposer must have attended the Pre-Proposal Conference.
2. The Proposer has provided a non-refundable fee of $5,000 for each proposal alternative in the form of a cashiers check made payable to OUC.
3. The Proposer must provide a minimum of 150 MW of unit or system capacity.
4. The Proposer must provide physically firm power, including ancillary services, delivered to OUC's delivery points. Power must be available to the Participants on a first call, non-recallable basis.
5. The proposal offer must remain effective through December 31, 2000.
6. The initial agreement period must extend for at least five (5) years and the proposal must contain a provision that permits OUC the sole option to extend the agreement for at least a further five (5) years.
7. The proposed service commencement date must be earlier or within 12 months later than October 1, 2003. Proposers must provide sufficient information to demonstrate that the service can commence by the date proposed.
8. All unit supply proposals must identify the specific generating units and the contribution that each unit will make to the sale. For system supply proposals, the reliability of the sale to Participants must be equivalent to native load.
9. The Proposer must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.

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10. The Proposer must declare ownership or contractual status of the unit, plant or system capacity.

11. The cost data including fuel cost and escalation rates must be prepared using the applicable fuel price indices provided in Attachment B unless energy prices are guaranteed. In addition, proposers may provide pricing based on alternative fuel price indices.

12. The price for power provided in the Pricing Proposal Form (Form 4) reflects all costs and losses delivered to OUC's delivery points.

13. The Proposer must be willing to provide a Negotiation Security in the amount of $250,000 prior to commencing negotiations with OUC.

14. The Proposer must complete the appropriate RFP Forms 2 through 6 and provide the information requested in Attachment A. All forms requiring a signature must be signed by a duly authorized official.

15. The proposal must include scheduling provisions for the sale.

16. Any must take provision in the proposal must not exceed 25% of the total proposed sale capacity on an annual basis.

17. Proposers that propose to develop a power generating project to provide power to the Participants must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers proposing to provide the Participants with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

18. Proposers offering power sales proposals from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract.

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19. Electric power plant operators of a unit, plant or system capacity proposal must provide proof of operating experience as requested in RFP Attachment A.

14.2 PRICE CRITERIA

Pricing information must be provided in sufficient detail for OUC to fully analyze each proposal. The fixed and variable price components must be filled out on the Pricing Proposal Form (Form 4). Proposals will be evaluated on the basis of the cost of power delivered to OUC's delivery points.

Proposals that commence later than October 1, 2003 may have power costs for the periods not covered assigned as determined by OUC. Proposals offering additional notice provisions solely available to OUC to extend the contract may receive additional consideration in the non-price evaluation.

14.3 NON-PRICE CRITERIA

The components of each proposal will be compared to the non-price criteria preferences of OUC and a score will be assigned to each criteria for each proposal evaluated. Non-price scores will be added to price related scores to obtain an overall ranking. The lowest cost proposal may not necessarily be selected.

The following non-price criteria will be used to evaluate the proposals.

Components of Power Cost - The fixed cost should be recovered in the capacity charge or rate, and all variable costs (fuel, variable operation and maintenance expenses, etc.) should be recovered in the energy charge or rate.

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Flexibility - OUC prefers flexible proposals with reasonable notice provisions that give OUC sole rights (e.g., adjust the contract term, the amount of purchases, type of purchase, payment provisions, price, etc.).

Term - Notice provisions solely available to OUC to increase or decrease the amount of purchases are also preferred.

Fuel Type - OUC prefers low cost power supply arrangements that allow the Participants to diversify its fuel mix.

Dispatchability - OUC prefers to be able to dispatch the proposed capacity off-line during periods when OUC deems it economical to do so. Dispatchability may also encompass the concept of scheduling power deliveries for economy transactions in a manner that contributes favorably to the Participants needs.

Firm Supply - Proposals will be evaluated on the availability of generating resources, arrangements for firming capacity, and penalties for nonperformance.

Technology Risk - Proposals utilizing commercially proven technologies are preferred.

Environmental Effects - Proposals that minimize potential adverse environmental impacts are preferred.

Transmission - Proposals that minimize the number of intermediate transmission systems are preferred.

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15 FINAL CONTRACT

Any final contract(s) that result from the proposal evaluation and negotiation processes will be submitted to the appropriate body of the respective Participants for approval. The tentative date for approval of contract(s) for the purchases is shown in Section 2, RFP Schedule.

16 RFP FORMS AND ATTACHMENTS

Form 1	-	Notice of Intent to Propose Form
Form 2	-	Proposal Summary Form
Form 3	-	Minimum Requirements Form
Form 4	-	Pricing Proposal Form
Form 5	-	Unit Sale Data Form
Form 6	-	System Sale Data Form
Form 7	-	Checklist
Attachment A		Required Data
Attachment B		Fuel Price Indices
Attachment C		Non-Collusive Affidavit
Attachment D		Map Showing Location of OUC's Pershing Facility

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ORLANDO UTILITIES COMMISSION
REQUEST FOR POWER SUPPLY PROPOSALS

Notice of Intent to Propose Form

(A separate form must be completed for each proposed alternative)

Due: June 15, 2000 5:00 P.M.
(Date) (Time)

The undersigned intends to respond to OUC's RFP for power supply with a proposal currently conceived as follows:

Type of Sale (System or Unit) _____

Total Capacity (MW): _____

Provide generating unit(s) details on form 1-B.

Respondent Classification: (Utility, Qualified Facility, Exempt Wholesale Generator, Power Marketer, etc.)
_____

Contract Start and Stop Dates: _____ to _____

Project Proposer: Company: _____

Name: _____

Title: _____

Address: _____

_____

_____

Telephone: _____

Fax: _____

e-mail _____

Proposer's Signature: _____
(Duly Authorized)

Date: _____

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RFP Form 1-B

ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

Notice of Intent to Propose Form

(A separate form must be completed for each proposed alternative)

Due: June 15, 2000 5:00 P.M.

(Date) (Time)

Proposed Capacity (MW)	Project Name/ Location	Unit Name and/or Number	Generating Technology	Primary Fuel	Secondary Fuel	In Service Date (New Unit)

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ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

PROPOSAL SUMMARY FORM

1. Company/Proposer _____
2. Name of Contact _____
3. Mailing Address _____
4. Telephone/Fax _____
5. Proposed Contract Start Date _____
6. Proposed Contract End Date _____
7. Proposed Contract Capacity Listing by Unit _____

Unit Name and Number	Fuel Type	Location	Proposed Capacity Delivered [1] (MW)
Total Capacity (MW)			

[1] *Capacity delivered to OUC's delivery points.*

8. *Certification:* Proposer hereby certifies that all of the statements and representations made in this proposal package, including attached documents, are true to the best of the proposer's knowledge and belief. Proposer agrees to be bound by its representations and the terms and conditions of the Request for Proposals:

Signed: _____

(Typed):

Title: _____

(Duly Authorized)

Date: _____

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ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

In submitting this form, we agree to the items below and/or have provided documents to attest to the information provided as requested below.

Duly Authorized Signature _____ _____
(Date)

If the proposer is a utility proposing a capacity sale from existing resources, the proposer must provide sufficient documentation to demonstrate that over time the utility will have sufficient capacity to sell to OUC as well as to serve its own load. If the proposer is proposing a sale of capacity from a unit or units that are not currently commercially available, the proposer must demonstrate that progress is sufficient to ensure a capacity sale to OUC by the proposed Power Supply Service Commencement Date.

All proposers must demonstrate the following by attaching appropriate information to this form:

1. The Proposer must have attended the Pre-Proposal Conference.
2. The Proposer has provided a non-refundable fee of $5,000 for each proposal alternative in the form of a cashiers check made payable to OUC.
3. The Proposer must provide a minimum of 150 MW of unit or system capacity.
4. The Proposer must provide physically firm power, including ancillary services, delivered to OUC's delivery points. Power must be available to the Participants on a first call, non-recallable basis.
5. The proposal offer must remain effective through December 31, 2000.
6. The initial agreement period must extend for at least five (5) years and the proposal must contain a provision that permits OUC the sole option to extend the agreement for at least a further five (5) years.
7. The proposed service commencement date must be earlier or within 12 months later than October 1, 2003. Proposers must provide sufficient information to demonstrate that the service can commence by the date proposed.
8. All unit supply proposals must identify the specific generating units and the contribution that each unit will make to the sale. For system supply proposals, the sale to Participants must be equivalent to native load.
9. The Proposer must ensure that all emissions allowance requirements will be satisfied and that such costs are included in the proposal.
10. The Proposer must declare ownership or contractual status of the unit, plant or system capacity.

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ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

Minimum Requirements Form

(Continued)

11. The cost data including fuel cost and escalation rates must be prepared using the applicable fuel price indices provided in Attachment B unless energy prices are guaranteed. In addition, proposers may provide pricing based on alternative fuel price indices.

12. The price for power provided in the Pricing Proposal Form (Form 4) reflects all costs and losses delivered to OUC's delivery points.

13. The Proposer must be willing to provide a Negotiation Security in the amount of $250,000 prior to commencing negotiations with OUC.

14. The Proposer must complete the appropriate RFP Forms 2 through 6 and provide the information requested in Attachment A. All forms requiring a signature must be signed by a duly authorized official.

15. The proposal must include scheduling provisions for the sale.

16. Any must take provision in the proposal must not exceed 25% of the total proposed sale capacity on an annual basis.

17. Proposers that propose to develop a power generating project to provide power to the Participants must have developed, and have had in operation for a minimum of one year, at least one currently operating power supply project that is similar to, or larger in size than, the project being proposed. Proposers proposing to provide the Participants with power from an existing generating resource or a portfolio of resources must have successfully provided similar levels of services to at least one electric utility for a minimum of one year.

18. Proposers offering power sales proposals from an existing unit(s) must own and operate the unit, plant or system capacity or must have the unit(s), plant or system capacity under contract.

19. Electric power plant operators of a unit, plant or system capacity proposal must provide proof of operating experience as requested in RFP Attachment A.

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ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

Pricing Proposal Form

Describe Methodology used to establish the Capacity Rate: _____

Describe how capacity is determined for purposes of calculating the capacity charge in dollars:

Delivered Capacity Rate						
Period 12 Mo. Ended Sept. 30	**Capacity $/kW-mo. (A)**	**Transmission $/kW-mo. (B)**	**Transmission $/kW-mo. (C)**	**Total Delivered Capacity $/kW-mo. (D)**	**Capacity kW (E)**	**Total $000 (F)**
2001						
2002						
2003						
2004						
2005						
2006						
2007						
2008						
2009						
2010						
2011						
2012						
2013						
2014						
2015						

NOTE: If the proposal extends past 2015, please provide additional sheets.

Describe Components of the Capacity Rate (Losses Must Be Included):

A. _____

B. _____

C. _____

D. _____

E. _____

F. _____

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ORLANDO UTILITIES COMMISSION

REQUEST FOR POWER SUPPLY PROPOSALS

PRICING PROPOSAL FORM
(Continued)

Describe Methodology of the Energy Rate: _____

_____

Explain specifically how heat rate and fuel cost component is calculated.

_____

	Delivered Energy Rate							
Period 12 Mo. Ended Sept. 30	**Guaranteed Fuel Cost $/MMBtu (G)**	**Guaranteed Heat Rate MMBtu/MWh (H)**	**Energy Cost $/MWh (I)**	**Transmission $/MWh (J)**	**Transmission $/MWh (K)**	**Total Delivered Energy $/MWh (L)**	**Projected Energy MWh (M)**	**Total $000 (N)**
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
2011								
2012								
2013								
2014								
2015								

NOTES: (i) If the proposal extends past 2015, please provide additional sheets.
(ii) If the fuel price indices provided in Attachment B are used to calculate the energy prices, then the calculation of energy prices must be demonstrated as shown on Attachment B.

Describe Components of the Energy Rate (Losses Must Be Included):

F. _____
G. _____
H. _____
I. _____
J. _____
K. _____
L. _____
M. _____
N. _____

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ORLANDO UTILITIES COMMISSION
REQUEST FOR POWER SUPPLY PROPOSALS

Unit Sale Data Form

COMPANY/PROPOSER _____

Please provide the following information for each unit on separately attached sheets if the proposal is for the sale of power from specific generating units:

- Owner (if other than Respondent)
- Contact (Name, address, telephone/fax)
- Fuel type, source and arrangement
- Technology
- Station service and start-up power requirements for each unit and source for meeting such requirements.
- Interconnection voltage and location
- Identity of intervening transmission systems
- Availability of wheeling, if necessary
- Contract start and stop date
- Commercial operation date
- Describe permit limitations, if any
- Describe pollution control equipment and compliance with Clean Air Act Amendments
- Is the project a QF or IPP?
- Has the project been subscribed to others?
- Please list buyers and quantities
- Dispatchability and time period each unit will be available to serve load
- Provide historical (5 years) annual equivalent availability factors
- Provide historical (5 years) capacity factors
- Provide historical (5 years) unit production cost data (fuel, energy and operation and maintenance)
- Maximum hours of operation for each unit on daily, monthly and annual basis and time period each resource is available to the Participants to serve load
- For each type of fuel each unit is capable of using, report the sulphur content of the fuel in percent, and the following emissions data in lbs/hr: P, SO_2, NOx, CO, CO2, Particulates and VOC's at maximum output

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ORLANDO UTILITIES COMMISSION
REQUEST FOR POWER SUPPLY PROPOSALS

Unit Sale Data Form

(Continued)

- Report for each unit, the amount of water usage and water discharge in lbs/hr at maximum output
- The location of each resource (including the reserves for each resource) and point(s) where power will be transferred to OUC's electric system
- The capability, at the point of transfer to OUC's electric system (net of losses) of each resource

If the Proposer is providing capacity and energy from a dispatchable unit, please provide the following for each unit:

- Minimum run time
- Start up time from cold conditions
- Start up time from hot conditions
- Shut down time cold start applies
- Maximum number of starts per week
- Must run level, if any
- Indicate whether the project will agree to schedule maintenance during periods reasonably scheduled by OUC
- Provide net output and incremental net heat rate (HHV) data under site conditions at four or more heat rate points including minimum load and maximum operating capability at 95°F. Specify other site conditions (___ % relative humidity and ____ elevation).

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ORLANDO UTILITIES COMMISSION
REQUEST FOR POWER SUPPLY PROPOSALS

System Sale Data Form

COMPANY/Proposer _____

Please provide the following information on separately attached sheets if the proposal is for the sale of system power from existing facilities:

- Contact (Name, address, telephone/fax)
- Type of contract (firm or unreserved)
- Proposed percentage capacity mix by unit
- Proposed percentage energy mix by fuel type
- Amount of capacity to be sold to the Participants at the delivery points
- Describe ability to change purchase amount
- Interconnection voltage and location
- Identity of third party transmission systems
- Availability of wheeling, if necessary
- Contract start and stop date
- Optional ancillary services
- State the conditions under which dispatch can occur
- Maximum hours on daily, monthly, and annual basis and time period each resource is available to the Participants to serve load
- Generation expansion plan for system for term of purchase including annual peak load, net capacity by unit, and reserve margin
- Station service and start-up power requirements and source for meeting such requirements
- The location of each resource (including the reserves for each resource) and point(s) where power will be transferred to OUC's system
- The capability, at the point of transfer to OUC's system (net of losses) of each resource

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ORLANDO UTILITIES COMMISSION
REQUEST FOR POWER SUPPLY PROPOSALS

Checklist

All RFP Forms checked below have been included as part of the response package*.

RFP Form 2 - Proposal Summary Form _____

RFP Form 3 - Minimum Requirements Form _____

RFP Form 4 - Pricing Proposal Form _____

RFP Form 5 - Unit Data Form _____

RFP Form 6 - System Data Form _____

Attachment A: Required Data For Power Supply Proposal _____

Attachment C: Non-Collusive Affidavit _____

Signed: _____

Title: _____

Company Name: _____

(*) *RFP Form 1 is the Notice of Intent to Propose Form which is sent to OUC prior to, and separately from, the proposal response package.*

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REQUIRED DATA FOR POWER SUPPLY PROPOSAL

The following data is required for all power supply proposals as applicable. The required data shall be provided in sections numbered in accordance with the specific items detailed below. Each section should begin on a new page. Information provided by Proposers, which is not in the requested format, may be disregarded and the proposal rejected for incompleteness. General information (e.g., promotional material, 'boiler plate', etc.) may be provided with the proposal, but only the formatted information will be considered in the event of a conflict between the general information and the information relating specifically to this proposal. Any proposal that does not contain the requested information may be deemed incomplete and may be rejected at OUC's' sole discretion. OUC may request additional data or clarifying information from Proposers.

A-1 Identity of Bidder Contact

Provide the full name, job title, business address, telephone number, e-mail address, and facsimile number of contact person from whom additional information relating to this proposal may be requested.

A-2 General Description of Proposal

(a) Provide a general overall summary of the proposal. Identify the type of proposal being offered as either: (1) discrete generating unit(s); (2) a varying, flexible portfolio (e.g. power marketer); or (3) System Sale.

(b) For proposals involving either discrete unit or System Sale, provide historical data on equivalent forced outage rates, and equivalent availability from each generating resource.

(c) Describe in detail how the Proposer will dynamically serve the Participants' load. Describe any additional requirement for remote terminal units (RTU's), system control and data acquisition (SCADA) equipment, communication lines, etc. Proposer will be responsible for cost

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of procuring, installing and maintaining this equipment if applicable to the Proposal.

(d) Describe the procedure for adding additional delivery points, if necessary, including who will be responsible for the cost of such facilities.

(e) For proposals involving System Sales, describe on RFP Form 2 the amount of total System resources available, and projected loads (including the proposal sale) on the System for each year of the proposed contract.

(f) For Proposals involving a flexible portfolio, please provide references for all previous bulk power sales contracts including the name of the utility, point of contact, phone number, term of contract, amount of transaction (annual peak demand, and total annual energy).

A-3 Location Of Generating Facilities

For proposals involving either discrete units or System Sales, identify the geographic location of the applicable generating resource(s) and the transmission system which interconnects these resources. Identify the transmission path and intervening transmission systems required to deliver the power to the Participants' electric systems.

A-4 Capacity and Expected Energy Production

Please verify that the Participants' rights to the output of the generating resources, which are to supply capacity and energy to the Participants, shall be equal to or greater than the rights of all other entities served by those generating resources. Describe limiting conditions (if any).

A-5 Schedule

If there are any limitations on the availability of capacity, specify the time frame when capacity will be available (or unavailable).

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A-6 Proposed Agreement Term

(a) Specify proposed contract term.

(b) Specify any and all proposed provisions for contract renewal, extension, or termination, identifying any and all proposed conditions for the above to occur, including whether such events are proposed to be mutually or unilaterally determined.

A-7 Third Party Information

For proposals involving either discrete units or System Sales, identify any other firm capacity and energy commitments during the proposed contract term to other parties, and provide a description of the Participants' rights compared to the rights of the other parties.

A-8 Historical Fuel Information

Where applicable to the proposal being offered (proposals that do not provide a guaranteed energy price, please describe the following:

(a) Primary and alternate fuel source for each generating unit on the System.

(b) Historical monthly average fuel prices in $/MMBtu for each applicable generating unit for the last three (3) years.

(c) Average monthly heat rate by unit, including separately MMBtu's and net generation for the last three (3) years.

A-9 Financial Information

(a) Identify any and all Proposer affiliates.

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(b) Provide audited financial statements, if available, or other financial statements for the last three years. Such information should be provided for all entities, including affiliates involved in the transaction. For investor owned utilities, this would include as a minimum FERC Forms 1's and SEC 10K Forms. Proposers should also provide where appropriate, the most recent Dunn and Bradstreet report, a description of pending litigation, and the most recent annual report.

A-10 Pricing Information

(a) Specify on the RFP Form 4 - Proposal Pricing Form, all proposed payment components and proposed incentive amounts, if any, and the conditions which engage such provisions. OUC requires that proposals clearly distinguish between energy-based and capacity-based pricing components. Please include all costs including: generation, reserves, transmission and subtransmission service, dispatching, load following, load regulation, reactive power, other ancillary services required, telecommunications and metering.

(b) Specify annual payment stream components, whether explicitly specified or driven by escalation factors. If price escalation factors are proposed, please identify what attribute the proposed factor is meant to represent (e.g., general inflation, general economic growth, etc.), proposed index or other source data to define the escalator (e.g., CPI, change in GDP, etc.), and Proposer's current projection of the designated escalator for each applicable time period.

(c) If the energy price in the proposal is not guaranteed the Proposer must use the applicable fuel indices provided in Attachment B and show an example calculation. The Proposer shall also include such information as: projected annual amount of MWh contributed and MMBtu's utilized by each resource for the proposed contract period; guaranteed net heat rate (HHV) for each contributing resource; fuel transportation costs and contract information explaining how transportation costs are determined; and any information on existing fuel contracts. If any of this information is Proprietary Confidential Business Information, it shall be so indicated by the Proposer and OUC will maintain confidentiality in accordance with Section 9 of this RFP. If the proposed energy price is based on a

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guaranteed total energy rate, the Proposer shall include all information pertinent to the pricing and its escalation.

A-11 Proposed Financial Security Arrangements

Provide samples of proposed form of security instruments specifying, at a minimum:

PROPOSED FORM OF SECURITY INSTRUMENT	
Corporate Guaranty	Proposed guarantor; proposed minimum dollar amount; any and all conditions, including revocation, expiration, etc.
Letter of Credit	Name of issuer; proposed minimum dollar amount; any and all conditions, including revocation, expiration, etc.
Performance Bond	Name of issuer and rating; proposed minimum dollar amount; any and all conditions, including revocation, expiration, etc.
Project Take-over Rights	Mechanics and limitations on the exercise of such rights.
Other	Please describe in detail.

A-12 Wheeling

Any Proposer proposing to wheel power and energy over the facilities of a third party will be required by OUC to provide:

(a) A detailed description of the proposed wheeling and interconnection arrangements, including, but not limited to, contract path and estimated cost of such wheeling services.

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(b) A description of any required new interconnection facilities and estimated costs and cost responsibility for such facilities.

(c) A description of upgrades in third party transmission systems which may be required to accommodate the Project and an estimate of costs.

(d) It is the responsibility of the Proposer to make all necessary arrangements and bear all the associated costs of firm wheeling of the power to the OUC's delivery points. Any required upgrades in third party transmission system required to accommodate the delivery of power under the proposal is also the Proposer's responsibility.

Please affirm your understanding and acceptance of these requirements related to delivery of power in response to this RFP.

A-13 Additional Information

Please provide any additional information, which the Proposer believes, will assist OUC in an accurate and fair evaluation of the proposal. Proposals involving flexible portfolios are encouraged to provide similar information as requested specifically for discrete unit sales and System Sales in A-2 (b) and (e), A-3, and A-7.

A-14 Guaranty For Firm Power

It is the intent of this RFP to secure guaranteed firm power for the Participants. As such, the Proposer must identify the arrangements it will make to secure appropriate back-up replacement power in order to ensure that the supply of power to the Participants is uninterrupted. The Proposer must affirm its agreement that any increased cost of such replacement power will be borne solely by the Proposer, throughout the duration of the contract.

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FUEL PRICE INDICES

If power sale proposals are based on a pass-through fuel cost arrangement, a choice of the following indices and structures must be used:

1. Natural Gas

Commodity Price:

Based on Gas Daily "Daily Price Survey' for Henry Hub daily midpoint index plus or minus $____/MMBtu

Transportation Rate:

$____/MMBtu

Gas Transportation Escalation (If applicable):

____% of percentage change, up or down, of the final reporting of the Implicit Price Deflator for the Gross Domestic Product (GDP Deflator) determined on an annual basis.

EXAMPLE

Commodity Price:

Gas Daily "Daily Price Survey" for Henry Hub daily midpoint index minus $ 0.03/MMBtu

Transportation Rate:

$0.50/MMBtu

Gas Transportation Escalation:

10% of percentage change, up or down, of the final reporting of the Implicit Price Deflator for the Gross Domestic Product (GDP Deflator) determined on an annual basis.

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2. Coal

Commodity Price:

Based on Coal Daily "Average Monthly Prices - Prompt, Applicable Month" for "CAPP: 12,500 - 2.0, CSX in $/Ton" as reported the 1st business Monday of each month, divided by a factor of 25 MMBtu/Ton, plus or minus $____/MMBtu. This price will apply for every day of the applicable month.

Coal Transportation Rate:

$____/MMBtu

Coal Transportation Escalation (If applicable):

____% of percentage change, up or down, of the final reporting of the Implicit Price Deflator for the Gross Domestic Product (GDP Deflator) determined on an annual basis.

EXAMPLE

Commodity Price:

Coal Daily "Average Monthly Prices - Prompt, Applicable Month" for "CAPP: 12,500 - 2.0, CSX in $/Ton" as reported the 1st business Monday of each month, divided by a factor of 25 MMBtu/Ton, minus $0.05/MMBtu

Coal Transportation Rate:

$0.60/MMBtu

Coal Transportation Escalation:

10% of percentage change, up or down, of the final reporting of the Implicit Price Deflator for the Gross Domestic Product (GDP Deflator) determined on an annual basis.

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3. No. 6 Fuel Oil

Commodity Price:

Based on *previous month average of daily* Platts Oilgram Price Report "US Gulf Coast Spot Waterborne 1% Sulfur, low posting, in US $ per Barrel, divided by factor of 6.35 MMBtu/BBL, plus or minus $_____/MMBtu

Oil Transportation Rate:

$_____/MMBtu

Oil Transportation Escalation (If applicable):

____% of percentage change, up or down, of the final reporting of the Implicit Price Deflator for the Gross Domestic Product (GDP Deflator) determined on an annual basis.

EXAMPLE

Commodity Price:

For month of May 2000: Average of daily postings for month of April 2000, Platts Oilgram Price Report "US Gulf Coast Spot Waterborne 1% Sulfur, low posting, in US $ per Barrel, divided by factor of 6.35 MMBtu/BBL, minus $0.10/MMBtu. This calculated April 2000 average price/MMBtu shall apply for each day of May 2000.

Oil Transportation Rate:

$0.20/MMBtu

Oil Transportation Escalation:

10% of percentage change, up or down, of the final reporting of the Implicit Price Deflator for the Gross Domestic Product (GDP Deflator) determined on an annual basis.

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NON-COLLUSIVE AFFIDAVIT

State of _____)
) SS
County of _____)

_____ being first duly sworn, deposes and says that:
Name

He/she is the _____ (owner, partner, officer, representative or agent) of _____, the Company that has submitted the attached Proposal.

He/she is fully informed respecting the preparation and contents of the attached Proposal and of all pertinent circumstances respecting such Proposal.

Such Proposal is genuine and is not a collusive or sham Proposal.

Neither the Company nor any of its officers, partners, owners, agents, representatives, employees or parties in interest, including this affiant, have in any way colluded, conspired, connived or agreed, directly or indirectly, with any other Proposer, firm, or person to submit a collusive or sham Proposal in connection with the work for which the attached Proposal has been submitted; or to refrain from bidding in connection with such work; or have in any manner, directly or indirectly, sought by agreement or collusion, or communication, or conference with any Proposer, firm, or person to fix the price or prices in the attached Proposal or of any other Proposer, or to fix any overhead, profit, or cost elements of the Proposal price or the Proposal price of any other Proposer, or to secure through any collusion, conspiracy, connivance, or unlawful agreement any advantage against (Recipient), or any person interested in the proposed work;

The price or prices quoted in the attached proposal are fair and proper and are not tainted by any collusion, conspiracy, connivance, or unlawful agreement on the part of the Company or any other of its agents, representatives, owners, employees or parties in interest, including this affiant.

Signed, sealed and delivered
in the presence of:

_____ By _____
Witness

_____ _____
Witness Printed Name

_____
Title

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ACKNOWLEDGMENT

State of _____)
) SS
County of _____)

BEFORE ME, the undersigned authority, personally appeared _____, to me well known and known by me to be the person described herein and who executed the foregoing Affidavit and Acknowledged to and before me

that _____ executed said Affidavit for the purpose therein expressed.

WITNESS my hand and official seal this _____ day of _____, 2000.

Notary Public - State of _____

My Commission expires _____

_____
(Printed typed or stamped commissioned name of Notary Public)

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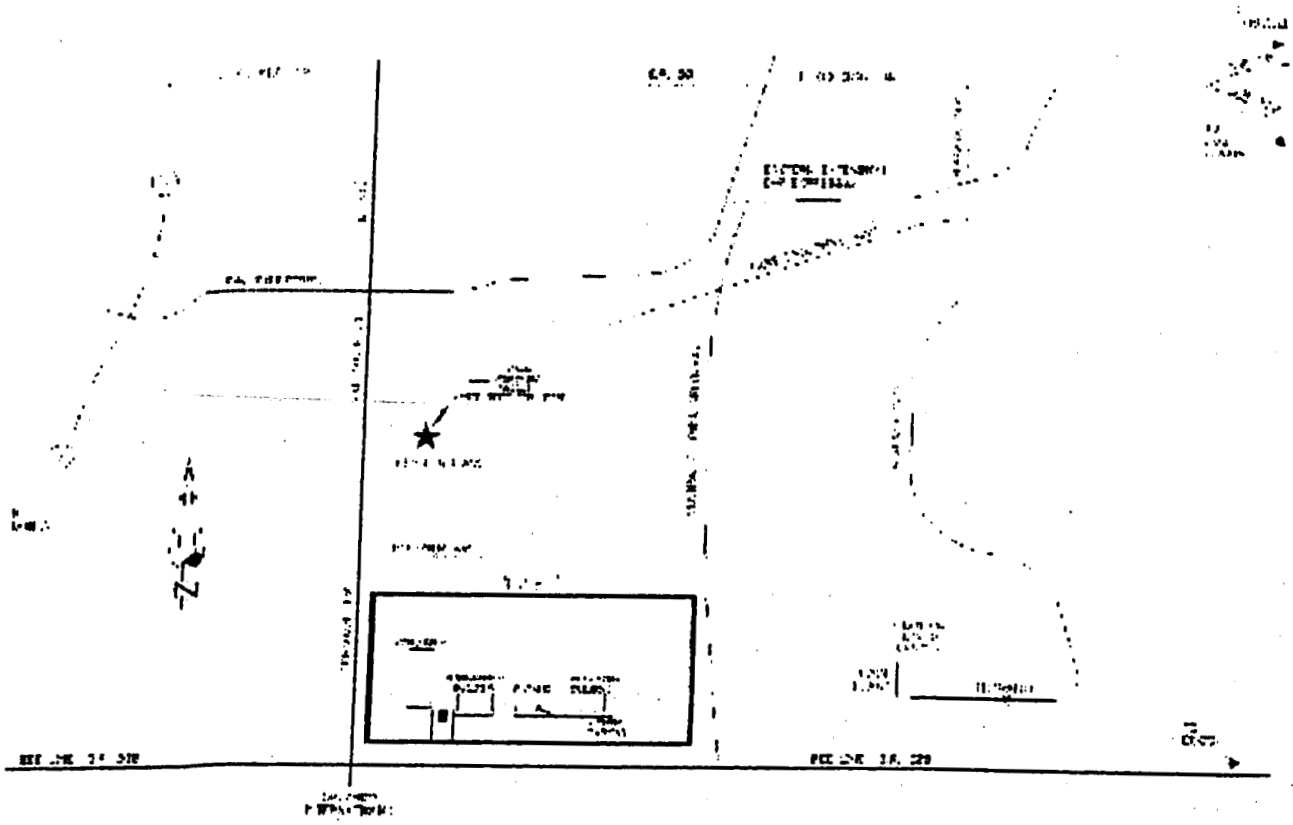
ORLANDO UTILITIES COMMISSION
PERSHING FACILITY



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Appendix 1A.D
Orlando Utilities Commission
Stanton Energy Center
Stanton Unit A - 2x1
Capital Cost Estimate

ATTACHMENT A
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1
CAPITAL COST ESTIMATES

EPC BASIS

The EPC Capital Cost Estimate for a nominal 500 MW two-on-one F class combustion turbine combined cycle power project located at Stanton Energy Center near Orlando, Florida is as follows. The estimate is based on Siemens Westinghouse Power Corporation (SWPC) "501F" class combustion turbines, two flow downward exhaust reheat steam turbine, and triple pressure HRSG's. General Electric (GE) "7FA" combustion turbines could also be used which would result in a slightly lower cost and also a slightly lower output. The estimate is based on availability of combustion turbines to meet a November 1, 2002 on site delivery and commercial operation by October 1, 2003.

The total estimated capital cost is $233,000,000 for commercial operation on October 1, 2003. The capital cost does not include interest during construction or other Owner costs. The capital cost estimate is based on a project scope that is described in Attachment D. In addition, the capital cost estimate is based on pricing that is indicative of similar competitive projects developed for the merchant market. Specifications incorporating unique requirements or non-standard equipment may result in higher prices. The estimate is on an EPC basis.

SELF BUILD BASIS

The Self-Build Cost Estimate for the same plant as defined above and in the attachments is $231,000,000.

NOTES:

The above estimates include an allowance of $38,000,000 for the SWPC combustion turbines. This allowance could vary significantly depending on when the contract is awarded.

The Above Normal Scope Adders listed in Attachment F would apply to either cost estimate.

OPTION 1:
Option 1 is for a natural gas supply pipeline and metering station from the FGT tie-in point to the Unit 3 site boundary. The pipeline size would be 16", and the length is estimated at 4.1 miles.

Option 1 cost estimate is $5,508.000.00.

OPTION 2:
Option 2 is for the installation of a 5,000-gallon condensate storage tank and powered resin type condensate polisher to reduce cycle makeup water usage.

Option 2 cost estimate is $1,200,000.00.

OPTION 3:
Option 3 is for the rehabilitation/upgrade of the existing zero discharge water treatment facilities.

Option 3 cost estimate is $1,300,000.00 per train.

NOT REVIEWED

ATTACHMENT B
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1
PERFORMANCE

The estimated plant performance for the project is included at the end of this section. The performance estimate is based on historical performance information for SWPC combustion turbine arrangements.

The performance will be based on the scope of equipment supply as defined herein and for the following operating conditions and cycle parameters.

A. The combustion turbines will operate at base load.

B. Natural gas will be provided by the Owner in compliance with the combustion turbine manufacturer's fuel requirements.

C. For purposes of plant auxiliary power loads, only the Facility equipment required to achieve base load operation of the plant will be in service.

D. Electrical output (megawatts only) will be measured either at the high side of the generator step-up transformer(s) or in the switchyard.

E. Tests to demonstrate guarantee performance will be conducted in accordance with the Test Descriptions and Protocol to be established by the EPC Contractor.

F. Plant equipment will be in new and clean condition. If equipment is not tested in the new and clean condition, the performance test results will be adjusted to new and clean values.

G. Power Factor = 0.9 lag or greater at the generator terminals.

H. A performance test is included which will be based on a two-hour test to demonstrate the ability of the facility to deliver firm output continuously to the grid. During the 2 hour continuous operating period, the actual net electrical output and actual net heat rate will be determined. Also, during the continuous test, emissions will be determined. This test will be used to verify the performance guarantees from the combustion turbine, steam turbine, and HRSG suppliers.

I. The estimated combined cycle performance is based on SWPC combustion turbine data, i.e., net outputs, net heat rates, exhaust flows (not exhaust energies) and exhaust temperatures as estimated by B&V based on previous projects. This performance data is not guaranteed.

J. The HRSG and steam turbine performance data is based on typical values, which must first be confirmed by the manufacturers before EPC guarantees can be made.

K. The EPC guarantees will be contingent upon the CTGs achieving the CTG exhaust flow shown rather than manufacturers' guaranteed exhaust energy value.

L. The EPC guarantees will be contingent upon a requirement that liquidated damages for failure to meet EPC performance guarantees which are due to shortfalls in CTG performance are only paid if they can be collected from the combustion turbine generator manufacturer.

M. B&V is willing to work with the Owner to optimize performance with respect to specific project economic criteria. Better (more efficient) cycle designs are technically feasible, but the cost basis for the indicative EPC price provided is based on major equipment designs and costs with the performance levels indicated herein.

Expected Noise Levels

Occupational Noise Exposure

All equipment will be specified to meet an average sound level of 90 dBA at 3 feet horizontal distance from the equipment and 4.5 feet above the floor or any personnel platform. The intent of this specification is to protect worker hearing and improve working conditions.

Certain power plant equipment is inherently noisy and special noise control measures will be necessary to comply with the 90 dBA noise criteria. These noise criteria measures typically include silencers, enclosures, and/or insulation and lagging around equipment. For certain equipment, these noise control measures are not practical for reasons of cost, maintenance access, heat buildup, space limitations, safety, etc. B&V will evaluate equipment noise control on an individual basis and optimize noise control measures through agreement with the Owner.

While all equipment will be limited to a sound level of 90 dBA at 3 feet to the fullest practical extent it must be noted that actual sound levels within the facility may exceed 90 dBA in certain locations due to the additive effect of several pieces of equipment located within close proximity to each other and interior building reverberation effects. Based upon previous power plant experience, mechanical area sound levels will likely range from 85 to 95 dBA.

Environmental Noise Emissions

The far-field A-weighted sound pressure level resulting from the operation of the facility at base load steady state conditions, exclusive of start up, shut down, bypass operation, steam release, and all other upset and off-normal conditions, shall not exceed a maximum of 75 dBA (ref. 20 microPa) along the site boundary shown noted on Black & Veatch's site arrangement drawing 98362-STA-S1002. The sound pressure levels shall be corrected to exclude the contribution of the background noise, any other noise not associated with the normal operation of the facility, and

any equipment not included in the contract scope of supply.

The current facility design basis is standard packaged equipment, which includes standard (no added cost) noise mitigation measures with all major equipment components. Should upgraded noise mitigation measures be necessary to meet the local noise regulations, specific noise criteria must be established by the Owner. The cost and performance impacts of these noise mitigation measures will then be determined.

ATTACHMENT C
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1
PROJECT SCHEDULE

The project schedule being proposed for this facility will be assumed to be 28 months from Notice to Proceed (NTP) to Guaranteed Substantial Completion with at least a two month Limited Notice to Proceed (LNTP). This does not include procurement of the combustion turbine equipment. The key milestone dates are as follows.

- Limited Notice to Proceed – March 1, 2001
- Notice to Proceed – May 1, 2001
- Combustion Turbine 1 delivery on-site complete – November 1, 2002
- Combustion Turbine 2 delivery on-site complete – December 1, 2002
- Substantial Completion – September 1, 2003
- Commercial Operation – October 1, 2003

For purposes of this proposal we have assumed that all permits, including the air permit, will be in place to support mobilization and foundation installation.

ATTACHMENT D
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1
EPC PRICE BASIS AND ASSUMPTIONS

General

1. The estimate is based on a 2 on 1 combined cycle unit using two combustion turbine generators, two supplementary fired heat recovery steam generators (HRSGs), and one condensing reheat steam turbine.

2. The combustion turbines will be capable of firing natural gas or number 2 fuel oil. The HRSG duct burners will be capable of firing natural gas only.

3. The cost of the combustion turbine generators are included in this estimate. The project schedule is based on the availability of the CTG's for delivery as shown in the schedule.

4. Operating spare parts have not been included.

5. This proposal is based on using IPP industry standard equipment that is the manufacturer's standard for the intended application without any sourcing restrictions. Any special ratings, options or spare capacity requirements; either not required by the relevant codes and laws or not required to make the system operable; may result in an increase in the contract price and/or schedule.

6. Construction costs were estimated based on union labor.

7. All permitting, fuel supplies, and interconnections supplied by the Owner and others shall be in place to support the schedule.

Mechanical

1. The EPC scope of supply includes two combustion turbine generator units and are assumed to be SWPC 501F. GE 7FA combustion turbine generators could also be used as described in Attachment A. The following equipment and services listed will be furnished as part of the EPC Contract for the combustion turbines.

   - Inlet system with two stage inlet filtration
   - Dry low NOx combustion system
   - Natural gas and number 2 fuel oil fuel systems
   - Lubricating and hydraulic oil systems
   - CTG fire detection and protection system

- Off-line and on-line compressor water wash system
- Hydrogen cooled generator and all generator cooling equipment
- Excitation system (including excitation transformer)
- Exhaust system with HRSG bypass damper and stack (130' stack height included)
- Starting and rotor turning systems (including static start transformer)
- Motor control center(s) and AC panelboard(s)
- Batteries, chargers, and DC panelboard(s)
- Turbine control panel(s)
- Generator control panel(s)
- Complete neutral grounding system
- On-base pipework, raceway and cables
- Special tools
- Standard combustion turbine control and protection system
- DCS interface capability
- Water injection equipment
- All necessary platforms, stairways and ladders
- Acoustics for noise control
- Ventilation system
- Technical Direction of Installation
- Operator Training

2. The EPC scope of supply includes a condensing steam turbine generator unit. The following equipment and services will be furnished as part of the EPC Contract for the steam turbine.

- TEWAC or Hydrogen cooled, synchronous generator
- Turbine generator control system
- Turning gear
- Emergency trip system
- Manufacturer's standard lubrication and hydraulic oil systems
- Shaft sealing system
- Supervisory instrumentation
- Technical Direction of Installation
- Operator Training

3 The EPC scope of supply includes two (2) triple pressure supplementary fired heat recovery steam generators (HRSGs). The following will be furnished with each HRSG as part of the EPC Contract for the HRSG.

- Assumed Field Modular design for shipment via rail
- Inlet duct, casings and ductwork
- Duct Burners (natural gas firing only)
- Interconnecting Piping, Valves and Steam Attemperators

- Exhaust stack (160' stack height included)
- All other appurtenances necessary for a complete HRSG unit.

4. Two (2) full capacity (based on 100% of the total design basis feedwater flow per HRSG), horizontal, split case or segmental ring, multi-stage, motor driven, high-pressure, boiler feed pumps per HRSG will be provided. Each pump will be provided with an inter-stage bleed-off connection for supply of intermediate-pressure feedwater.

5. An auxiliary boiler has not been included. Startup steam will be provided by starting the combustion turbines and heating the HRSGs.

6. One fuel gas scrubber/filter for each combustion turbine will be provided to remove impurities and condensate from the gas prior to entering the combustion turbines. A fuel gas heater for startup and initial operation of the combustion turbine has been included. A shell and tube water to gas fuel gas preheater will be provided to meet the combustion turbine manufacturer's minimum requirements for superheat temperature and for performance enhancement of the combined cycle unit during normal operation.

7. The following Shop Fabricated Tanks have been included in the EPC scope of supply:

	Qty.
Acid Storage	1
HRSG Blowdown	2
Fuel Gas Scrubber Drains	2
Air Receiver	1
Closed Cycle Cooling Water Head Tank	1

8. A fire protection and detection system will be provided by the manufacturer for the combustion turbines. Dry-pipe or preaction fire protection systems for the electrical and control equipment areas, and a fire loop around the site has also been included. Water supply will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

9. The following field erected tanks have been included in the EPC scope of supply:

	Qty	Capacity
Fuel Oil Storage Tank (Sized for 3 days of base load operation)	2	1,000,000 gallons
Demineralized Water Storage Tank (Sized for 3 days of base load operation with water injection)	1	850,000 gallons

10. The following General service pumps have been included in the EPC scope of supply:

	Qty.
Demineralized Water Pumps	2
Auxiliary Cooling Water Pumps	2
Closed Cycle Cooling Water Pumps	2
Cooling Tower Makeup Pumps	2
Wastewater Pumps	2
Fuel Oil Unloading Pumps	2
Fuel Oil Supply Pumps	2
Ammonia Supply Pumps	2

11. A selective catalytic reduction system (SCR) to reduce combustion turbine NO_x emissions has been included with the HRSGs. Ammonia supply will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor. Ammonia Supply Pumps, electric vaporizers, and dilution air fans will be included. No CO catalyst has been included, but a spool piece has been included should a CO catalyst be required in the future.

12. One full capacity air receiver, and a full capacity, heatless, dual tower, self-regenerative, desiccant type air dryer will be provided to for the compressed air requirements for the plant. Compressed Air supply will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

13. The condenser exhauster system will consist of two full capacity, two-stage, water sealed, liquid ring vacuum pump units.

14. Three (3) half capacity, based on the total plant design flowrate, vertical circulating water pumps will be provided.

15. A steam turbine lube oil system complete with lube oil purifier and transfer pump will be included with the steam turbine.

16. Two (2) full capacity closed cycle cooling water pumps will be provided to supply closed cooling water to the equipment components requiring cooling water. Each pump will be sized to accommodate flow through one of the two full capacity plate and frame type closed cycle heat exchangers.

17. Three (3) half capacity, based on the total plant design flowrate, condensate pumps will be provided.

18. Exhaust steam from the steam turbine will be condensed in a surface condenser. The condenser will be sized based on a 75 percent cleanliness factor.

19. Heat rejection will be via a wood or fiberglass, multi-cell, mechanical draft, counterflow cooling tower without plume abatement. Cooling tower fans are assumed to be single speed, non-reversing. Manufacturer's standard non-fouling splash block fill suitable for a reclaimed municipal effluent makeup source has been included. A fire protection system for the cooling tower has also been included.

20. Condensate makeup to the condenser hotwell will be provided by two (2) full capacity demineralized water pumps, which will take suction from the demineralized water tank.

21. A full capacity steam turbine bypass system has been included.

22. Fuel gas shall be provided at the site boundary by an Owner furnished (or option EPC Contractor furnished) fuel gas pipeline. The fuel gas will be provided at adequate pressure, quantity, and at suitable temperature based on the combustion turbine manufacturer's requirements. Therefore, fuel gas compressors have not been included.

23. A continuous emissions monitoring system has been included.

24. A black start or emergency diesel generator is not included.

25. A fuel gas chromatograph has been included.

Chemical

1. For proper biofouling control in the circulating water system, the circulating water chemical feed system shall maintain a total available chlorine residual of approximately 0.5 mg/l at the condensr outlet during shock chlorination. The system shall be designed to feed up to 5.0 mg/l sodium hypochlorite. Water conditioning chemicals will be added to the circulating water as appropriate to control biological fouling, scaling, and corrosion. Provisions have been included for feeding sodium hypochlorite, sulfuric acid, proprietary inhibitor/dispersant, and periodic feed of non-oxidizing biocides.

2. The cycle makeup will be from the existing demineralized water system at a quality, quantity, and pressure required by the EPC Contractor.

3. The plant wastewater drains system will collect and direct plant wastewater to the Wastewater Collection Sump and from there to the existing recycle basin.

4. Sanitary waste from the drains and plumbing systems will be routed to a lift station for transfer to the existing sanitary waste treatment system.

5. The cycle chemical feed system will be designed based on the coordinated phosphate

method of cycle chemistry. Amine, oxygen scavenger, and di/tri-sodium phosphate solutions will be supplied by the Owner's chemical supplier in semi-bulk containers. These solutions will be fed neat.

6. A steam and feedwater sampling and analysis system will be provided to monitor the cycle chemistry. Actual samples and monitoring requirements will be determined during detailed design.

7. Drains with the potential for contamination with oily wastes will be routed to an oil/water separator prior to discharge to the Wastewater Collection Sump.

8. HRSG blowdown will be routed to the circulating water return line.

9. Chemical spills will be contained and require manual neutralization and disposal.

10. A laboratory room will not be provided.

11. Service water supply for general plant use, hose bibs, and cleaning will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

12. Potable water supply for building plumbing, sanitary systems, and safety showers/eye wash stations will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

13. Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system. The existing system will need to be expanded and upgraded as required. See Option 3.

14. Condenser dump water will be routed to the cooling tower basin. Under Option 2 a condensate storage tank and a condensate polisher will be installed to conserve cycle water.

Civil/Structural

1. A minimal geotechnical and subsurface investigation to confirm soil conditions for equipment and other facilities foundation designs is included. Allowances for underground obstructions, such as abandoned pipe, tanks, foundations, etc. are not included. The results of this investigation will confirm the foundation system design. Foundations for all major equipment and structures are assumed to be pile supported. All other foundations are assumed to be soil supported spread footings or mat type foundations. The assumed minimum allowable bearing pressure capacity for on-site material is 3.0 ksf. General, drilled piers or soil stabilization are not assumed to be needed, and therefore, are not included. A price and/or schedule adjustment may be required following evaluation of the subsurface investigation.

2. The water table is assumed to be below the bottom of all foundations and underground

utilities and an engineered dewatering system will not be required.

3. Sufficient area within the Stanton power plant facility is assumed to be available for construction activities including, but not limited to, offices, parking, laydown and staging.

4. The plant site area is assumed to be cleared and grubbed. It is assumed that the on-site material is suitable for structural fill and no material will need to be imported. Some minimal off-site disposal is assumed.

5. It is assumed that no hazardous and/or contaminated materials will be encountered on site, therefore no removal or replacement of contaminated soil has been included.

6. Demolition, protection, relocation, or rehabilitation of existing facilities or underground utilities is excluded.

7. A surface drainage system will be provided for the site to direct surface run-off, not at risk of contamination from potential spills of fuel, oils, and coolants, away from equipment and structures by appropriate grading and sloping. Unlined swales, ditches, inlets, and drainage pipe will collect and discharge the run-off flow to an existing unlined storm water collection pond, if required, and then to natural drainage courses. Drainage pipe material will be RCP, CMP, or corrugated HDPE.

8. All areas inside the power block loop road will be finished with aggregate surfacing, approximately 6 inches thick. The remaining open site areas not paved or aggregate surfaced, will be graded. All permanent landscaping on the plant site will be supplied and installed by the Owner.

9. Asphalt paved plant roads will be provided in and around the power block as required for access and maintenance. The plant primary access loop road will be a 20 foot wide road consisting of 3 inches of asphalt over 8 inches of aggregate base material. Any required upgrades to the existing plant roads will be by the Owner.

10. Security fencing and TV cameras will not be provided.

11. Plant boundary and topography surveys, including benchmarks, are to be provided by the Owner.

12. Buildings:

General:
Exterior building finishes will be provided with manufacturer or industry standard warranties. The weather tightness of the buildings will be warranted in accordance with the normal construction warranty. In general all buildings will conform to the following requirements:

All pre-engineered metal buildings will be the product of a recognized metal building systems manufacturer who has been in the practice of manufacturing metal buildings of the size and complexity of the buildings required for a period of no less than 5 years. The manufacturer shall be chiefly engaged in the practice of designing and fabricating metal building systems.

The buildings will be pre-engineered steel frame constructions, with metal wall panel and a standing seam roof system. The wall panels will be minimum 24 gauge thick, preformed galvanized steel with insulation as required. In finished areas, 26 gauge liner panel, eight feet high, will be provided above each floor to protect the insulation. The roofs will be minimum 24 gauge thick, preformed, galvanized steel standing seam metal panels with insulation as required.

Interior finishes shall be compatible with the intended operational use of each building area. Interior finishes for the control room/administration areas shall be aesthetically pleasing to the workers and the potential large number of visitors to such a facility.

Signs and graphic designs for identification and directions shall be incorporated into the interior finishes of each area. Signs shall be placed for safety, ease of operation and direction. The sign system utilized shall provide simple and direct indications using both graphics and text as required by the project facility site's code requirements.

13. The following buildings are included.

- Steam Turbine Building with approximately 18,350 ft^2 of plan area will house the steam turbine and associated gear, electronics room, electrical equipment, battery room, compressed air receiver and dryer, cycle chemical feed equipment area, and restrooms. The Steam Turbine Building high bay is assumed to be approximately 88 feet above grade. A lower bay over the electrical switchgear and equipment is approximately 53 feet above grade.

- Circulating Water Chemical Feed Building with approximately 1800 ft^2 of plan area, which will house the chemical and electrical equipment for the cooling tower.

The Steam Turbine Building will be a custom designed structural steel braced frame. All other buildings will be pre-engineered metal building moment frame construction. Building wall panels will be minimum 24 gauge thick, preformed galvanized steel with insulation as required. In finished areas, a 26-gauge liner panel will be provided in walled areas to protect the insulation. The building roofs will be minimum 24 gauge thick, preformed, galvanized steel, standing seam metal panels with insulation as required. Rolling steel overhead doors will be appropriately located as required for equipment maintenance and access. Floors within the buildings will generally be troweled finished concrete. The floor areas used for chemical storage and feed will be coated with special

protective coatings. Interior partitions in finished areas will be metal stud dry wall construction. The dry wall will be finished painted. The ceilings with buildings will generally be open. The ceilings in finished areas will have suspended acoustical panels.

14. The Steam Turbine Building includes a 50 TN/10TN overhead traveling bridge crane to provide service and maintain the steam turbine and associated generator. All other equipment will be situated so that maintenance can be carried out using a mobile crane provided by the Owner.

15. No costs are included for interior furnishings for the buildings such as desk/furniture, bulletin boards, and lab equipment.

16. Space conditioning for the buildings will be provided and is described as follows:

The electronics room, battery room, and electrical room containing the UPS and DCS equipment will utilize a high efficiency, central air conditioning system with ducted supply air to each conditioned zone. Restrooms will exhaust air to eliminate the build up of odors and moisture. For the remainder of the buildings/areas, the ventilation will be achieved through the use of panel fans in wall mounted fan boxes, fixed louvers, and power roof ventilators. In the Steam Turbine Building, the steam turbine, generator, and equipment area space conditioning will be achieved by natural ventilation through a combination of louvers and operating windows. Ventilation relief will be provided by gravity or power roof ventilators. Heating will be provided by electric unit heaters.

17. Lighting:

Facility equipment and plant roadway lighting is included and is described as follows:

The building and equipment lighting system will include high-pressure sodium light sources for high-bay and outdoor installations, fluorescent light sources for indoor area installations, and incandescent light sources for emergency illumination. Incandescent lamps with integral battery and charger units will be used for emergency lighting of passages, operating areas, and for evacuation.

Illumination for roadways and other plant outdoor areas will be provided by high-pressure sodium luminaries. Lighting will be provided at all plant entrances in conjunction with the roadway lighting.

Luminaries for roadways and other plant areas will be mounted on hot-dip galvanized steel poles. Additional area lighting fixtures will be mounted on equipment, buildings, and structures.

18. All easements and any water development or usage rights are to be provided by others.

19. Identification, protection, or relocation of existing fish and wildlife habitat, wetlands,

threatened and endangered species, or historical, cultural, and archaeological artifacts is not included in the scope of work.

20. The interior structural steel is shop prime painted only. The exterior structural steel components will be galvanized or finish painted.

21. Gravity drains with the potential for contamination with oily wastes will be routed to an oil/water separator prior to discharge to the waste water system.

22. Land and right of ways are to be provided by the Owner.

23. The EPC Contractor will be allowed unlimited access to the project site at the Notice to Proceed date.

24. Cost to upgrade roads, bridges, railroads, etc. outside the plant boundary for equipment transportation to the plant site are not included except as previously noted.

25. Costs associated with temporary office facilities, furnishings, and supplies are included for the EPC Contractor only.

26. A page/party communication system is not included. A raceway system for an Owner provided telephone system will be provided.

27. No permanent plant security system is included.

28. The site is assumed to be located above the 100 year flood plain.

29. A rail spur is located on the existing plant site. The EPC Contractor plans on utilizing this rail spur for offloading heavy equipment. It is assumed that the Owner will have the rail spur upgraded, if required, prior to delivery of the major plant equipment. If this rail spur is not available for use, then a contract price adjustment will be required to utilize a separate rail unloading location.

Electrical/Control

1. None of the transformers are provided with on-load tap changers. It is assumed that, with the units offline, the existing 230kV system has sufficient capacity to start the largest motor while supplying auxiliary load equal to the sum of each unit auxiliary transformers top cooled rating. When the actual 230kV system impedance's are provided, a system analysis will be completed to determine if changes to the auxiliary electric system are required (on-load tap changers, higher transformer capacity, lower than standard transformer impedance, reduced voltage motor starters, etc.). Any changes to the auxiliary electric system required as a result of a lower than required 230kV system

capability may cause an increase in the contract price.

2. Startup auxiliary power will be back fed through generator step-up transformer(s) and unit auxiliary transformer(s).

3. Regardless of any off take agreement, the mega-var output is guaranteed at the terminals of the generator, and not at the high side of the generator step-up transformers. When the existing 230kV system impedances are provided, Black & Veatch will work with the Owner to get the system mega-var output desired. Any changes to the auxiliary electric system required to achieve a desired mega-var output may result in an increase in the contract price.

4. It is assume that the existing 230kV system is maintained within +/-5% of the nominal voltage and +/-0.5% of the nominal frequency (60Hz).

5. All outdoor BOP electrical equipment normally rated at 40C will be derated to the maximum site ambient temperature of 43.3C (110F). Electrical equipment in controlled buildings will not be derated.

6. All 230kV equipment, including transformer bushings, will have a BIL rating of 1175kV.

7. Four, two winding generator step-up (GSU) transformers will be provided, one for each unit. Each GSU transformer will be furnished with an OA/FA/FA cooling rating and 65C-temperature rise.

8. Each GSU transformer will be provided with a solidly grounded wye primary and delta connected secondary.

9. Each GSU transformer will be sized to deliver the full output of the connected turbine across the site ambient temperature range.

10. The impedance of each GSU transformer will be chosen to minimize losses and voltage drop while limiting fault currents to design levels.

11. Each GSU transformer will be oil filled and will be provided with an off-load tap changer (+/-2 * 2.5%), oil containment, bushing type current transformers, and accessories.

12. The terminals of each turbine generator will be connected to its associated GSU transformer through isolated phase bus duct. The bus duct will be sized to carry the full output of the connected unit, and braced to withstand the designed available fault currents.

13. Each set of isolated phase bus duct will have aluminum conductors and enclosures.

14. Each set of isolated phase bus duct will have provisions for connecting a low-pressure,

low flow instrument air source to pressurize the bus. The low-pressure air system equipment is not included.

15. Two sets of CT isolated phase bus duct will include a tap to a unit auxiliary transformer.

16. Each CT generator bus connected to an auxiliary transformer (two units) will be furnished with a low-side generator breaker. Each generator breaker will have the same voltage rating as the generator, and will have an interrupting capability greater than the maximum fault current available as determined by a system fault analysis.

17. Two unit auxiliary transformers (UAT) will be furnished. Each UAT will be connected to the generator bus (between the generator breaker and GSU transformer) through an isolated phase bus duct tap. Each UAT will be furnished with an OA/FA or OA/FA/FA cooling rating and a 55C or 65C-temperature rise.

18. Each UAT will be a two winding transformer with a delta primary and low resistance grounded wye secondary and tertiary. The secondary line-to-line voltage will be 4160V.

19. One winding of each UAT will be sized to operate the steam turbine and one combustion turbine, while starting the second combustion turbine.

20. The impedance of each UAT will be chosen to enable motor starts while limiting fault currents to the design levels.

21. Each UAT will be oil filled and will be provided with an off-load tap changer (+/-2 * 2.5%), bushing type current transformers, and accessories.

22. One lineup of medium voltage switchgear (MV switchgear) will be provided. The switchgear will be a double-ended lineup consisting of two main breakers, a tie breaker, SUS feeder contactors and motor contactors. The MV switchgear will distribute power to large motors and Secondary Unit Substations. The MV switchgear will be located indoors (in a NEMA 1 enclosure as defined in ANSI/IEEE C37.20.2, Section 6.2.11), or outdoors in non-walk-in (NEMA 3R as defined in ANSI/IEEE C37.20.2, Section 6.2.12(1)) enclosures.

23. The MV switchgear will not be furnished with an automatic transfer scheme for loss of power.

24. The MV Switchgear lineup will be provided with one (1) spare SUS feeder contactor and one (1) spare motor contactor.

25. The MV switchgear may be furnished with SUS and motor circuit breakers in lieu of contactors, as determined by the EPC contractor.

26. The MV switchgear (and secondary of each UAT) may be furnished as 4.16kV or 6.9kV as determined by the EPC contractor and an auxiliary electric study.

27. Medium voltage relaying will utilize GE Multilin protective relays, or similar.

28. Three double-ended 480V Secondary Unit Substations (SUS) will be provided. Each SUS will receive power from the MV switchgear and transform the power to 480V for distribution to motor control centers and other 480V loads. Each 480V SUS may be located indoors (NEMA 1 as defined in ANSI/IEEE C37.20.1, Section 6.7) or in suitable outdoor enclosures (non-walk-in NEMA 3R as defined in ANSI/IEEE C37.20.1, Section 6.8) depending upon location and load requirements.

29. Each indoor SUS transformer will be a dry type transformer furnished with an AA or AA/FA cooling rating and a 150C temperature rise. Each outdoor SUS transformer will be an oil-filled type transformer furnished with on OA or OA/FA cooling rating and a 55C or 65C temperature rise.

30. Each SUS transformer and will be sized to provide sufficient power at its maximum rating to feed the maximum worst case load requirements of the connected loads

31. Each SUS transformer will be a two winding transformer with a delta connected primary and high resistance grounded wye secondary.

32. Each 480V SUS will be provided with one (1) spare 800A-frame breaker.

33. Motor Control Centers will be provided as needed to distribute power to cyclic 480V loads, 480V intermediate loads, and small 480V loads that require motor starters or are essential to plant operation. All other loads will receive power from 480/277V, 208/120V, or 120/240V panelboards.

34. One Reliable MCC will be provided. The Reliable MCC will receive power from two different 480V SUS though a break-before-make automatic transfer switch. Each battery charger and the alternate source transformer will be connected to the Reliable MCC.

35. Individual 480V MCC's will be provided with one (1) spare starter and one (1) spare breaker utilized on the 480V MCC.

36. Motor control centers may be furnished indoors (NEMA 1 enclosure) or in suitable outdoor enclosures (non-walk-in NEMA 3R) depending upon location and load requirements. The location and quantity of MCC's will be determined during detailed design by the EPC Contractor.

37. All MCC's will be provided with NEMA Type B wiring as defined in NEMA ICS 3.

38. MCC's will not be provided with indicating lights.

39. All panelboards will be initially designed with a minimum of 10 percent spare circuit breakers.

40. All motors will be designed in accordance with NEMA MG1 and ANSI C50.41 as applicable, unless noted otherwise.

41. All motors will be designed for direct across the line starting.

42. Motors larger than 250 hp will be fed from the 4160V system. Motors 250 hp and below will be fed from the 480V system.

43. All 4000V motors will be horizontal or vertical, single speed, squirrel-cage, induction type motors.

44. All 4000V motors will be provided with a 1.0 or 1.15 service factor.

45. All outdoor 4000V motors will be provided with a WPII enclosure. All indoor 4000V motors will be provided with an ODP enclosure.

46. All low voltage motors will be horizontal or vertical motors as required, single-speed squirrel-cage, induction type motors. Motors for the cooling tower may be two-speed and/or reversing motors, if required. However, the proposal is based on single speed motors.

47. All low-voltage motors will be provided with a 1.0 or 1.15 service factor.

48. All low-voltage motors will be provided with a TEFC enclosure.

49. All motors will be provided with a Class B or Class F insulation system. The temperature rise will not exceed a Class B insulation system temperature rise as defined by ANSI C50.41.

50. The nameplate horsepower times the nameplate service factor or each motor will be at least ten percent above the maximum expected break-horsepower of the driven equipment.

51. In general, the preceding comments concerning motors do not apply to pre-engineered equipment (sump pumps, HVAC equipment, cranes, hoists, motor operated valves, air compressors, etc.), or motors provided with standard packages (combustion turbine/generator, steam turbine/generator, etc.)

52. All motor operators for valves shall be Limitorque Type L120 or equal.

53. It is assumed that each combustion turbine generator package will be furnished complete

with Black & Veatch's inadvertent back energization scheme, generator breaker protective relaying (for two units), generator step-up transformer protective relaying, unit auxiliary transformer protective relaying (for two units), the Owner's requirements, and state and local requirements.

54. It is assumed that each combustion turbine package will be provided with an adequate number of current transformers (line side and neutral side) and potential transformers for all protective relaying requirements.

55. It is assumed that each combustion turbine package will be provided with SWPC electrical package including, but not limited to, motor control center(s), AC panelboard, batteries, chargers, DC panelboard, control panels, and protective relaying panels.

56. It is assumed that each combustion turbine package will be provided with all cables required between equipment provided within the package.

57. A plant 125Vdc system will be provided. The plant 125Vdc system will include one set of 125Vdc batteries, two 125Vdc full capacity chargers, and 125Vdc distribution panels as required. The plant 125Vdc system will be sized to provide 125Vdc power for 30 minutes after 480Vac power becomes unavailable.

58. The plant DC system will provide the DC requirements of the steam turbine/generator and BOP equipment. The plant DC system will not be tied to the CT/G systems.

59. A 120Vac UPS system will be provided. The 120Vac UPS system will include an inverter, automatic transfer switch, static transfer switch, alternate source/isolation transformer, and 120Vac distribution panels as required. The inverter and alternate source/isolation transformer will be sized to provide 120Vac UPS power to all critical 120Vac plant loads.

60. Freeze protection will be provided as required for outdoor above grade pipe and instrumentation. The freeze protection system will consist of one or more monitoring and control panels with a dedicated transformer, power circuits, and heat trace circuits. Heat tracing cable will be of the self-limiting type and mineral insulated type as required.

61. A galvanic cathodic protection system for all underground carbon steel, stainless steel, and copper piping, unless the current requirement dictates an impressed current system, will be provided. The cathodic protection system for this underground piping will be in accordance with NACE International Standard RP-0169-96. The cathodically protected piping will receive a bonded, dielectric coating system, and be electrically isolated from above grade piping, concrete reinforcing steel, and other underground metals. Underground ductile iron piping will be polyethylene encased in accordance with AWWA-C105.

62. All cable tray and junction boxes for non-indoor lighting applications will utilize aluminum material. All above grade conduit for non-indoor lighting will be RGS. Below grade conduit in duct bank will utilize PVC conduit. Duct banks will not be reinforced.

63. One plant grounding system will be provided. A minimum of two (2) connections from the plant ground grid to the substation ground grid will be provided.

64. The cable provided by any third party manufacturer will be the manufacturer's standard cable offering.

65. All BOP medium voltage power cable will be 5kV cable with a 133% insulation cable, single copper conductor, Class B stranded, shielded power cable, 0.115 inch EPR insulation, flame retardant PVC or CPE jacket. Cable will meet AEIC CS6 and ICEA S-68-516 requirements and will be UL listed for cable tray use. All cable will meet the flame test requirements of IEEE 383

66. All BOP 600V single conductor power cable will have Class B stranded copper conductor, flame retardant XLPE or EPR insulation, with no jacket, and will be UL listed for cable tray use. Cable will meet ICEA S-66-524 or S-68-516, and will meet the flame test requirements of UL VW-1 (#8AWG and smaller) and IEEE 383 (#6AWG and larger). All cable will meet the flame test requirements of IEEE 383.

67. All BOP 600V three conductor power cable will have Class B stranded copper conductor, flame retardant EPR or XLPE insulation, flame retardant PVC overall jacket, with ground conductors sized in accordance with UL 1277, and will be UL listed Type TC. Cable will meet ICEA S-66-524 or S-68-516. All cable will meet the flame test requirements of IEEE 383.

68. All BOP 600V control cable will have Class B stranded copper conductor, flame retardant EPR or XLPE insulation, flame retardant PVC overall jacket, with ICEA S-68-516 Method 1 Table K-2 conductor identification, and will be UL listed Type TC. Cable will meet ICEA S-66-525 or S-68-516 and UL 1277. All cable will meet the flame test requirements of IEEE 383.

69. All BOP instrument cable will be single pair, single triad, multi-pair shielded or multi-triad shielded instrument cable with an overall shield. Instrument cable will have Class B stranded copper conductors, PVC Nylon insulation, flame retardant PVC overall jacket with ICEA S-68-516 Method 1 Table K-1 conductor identification, and will be UL listed Type TC. All cable will meet the flame test requirements of IEEE 383.

70. All BOP thermocouple cable will be single pair or multi-pair shielded thermocouple extension solid conductor cable with a shield over each pair, an overall shield, flame retardant PVC insulation, CPE overall jacket, and will be UL listed Type PLTC. All cable will meet the flame test requirements of IEEE 383.

71. All BOP Ground cable will be Class B stranded soft drawn cooper conductor per ASTM B8. Insulated ground cable will have a green colored polyvinyl chloride insulation UL 83 Type TW, THW, or THHN.

72. All BOP lighting and fixture cable will be single conductor Class B stranded copper conductor, XLPE insulated cable, and will be UL listed as NEC Type XHHW.

73. A raised floor will be installed in the electronics room.

74. Plant synchronization to the 230kV grid will be accomplished through the two low-side generator breakers for the two combustion turbine generators, and through the high-side generator breakers for the other combustion turbine generator and the steam turbine generator.

75. Plant control will be through a distributed control system with three operator stations with dual CRT's for operator interface and one engineering work station. Data links will be provided to interface to other control systems furnished with the facility. This integrated control system for plant operation and monitoring does not provide for complete remote operation of all systems. Manufacturer's standard control systems will be supplied with remote indications and alarms. There is no Main Electrical Panel; however, similar functionality will be provided within the DCS. No provisions for on-line performance monitoring have been included. The level of automation and redundancy will be determined by the Black & Veatch standard controls and instrumentation philosophy.

76. All combustion turbines and the steam turbine will have remote control stations (supplied by the turbine vendors) located in the Stanton central control room. The Black & Veatch standard controls and instrumentation philosophy will be used.

77. The natural gas fuel input custody transfer meters are included. Individual component performance testing instrumentation has not been included.

ATTACHMENT E
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 3X1
TERMINAL POINTS

The following terminal points identify the termination points or interfaces for those services or facilities, which extend beyond the EPC scope of the work. The definitions of terminal points include the physical location and, if necessary, the design conditions, which form the basis of the EPC cost estimate.

CIVIL

(1) **Site Access** -- The EPC Contractor will provide access roads within the Unit 3 Facility boundary from the existing plant roads.

(2) **Telephone** -- The raceway for the telephone system will terminate at the Facility boundary, however, the telephone system will be provided by the Owner.

(3) **Sitework** -- Sitework will terminate at the limits of the plant site boundary and construction laydown yard areas.

(4) **Landscaping** -- The EPC Contractor will provide aggregate surfacing in the power block area and grass seeding for soil stabilization and erosion control for other areas within the Facility's perimeter fence. Any additional landscaping will be provided by the Owner.

(5) **Rail Siding** -- A rail siding for equipment off loading is exists on the existing plant site will be available for use by the EPC Contractor.

(6) **Sanitary** -- Sanitary drains will be pumped to the existing sanitary waste treatment system.

MECHANICAL

(1) **Fuel** -- Pipeline quality natural gas will be made available via an Owner (or optional EPC Contractor supplied-see Option 1) supplied pipeline terminating at the Unit 3 site boundary shown on the site arrangement drawing. The natural gas will be available at adequate pressure, quantity, and suitable temperature to meet the combustion turbine manufacturer's requirements.

(2) **Service Water** -- Service water for general plant use will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing

system.

(3) **Potable Water** – Potable water for building plumbing, sanitary systems and safety showers/eye wash stations will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(4) **Fire Protection Water** -- Fire Protection water for various fire protection systems will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(5) **Cycle Makeup Water** -- Demineralized water for cycle makeup and water injection will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(6) **Cooling Tower Makeup** – Circulating water system makeup water will be from the existing municipal wastewater treatment plant effluent system and will be made available at a quality, quantity, and pressure required by the EPC Contractor.

(7) **Cooling Tower Blowdown** – Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system. The existing systems will need to expanded and upgrade and an allowance for this work is included in this estimate.

(8) **Compressed Air** – Compressed air for general use and instruments/controls will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(9) **Ammonia Supply** – Anhydrous ammonia for the HRSG SCR systems will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system

(10) **Wastewater** -- Oily wastes will be collected and treated in an oil/water separator. Treated effluent from the oil/water separator and other plant drains will be combined and conveyed by the wastewater discharge system to the existing recycle basin.

ELECTRICAL

(1) **Construction Power** – The construction power source will be provided by the Owner within the Facility perimeter fence at a location determined by the EPC Contractor. Construction power will be 480 volt, three-phase, 1200 amperes.

(2) **Power Out Electric Interface** – The termination point is defined as the terminals on the high side of the GSU transformer.

(3) **Power In Electrical Interface** -- The termination point is the same as the Power Out Electric Interface.

(4) **Dispatch Control Signals** -- The termination point for dispatching will be at the terminals of the SCADA RTU supplied by the Owner.

(5) **Grounding System** -- A grounding system consisting of ground rods and interconnecting copper conductors will be provided for the generating facility and the switchyard. No connections outside of the Facility are included.

(6) **Fuel Gas Metering** – The gas pipeline fuel gas metering signals termination point will be a junction box at the site boundary or at the on-site metering equipment.

ATTACHMENT F
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1
ABOVE NORMAL SCOPE ADDERS

The following items are necessary additions to the base EPC cost for site and owner specific considerations.

Description	Cost Adders	Remarks
Sitework		
Utility Excavation	$253,920	for interconnection to existing facility
Arch/Metal		
STG Building	$3,709,950	owner request
Piping		
Below Ground Lrg Bore/Insulation	$1,892,376	for interconnection to existing facility
Mechanical		
Bypass Stack/Silencers 2 ea.	$3,000,000	owner request
Cooling Tower	$1,500,000	owner request non foul fill
Condenser	$300,000	owner request Stainless Steel 316
Construction Indirects	$462,769	
Total Adder Cost	**$11,119,015**	

NOT REVIEWED

ATTACHMENT G
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1
MAJOR COMMERCIAL TERMS

The EPC proposal is based on the following major commercial terms.

1. The EPC BOP budget price for the project work scope defined herein is based on a limited notice to proceed (LNTP) on or before March 1, 2001 and a full notice to proceed (NTP) on or before May 1, 2001, with a Substantial Completion Date of September 1, 2003.

2. Terms of payment for the EPC BOP scope shall be as follows.

   - Payment of $500,000 for the term of the LNTP to coordinate and initiate combustion turbine, steam turbine, HRSG, and EPC BOP design engineering and to conduct on site soil investigation work.

   - Additional payment to reach a value equal to ten (10) percent of the EPC total price within 10 days of Notice to Proceed.

   - Eighty five (85) percent of the total price in monthly progress payments, without retainage, based on the percent complete (including percent complete of uncompleted milestones) or the weighted values of engineering, manufacturing, material delivery, construction, and commissioning.

   - Five (5) percent of the total price less the value of the Punch List upon Substantial Completion.

   - Monthly progress payments for completion of the Punch List items.

   Terms of payment for the Combustion Turbines shall be as defined in the Owner's Contracts with each supplier, if such contracts are assigned to the EPC Contractor.

3. All payments are due within 30 days of receipt of the invoice. In event that payment is not made within 30 days, interest shall accrue at the Chase Manhattan (New York) prime rate plus two (2) percent in effect on the date such amount was due. Failure of the Owner to make payment within 30 days shall be considered an Event of Default, and the Owner shall have 10 days to cure such default.

4. A performance or payment bond is not included or required.

5. The EPC BOP price does not include any property, sales, or use taxes, gross receipts tax, import or export duties, excise or local taxes, license fees, value added tax, or other similar taxes.

6. The plant performance test will be a two hour test to demonstrate the ability of the Facility to deliver firm output continuously to the grid. During the 2 hour continuous operating period, the actual net electrical output and actual net heat rate will be determined. Also, during the continuous test, emissions will be determined. Performance and emissions tests will be conducted in accordance with the test descriptions and protocol established by the EPC Contractor. Individual Power Train Equipment tests will be conducted to the extent necessary to verify plant performance is met, or to the extent necessary to identify components contributing to a shortfall.

7. The Owner shall provide the EPC Contractor with a minimum cure period of six months following Substantial Completion to allow remedial actions to be taken to achieve the performance, if required.

8. Substantial Completion shall be achieved when the following have been satisfied.

   - Construction of the facility has been completed except for Punch List items which will not interrupt, disrupt, or interfere with, to any significant extent, commercial operation of the facility.

   - The performance test has been completed and the facility achieves not less than 95 percent of the actual net electrical output and/or not more than 105 percent of the actual net heat rate (fuel consumption).

9. Care, custody, and control and risk of loss of the Facility shall pass to the Owner on the Substantial Completion date.

   It is assumed that the Owner will provide an experienced plant staff, complete with supervision, that will operate the plant during checkout, startup, and testing activities subject to the technical direction of the EPC Contractor.

10. Warranty on the EPC BOP material and workmanship is one year from Substantial Completion provided that any re-performance, repair, or replacement work performed prior to Substantial Completion shall be re-warranted for 12 months after the completion date of such work. In no event shall any EPC BOP warranty period be extended beyond two years after the Scheduled Substantial Completion Date. After the EPC Contractor leaves the site, administration and labor for replacement of defective material is to be provided by the Owner. Warranty on the Combustion Turbines shall be as defined in the Owner's contract with the supplier if such contract is assigned to the EPC Contractor.

11. Final liquidated damage/bonus provisions related to performance and schedule will be determined later. However, the EPC Contractor will agree to pay as liquidated damages and not as a penalty, schedule delays and Facility performance shortfalls commensurate with the normal terms and conditions of a typical EPC contract for the project configuration and technology selected for this project, up to the maximum levels stated below. The final actual maximum levels will in no case be larger than the maximum levels included in the Owner's Combustion Turbine Contract, for shortfalls caused by such contractor, if such contract is assigned to the EPC Contractor.

EPC Contract Liquidated Damages Cap

Project Schedule --	Up to a maximum of 10% of the EPC contract price.
Output and Heat Rate --	Up to a maximum of 15% of the EPC contract price.
Maximum Aggregate --	Maximum aggregate for all liquidated damages of 25%.

Liquidated damages for schedule and performance are Owner's exclusive remedy for delays or performance shortfalls.

12. Consequential damages shall be excluded and the EPC Contractor's overall liability shall be limited to no greater than 100% of the Contract Price in either case whether arising out of contract, tort (including negligence whether active or passive), strict liability or other theory of law and extend to all Contractor's subcontractors and vendors of every tier.

13. Force Majeure includes an occurrence beyond the reasonable control of the EPC Contractor in performing its obligations. Such events include but are not to be limited to floods, droughts, earthquakes, storms, fire, pestilence, lightning, or other natural catastrophes, epidemics, wars, riots, civil disturbance, sabotage, or other civil disobedience; strikes or other labor disputes; action or inaction of legislature, judicial, regulatory or other governmental bodies that may render or may have rendered illegal action in accordance with the provisions of the EPC agreement.

Force Majeure events shall result in an appropriate price adjustment to the contract price and Guaranteed Substantial Completion Date adjustment of not less than a day for day slip.

14. Owner caused delays include the absence of full project release, lack of permits and licenses, a lack of site access, unavailability of clean, reliable natural gas at required capacity and pressure, makeup water, construction power, and late inter-tie to the electrical transmission system. Owner caused delays shall result in a price adjustment to the contract price and Guaranteed Substantial Completion Date of not less than a day for day slip.

15. Any existing facility property and builders risk insurance maintained or provided by the Owner and other contractors shall name the EPC Contractor as an additional insured and shall include a waiver of subrogation. The indemnities, limitations, waivers and releases shall apply regardless of the negligence, breach of contract, breach of warranty, or strict liability of the party so released, and shall extend to the affiliates and subcontractors of Contractor. The remedies set forth in the Agreement shall be the Owner's exclusive remedies against Contractor and its subcontractors.

16. Owner will purchase operating spares in accordance with vendor recommendations and make them available to EPC Contractor for use during startup and initial operation. EPC Contractor will replace any Owner spares utilized.

17. Owner assumes all risk of existing onsite hazardous materials disposal and agrees to defend, indemnify and hold EPC Contractor harmless from and against any and all claims, damages, costs and liability arising therefrom; EPC Contractor is responsible for the disposal of hazardous waste and toxic substances which are used or produced in the execution of the work. EPC Contractor has no responsibility for the excavation, transportation, storage, handling, removal, or treatment for material discovered or encountered at the work site.

18. Owner's contracts for the Power Train Equipment shall name the EPC Contractor and its affiliates and subcontractors as an additional insured and shall include a waiver of subrogation. Such contracts shall also include the EPC Contractor and its affiliates and subcontractors as an indemnified party. If such provisions are not provided, Owner shall indemnify the EPC Contractor from and associated losses and claims from such contractors.

19. Other terms and conditions mutually agreed to by the Owner and EPC Contractor which incorporate the following provisions.

- Schedule and price relief for changes in law.
- Contractor's right to terminate for non-payment.
- No plant rejection clause.
- Third party indemnification clause based on comparative negligence. EPC Contractor shall have no liability for Owner's existing property.
- EPC Contractor will assume risk of site subterranean features based on the results of soil investigations completed. If site conditions differ from such investigations, a change order for price and schedule relief shall be allowed.

Appendix 1A.E
Orlando Utilities Commission
Stanton Energy Center
Stanton Unit A - 2x1 Large STG
Capital Cost Estimate

ATTACHMENT A
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1 LARGE STG
CAPITAL COST ESTIMATES

EPC BASIS

The EPC Capital Cost Estimate for a nominal 630 MW two-on-one F class combustion turbine combined cycle power project located at Stanton Energy Center near Orlando, Florida is as follows. The estimate is based on Siemens Westinghouse Power Corporation (SWPC) "501F" class combustion turbines, two flow downward exhaust reheat steam turbine, and triple pressure HRSG's. General Electric (GE) "7FA" combustion turbines could also be used which would result in a slightly lower cost and also a slightly lower output. The estimate is based on availability of combustion turbines to meet a November 1, 2002 on site delivery and commercial operation by October 1, 2003.

The total estimated capital cost is $242,000,000 for commercial operation on October 1, 2003. The capital cost does not include interest during construction or other Owner costs. The capital cost estimate is based on a project scope that is described in Attachment D. In addition, the capital cost estimate is based on pricing that is indicative of similar competitive projects developed for the merchant market. Specifications incorporating unique requirements or non-standard equipment may result in higher prices. The estimate is on an EPC basis.

SELF BUILD BASIS

The Self-Build Cost Estimate for the same plant as defined above and in the attachments is $235,000,000.

NOTES:

The above estimates include an allowance of $38,000,000 for the SWPC combustion turbines. This allowance could vary significantly depending on when the contract is awarded.

The Above Normal Scope Adders listed in Attachment F would apply to either cost estimate.

OPTION 1:
Option 1 is for a natural gas supply pipeline and metering station from the FGT tie-in point to the Unit 3 site boundary. The pipeline size would be 16", and the length is estimated at 4.1 miles.

Option 1 cost estimate is $5,508.000.00.

OPTION 2:
Option 2 is for the installation of a 5,000-gallon condensate storage tank and powered resin type

condensate polisher to reduce cycle makeup water usage.

Option 2 cost estimate is $1,200,000.00.

OPTION 3:
Option 3 is for the rehabilitation/upgrade of the existing zero discharge water treatment facilities.

Option 3 cost estimate is $1,300,000.00 per train.

NOT REVIEWED

ATTACHMENT B
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1 LARGE STG
PERFORMANCE

(later)

ATTACHMENT C
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1 LARGE STG
PROJECT SCHEDULE

The project schedule being proposed for this facility will be assumed to be 28 months from Notice to Proceed (NTP) to Guaranteed Substantial Completion with at least a two month Limited Notice to Proceed (LNTP). This does not include procurement of the combustion turbine equipment. The key milestone dates are as follows.

- Limited Notice to Proceed – March 1, 2001
- Notice to Proceed – May 1, 2001
- Combustion Turbine 1 delivery on-site complete – November 1, 2002
- Combustion Turbine 2 delivery on-site complete – December 1, 2002
- Substantial Completion – September 1, 2003
- Commercial Operation – October 1, 2003

For purposes of this proposal we have assumed that all permits, including the air permit, will be in place to support mobilization and foundation installation.

ATTACHMENT D
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1 LARGE STG
EPC PRICE BASIS AND ASSUMPTIONS

General

1. The estimate is based on a 2 on 1 combined cycle unit using two combustion turbine generators, two supplementary fired heat recovery steam generators (HRSGs), and one condensing reheat steam turbine.

2. The combustion turbines will be capable of firing natural gas or number 2 fuel oil. The HRSG duct burners will be capable of firing natural gas only.

3. The cost of the combustion turbine generators are included in this estimate. The project schedule is based on the availability of the CTG's for delivery as shown in the schedule.

4. Operating spare parts have not been included.

5. This proposal is based on using IPP industry standard equipment that is the manufacturer's standard for the intended application without any sourcing restrictions. Any special ratings, options or spare capacity requirements; either not required by the relevant codes and laws or not required to make the system operable; may result in an increase in the contract price and/or schedule.

6. Construction costs were estimated based on union labor.

7. All permitting, fuel supplies, and interconnections supplied by the Owner and others shall be in place to support the schedule.

Mechanical

1. The EPC scope of supply includes two combustion turbine generator units and are assumed to be SWPC 501F. GE 7FA combustion turbine generators could also be used as described in Attachment A. The following equipment and services listed will be furnished as part of the EPC Contract for the combustion turbines.

   - Inlet system with two stage inlet filtration
   - Dry low NOx combustion system
   - Natural gas and number 2 fuel oil fuel systems
   - Lubricating and hydraulic oil systems
   - CTG fire detection and protection system
   - Off-line and on-line compressor water wash system

- Hydrogen cooled generator and all generator cooling equipment
- Excitation system (including excitation transformer)
- Exhaust system with HRSG bypass damper and stack (130' stack height included)
- Starting and rotor turning systems (including static start transformer)
- Motor control center(s) and AC panelboard(s)
- Batteries, chargers, and DC panelboard(s)
- Turbine control panel(s)
- Generator control panel(s)
- Complete neutral grounding system
- On-base pipework, raceway and cables
- Special tools
- Standard combustion turbine control and protection system
- DCS interface capability
- Water injection equipment
- All necessary platforms, stairways and ladders
- Acoustics for noise control
- Ventilation system
- Technical Direction of Installation
- Operator Training

2. The EPC scope of supply includes a condensing steam turbine generator unit. The following equipment and services will be furnished as part of the EPC Contract for the steam turbine.

- TEWAC or Hydrogen cooled, synchronous generator
- Turbine generator control system
- Turning gear
- Emergency trip system
- Manufacturer's standard lubrication and hydraulic oil systems
- Shaft sealing system
- Supervisory instrumentation
- Technical Direction of Installation
- Operator Training

3 The EPC scope of supply includes two (2) triple pressure supplementary fired heat recovery steam generators (HRSGs). The following will be furnished with each HRSG as part of the EPC Contract for the HRSG.

- Assumed Field Modular design for shipment via rail
- Inlet duct, casings and ductwork
- Duct Burners (natural gas firing only)
- Interconnecting Piping, Valves and Steam Attemperators
- Exhaust stack (160' stack height included)

- All other appurtenances necessary for a complete HRSG unit.

4. Two (2) full capacity (based on 100% of the total design basis feedwater flow per HRSG), horizontal, split case or segmental ring, multi-stage, motor driven, high-pressure, boiler feed pumps per HRSG will be provided. Each pump will be provided with an inter-stage bleed-off connection for supply of intermediate-pressure feedwater.

5. An auxiliary boiler has not been included. Startup steam will be provided by starting the combustion turbines and heating the HRSGs.

6. One fuel gas scrubber/filter for each combustion turbine will be provided to remove impurities and condensate from the gas prior to entering the combustion turbines. A fuel gas heater for startup and initial operation of the combustion turbine has been included. A shell and tube water to gas fuel gas preheater will be provided to meet the combustion turbine manufacturer's minimum requirements for superheat temperature and for performance enhancement of the combined cycle unit during normal operation.

7. The following Shop Fabricated Tanks have been included in the EPC scope of supply:

	Qty.
Acid Storage	1
HRSG Blowdown	2
Fuel Gas Scrubber Drains	2
Air Receiver	1
Closed Cycle Cooling Water Head Tank	1

8. A fire protection and detection system will be provided by the manufacturer for the combustion turbines. Dry-pipe or preaction fire protection systems for the electrical and control equipment areas, and a fire loop around the site has also been included. Water supply will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

9. The following field erected tanks have been included in the EPC scope of supply:

	Qty	Capacity
Fuel Oil Storage Tank (Sized for 3 days of base load operation)	2	1,000,000 gallons
Demineralized Water Storage Tank (Sized for 3 days of base load operation with water injection)	1	850,000 gallons

10. The following General service pumps have been included in the EPC scope of supply:

	Qty.
Demineralized Water Pumps	2
Auxiliary Cooling Water Pumps	2
Closed Cycle Cooling Water Pumps	2
Cooling Tower Makeup Pumps	2
Wastewater Pumps	2
Fuel Oil Unloading Pumps	2
Fuel Oil Supply Pumps	2
Ammonia Supply Pumps	2

11. A selective catalytic reduction system (SCR) to reduce combustion turbine NO_x emissions has been included with the HRSGs. Ammonia supply will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor. Ammonia Supply Pumps, electric vaporizers, and dilution air fans will be included. No CO catalyst has been included, but a spool piece has been included should a CO catalyst be required in the future.

12. One full capacity air receiver, and a full capacity, heatless, dual tower, self-regenerative, desiccant type air dryer will be provided to for the compressed air requirements for the plant. Compressed Air supply will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

13. The condenser exhauster system will consist of two full capacity, two-stage, water sealed, liquid ring vacuum pump units.

14. Three (3) half capacity, based on the total plant design flowrate, vertical circulating water pumps will be provided.

15. A steam turbine lube oil system complete with lube oil purifier and transfer pump will be included with the steam turbine.

16. Two (2) full capacity closed cycle cooling water pumps will be provided to supply closed cooling water to the equipment components requiring cooling water. Each pump will be sized to accommodate flow through one of the two full capacity plate and frame type closed cycle heat exchangers.

17. Three (3) half capacity, based on the total plant design flowrate, condensate pumps will be provided.

18. Exhaust steam from the steam turbine will be condensed in a surface condenser. The condenser will be sized based on a 75 percent cleanliness factor.

19. Heat rejection will be via a wood or fiberglass, multi-cell, mechanical draft, counterflow

cooling tower without plume abatement. Cooling tower fans are assumed to be single speed, non-reversing. Manufacturer's standard non-fouling splash block fill suitable for a reclaimed municipal effluent makeup source has been included. A fire protection system for the cooling tower has also been included.

20. Condensate makeup to the condenser hotwell will be provided by two (2) full capacity demineralized water pumps, which will take suction from the demineralized water tank.

21. A full capacity steam turbine bypass system has been included.

22. Fuel gas shall be provided at the site boundary by an Owner furnished (or option EPC Contractor furnished) fuel gas pipeline. The fuel gas will be provided at adequate pressure, quantity, and at suitable temperature based on the combustion turbine manufacturer's requirements. Therefore, fuel gas compressors have not been included.

23. A continuous emissions monitoring system has been included.

24. A black start or emergency diesel generator is not included.

25. A fuel gas chromatograph has been included.

Chemical

1. For proper biofouling control in the circulating water system, the circulating water chemical feed system shall maintain a total available chlorine residual of approximately 0.5 mg/l at the condensr outlet during shock chlorination. The system shall be designed to feed up to 5.0 mg/l sodium hypochlorite. Water conditioning chemicals will be added to the circulating water as appropriate to control biological fouling, scaling, and corrosion. Provisions have been included for feeding sodium hypochlorite, sulfuric acid, proprietary inhibitor/dispersant, and periodic feed of non-oxidizing biocides.

2. The cycle makeup will be from the existing demineralized water system at a quality, quantity, and pressure required by the EPC Contractor.

3. The plant wastewater drains system will collect and direct plant wastewater to the Wastewater Collection Sump and from there to the existing recycle basin.

4. Sanitary waste from the drains and plumbing systems will be routed to a lift station for transfer to the existing sanitary waste treatment system.

5. The cycle chemical feed system will be designed based on the coordinated phosphate method of cycle chemistry. Amine, oxygen scavenger, and di/tri-sodium phosphate solutions will be supplied by the Owner's chemical supplier in semi-bulk containers.

These solutions will be fed neat.

6. A steam and feedwater sampling and analysis system will be provided to monitor the cycle chemistry. Actual samples and monitoring requirements will be determined during detailed design.

7. Drains with the potential for contamination with oily wastes will be routed to an oil/water separator prior to discharge to the Wastewater Collection Sump.

8. HRSG blowdown will be routed to the circulating water return line.

9. Chemical spills will be contained and require manual neutralization and disposal.

10. A laboratory room will not be provided.

11. Service water supply for general plant use, hose bibs, and cleaning will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

12. Potable water supply for building plumbing, sanitary systems, and safety showers/eye wash stations will be from the existing system at a quality, quantity, and pressure required by the EPC Contractor.

13. Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system. The existing system will need to be expanded and upgraded as required. See Option 3.

14. Condenser dump water will be routed to the cooling tower basin. Under Option 2 a condensate storage tank and a condensate polisher will be installed to conserve cycle water.

Civil/Structural

1. A minimal geotechnical and subsurface investigation to confirm soil conditions for equipment and other facilities foundation designs is included. Allowances for underground obstructions, such as abandoned pipe, tanks, foundations, etc. are not included. The results of this investigation will confirm the foundation system design. Foundations for all major equipment and structures are assumed to be pile supported. All other foundations are assumed to be soil supported spread footings or mat type foundations. The assumed minimum allowable bearing pressure capacity for on-site material is 3.0 ksf. General, drilled piers or soil stabilization are not assumed to be needed, and therefore, are not included. A price and/or schedule adjustment may be required following evaluation of the subsurface investigation.

2. The water table is assumed to be below the bottom of all foundations and underground utilities and an engineered dewatering system will not be required.

3. Sufficient area within the Stanton power plant facility is assumed to be available for construction activities including, but not limited to, offices, parking, laydown and staging.

4. The plant site area is assumed to be cleared and grubbed. It is assumed that the on-site material is suitable for structural fill and no material will need to be imported. Some minimal off-site disposal is assumed.

5. It is assumed that no hazardous and/or contaminated materials will be encountered on site, therefore no removal or replacement of contaminated soil has been included.

6. Demolition, protection, relocation, or rehabilitation of existing facilities or underground utilities is excluded.

7. A surface drainage system will be provided for the site to direct surface run-off, not at risk of contamination from potential spills of fuel, oils, and coolants, away from equipment and structures by appropriate grading and sloping. Unlined swales, ditches, inlets, and drainage pipe will collect and discharge the run-off flow to an existing unlined storm water collection pond, if required, and then to natural drainage courses. Drainage pipe material will be RCP, CMP, or corrugated HDPE.

8. All areas inside the power block loop road will be finished with aggregate surfacing, approximately 6 inches thick. The remaining open site areas not paved or aggregate surfaced, will be graded. All permanent landscaping on the plant site will be supplied and installed by the Owner.

9. Asphalt paved plant roads will be provided in and around the power block as required for access and maintenance. The plant primary access loop road will be a 20 foot wide road consisting of 3 inches of asphalt over 8 inches of aggregate base material. Any required upgrades to the existing plant roads will be by the Owner.

10. Security fencing and TV cameras will not be provided.

11. Plant boundary and topography surveys, including benchmarks, are to be provided by the Owner.

12. Buildings:

General:
Exterior building finishes will be provided with manufacturer or industry standard warranties. The weather tightness of the buildings will be warranted in accordance with the normal construction warranty. In general all buildings will conform to the following requirements:

All pre-engineered metal buildings will be the product of a recognized metal building systems manufacturer who has been in the practice of manufacturing metal buildings of

the size and complexity of the buildings required for a period of no less than 5 years. The manufacturer shall be chiefly engaged in the practice of designing and fabricating metal building systems.

The buildings will be pre-engineered steel frame constructions, with metal wall panel and a standing seam roof system. The wall panels will be minimum 24 gauge thick, preformed galvanized steel with insulation as required. In finished areas, 26 gauge liner panel, eight feet high, will be provided above each floor to protect the insulation. The roofs will be minimum 24 gauge thick, preformed, galvanized steel standing seam metal panels with insulation as required.

Interior finishes shall be compatible with the intended operational use of each building area. Interior finishes for the control room/administration areas shall be aesthetically pleasing to the workers and the potential large number of visitors to such a facility.

Signs and graphic designs for identification and directions shall be incorporated into the interior finishes of each area. Signs shall be placed for safety, ease of operation and direction. The sign system utilized shall provide simple and direct indications using both graphics and text as required by the project facility site's code requirements.

13. The following buildings are included.

- Steam Turbine Building with approximately 18,350 ft^2 of plan area will house the steam turbine and associated gear, electronics room, electrical equipment, battery room, compressed air receiver and dryer, cycle chemical feed equipment area, and restrooms. The Steam Turbine Building high bay is assumed to be approximately 88 feet above grade. A lower bay over the electrical switchgear and equipment is approximately 53 feet above grade.

- Circulating Water Chemical Feed Building with approximately 1800 ft^2 of plan area, which will house the chemical and electrical equipment for the cooling tower.

The Steam Turbine Building will be a custom designed structural steel braced frame. All other buildings will be pre-engineered metal building moment frame construction. Building wall panels will be minimum 24 gauge thick, preformed galvanized steel with insulation as required. In finished areas, a 26-gauge liner panel will be provided in walled areas to protect the insulation. The building roofs will be minimum 24 gauge thick, preformed, galvanized steel, standing seam metal panels with insulation as required. Rolling steel overhead doors will be appropriately located as required for equipment maintenance and access. Floors within the buildings will generally be troweled finished concrete. The floor areas used for chemical storage and feed will be coated with special protective coatings. Interior partitions in finished areas will be metal stud dry wall construction. The dry wall will be finished painted. The ceilings with buildings will

generally be open. The ceilings in finished areas will have suspended acoustical panels.

14. The Steam Turbine Building includes a 50 TN/10TN overhead traveling bridge crane to provide service and maintain the steam turbine and associated generator. All other equipment will be situated so that maintenance can be carried out using a mobile crane provided by the Owner.

15. No costs are included for interior furnishings for the buildings such as desk/furniture, bulletin boards, and lab equipment.

16. Space conditioning for the buildings will be provided and is described as follows:

    The electronics room, battery room, and electrical room containing the UPS and DCS equipment will utilize a high efficiency, central air conditioning system with ducted supply air to each conditioned zone. Restrooms will exhaust air to eliminate the build up of odors and moisture. For the remainder of the buildings/areas, the ventilation will be achieved through the use of panel fans in wall mounted fan boxes, fixed louvers, and power roof ventilators. In the Steam Turbine Building, the steam turbine, generator, and equipment area space conditioning will be achieved by natural ventilation through a combination of louvers and operating windows. Ventilation relief will be provided by gravity or power roof ventilators. Heating will be provided by electric unit heaters.

17. Lighting:

    Facility equipment and plant roadway lighting is included and is described as follows:

    The building and equipment lighting system will include high-pressure sodium light sources for high-bay and outdoor installations, fluorescent light sources for indoor area installations, and incandescent light sources for emergency illumination. Incandescent lamps with integral battery and charger units will be used for emergency lighting of passages, operating areas, and for evacuation.

    Illumination for roadways and other plant outdoor areas will be provided by high-pressure sodium luminaries. Lighting will be provided at all plant entrances in conjunction with the roadway lighting.

    Luminaries for roadways and other plant areas will be mounted on hot-dip galvanized steel poles. Additional area lighting fixtures will be mounted on equipment, buildings, and structures.

18. All easements and any water development or usage rights are to be provided by others.

19. Identification, protection, or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species, or historical, cultural, and archaeological artifacts is not included in the scope of work.

20. The interior structural steel is shop prime painted only. The exterior structural steel components will be galvanized or finish painted.

21. Gravity drains with the potential for contamination with oily wastes will be routed to an oil/water separator prior to discharge to the waste water system.

22. Land and right of ways are to be provided by the Owner.

23. The EPC Contractor will be allowed unlimited access to the project site at the Notice to Proceed date.

24. Cost to upgrade roads, bridges, railroads, etc. outside the plant boundary for equipment transportation to the plant site are not included except as previously noted.

25. Costs associated with temporary office facilities, furnishings, and supplies are included for the EPC Contractor only.

26. A page/party communication system is not included. A raceway system for an Owner provided telephone system will be provided.

27. No permanent plant security system is included.

28. The site is assumed to be located above the 100 year flood plain.

29. A rail spur is located on the existing plant site. The EPC Contractor plans on utilizing this rail spur for offloading heavy equipment. It is assumed that the Owner will have the rail spur upgraded, if required, prior to delivery of the major plant equipment. If this rail spur is not available for use, then a contract price adjustment will be required to utilize a separate rail unloading location.

Electrical/Control

1. None of the transformers are provided with on-load tap changers. It is assumed that, with the units offline, the existing 230kV system has sufficient capacity to start the largest motor while supplying auxiliary load equal to the sum of each unit auxiliary transformers top cooled rating. When the actual 230kV system impedance's are provided, a system analysis will be completed to determine if changes to the auxiliary electric system are required (on-load tap changers, higher transformer capacity, lower than standard transformer impedance, reduced voltage motor starters, etc.). Any changes to the auxiliary electric system required as a result of a lower than required 230kV system capability may cause an increase in the contract price.

2. Startup auxiliary power will be back fed through generator step-up transformer(s) and

unit auxiliary transformer(s).

3. Regardless of any off take agreement, the mega-var output is guaranteed at the terminals of the generator, and not at the high side of the generator step-up transformers. When the existing 230kV system impedances are provided, Black & Veatch will work with the Owner to get the system mega-var output desired. Any changes to the auxiliary electric system required to achieve a desired mega-var output may result in an increase in the contract price.

4. It is assume that the existing 230kV system is maintained within +/-5% of the nominal voltage and +/-0.5% of the nominal frequency (60Hz).

5. All outdoor BOP electrical equipment normally rated at 40C will be derated to the maximum site ambient temperature of 43.3C (110F). Electrical equipment in controlled buildings will not be derated.

6. All 230kV equipment, including transformer bushings, will have a BIL rating of 1175kV.

7. Four, two winding generator step-up (GSU) transformers will be provided, one for each unit. Each GSU transformer will be furnished with an OA/FA/FA cooling rating and 65C-temperature rise.

8. Each GSU transformer will be provided with a solidly grounded wye primary and delta connected secondary.

9. Each GSU transformer will be sized to deliver the full output of the connected turbine across the site ambient temperature range.

10. The impedance of each GSU transformer will be chosen to minimize losses and voltage drop while limiting fault currents to design levels.

11. Each GSU transformer will be oil filled and will be provided with an off-load tap changer (+/-2 * 2.5%), oil containment, bushing type current transformers, and accessories.

12. The terminals of each turbine generator will be connected to its associated GSU transformer through isolated phase bus duct. The bus duct will be sized to carry the full output of the connected unit, and braced to withstand the designed available fault currents.

13. Each set of isolated phase bus duct will have aluminum conductors and enclosures.

14. Each set of isolated phase bus duct will have provisions for connecting a low-pressure, low flow instrument air source to pressurize the bus. The low-pressure air system equipment is not included.

15. Two sets of CT isolated phase bus duct will include a tap to a unit auxiliary transformer.

16. Each CT generator bus connected to an auxiliary transformer (two units) will be furnished with a low-side generator breaker. Each generator breaker will have the same voltage rating as the generator, and will have an interrupting capability greater than the maximum fault current available as determined by a system fault analysis.

17. Two unit auxiliary transformers (UAT) will be furnished. Each UAT will be connected to the generator bus (between the generator breaker and GSU transformer) through an isolated phase bus duct tap. Each UAT will be furnished with an OA/FA or OA/FA/FA cooling rating and a 55C or 65C-temperature rise.

18. Each UAT will be a two winding transformer with a delta primary and low resistance grounded wye secondary and tertiary. The secondary line-to-line voltage will be 4160V.

19. One winding of each UAT will be sized to operate the steam turbine and one combustion turbine, while starting the second combustion turbine.

20. The impedance of each UAT will be chosen to enable motor starts while limiting fault currents to the design levels.

21. Each UAT will be oil filled and will be provided with an off-load tap changer (+/-2 * 2.5%), bushing type current transformers, and accessories.

22. One lineup of medium voltage switchgear (MV switchgear) will be provided. The switchgear will be a double-ended lineup consisting of two main breakers, a tie breaker, SUS feeder contactors and motor contactors. The MV switchgear will distribute power to large motors and Secondary Unit Substations. The MV switchgear will be located indoors (in a NEMA 1 enclosure as defined in ANSI/IEEE C37.20.2, Section 6.2.11), or outdoors in non-walk-in (NEMA 3R as defined in ANSI/IEEE C37.20.2, Section 6.2.12(1)) enclosures.

23. The MV switchgear will not be furnished with an automatic transfer scheme for loss of power.

24. The MV Switchgear lineup will be provided with one (1) spare SUS feeder contactor and one (1) spare motor contactor.

25. The MV switchgear may be furnished with SUS and motor circuit breakers in lieu of contactors, as determined by the EPC contractor.

26. The MV switchgear (and secondary of each UAT) may be furnished as 4.16kV or 6.9kV as determined by the EPC contractor and an auxiliary electric study.

27. Medium voltage relaying will utilize GE Multilin protective relays, or similar.

28. Three double-ended 480V Secondary Unit Substations (SUS) will be provided. Each SUS will receive power from the MV switchgear and transform the power to 480V for distribution to motor control centers and other 480V loads. Each 480V SUS may be located indoors (NEMA 1 as defined in ANSI/IEEE C37.20.1, Section 6.7) or in suitable outdoor enclosures (non-walk-in NEMA 3R as defined in ANSI/IEEE C37.20.1, Section 6.8) depending upon location and load requirements.

29. Each indoor SUS transformer will be a dry type transformer furnished with an AA or AA/FA cooling rating and a 150C temperature rise. Each outdoor SUS transformer will be an oil-filled type transformer furnished with on OA or OA/FA cooling rating and a 55C or 65C temperature rise.

30. Each SUS transformer and will be sized to provide sufficient power at its maximum rating to feed the maximum worst case load requirements of the connected loads

31. Each SUS transformer will be a two winding transformer with a delta connected primary and high resistance grounded wye secondary.

32. Each 480V SUS will be provided with one (1) spare 800A-frame breaker.

33. Motor Control Centers will be provided as needed to distribute power to cyclic 480V loads, 480V intermediate loads, and small 480V loads that require motor starters or are essential to plant operation. All other loads will receive power from 480/277V, 208/120V, or 120/240V panelboards.

34. One Reliable MCC will be provided. The Reliable MCC will receive power from two different 480V SUS though a break-before-make automatic transfer switch. Each battery charger and the alternate source transformer will be connected to the Reliable MCC.

35. Individual 480V MCC's will be provided with one (1) spare starter and one (1) spare breaker utilized on the 480V MCC.

36. Motor control centers may be furnished indoors (NEMA 1 enclosure) or in suitable outdoor enclosures (non-walk-in NEMA 3R) depending upon location and load requirements. The location and quantity of MCC's will be determined during detailed design by the EPC Contractor.

37. All MCC's will be provided with NEMA Type B wiring as defined in NEMA ICS 3.

38. MCC's will not be provided with indicating lights.

39. All panelboards will be initially designed with a minimum of 10 percent spare circuit breakers.

40. All motors will be designed in accordance with NEMA MG1 and ANSI C50.41 as applicable, unless noted otherwise.

41. All motors will be designed for direct across the line starting.

42. Motors larger than 250 hp will be fed from the 4160V system. Motors 250 hp and below will be fed from the 480V system.

43. All 4000V motors will be horizontal or vertical, single speed, squirrel-cage, induction type motors.

44. All 4000V motors will be provided with a 1.0 or 1.15 service factor.

45. All outdoor 4000V motors will be provided with a WPII enclosure. All indoor 4000V motors will be provided with an ODP enclosure.

46. All low voltage motors will be horizontal or vertical motors as required, single-speed squirrel-cage, induction type motors. Motors for the cooling tower may be two-speed and/or reversing motors, if required. However, the proposal is based on single speed motors.

47. All low-voltage motors will be provided with a 1.0 or 1.15 service factor.

48. All low-voltage motors will be provided with a TEFC enclosure.

49. All motors will be provided with a Class B or Class F insulation system. The temperature rise will not exceed a Class B insulation system temperature rise as defined by ANSI C50.41.

50. The nameplate horsepower times the nameplate service factor or each motor will be at least ten percent above the maximum expected break-horsepower of the driven equipment.

51. In general, the preceding comments concerning motors do not apply to pre-engineered equipment (sump pumps, HVAC equipment, cranes, hoists, motor operated valves, air compressors, etc.), or motors provided with standard packages (combustion turbine/generator, steam turbine/generator, etc.)

52. All motor operators for valves shall be Limitorque Type L120 or equal.

53. It is assumed that each combustion turbine generator package will be furnished complete with Black & Veatch's inadvertent back energization scheme, generator breaker protective relaying (for two units), generator step-up transformer protective relaying, unit

auxiliary transformer protective relaying (for two units), the Owner's requirements, and state and local requirements.

54. It is assumed that each combustion turbine package will be provided with an adequate number of current transformers (line side and neutral side) and potential transformers for all protective relaying requirements.

55. It is assumed that each combustion turbine package will be provided with SWPC electrical package including, but not limited to, motor control center(s), AC panelboard, batteries, chargers, DC panelboard, control panels, and protective relaying panels.

56. It is assumed that each combustion turbine package will be provided with all cables required between equipment provided within the package.

57. A plant 125Vdc system will be provided. The plant 125Vdc system will include one set of 125Vdc batteries, two 125Vdc full capacity chargers, and 125Vdc distribution panels as required. The plant 125Vdc system will be sized to provide 125Vdc power for 30 minutes after 480Vac power becomes unavailable.

58. The plant DC system will provide the DC requirements of the steam turbine/generator and BOP equipment. The plant DC system will not be tied to the CT/G systems.

59. A 120Vac UPS system will be provided. The 120Vac UPS system will include an inverter, automatic transfer switch, static transfer switch, alternate source/isolation transformer, and 120Vac distribution panels as required. The inverter and alternate source/isolation transformer will be sized to provide 120Vac UPS power to all critical 120Vac plant loads.

60. Freeze protection will be provided as required for outdoor above grade pipe and instrumentation. The freeze protection system will consist of one or more monitoring and control panels with a dedicated transformer, power circuits, and heat trace circuits. Heat tracing cable will be of the self-limiting type and mineral insulated type as required.

61. A galvanic cathodic protection system for all underground carbon steel, stainless steel, and copper piping, unless the current requirement dictates an impressed current system, will be provided. The cathodic protection system for this underground piping will be in accordance with NACE International Standard RP-0169-96. The cathodically protected piping will receive a bonded, dielectric coating system, and be electrically isolated from above grade piping, concrete reinforcing steel, and other underground metals. Underground ductile iron piping will be polyethylene encased in accordance with AWWA-C105.

62. All cable tray and junction boxes for non-indoor lighting applications will utilize aluminum material. All above grade conduit for non-indoor lighting will be RGS. Below

grade conduit in duct bank will utilize PVC conduit. Duct banks will not be reinforced.

63. One plant grounding system will be provided. A minimum of two (2) connections from the plant ground grid to the substation ground grid will be provided.

64. The cable provided by any third party manufacturer will be the manufacturer's standard cable offering.

65. All BOP medium voltage power cable will be 5kV cable with a 133% insulation cable, single copper conductor, Class B stranded, shielded power cable, 0.115 inch EPR insulation, flame retardant PVC or CPE jacket. Cable will meet AEIC CS6 and ICEA S-68-516 requirements and will be UL listed for cable tray use. All cable will meet the flame test requirements of IEEE 383

66. All BOP 600V single conductor power cable will have Class B stranded copper conductor, flame retardant XLPE or EPR insulation, with no jacket, and will be UL listed for cable tray use. Cable will meet ICEA S-66-524 or S-68-516, and will meet the flame test requirements of UL VW-1 (#8AWG and smaller) and IEEE 383 (#6AWG and larger). All cable will meet the flame test requirements of IEEE 383.

67. All BOP 600V three conductor power cable will have Class B stranded copper conductor, flame retardant EPR or XLPE insulation, flame retardant PVC overall jacket, with ground conductors sized in accordance with UL 1277, and will be UL listed Type TC. Cable will meet ICEA S-66-524 or S-68-516. All cable will meet the flame test requirements of IEEE 383.

68. All BOP 600V control cable will have Class B stranded copper conductor, flame retardant EPR or XLPE insulation, flame retardant PVC overall jacket, with ICEA S-68-516 Method 1 Table K-2 conductor identification, and will be UL listed Type TC. Cable will meet ICEA S-66-525 or S-68-516 and UL 1277. All cable will meet the flame test requirements of IEEE 383.

69. All BOP instrument cable will be single pair, single triad, multi-pair shielded or multi-triad shielded instrument cable with an overall shield. Instrument cable will have Class B stranded copper conductors, PVC Nylon insulation, flame retardant PVC overall jacket with ICEA S-68-516 Method 1 Table K-1 conductor identification, and will be UL listed Type TC. All cable will meet the flame test requirements of IEEE 383.

70. All BOP thermocouple cable will be single pair or multi-pair shielded thermocouple extension solid conductor cable with a shield over each pair, an overall shield, flame retardant PVC insulation, CPE overall jacket, and will be UL listed Type PLTC. All cable will meet the flame test requirements of IEEE 383.

71. All BOP Ground cable will be Class B stranded soft drawn cooper conductor per ASTM

B8. Insulated ground cable will have a green colored polyvinyl chloride insulation UL 83 Type TW, THW, or THHN.

72. All BOP lighting and fixture cable will be single conductor Class B stranded copper conductor, XLPE insulated cable, and will be UL listed as NEC Type XHHW.

73. A raised floor will be installed in the electronics room.

74. Plant synchronization to the 230kV grid will be accomplished through the two low-side generator breakers for the two combustion turbine generators, and through the high-side generator breakers for the other combustion turbine generator and the steam turbine generator.

75. Plant control will be through a distributed control system with three operator stations with dual CRT's for operator interface and one engineering work station. Data links will be provided to interface to other control systems furnished with the facility. This integrated control system for plant operation and monitoring does not provide for complete remote operation of all systems. Manufacturer's standard control systems will be supplied with remote indications and alarms. There is no Main Electrical Panel; however, similar functionality will be provided within the DCS. No provisions for on-line performance monitoring have been included. The level of automation and redundancy will be determined by the Black & Veatch standard controls and instrumentation philosophy.

76. All combustion turbines and the steam turbine will have remote control stations (supplied by the turbine vendors) located in the Stanton central control room. The Black & Veatch standard controls and instrumentation philosophy will be used.

77. The natural gas fuel input custody transfer meters are included. Individual component performance testing instrumentation has not been included.

ATTACHMENT E
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 3X1 LARGE STG
TERMINAL POINTS

The following terminal points identify the termination points or interfaces for those services or facilities, which extend beyond the EPC scope of the work. The definitions of terminal points include the physical location and, if necessary, the design conditions, which form the basis of the EPC cost estimate.

CIVIL

(1) **Site Access** -- The EPC Contractor will provide access roads within the Unit 3 Facility boundary from the existing plant roads.

(2) **Telephone** -- The raceway for the telephone system will terminate at the Facility boundary, however, the telephone system will be provided by the Owner.

(3) **Sitework** -- Sitework will terminate at the limits of the plant site boundary and construction laydown yard areas.

(4) **Landscaping** -- The EPC Contractor will provide aggregate surfacing in the power block area and grass seeding for soil stabilization and erosion control for other areas within the Facility's perimeter fence. Any additional landscaping will be provided by the Owner.

(5) **Rail Siding** -- A rail siding for equipment off loading is exists on the existing plant site will be available for use by the EPC Contractor.

(6) **Sanitary** -- Sanitary drains will be pumped to the existing sanitary waste treatment system.

MECHANICAL

(1) **Fuel** -- Pipeline quality natural gas will be made available via an Owner (or optional EPC Contractor supplied-see Option 1) supplied pipeline terminating at the Unit 3 site boundary shown on the site arrangement drawing. The natural gas will be available at adequate pressure, quantity, and suitable temperature to meet the combustion turbine manufacturer's requirements.

(2) **Service Water** -- Service water for general plant use will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing

system.

(3) **Potable Water** -- Potable water for building plumbing, sanitary systems and safety showers/eye wash stations will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(4) **Fire Protection Water** -- Fire Protection water for various fire protection systems will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(5) **Cycle Makeup Water** -- Demineralized water for cycle makeup and water injection will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(6) **Cooling Tower Makeup** -- Circulating water system makeup water will be from the existing municipal wastewater treatment plant effluent system and will be made available at a quality, quantity, and pressure required by the EPC Contractor.

(7) **Cooling Tower Blowdown** -- Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system. The existing systems will need to expanded and upgrade and an allowance for this work is included in this estimate.

(8) **Compressed Air** -- Compressed air for general use and instruments/controls will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system.

(9) **Ammonia Supply** – Anhydrous ammonia for the HRSG SCR systems will be made available at a quality, quantity, and pressure required by the EPC Contractor from the existing system

(10) **Wastewater** -- Oily wastes will be collected and treated in an oil/water separator. Treated effluent from the oil/water separator and other plant drains will be combined and conveyed by the wastewater discharge system to the existing recycle basin.

ELECTRICAL

(1) **Construction Power** -- The construction power source will be provided by the Owner within the Facility perimeter fence at a location determined by the EPC Contractor. Construction power will be 480 volt, three-phase, 1200 amperes.

(2) **Power Out Electric Interface** -- The termination point is defined as the terminals

on the high side of the GSU transformer.

(3) **Power In Electrical Interface** -- The termination point is the same as the Power Out Electric Interface.

(4) **Dispatch Control Signals** -- The termination point for dispatching will be at the terminals of the SCADA RTU supplied by the Owner.

(5) **Grounding System** -- A grounding system consisting of ground rods and interconnecting copper conductors will be provided for the generating facility and the switchyard. No connections outside of the Facility are included.

(6) **Fuel Gas Metering** – The gas pipeline fuel gas metering signals termination point will be a junction box at the site boundary or at the on-site metering equipment.

ATTACHMENT F
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1 LARGE STG
ABOVE NORMAL SCOPE ADDERS

The following items are necessary additions to the base EPC cost for site and owner specific considerations.

Description	Cost Adders	Remarks
Sitework		
Utility Excavation	$253,920	for interconnection to existing facility
Arch/Metal		
STG Building	$3,709,950	owner request
Piping		
Below Ground Lrg Bore/Insulation	$2,747,703	for interconnection to existing facility
Mechanical		
Bypass Stack/Silencers 2 ea.	$3,000,000	owner request
Cooling Tower	$1,500,000	owner request non foul fill
Condenser	$300,000	owner request Stainless Steel 316
Construction Indirects	$462,769	
Total Adder Cost	**$11,974,342**	

NOT REVIEWED

ATTACHMENT G
ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER
STANTON UNIT 3 – 2X1 LARGE STG
MAJOR COMMERCIAL TERMS

(later)

Stanton Energy Center Combined Cycle Unit A

Need for Power Application

Orlando Utility Commission - Volume 1B

January 29, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010142-EM EXHIBIT NO. 1 (Part 2 of 1)
COMPANY/ WITNESS. Orlando Utilities Commission
DATE: 4-23-01

BLACK & VEATCH

11401 Lamar, Overland Park, Kansas, 66211, USA (913) 458-2000

Table of Contents

1B.1.0 Overview and Summary 1-1
1B.1.1 Overview 1-1
1B.1.2 Summary 1-2

1B.2.0 Description of System 2-1
1B.2.1 OUC Structure 2-1
1B.2.2 Generation System 2-2
1B.2.3 Purchase Power Resources 2-4
1B.2.4 Power Sales Contracts 2-5
1B.2.4.1 Unit Power Sales 2-5
1B.2.4.2 System Power Sales 2-6
1B.2.4.3 Power Sales Forecast Load Requirements 2-6
1B.2.5 Transmission System 2-7
1B.2.6 Service Area 2-9

1B.3.0 Evaluation Criteria 3-1

1B.4.0 Forecast of Power Demand and Energy Consumption 4-1
1B.4.1 Forecast Methodology 4-1
1B.4.1.1 Residential Sector Model 4-2
1B.4.1.2 Non-residential Sector Models 4-5
1B.4.1.3 GSD Models 4-10
1B.4.1.4 Hourly Load and Peak Forecast 4-13
1B.4.2 Forecast Assumptions 4-16
1B.4.2.1 Economics 4-16
1B.4.2.2 Price Assumption 4-18
1B.4.2.3 Weather 4-19
1B.4.3 Base Case Load Forecast 4-22
1B.4.3.1 Base Case Economic Outlook 4-24
1B.4.3.2 Forecast Results 4-26
1B.4.4 Net Peak Demand and Net Energy for Load 4-34
1B.4.5 High and Low Case Scenarios 4-34
1B.4.5.1 High Case Scenarios 4-42
1B.4.5.2 Low Case Scenario 4-42
1B.4.5.3 High and Low Forecast Scenario Results 4-43

Table of Contents (Continued)

1B.5.0 Demand-Side Analysis 5-1
1B.5.1 Existing Conservation Programs 5-1
1B.5.1.1 Residential Energy Survey 5-2
1B.5.1.2 Residential Heat Pump Program 5-2
1B.5.1.3 Residential Weatherization Program 5-3
1B.5.1.4 Low Income Home Energy Fixup Program 5-3
1B.5.1.5 Education Outreach Program 5-3
1B.5.1.6 Commercial Energy Survey Program 5-4
1B.5.2 Analysis of Demand-Side Management Alternatives 5-4
1B.5.2.1 FIRE Model Output Analysis 5-4

1B.6.0 Reliability Criteria 6-1
1B.6.1 Development of Reliability Criteria 6-1
1B.6.1.1 Traditional Reserve Margin 6-1
1B.6.1.2 Loss of Load Probability 6-1
1B.6.2 Reliability Need 6-2

1B.7.0 Economic Analysis 7-1
1B.7.1 Methodology 7-1
1B.7.2 Expansion Candidates 7-1
1B.7.3 Results of Economic Analysis 7-3

1B.8.0 Sensitivity Analysis 8-1
1B.8.1 High Fuel Price Escalation 8-1
1B.8.2 Low Fuel Price Escalation 8-1
1B.8.3 AEO Fuel Price Projections 8-1
1B.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation 8-2
1B.8.5 Constant 2000 Fuel Price Projections 8-2
1B.8.6 High Load and Energy Growth 8-2
1B.8.7 Low Load and Energy Growth 8-3

1B.9.0 Financial Analysis 9-1

Table of Contents (Continued)

Appendix

Appendix 1B.A Load Forecast Model Statistics
Appendix 1B.B Economic Evaluation Spreadsheets

Tables

Table 1B.2-1 Summary of OUC Generation Facilities 2-3
Table 1B.2-2 Power Purchase Agreements 2-5
Table 1B.2-3 Excess KUA Entitlement Purchased By OUC 2-5
Table 1B.2-4 OUC Unit Power Sales (MW) 2-6
Table 1B.2-5 OUC Projected System Power Sales (MW) 2-6
Table 1B.2-6 OUC Projected Energy Sales (GWh) 2-7
Table 1B.2-7 OUC Transmission Interconnections 2-7
Table 1B.4-1 Nonmanufacturing Employment (Thousands) and Gross Regional Product Projections (Billion Real $) 4-17
Table 1B.4-2 Population, Household, and Income Projections 4-18
Table 1B.4-3 Historical and Forecasted Price Series Average Annual Price 4-20
Table 1B.4-4 System Peak (Summer and Winter) and Net Energy Forecast (Total of OUC and St. Cloud) 4-23
Table 1B.4-5 Largest Regional Employers 4-25
Table 1B.4-6 Orlando MSA Economic Projections 4-27
Table 1B.4-7 OUC Long-Term Sales Forecast (GWH) 4-28
Table 1B.4-8 OUC Average Number of Customers Forecast 4-29
Table 1B.4-9 St. Cloud Sales Forecast (GWH) 4-30
Table 1B.4-10 St. Cloud Average Number of Customers Forecast 4-31
Table 1B.4-11 OUC Residential Sales Forecast Summary 4-32
Table 1B.4-12 St. Cloud Residential Sales Forecast Summary 4-33
Table 1B.4-13 OUC General Service Nondemand Sales Forecast 4-35
Table 1B.4-14 St. Cloud General Service Nondemand Sales Forecast 4-36
Table 1B.4-15 OUC Large General Service Demand Sales Forecast 4-37
Table 1B.4-16 St. Cloud Large General Service Demand Sales Forecast 4-38
Table 1B.4-17 OUC Net Peak Demand (Summer and Winter) and Net Energy for Load: History and Forecast 4-39
Table 1B.4-18 St. Cloud Net Peak Demand (Summer and Winter) and Net Energy for Load: History and Forecast 4-40
Table 1B.4-19 Economic Assumptions 4-41
Table 1B.4-20 Scenario Energy Forecast 4-44

Table of Contents (Continued)
Tables (Continued)

Table 1B.4-21 Scenario Peak Forecast 4-45
Table 1B.5-1 Total Conservation Goals Approved by the FPSC 5-2
Table 1B.5-2 FIRE Model Results 5-4
Table 1B.6-1 OUC Winter Reserve Requirements 6-3
Table 1B.6-2 OUC Summer Reserve Requirements 6-4
Table 1B.7-1 Summary of OUC Generation Alternatives (2000 $, unless otherwise noted) 7-2
Table 1B.7-2 OUC Least-Cost Base Case Expansion Plan 7-5
Table 1B.7-3 OUC Base Case Expansion Plan – Runner Up #1 7-6
Table 1B.7-4 OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2) 7-7
Table 1B.7-5 OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2) 7-8
Table 1B.7-6 OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3) 7-9
Table 1B.7-7 OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3) 7-10
Table 1B.8-1 OUC High Fuel Price Escalation Expansion Plan 8-4
Table 1B.8-2 OUC High Fuel Price Escalation Runner Up Expansion Plan 8-5
Table 1B.8-3 OUC Low Fuel Price Escalation Expansion Plan 8-6
Table 1B.8-4 OUC Low Fuel Price Escalation Runner-Up Expansion Plan 8-7
Table 1B.8-5 AEO Fuel Price Projection Expansion Plan 8-8
Table 1B.8-6 OUC AEO Fuel Price Projection Runner-Up Expansion Plan 8-9
Table 1B.8-7 OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan 8-10
Table 1B.8-8 OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan 8-11
Table 1B.8-9 OUC Constant 2000 Fuel Price Projection Expansion Plan 8-12
Table 1B.8-10 OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan 8-13
Table 1B.8-11 OUC Summer Reserve Requirements - High Load and Energy Growth Scenario 8-14
Table 1B.8-12 OUC Winter Reserve Requirements - High Load and Energy Growth Scenario 8-15
Table 1B.8-13 OUC High Load and Energy Growth Expansion Plan 8-16
Table 1B.8-14 OUC High Load and Energy Growth Runner-Up Expansion Plan 8-17

Table of Contents (Continued)
Tables (Continued)

Table 1B.8-15 OUC Summer Reserve Requirements - Low Load and Energy Growth Scenario 8-18
Table 1B.8-16 OUC Winter Reserve Requirements - Low Load and Energy Growth Scenario 8-19
Table 1B.8-17 OUC Low Load and Energy Growth Expansion Plan 8-20
Table 1B.8-18 OUC Low Load and Energy Growth Runner-Up Expansion Plan 8-21

Figures

Figure 1B.2-1 Orlando Utilities Commission Service Territory 2-8
Figure 1B.4-1 Residential Customer Forecast 4-2
Figure 1B.4-2 End-Use Trend Variables 4-3
Figure 1B.4-3 Residential Average Use Forecast (kWh) 4-6
Figure 1B.4-4 Residential Sales Forecast (GWh) 4-6
Figure 1B.4-5 GSND Customer Forecast 4-7
Figure 1B.4-6 Commercial End-Use Index Projections (1995 = 1.0) 4-8
Figure 1B.4-7 GSND Average Use Forecast (kWh) 4-9
Figure 1B.4-8 GSND Sales Forecast (GWh) 4-10
Figure 1B.4-9 New GSD Load (GWh) 4-11
Figure 1B.4-10 GSD Sales Forecast (GWh) 4-12
Figure 1B.4-11 OUC Street Light Sales Forecast (GWh) 4-12
Figure 1B.4-12 St. Cloud Street Light Sales Forecast (GWh) 4-13
Figure 1B.4-13 January OUC Hourly Load for 2001 (MW) 4-15
Figure 1B.4-14 July OUC Hourly Load for 2001 (MW) 4-15
Figure 1B.4-15 Summer and Winter System Peak Forecasts (OUC and St. Cloud Combined) (MW) 4-17
Figure 1B.4-16 Historical and Forecasted Average Electricity Prices (1992 Cents per kWh) 4-19
Figure 1B.4-17 Monthly Cooling Degree Days 4-21
Figure 1B.4-18 Heating Degree Days 4-22
Figure 1B.4-19 Summer and Winter System Peak Forecasts (OUC and St. Cloud Combined) (MW) 4-23
Figure 1B.4-20 Relative Employment Performance (RFA) (1993=1.0) 4-24
Figure 1B.4-21 Comparison of Commercial "Other Use" Index 4-43

1B.1.0 Overview and Summary

1B.1.1 Overview

Stanton A is planned as a new combined cycle addition to the existing Stanton Energy Center site, located 12 miles southeast of Orlando, Florida. The Stanton Energy Center site was originally certified for an ultimate capacity of approximately 2,000 MW. The existing Stanton 1 is a 444 MW net coal fired facility and Stanton 2 is a 446 MW net coal fired generating facility. Stanton 1 was placed in commercial operation on July 1, 1987 followed by Stanton 2, which was placed in commercial operation on June 1, 1996. Stanton A will provide very economical power for the Orlando Utilities Commission (OUC) with a minimal environmental impact. Stanton A will be a 2 x 1 GE 7FA combined cycle unit. The net output of the unit is estimated to be 633 MW at 70° F under new and clean conditions and will be jointly owned by OUC, Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and Southern Company-Florida LLC (Southern-Florida). OUC will be an 80 percent joint owner of the 35 percent (222 MW) capacity to be owned by the utility applicants. OUC's portion will be approximately 177 MW. OUC will also be entitled to 80 percent of the 65 percent capacity supplied under the power purchase agreement (PPA). Details specific to the project are presented in Volume 1A. This volume, Volume 1B, contains information specific to OUC's need for the project.

OUC strives to meet its responsibility to supply its customer's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. OUC's rates are among the lowest in the state due to strategic planning and ability to provide economies of scale to its customers.

OUC is committed to meet its customer's needs and identify projects that will provide economical power through the combination of demand-side and supply-side resources. OUC has been a strong supporter of conservation and demand-side programs where cost-effective. With OUC's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

OUC achieves savings through economy interchange and central dispatch obtained through participation in the Florida Municipal Power Pool (FMPP), which consists of OUC, Lakeland, KUA, and the FMPA All-Requirements Project.

OUC's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with the Stanton A project. Stanton A will burn natural gas as the primary fuel with Selective Catalytic Reduction (SCR) providing a very clean highly efficient unit.

As discussed in the remainder of this Volume, OUC has evaluated appropriate alternatives to Stanton A to determine if any are more cost-effective.

OUC believes that Stanton A represents the minimal cost and performance risk to its customers due to the proven performance of the F class combined cycle technology. As demonstrated in this application, Stanton A has proven to be OUC's most cost-effective alternative through exhaustive evaluations as well as a thorough test of the marketplace.

1B.1.2 Summary

OUC historically has been one of the fastest growing utilities in the United States with a 4.8 percent annual growth rate in peak demand over the last 10 years. With the addition of St. Cloud, rapid growth is projected to continue with a 2.5 percent annual growth rate in peak demand projected through the end of the 20 year planning period.

OUC is currently using a 15 percent reserve margin for planning purposes. OUC has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the most cost-effective alternative under both base and nearly all of the sensitivity analyses.

1B.2.0 Description of System

1B.2.1 OUC Structure

At the turn of the twentieth century, John M. Cheney, an Orlando judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kilowatt generator. Twenty-four hour service began in 1903. The City's population had grown to roughly 10,000 by 1922 and Cheney, realizing the need for wider services than his company was capable of supplying, urged his friends to work and vote for a $97,500 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately owned utilities. The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando took over Cheney's company and its 2,795 electricity customers and 5,000 water customers for a total initial investment of $1.5 million.

In 1923, the Orlando Utilities Commission (OUC) was created by an act of the State Legislature and full authority was granted to OUC to operate the plant as a municipal utility. The business was a paying venture from the start, and by 1924, the number of customers had more than doubled and OUC contributed $53,000 to the City. When Orlando citizens took over operations of their utility, the population was less than 10,000; by 1925, it had grown to 23,000. In 1925, more than $165,000 was transferred to the City and in 1926 an additional $111,000 was transferred. One outside private utility offered $3 million to purchase the utility in 1928.

Between 1928 and 1931 there was a great deal of talk both for and against the sale of the utility. On August 18, 1931, an election was held and the people voted 1,033 to 140 not to sell the utility; 1,030 to 160 not to mortgage the utility, 744 to 436 not to issue tax notes; and 919 to 158 not to lease the utility. However, the question as to whether or not Orlando's utility should remain under municipal ownership did not end with the vote of the people in 1931. A year later a $5 million offer was made for the plant, $2 million more than the actual physical value at the time.

Today, 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 of Orlando. OUC has the full authority over the management and control of the electric and water works plants in the City of Orlando and has been approved by the Florida Legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission and distribution systems, and water production, transmission and distribution systems in order to meet the requirements of its customers.

In 1997, OUC entered an Interlocal Agreement with the City of St. Cloud in which OUC took over responsibility for supplying all of St. Cloud's loads for the 25 year term of the agreement, which added an additional 150 square miles of service area. OUC also took over management of St. Cloud's existing generating units and purchase power contracts.

OUC's electric system consisted of a year-end average of 145,410 active services for 2000. Of these, 125,523 are residential services, 15,262 are general service non-demand services, and the remaining, 4,262 are general service demand services. St. Cloud's service area consisted of a year-end average of 17,995 active services for 2000.

1B.2.2 Generation System

OUC presently has ownership interests in the following five electric generating plants, which are further described below. Table 1B.2-1 summarizes OUC's generating facilities.

- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Stanton Energy Center Units 1 and 2.
- Florida Power Corporation Crystal River Unit 3 Nuclear Generating Facility.
- City of Lakeland McIntosh Unit 3.
- Florida Power and Light Company St. Lucie Unit 2 Nuclear Generating Facility.

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280 acre site contains Stanton 1 and 2 and the necessary supporting facilities. Stanton 1 was placed in commercial operation on July 1, 1987, followed by Stanton 2, which was placed in commercial operation on June 1, 1996. Both units are fueled by pulverized coal and operate at emission levels that are within the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection requirement standards for SO_2, NO_x, and particulates. Stanton 1 is a 444 MW net coal fired facility, of which OUC has a 68.6 percent ownership share providing 302 MW of capacity to the OUC system. Stanton 2 is a 446 MW net coal fired generating facility, of which OUC maintains a 71.6 percent (319 MW) ownership share.

The Indian River Plant is located 4 miles south of Titusville on US Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units, Nos. 1, 2, and 3, and four combustion turbine units, A, B, C, and D. The three steam turbine units were sold to Reliant in 1999. As part of the sale, OUC has signed a power purchase agreement (PPA) with Reliant, the details of which are presented in Section 1B.2.3. The combustion turbine units are primarily fueled by natural gas, with

Table 1B.2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability[1]	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	41.400	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	41.400	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	122.040	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	122.040	85.3	100.3
Indian River	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.580	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	464.580	319.3	319.3
Stanton Energy Center	3	Polk	ST	BIT	REF	RR	TK	09/82	Unknown	363.870	133	136
McIntosh	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	890.460	13	13
Crystal River	2	St. Lucie	NP	UR	---	TKPL	TK	08/83	Unknown	839.000	51	52
St. Lucie[2]	1	Osceola	IC	NG	FO2	PL	TK	07/82	11/04	2.000	2	1.825
St. Cloud[3]	2		IC	NG	FO2	PL	TK	12/74	11/04	5.850	5.85	5
	3		IC	NG	FO2	PL	TK	09/82	11/04	2.000	2	1.825
	4		IC	NG	FO2	PL	TK	08/61	11/04	3.750	3	3
	6		IC	NG	FO2	PL	TK	03/67	11/04	3.750	3	3
	7		IC	NG	FO2	PL	TK	09/82	11/04	6.300	6	6
	8		IC	NG	FO2	PL	TK	04/77	11/04	6.445	6	6

OUC ownership share.

OUC owns St. Lucie Unit No. 2. Reliability exchange divides 50% power from Unit No. 1 and 50% power from Unit No. 2.

St. Cloud No. 8 has never been connected to the grid and, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent, or 36 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent (170 MW) in Indian River Units C and D.

Crystal River Unit 3 is an 835 MW net nuclear generating facility operated by the Florida Power Corporation. OUC has a 1.6015 percent ownership share in this facility, providing approximately 13 MW to the OUC system.

McIntosh Unit 3 is a 340 MW net coal fired unit operated by the City of Lakeland. McIntosh Unit 3 has supplementary oil and refuse fuel burning capability and also is capable of burning up to 20 percent petroleum coke. OUC has a 40 percent ownership share in this unit, providing approximately 133 MW of capacity to the OUC system.

St. Lucie Unit 2 is a net 853 MW nuclear generating facility operated by the Florida Power and Light Company. OUC maintains a 6.08951 percent ownership share in this facility, providing approximately 51 MW of generating capacity to OUC. A reliability exchange with St. Lucie Unit 1 results in half of the capacity being supplied from St. Lucie Unit 1 and half provided by St. Lucie Unit 2.

As part of the Interlocal Agreement with St. Cloud, OUC has operating control of St. Cloud's seven internal combustion generating units, with a total summer rating of 27.85 MW. Unit 8 has never been connected to the grid, so the resulting net summer generating capacity from St. Cloud's internal combustion units is 21.85 MW.

1B.2.3 Purchase Power Resources

As part of the sale of Indian River steam units, OUC entered into a power purchase agreement with Reliant (Reliant Agreement) for capacity and energy from the Indian River steam units. The term of the Reliant Agreement extends from October 1, 1999, through September 30, 2003. OUC also has an option to extend the Reliant Agreement an additional 4 years. Additionally, St. Cloud has a Partial Requirements (PR) contract with Tampa Electric Company (TECO). As a result of the Interlocal Agreement with St. Cloud, OUC schedules the TECO PR. The capacities from the Power Purchase Agreements are summarized in Table 1B.2-2. The capacity from the Reliant Agreement shown in Table 1B.2-2 from October 1, 2001, through September 30, 2003, is 525 MW, but has an option for an additional 10 percent capacity. Thus, the capacity shown in Table 1B.2-2 is the maximum available.

The maximum capacity available should OUC exercise its additional 4 year option with Reliant is 500 MW per year. The 500 MW can be reduced in 100 MW increments annually over the duration of the 4 year option term through proper notice from OUC, but cannot increase from the previous year. The cost of the capacity and energy is based on a demand and energy charge. The energy charge is based on fixed heat rate and a specified split of gas and oil for fuel.

Table 1B.2-2
Power Purchase Agreements

Company	Capacity	Duration
TECO PR	15 MW	Through 12/31/2012
Reliant	593 MW	10/01/1999 – 09/30/2001
Reliant	577.5 MW	10/01/2001 09/30/2003

OUC is also planning to purchase KUA's excess capacity from KUA's entitlement in Stanton A during the first 3 years of the Southern-Florida PPA. The excess capacity assumed in the evaluations is presented in Table 1B.2-3. The purchase price is assumed to be equal to the price paid to Southern-Florida under the PPA and, in essence, just increases OUC's entitlement during the first 3 years that KUA has excess.

Table 1B.2-3
Excess KUA Entitlement Purchased By OUC

Period	MW[1]
10/1/2003 – 9/30/2004	40
10/1/2004 – 9/30/2005	24
10/1/2005 – 9/30/2006	10

[1]Based on 633 MW rating of 70° F.

1B.2.4 Power Sales Contracts

OUC is contractually obligated to supply power to a number of different purchasers for various durations of time. These power sales contracts are classified as either unit power sales or system power sales.

1B.2.4.1 Unit Power Sales

OUC has two separate unit power sales contracts in place with FMPA. The first of these contracts has been in place since May 1, 1986, and expires December 31, 2006. The capacity is available from the Indian River Plant and can be provided by OUC's other units if the capacity is available. The second such contract with FMPA has been in place since January 1, 1989, and is scheduled to expire December 31, 2003. This

contract is based on providing power from the highest fuel cost unit operating on OUC's system at the time that energy is scheduled.

Additionally, OUC has had a unit power sales contract with Seminole Electric Cooperative (SEC) since January 1, 1996, which will expire May 31, 2004. The SEC unit power sale is from the Indian River Steam Units and the Indian River Combustion Turbines and can be supplied by other OUC units if the capacity is available. Table 1B.2-4 displays OUC's unit power sales obligations.

Table 1B.2-4
OUC Unit Power Sales (MW)

Unit Sales	2001	2002	2003	2004	2005	2006
FMPA I.R.	130	108	87	65	43	22
FMPA D-2	20	20	20	0	0	0
SEC I.R.	75	75	75	75	0	0
Total	225	203	182	140	43	22

1B.2.4.2 System Power Sales

OUC has had a system power sales contract in place with KUA since January 1, 1989, which will expire December 31, 2003. In addition, OUC has been involved in a partial requirements power sales contract with Reedy Creek Improvement District (RCID) since January 1, 1999. The contract is scheduled to expire December 31, 2005, but has an option for extension through 2010. For evaluation purposes, the contract is assumed to extend through 2010. Table 1B.2-5 summarizes OUC's system power sales contracts.

Table 1B.2-5
OUC Projected System Power Sales (MW)

Unit Sales	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
KUA D.	20	20	20	0	0	0	0	0	0	0
RCID PR	96	100	110	123	129	117	139	142	144	146
Total	116	120	130	123	129	117	139	142	144	146

1B.2.4.3 Power Sales Forecast Load Requirements

Table 1B.2-6 summarizes the forecast energy requirements associated with each of the power sales described in Sections 1B.2.4.1 and 1B.2.4.2. For evaluation purposes, unit power sales and system power sales are treated identically.

Table 1B.2-6
OUC Projected Energy Sales (GWh)

Unit Sales	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
FMPA I.R.	167	133	97	62	39	20	0	0	0	0
FMPA D2	10	10	10	0	0	0	0	0	0	0
SEC I.R.	70	65	65	24	0	0	0	0	0	0
KUA D.	17	17	17	0	0	0	0	0	0	0
RCID PR	602	613	641	689	664	713	703	714	724	728
Total	866	838	830	775	703	733	703	714	724	728

1B.2.5 Transmission System

OUC's existing transmission system consists of 26 substations interconnected through approximately 302 miles of 230 kV and 115 kV lines and cables. OUC is fully integrated into the state transmission grid through its twelve 230 kV interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 1B.2-7. OUC's service area and transmission system are also shown in Figure 1B.2-1.

Table 1B.2-7
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL (2 circuits)	230	1
FPC	230	5
KUA	230	2
KUA/FMPA	230	1
Lakeland	230	1
TECO	230	1
TECO/RCID	230	1

FPL – Florida Power & Light
FPC – Florida Power Corporation
KUA – Kissimmee Utility Authority
TECO – Tampa Electric Company
RCID – Reedy Creek Improvement District
FMPA – Florida Municipal Power Agency

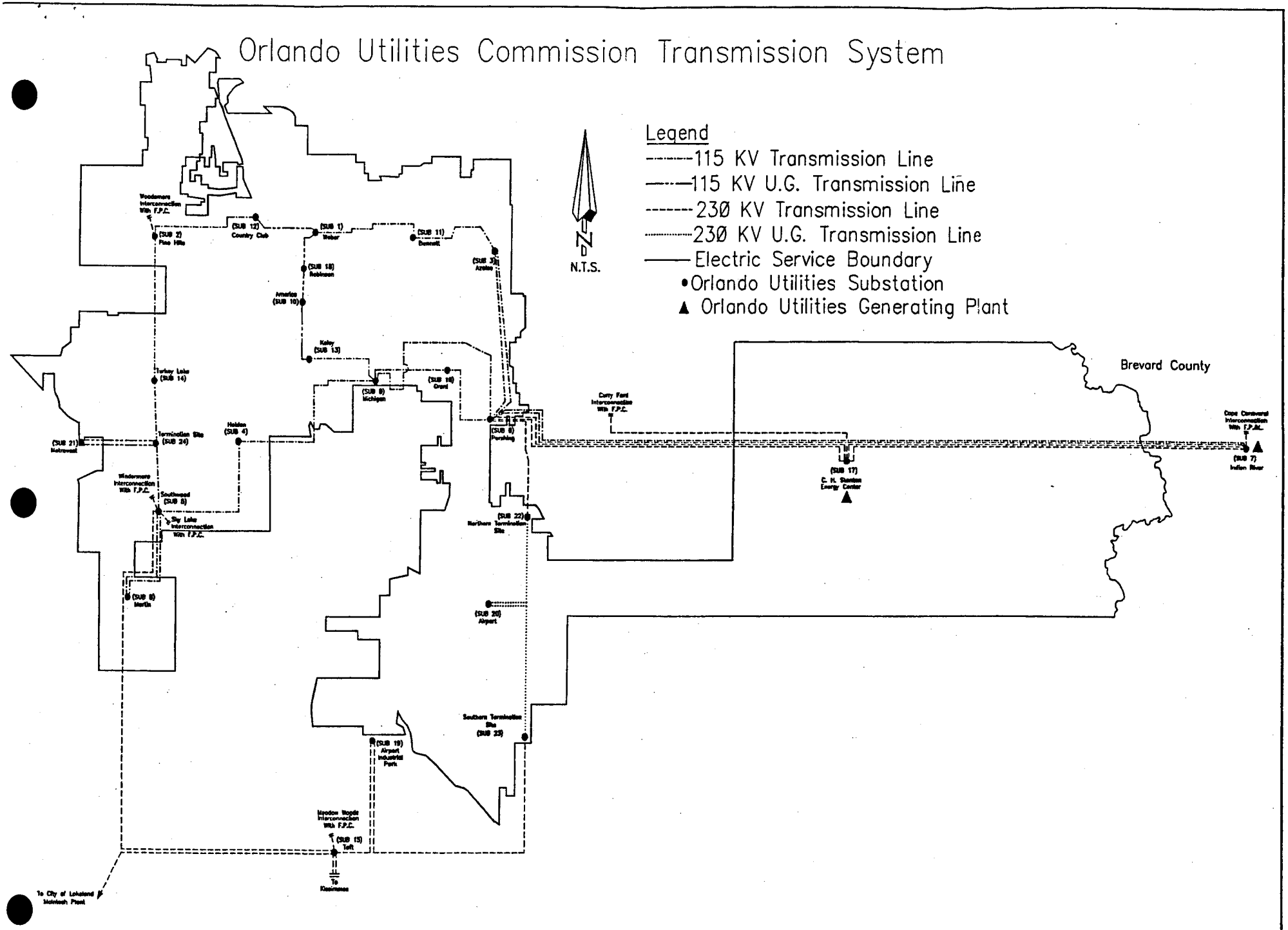

Orlando Utilities Commission Transmission System
Legend
115 KV Transmission Line
115 KV U.G. Transmission Line
230 KV Transmission Line
230 KV U.G. Transmission Line
Electric Service Boundary
Orlando Utilities Substation
Orlando Utilities Generating Plant
N.T.S.
Brevard County
Woodsmere Interconnection With F.P.C.
(SUB 2) Pine Hills
(SUB 12) Country Club
(SUB 1) Weber
(SUB 11) Dumnett
(SUB 3) Anston
(SUB 18) Robinson
Amston (SUB 10)
Kaley (SUB 13)
Turkey Lake (SUB 14)
(SUB 9) Michigan
(SUB 16) Orant
(SUB 8) Pershing
Curry Ford Interconnection With F.P.C.
Cape Canaveral Interconnection With F.P.&L.
(SUB 7) Indian River
(SUB 17) C. H. Stanton Energy Center
(SUB 21) Metrowest
Termination Site (SUB 24)
Holden (SUB 4)
Windermere Interconnection With F.P.C.
Southwest (SUB 5)
Sky Lake Interconnection With F.P.C.
(SUB 22) Northern Termination Site
(SUB 6) Martin
(SUB 20) Airport
Southern Termination Site (SUB 23)
(SUB 19) Airport Industrial Park
Meadow Woods Interconnection With F.P.C.
(SUB 15) Taft
To Kissimmee
To City of Lakeland Mcintosh Plant

Figure 2-1

Additionally, OUC is now responsible for approximately 50 miles of St. Cloud's transmission system, including the 69 kV interconnection from St. Cloud's Central Substation to KUA's Carl Wall Substation, and a 230 kV interconnection from St. Cloud's East Substation to Florida Power Corporation's (FPC) Holopaw Substation.

OUC has developed the following schedule of upgrades to maintain reliable and economic service:

- A second 230 kV tie line between Stanton and FPC. Expected completion date is January, 2001.
- Upgrade the 69 kV line from KUA to the City of St. Cloud. Expected completion date is in 2003.
- Addition of the Grant to Robinson 115 kV transmission line. Expected completion date is in 2002.
- Addition of second bus tie transformer at the Southwood Substation. Expected completion date is in 2004.

1B.2.6 Service Area

OUC's service area encompasses approximately 394 square miles. This estimate includes the service OUC provides to the City of St. Cloud under a partnership formed in 1997. This 25 year agreement is precedent setting, as OUC has become the first municipal electric utility in the state to manage, operate, and maintain another municipal utility.

1B.3.0 Evaluation Criteria

The evaluation criteria used by OUC is described in Section 1A.3.0.

1B.4.0 Forecast of Power Demand and Energy Consumption

OUC has retained Regional Economic Research, Inc. (RER) to develop forecasts of power demand and energy consumption. The initial forecast scope was to develop a sales forecast for the OUC budgeting process and short-term financial planning. The scope was then extended to develop a long-term energy and demand forecast through 2020. The objective was thus to develop a forecast model that could be used successfully for forecasting both short and long-term energy and peak demand.

1B.4.1 Forecast Methodology

There are two primary forecasting approaches used in forecasting electricity requirements - econometric-based modeling (such as linear regression) or end-use models (such as EPRI's REEPS and COMMEND models). In general, econometric forecast models provide better forecasts in the short-term time frame and end-use models are better at capturing long-term structural change resulting from competition across fuels, and changes in appliance stock and efficiency.

The difficulty of end-use modeling is that end-use models are extremely data-intensive and provide relatively poor short-term forecasts. End-use models require detailed information on appliance ownership, efficiency of the existing stock, new purchase behavior, utilization patterns, commercial floor-stock estimates by building type, and commercial end-use saturations and intensities in both new and existing construction. It typically costs several hundred thousand dollars to update and to maintain such a detailed database. Lack of detailed end-use information precluded developing end-use forecasts for the OUC/St. Cloud service territories. Further, given that there is little to no retail natural gas in the OUC service territory, end-use modeling would add little in terms of accounting for cross-fuel competition – one of the primary benefits of end-use modeling.

Since end-use modeling was not an option, the approach adopted was to develop linear regression sales models. To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as a Statistically Adjusted Engineering (SAE) model, entails specifying end-use variables - heating, cooling, and base use - and utilizing these variables in sales regression models. While the SAE approach loses some end-use detail, it performs well forecasting short-term energy requirements, and it provides reasonable structure for forecasting energy requirements over the long term.

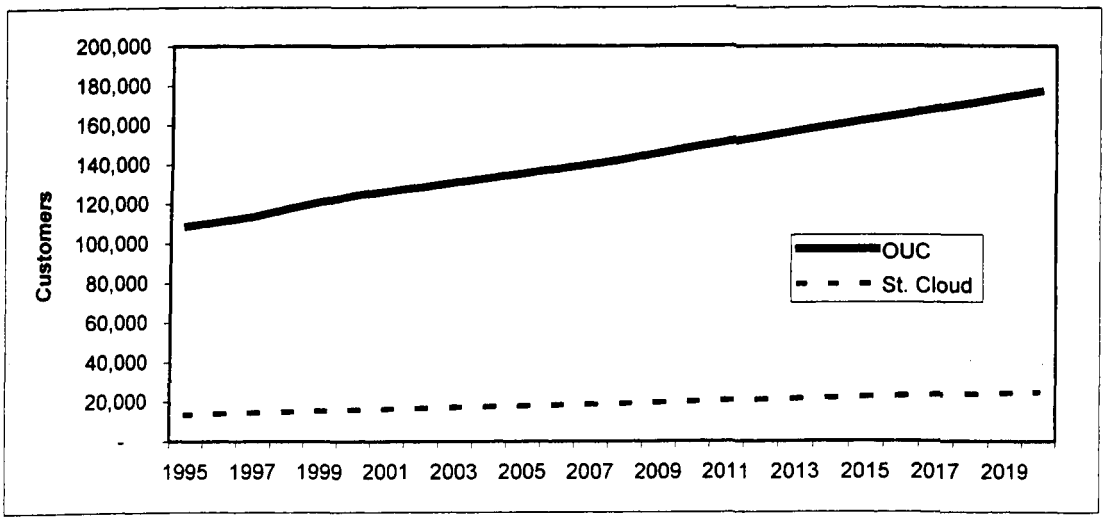
1B.4.1.1 Residential Sector Model

The residential model consists of two equations – an average use per household model, and a customer forecast model. Monthly average use models are estimated over the period 1992 to 1999. This provides 8 years of historical data, with more than enough observations to estimate strong regression models. Once models are estimated, the residential energy requirements in month T is calculated as the product of the customer and average use forecast:

$$Residential\ Sales_T = Average\ User\ Per\ Household_T * Number\ of\ Customers_T$$

Residential Customer Forecast. The number of customers is forecasted as a simple function of household projections for the Orlando MSA. Models were estimated using MSA-level data, as county level economic data is only available on an annual basis. Not surprisingly, the historical relationship between OUC customers and households in the Orlando MSA is extremely strong. The OUC customer forecast model has an adjusted R^2 of 0.997 with an in-sample Mean Absolute percent Error (MAPE) of 0.2 percent. For St. Cloud, the model performance is not as strong, given the "noise" in the historical monthly billing data. The adjusted R^2 is 0.71 with an in-sample MAPE of 4.2 percent. Given that St. Cloud is a relatively small part of OUC's service territory, the 4.2 percent average customer forecast error represents a relatively small number of total system customers. Combined, the average model error (the Mean Absolute Deviation) is 744 customers; this compares with an average number of customers over the estimation period of 123,100. The combined error is less than 1 percent. The model statistics are included in Appendix 1B.A. Figure 1B.4-1 shows the residential customer forecast.

Figure 1B.4-1
Residential Customer Forecast



Average Use Forecast. To incorporate end-use structure into the residential sales model, average use is disaggregated into its primary end-use components - heating, cooling, and base-use requirements:

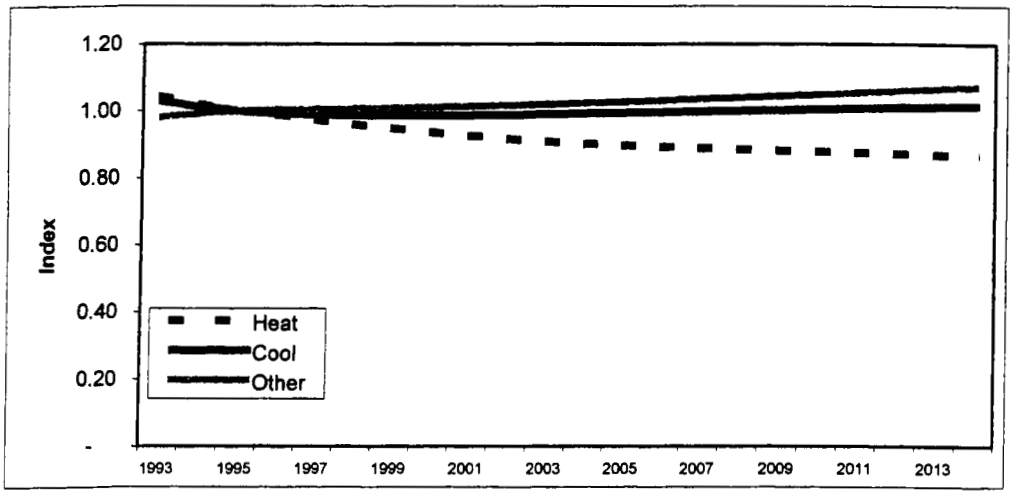
$$\text{Average Use}_t = \text{Heat}_t + \text{Cooling}_t + \text{BaseUse}_t$$

Each end use is defined in terms of both an appliance index variable, which indicates relative saturation and efficiency of the existing stock, and a utilization variable, which reflects how the stock is utilized. The end-use variables are defined as:

$$Cooling_t = CoolIndex_t * CoolUse_t$$
$$Heating_t = HeatIndex_t * HeatUse_t$$
$$BaseUse_t = BaseIndex_t * OtherUse_t$$

End-Use Index Variables. The end-use index variables (*CoolIndex*, *HeatIndex*, and *BaseIndex*) are illustrated in Figure 1B.4-2. These variables are designed to capture both increases in appliance saturation and changes in the relative efficiency of the stock.

Figure 1B.4-2
End-Use Trend Variables



The indices are calculated as the ratio of the appliance saturation to average efficiency of the existing appliance stock. To generate a relative index, the ratio is divided by the estimated value for 1995. Thus, the index has a value of 1.0 in 1995. The indices are defined as:

$$CoolIndex_t = (CoolSat_t/CoolEff_t) \;/\; (CoolSat_{1995}/CoolEff_{1995})$$

$$HeatIndex_t = (HeatSat_t/HeatEff_t) / (HeatSat_{1995}/HeatEff_{1995})$$
$$BaseIndex_t = (BaseSat_t/BaseEff_t) / (HeatSat_{1995}/CoolEff_{1995})$$

OUC appliance saturation surveys from 1990 and 1994 were used to develop the indices. Appliance saturation and efficiency trends were projected using the EPRI REEPS (Residential End-Use Planning System) model. The projections are based on OUC saturation estimates and price projections, and on national default appliance stock age distribution, efficiency characteristics, and future efficiency standards.

Given that there is little residential gas availability in the OUC service territory, the saturation of electric space heat is over 80 percent in 1994. Similarly, given the heat and humidity in Orlando, there is nearly a 98 percent saturation of air conditioning. OUC is already starting out with an appliance stock that is highly sensitive to variation in weather conditions. For heating, while the saturation trend continues to increase, the overall index actually declines over the forecast period, as less efficient heating technologies (electric furnace and room heating) are replaced with more efficient heat pumps. Similarly, residential cooling load resulting from increases in central air conditioning saturation is largely mitigated by expected heat pump and central air conditioning efficiency gains. The overall cooling index is relatively flat throughout the forecast period. The implication of these index trends is that, despite a high saturation of electric heat and cooling, residential average use should be less sensitive to changes in temperature through the forecast period, with increasing end-use efficiency slowing residential average use growth. Improvements in efficiency of nonweather-sensitive appliances (including refrigerators, ranges, washers, and dryers) also help to mitigate residential electricity growth.

Utilization Variables. The utilization variables ($CoolUse_t$, $HeatUse_t$, and $BaseUse_t$) are designed to capture energy demand driven by use of the appliance stock (the end-use index variables). The utilization drivers include:

- Weather conditions (as captured by heating and cooling degree days).
- Electricity prices.
- Household income.
- Household size.

The typical modeling approach is simply to specify an average use model with the variables above on the "right-hand side" of the regression model. Due to multicollinearity, however, it is often impossible to isolate the impact of one variable on average use from the impact of another variable. This is because the variables are moving in the same direction – household income is increasing while price and household size are declining. While generally not a problem in a short-term forecast (the

price impact will often be simply ignored), it is desirable to capture how changes in these variables impact the forecast over the longer term. To allow each of these drivers to impact usage, elasticities for the driver variables are imposed during the construction of the utilization variables. The utilization variables are defined as:

$$CoolUse_t = (Price_t \wedge (-.20)) * (Inc_per_HH_t \wedge .20) * (HH_Size_t \wedge 0.25) * CDD$$
$$HeatUse_t = (Price_t \wedge (-.20)) * (Inc_per_HH_t \wedge .20) * (HH_Size_t \wedge 0.25) * HDD$$
$$OtherUse_t = (Price_t \wedge (-.20)) * (Inc_per_HH_t \wedge .15) * (HH_Size_t \wedge 0.20)$$

In this functional form, the values shown in the specifications are, in effect, elasticities. The elasticities give the percent change in utilization (*CoolUse*, *HeatUse*, and *BaseUse*) given a 1 percent change in the forecast drivers – price, household income, and household size. The elasticities imposed are relatively small, but reasonable. Changes in price, household income, and household size will have a small, but reasonable, impact on changes in the utilization variables. Over the historical period, heating and cooling use are dominated by month-to-month variation in cooling and heating degree days (CDD and HDD).

Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on *Cooling*, *Heating*, and *BaseUse*. Lagged *Use* variables are also included in the specification because the *Use* variables are constructed with calendar-month weather data, but the dependent variable (residential average use) is based on revenue-month sales. July residential sales, for example, reflect usage in both calendar months June and July. The end-use variables proved to work extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.94 with an in-sample MAPE of less than 4 percent. The standard error of the regression model is 52.43 kWh compared with residential monthly average usage of 1,033 kWh. All the model coefficients are highly significant (exhibiting P-values less than 0.05). The St. Cloud model explains slightly less of the variation in average use, with an adjusted R^2 of 0.91 and an in-sample MAPE of 5.6 percent. The model coefficients are highly significant.

Figure 1B.4-3 shows projected average residential use on an annual basis and Figure 1B.4-4 depicts projected residential sales.

1B.4.1.2 Non-residential Sector Models

The Nonresidential sector is segmented into two revenue classes:

- *Small General Service (GS Nondemand or GSND)*
- *Large General Service (GS Demand or GSD)*

The GSND class consists of small commercial customers with a measured demand of less than 50 kW. The GSD class consists of those customers with monthly maximum demand exceeding 50 kW.

Figure 1B.4-3
Residential Average Use Forecast (kWh)

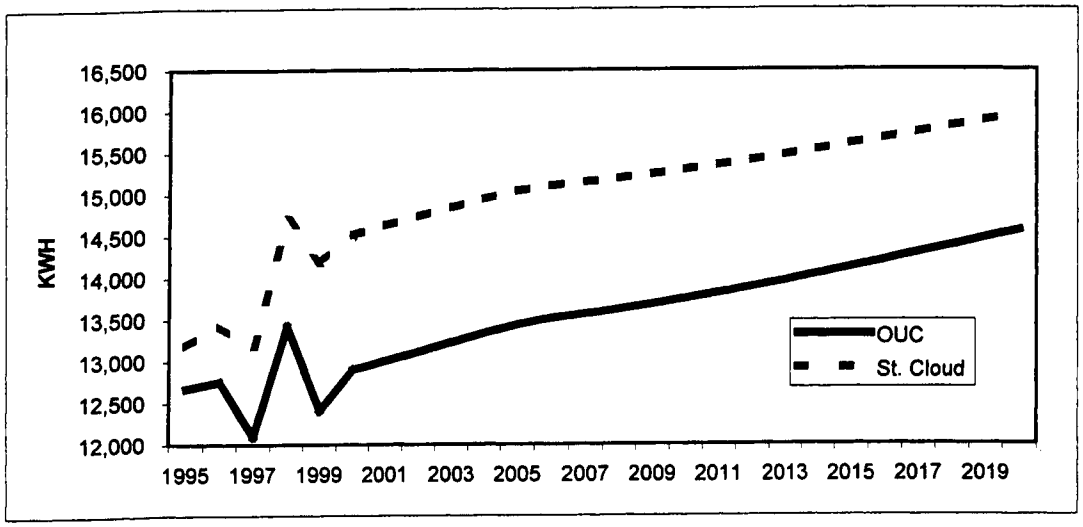
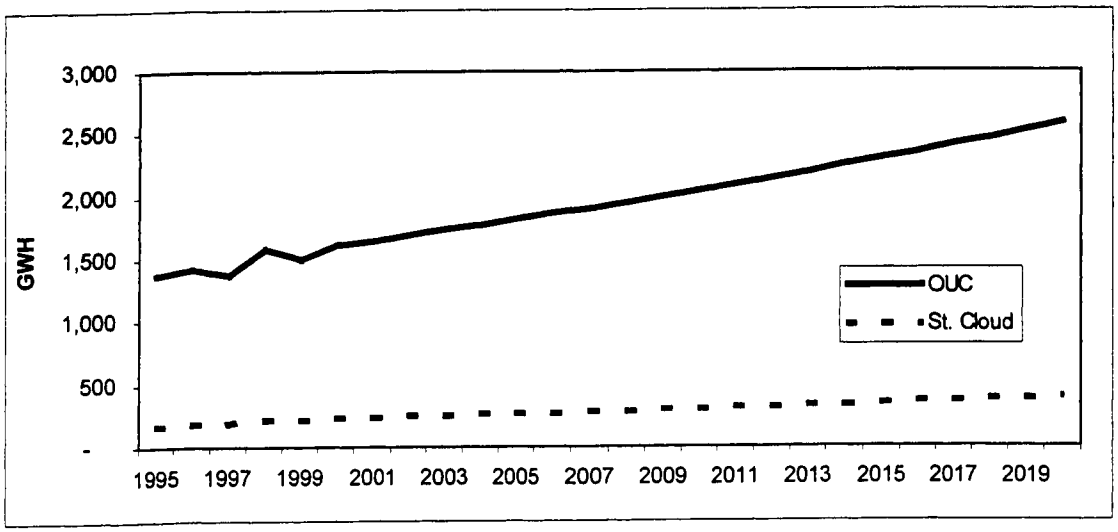


Figure 1B.4-4
Residential Sales Forecast (GWh)

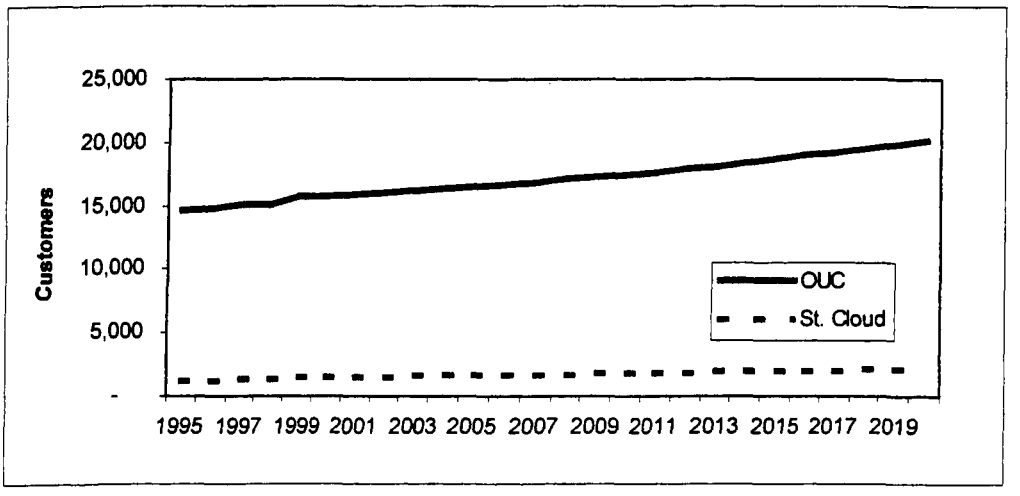


GSND Model. The GSND models are developed along lines similar to the residential forecast with the GSND monthly energy demand calculated as:

$$GSND_T = \text{GSND Average Use}_T * \text{GSND Customers}_T$$

GSND Customers. GSND customers are forecasted using a simple regression model that relates GSND customers to Orlando MSA nonmanufacturing employment projections. An AR1 correction term was added to the specification to correct for serial correlation. The OUC customer model was estimated using monthly customer counts for the period October 1990 through 1999. For OUC, the overall model adjusted R^2 is 0.996 with an in-sample MAPE of 0.20 percent. Again, the customer model for St. Cloud did not perform as well due to significant "noise" in the month-to-month variation in customer counts. The adjusted R^2 is 0.73, with an in-sample MAPE of 3.45 percent. An AR1 and AR2 correction were added to the St. Cloud model to help account for month-to-month swings in customer counts. The model coefficients in both the OUC and St. Cloud models are all highly significant. Figure 1B.4-5 shows the GSND customer forecasts.

Figure 1B.4-5
GSND Customer Forecast



A similar SAE modeling approach is used in specifying the GSND average use model. Where average GSND use is defined as:

$$Average\ Use_t = Heating_t + Cooling_t + BaseUse_t$$

Cooling, *Heating*, and *BaseUse*, are defined as the product of an end-use stock index and utilization variable:

$Cooling_t = CoolIndex_t * CoolUse_t$

$Heating_t = HeatIndex_t * HeatUse_t$

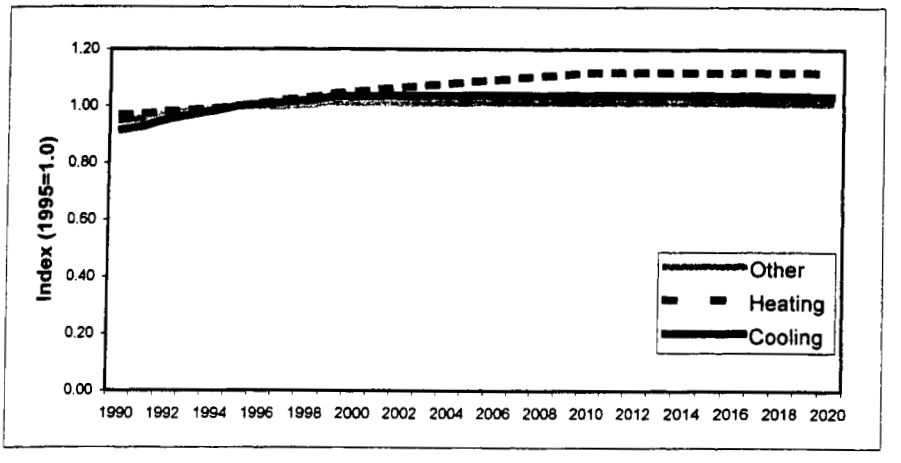
$BaseUse_t = BaseIndex_t * OtherUse_t$

Nonresidential End-Use Index Variables. For the Nonresidential models, saturation and efficiency trends are accounted for by the change in annual energy intensities (kWh per square foot) over the forecast horizon. Energy intensity estimates are derived using the EPRI COMMEND model. The national default COMMEND model was modified to reflect OUC heating and cooling saturation estimates and long-term electric price forecasts. The commercial building type mix in the OUC/St. Cloud service territory is assumed to look like that of the national default model. In the OUC service territory, the base-year electric heating saturation is nearly 80 percent, and cooling saturation is 100 percent. The high electric saturation again reflects limited natural gas alternatives. The index is calculated using 1995 as the base year:

$Index_t = Energy\ Intensity_t / Energy\ Intensity_{95}$

With 100 percent saturation and constant real electricity prices over the long term, annual cooling intensities (i.e., use per square foot) are relatively flat and thus affect the Cooling Index very little over the forecast horizon. Similarly, the Other Use Index shows relatively slow growth through the forecast period. The heating index increases through 2010, as electric heat saturation continues to gain the remaining market share; however, as there are relatively days of actual commercial heating (utilization of the heating stock) the heating index has relatively little impact on overall GSND average use. Figure 1B.4-6 depicts the end-use trend variables.

Figure 1B.4-6
Commercial End-Use Index Projections (1995 = 1.0)



GSND Usage Variables. The usage variables (*CoolUse*, *HeatUse*, and *OtherUse*) are designed to capture GSND end-use utilization. Where household size and income are the primary economic variables used in driving residential utilization, employment and output are used to drive Nonresidential utilization. The Use variables are defined as:

CoolUse = (Price^-.20)(Output per Employee^.20)*(CDD)*

HeatUse = (Price^-.20)(Output per Employee^.20)*(HDD)*

OtherUse = (Price^-.20)(Output per Employee^.20)*

The assumed utilization elasticities are relatively small, but reasonable. The price elasticity is set at -0.20 – a 1 percent decrease in price causes a 0.2 percent increase in the use variables. Similarly the productivity elasticity is set at 0.2 percent – a 1 percent increase in productivity leads to a 0.2 percent increase in the end-use utilization.

The *Use* variables are multiplied by the *Index* variables to generate *Cooling*, *Heating*, and *BaseUse*. Since 1992, GSND average use for OUC has actually been declining. This is largely because GSND customers tend to be larger (when compared with St. Cloud), and they are typically migrated to the GSD classification as soon as customers exceed the GSND usage limit. To account for the downward trend, a trend variable interactive with the *BaseUse* is incorporated into the average use specification; the variable has a negative sign and is highly significant. All the GSND model variables are highly significant. The adjusted R^2 for the OUC GSND average use model is 0.99 with an in-sample MAPE of 2.8 percent. For St. Cloud the GSND average use model has an adjusted R^2 of 0.86, with an in-sample MAPE of 4.1 percent. Figure 1B.4-7 shows forecasted GSND average use on an annual basis. Total GSND sales are depicted in Figure 1B.4-8. Model results are included in Appendix 1B.A.

Figure 1B.4-7
GSND Average Use Forecast (kWh)

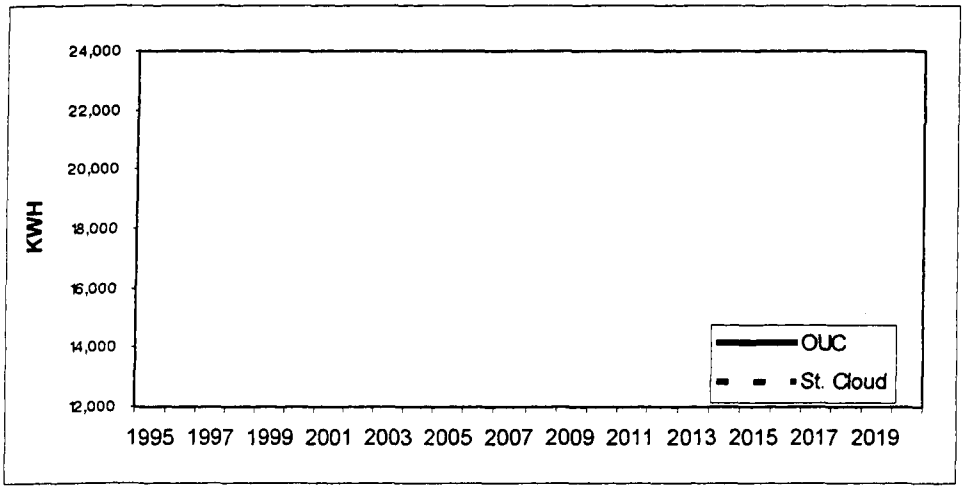
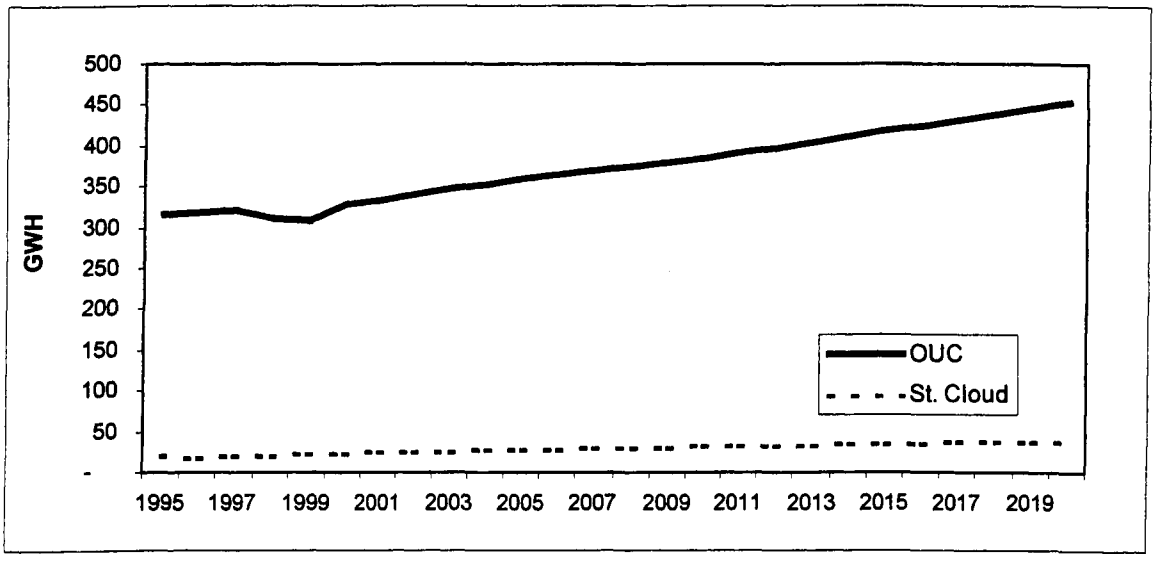


Figure 1B.4-8
GSND Sales Forecast (GWh)



1B.4.1.3 GSD Models

The general service demand class represents the largest Nonresidential customers. Over the last 5 years, OUC has seen the strongest sales gains in the GSD customer class, with GSD sales growth averaging 4.6 percent for the combined OUC and St. Cloud service territories. While sales growth will slow significantly over the forecast period, GSD sales are expected to continue to show relatively strong sales growth through the forecast horizon.

Because the GSD class represents such a diverse customer base, an aggregate sales model is used in place of an average use model. Again, end-use variable concepts are incorporated into the model specification where:

$$GSD\ Sales_t = f(BaseUse_t, CoolUse_t, and\ HeatUse_t)$$

Where

$$Cooling_t = CoolIndex_t * (Price_t\text{^}{-.20}) * (GSP_t\text{^}.20) * CDD_t$$

$$Heating_t = HeatIndex_t * (Price_t\text{^}{-.20}) * (GSP_t\text{^}.20) * HDD_t$$

$$BaseUse_t = BaseIndex_t * (Price_t\text{^}{-.20}) * (GSP_t\text{^}.20)$$

The index variables are the same as those used in estimating the GSND model. Aggregate regional output for the Orlando MSA (GSP_t) is used to capture utilization resulting from historical and projected economic activity. In the OUC model, the end-use variables are all highly significant (except for the lagged heating variable). The adjusted R^2 is 0.94, with an in-sample MAPE of 2.7 percent. In the St. Cloud model, the adjusted

R^2 is 0.92, with a MAPE of 3.7 percent. The low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class.

In 1999, GSD saw a significant jump in sales as a result of the opening of Universal Studios' *Islands of Adventure*, which is expected to continue contributing strong growth to the GSD rate class. While the large load increase in 1999 is partially captured by the regression model with a binary variable (*Aug99_Later*), it is impossible to capture future large incremental load additions that cannot be directly related to regional output data. Expected near-term sales growth from *Islands of Adventure* and other large development projects are added to the GSD statistical baseline forecast. Exogenous load adjustments include the airport expansion, the new convention center, an internet switching center, and the continued expansion at Universal Studios. Aggregate new-project load is shown in Figure 1B.4-9.

Figure 1B.4-9
New GSD Load (GWh)

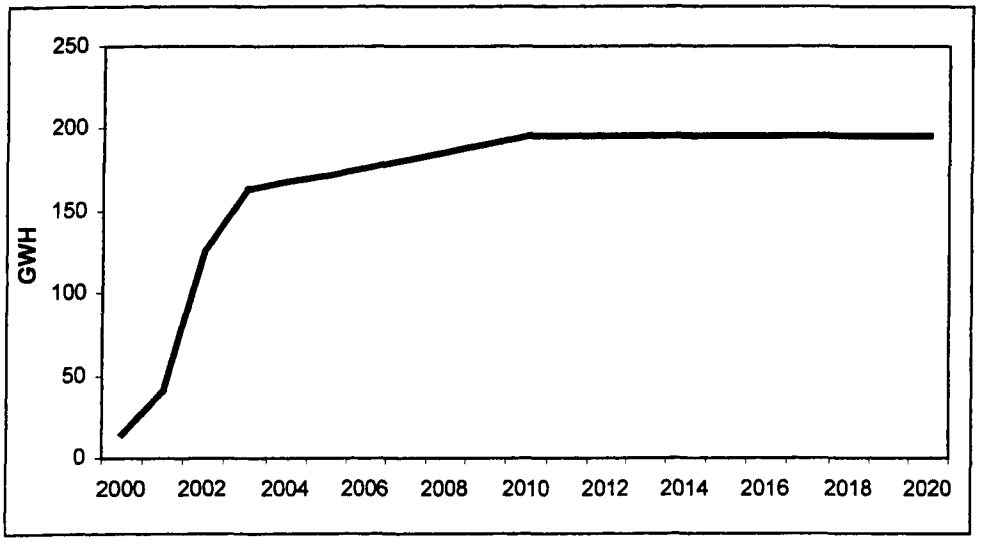


Figure 1B.4-10 shows total forecasted GSD loads for OUC and St. Cloud.

Street Lighting Sales. Street lighting sales are forecasted using a simple trend model. It is assumed that street lighting sales will continue to increase at the rate experienced over the last 7 years. The forecast also includes sales from a new OUC program called the *OUC Convenient Lighting Program*, which targets outdoor lighting use in the GSD sector. The lighting program absorbs sales that would otherwise be billed in the GSD tariffs; as such, the lighting program does not represent any new load growth. It is assumed that the *Convenient Lighting Program* will grow by 3.4 GWh a year through the forecast period. Figures 1B.4-11 and 1B.4-12 show forecasted street lighting sales.

Figure 1B.4-10
GSD Sales Forecast (GWh)

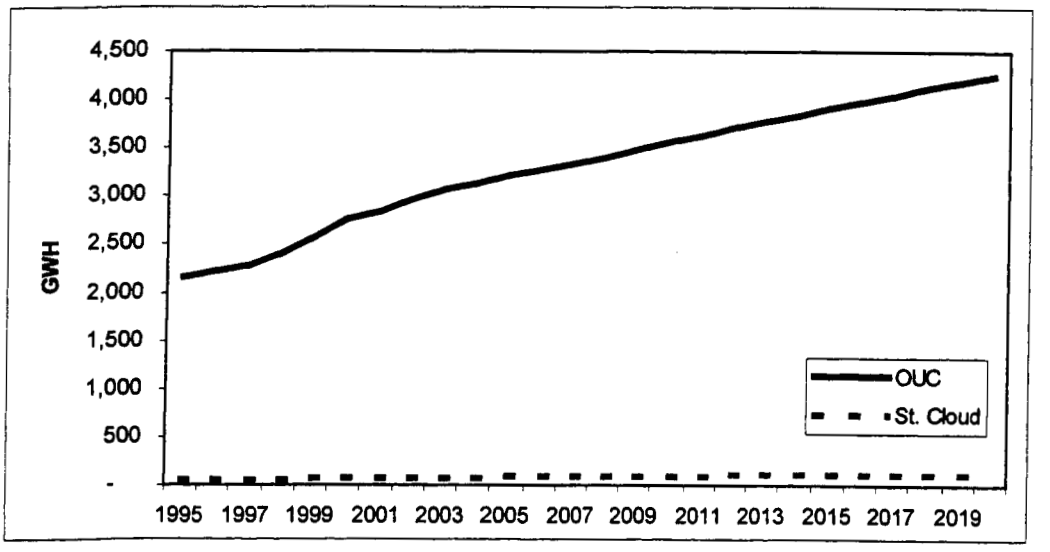


Figure 1B.4-11
OUC Street Light Sales Forecast (GWh)

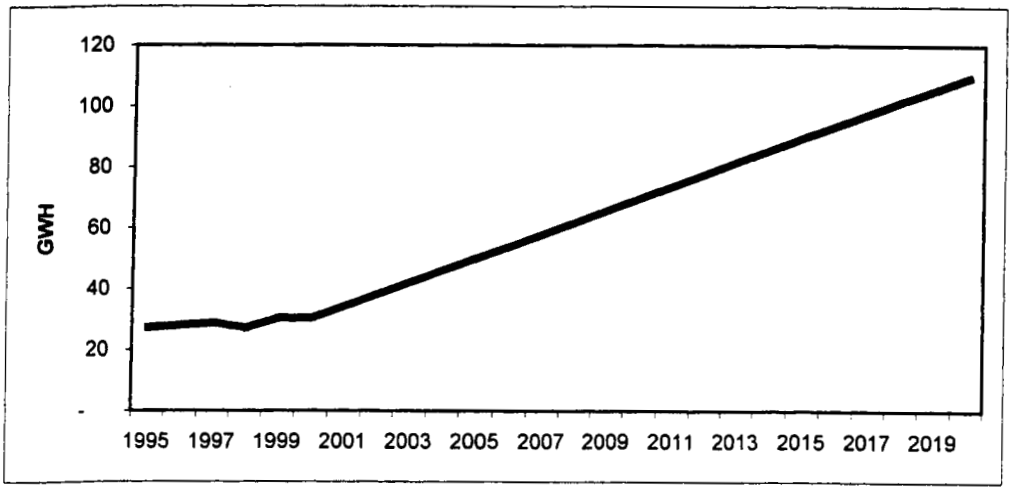
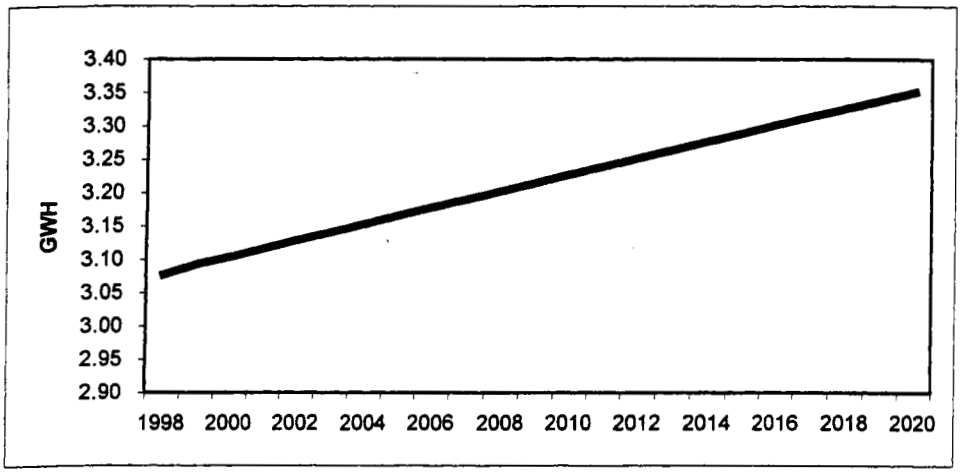


Figure 1B.4-12
St. Cloud Street Light Sales Forecast (GWh)



1B.4.1.4 Hourly Load and Peak Forecast

The system hourly load forecast is based on a set of hourly load models using load data covering the period January 1992 to December 1999. To forecast hourly loads, historical hourly loads are expressed as a percentage of the total daily energy:

$$Fraction_{hd} = Load_{hd}/Energy_d$$

Where

$Load_{hd}$= *the system load in hour h and day d*

$Energy_d$ = *the system energy in day d*

Hourly percent models are then estimated for each hour using Ordinary Least Squares (OLS) regression. The hourly models are specified as a function of daily weather conditions, months, day of the week, and holidays. In the on-peak hours (6:00 a.m. to 8:00 p.m.) adjusted R^2 varies from 0.65 to 0.81, with MAPEs that vary from 4.0 percent to 2.4 percent. The off-peak fractional models have adjusted R^2 values that vary from 0.65 to as low as 0.35. The low R^2 in the off-peak model is attributable to significant "noise" in the off-peak load data that can't be explained by weather or day-type variables. Still, even the models with low R^2 values have MAPEs of less than 4 percent.

The hourly load forecast is driven by the long-term retail energy forecast. Hourly loads are forecasted as the product of the daily energy forecast and forecasted hourly fraction. Thus the forecast for hour (h) equals:

$$Load_h = Fraction_h * DailyEnergyForecast_d$$

The daily energy forecast is generated from the long-term monthly retail sales forecast. Monthly retail energy forecasts are translated to daily system energy requirements through the conversion variable $DaykWh_t$, which is calculated by dividing actual system daily energy by a retail sales trend based on actual monthly retail sales:

$$DaykWh_d = System\ Energy_d / SalesTrend_m$$

$$SalesTrend_m = ResTrend_m + NonResTrend_m$$

Where:

$ResSaleTrend_m$ = *12-month moving average (Residential Sales)*

$NonResTrend_m$ = *12-month moving average (Nonresidential Sales)*

A regression model to forecast $DaykWh_d$ is then estimated that relates $DaykWh_d$ to daily weather conditions, day of the week, holidays, and season. The model adjusted R^2 is 0.95, with a MAPE of 2.6 percent. Forecasted daily energy in period T is then calculated as:

$$DailyEnergyForecast_T = KWperKWh_T * SalesTrend_T$$

Where:

$SalesTrend_T$ *is calculated from retail monthly sales forecast*

Normal daily average temperatures are used to forecast hourly demand. Normal daily temperatures are calculated by ranking each historical year from the hottest to coldest average daily temperature. The ranked data are then averaged to generate the hottest average temperature day to the coolest average temperature day. Daily normal temperatures are then mapped back to a representative calendar day based on a typical daily weather pattern. The hottest normal temperature is mapped to July and the coldest normal temperature to January.

The resulting hourly load forecast for January and July of 2001 are depicted in Figures 1B.4-13 and 1B.4-14.

One surprising element is that under normal daily weather conditions OUC is just as likely to experience a winter peak as it is a summer peak. OUC experiences a "needle-like" peak in the winter months on the 1 or 2 days where the low temperature falls below freezing. The needle peak is driven by back-up resistant heat built into residential heat pumps. With heat pumps continuing to gain market share, winter peaks are projected to grow slightly faster than summer peaks during the forecast horizon.

A separate hourly load forecast is estimated for St. Cloud. Given that St. Cloud is dominated by the residential sector, St. Cloud is even more likely to peak during the winter season.

Figure 1B.4-13
January OUC Hourly Load for 2001 (MW)

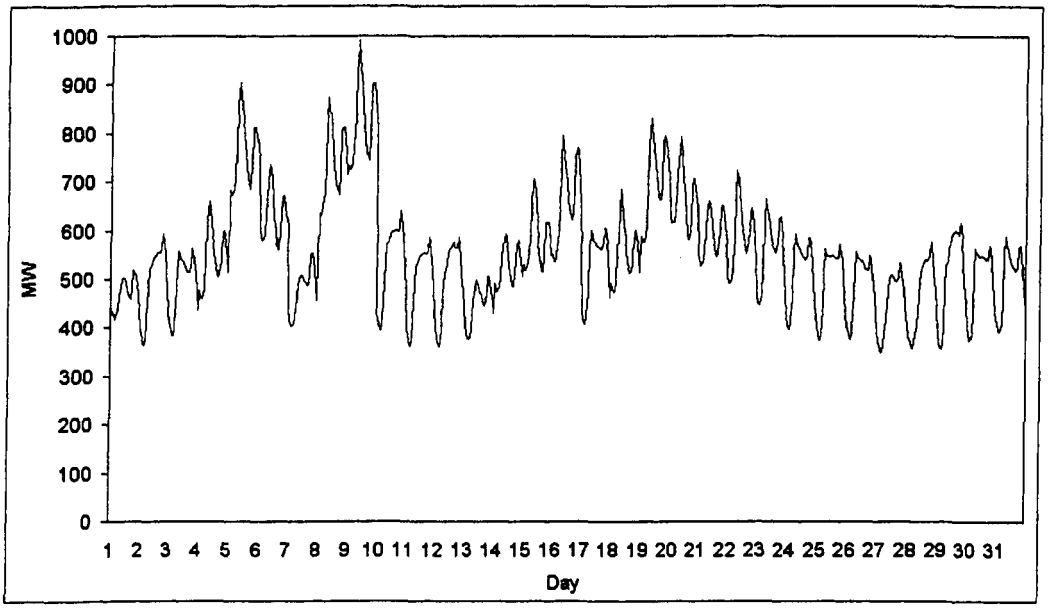
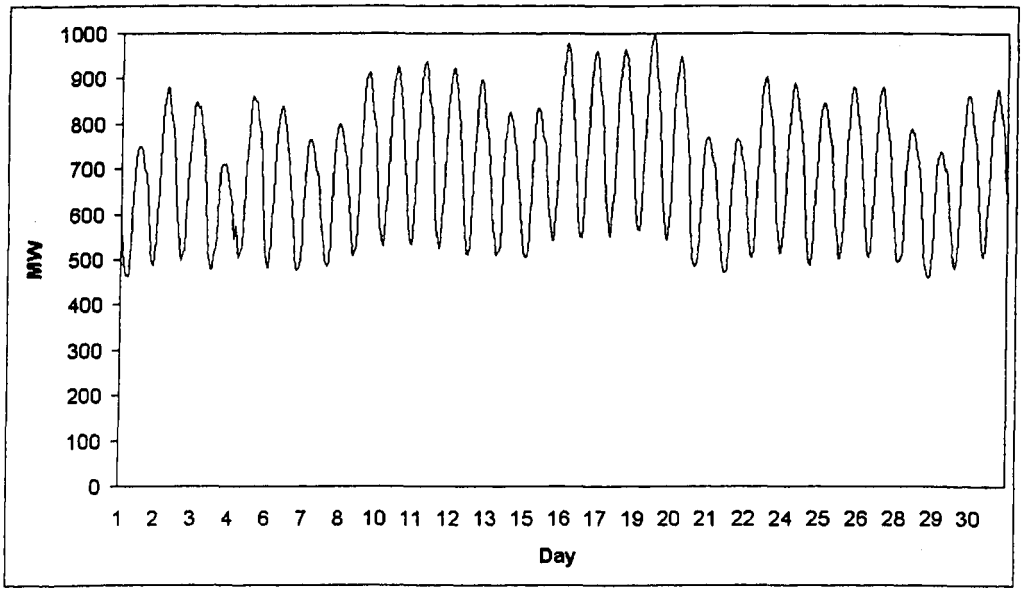


Figure 1B.4-14
July OUC Hourly Load for 2001 (MW)



The hourly OUC and St. Cloud forecast is aggregated to yield a total system hourly load requirement. Forecasted seasonal peaks are derived by then finding the maximum hourly demand in January, for the winter peak, and July, for the summer peak. Figure 1B.4-15 shows forecasted summer and winter system peak for the combined OUC and St. Cloud load requirements.

1B.4.2 Forecast Assumptions

The forecast is driven by a set of underlying demographic, economic, weather, and price assumptions. Given long-term economic uncertainty, the approach was to develop a set of reasonable, but conservative, set of forecast drivers.

1B.4.2.1 Economics

The economic assumptions are derived from forecasts from Regional Financial Associates (RFA), which is now doing business under the name Economy.com, and the University of Florida. RFA's monthly economic forecast for the Orlando MSA is used to drive the forecast through 2005. Thereafter, adjustments were made to create a more conservative economic outlook.

1B.4.2.1.1 Employment and Regional Output. The nonresidential forecast models are driven by nonmanufacturing and regional output forecasts. RFA employment forecasts were used through 2005. Employment growth over this period is consistent with the University of Florida's outlook. After 2005, RFA projects regional employment and output growth that continues to exceed RFA's Florida forecast and are somewhat more optimistic than the University of Florida. For the longer term (after 2005 to 2010), employment is assumed to continue to grow at the more conservative state growth rate forecasted by RFA. The slower growth is extrapolated beyond 2010 using an exponential smoothing model. The same process is used to develop a more conservative regional forecast of gross output. The resulting long-term employment and output growth (after 2010) is lower than RFA's outlook for Orlando and the state, and consistent with the University of Florida's long-term population forecast for the region. Table 1B.4-1 shows the annual employment and gross state product projections.

1B.4.2.1.2 Population, Households, and Income. The primary economic drivers in the residential forecast model are population, the number of households, and real personal income. RFA's projections for the Orlando MSA were used through 2005. Between 2005 and 2010 the number of households and real income are assumed to grow at the slower state rate. After 2010, population is assumed to grow at the rate projected by the University of Florida. Household projections are then calculated by dividing population projections by household size (number of household members) projections. An exponential smoothing model is used to extrapolate household size beyond 2010. Table 1B.4-2 shows annual population, household, and real income forecast.

Figure 1B.4-15
Summer and Winter System Peak Forecasts (OUC and St. Cloud Combined) (MW)

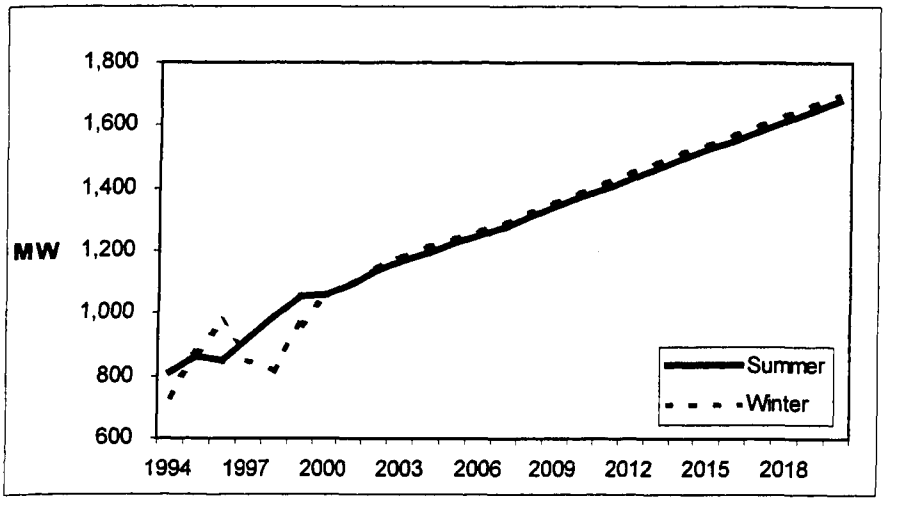


Table 1B.4-1
Nonmanufacturing Employment (Thousands) and
Gross Regional Product Projections (Billion Real $)

Year	Retail	Wholesale	Services	Financial Services	Government	Gross Product (Billion Real $)
1995	139.4	38.6	288.2	42.2	79.6	35.8
1996	146.7	41.3	304.4	44.5	81.6	37.8
1997	154.2	44.3	329.7	46.0	83.9	40.3
1998	158.7	46.2	354.7	49.3	86.9	43.1
1999	166.1	47.7	373.6	52.2	89.5	44.9
2000	171.2	49.4	391.1	54.4	91.9	46.8
2005	183.5	56.2	456.4	59.9	98.3	54.7
2010	197.7	63.5	540.9	66.5	105.2	64.9
2015	209.3	70.5	631.6	72.9	112.8	76.2
2020	220.6	77.5	722.1	79.1	120.3	87.4
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	5.3	7.0	5.6	5.5	2.5	5.6
1997	5.1	7.4	8.3	3.3	2.9	6.4
1998	3.0	4.3	7.6	7.2	3.5	7.0
1999	4.7	3.2	5.3	5.9	3.1	4.2
00-05	1.4	2.6	3.1	2.0	1.3	3.2
05-10	1.5	2.5	3.5	2.1	1.4	3.5
10-15	1.1	2.1	3.1	1.8	1.4	3.2
15-20	1.1	1.9	2.7	1.7	1.3	2.8

Table 1B.4-2
Population, Household, and Income Projections

Year	Real Income per HH	Households (Thousands)	Population (Thousands)
1992	54,673	491	1,306
1993	56,031	499	1,337
1994	56,957	508	1,366
1995	57,724	520	1,393
1996	59,487	534	1,427
1997	61,079	551	1,468
1998	63,582	567	1,509
1999	64,343	582	1,545
2000	65,684	596	1,577
2005	70,545	655	1,723
2010	74,207	721	1,894
2015	78,478	791	2,079
2020	83,331	863	2,273
Change	Percent	Percent	Percent
1993	2.5	1.6	2.3
1994	1.7	1.8	2.1
1995	1.3	2.3	2.0
1996	3.1	2.8	2.4
1997	2.7	3.1	2.9
1998	4.1	3.0	2.8
1999	1.2	2.7	2.3
00-05	1.4	1.9	1.8
05-10	1.0	2.0	1.9
10-15	1.1	1.9	1.9
15-20	1.2	1.8	1.8

1B.4.2.2 Price Assumption

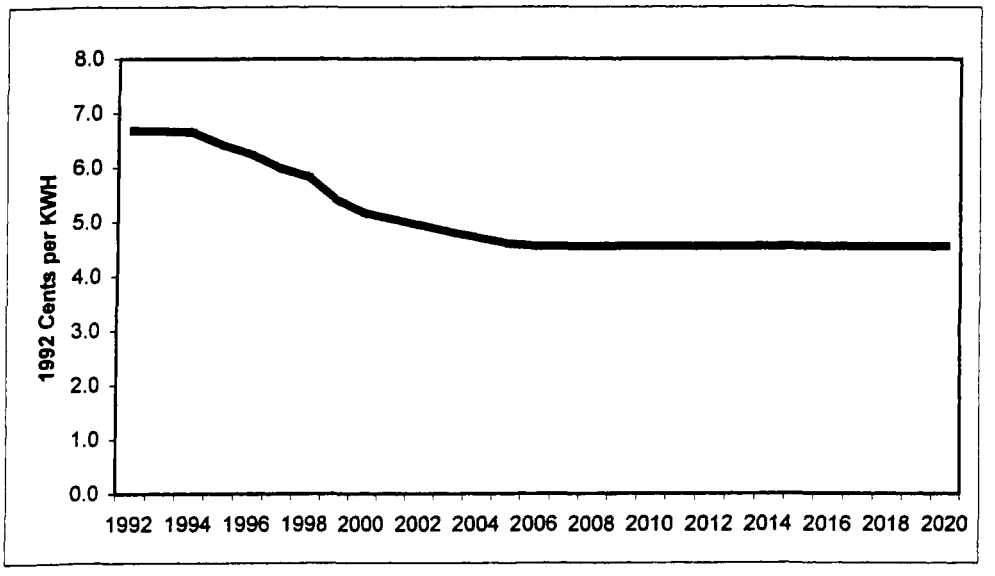
An aggregate retail price series was used as a proxy for effective prices in each of the model specifications. Since retail rates (across rate schedules) have generally moved in the same direction, an average retail price variable captures price movement across all the customer classes.

The price series is calculated by first deflating historical monthly revenues by the Consumer Price Index. Real revenues are then divided by retail sales to yield a monthly revenue per kWh value. Since revenue is itself a function of sales, it is inappropriate to regress sales directly on revenue per kWh. To generate a price series, a 12 month moving

average of the real revenue per kWh series was calculated. This is a more appropriate price variable, as it assumes that households and businesses respond to changes in electricity prices that have occurred over the prior year.

Since 1992, real prices have been trending downward. For the first 5 years of the forecast (2000 to 2005) no increases in nominal rates are assumed, thus real prices continue to trend downward. After 2005, real prices are assumed constant. Historical and projected prices are depicted on Figure 1B.4-16. The average annual price series is provided in Table 1B.4-3.

Figure 1B.4-16
Historical and Forecasted Average Electricity Prices
(1992 Cents per kWh)



1B.4.2.3 Weather

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly cooling degree-days (CDD) are used to capture cooling requirements while heating degree-days (HDD) account for variation in usage due to electric heating needs. CDD and HDD are calculated from daily average temperatures for Orlando.

CDD is calculated using a 65 degree Fahrenheit base. First a daily CDD is calculated as:

$CDD_d = (AvgTemp_d - 65) * (AvgTemp_d >= 65)$

Table 1B.4-3
Historical and Forecasted Price Series
Average Annual Price

Year	Real Price (cents/kWh)
1992	6.7
1993	6.7
1994	6.7
1995	6.4
1996	6.3
1997	6.0
1998	5.8
1999	5.4
2000	5.2
2005	4.6
2010	4.6
2015	4.6
2020	4.6

Change	Percent
1993	-0.1
1994	-0.4
1995	-3.4
1996	-2.7
1997	-4.1
1998	-2.7
1999	-7.3
00-05	-2.3
05-10	-0.2
10-15	0.0
15-20	0.0

CDD_d has a value equal to the average daily temperature minus 65 when temperatures are greater than or equal to 65° F, and 0° if average daily temperature is less than 65°. The daily CDD values are then aggregated to yield a monthly CDD:

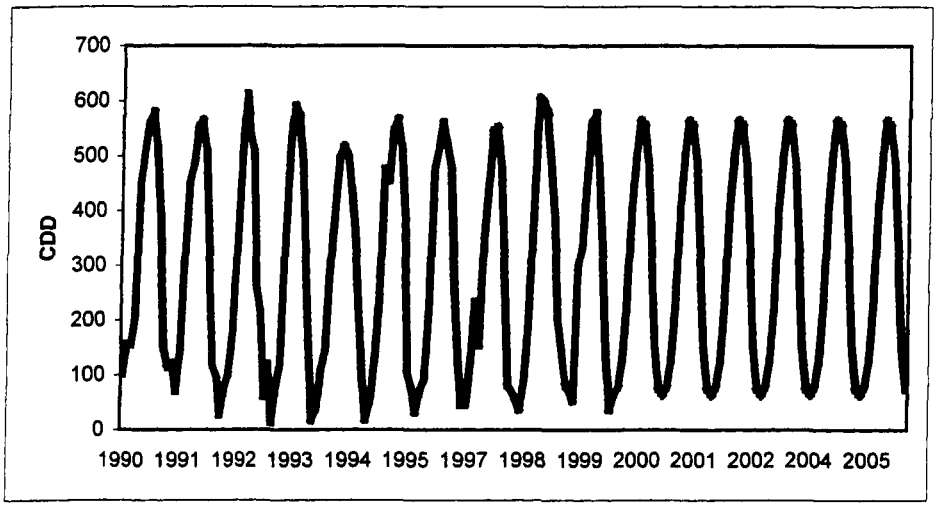
$CDD_m = \Sigma CDD_{md}$

For each month, a normal CDD estimate is calculated using a 10 year average of the monthly values calculated from 1990 through 1999:

$CDD_{nm} = \Sigma CDD_m / 10$

Figure 1B.4-17 shows historical and forecasted monthly CDD. The forecast begins in 2000.

Figure 1B.4-17
Monthly Cooling Degree Days



Heating degree-days are calculated in a similar manner. Daily HDD is first derived using a base temperature of 65 degrees:

$HDD_d = (65 - AvgTemp_d) * (AvgTemp_d <= 65)$

HDD_d equals 65° minus the average daily temperature, if the average daily temperature is less than or equal to 65, and equals 0° if the daily temperature is greater than 65°. Aggregate monthly HDD (HDD_m) is then calculated by summing daily HDD over each month:

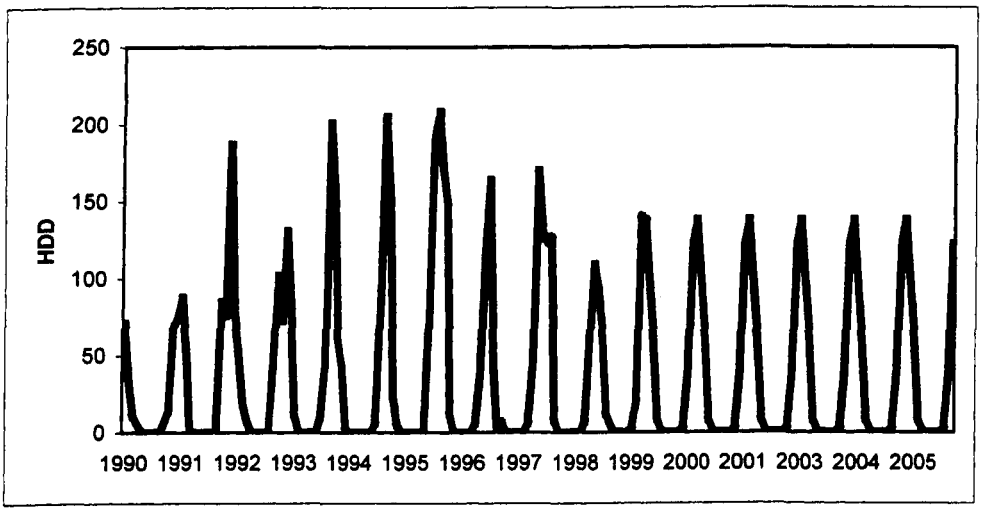
$HDD_m = \Sigma HDD_{md}$

The monthly normal HDD is calculated as a 10 year average of the calendar month HDD:

$HDD_{nm} = \Sigma HDD_m / 10$

Figure 1B.4-18 depicts the resulting HDD series. The forecast begins in 2000.

Figure 1B.4-18
Heating Degree Days



1B.4.3 Base Case Load Forecast

A short-term monthly budget forecast was estimated through 2002, with a long-term annual forecast through 2020. As outlined in the methodology section, 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. Forecast models are estimated for each of the major rate classifications including:

- *Residential.*
- *General Service Non-Demand (Small Commercial Customers).*
- *General Service Demand (Large Commercial and Industrial Customers).*
- *Street Lighting.*

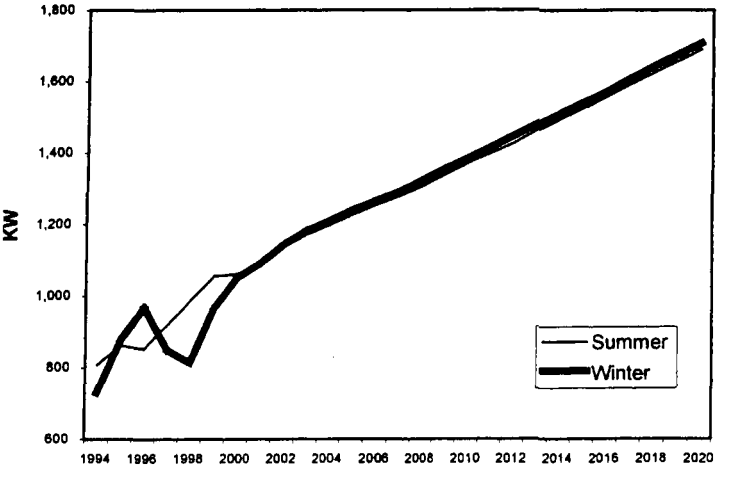
Models are estimated using monthly sales data covering the period 1991 through 1999. A separate set of forecast models are estimated for the OUC and St. Cloud service territories.

To support production-costing modeling, an 8,760 hourly load forecast is derived for each of the forecast years. The hourly load forecasts are based on a set of hourly and daily energy statistical models. The models are estimated from hourly system load data over the period January 1992 to December 1999. A separate set of models is estimated for OUC and St. Cloud. Seasonal peak demand forecasts are derived as the maximum hourly demand forecast occurring in the summer and winter months. Table 1B.4-4 and Figure 1B.4-19 summarize annual sales and peak forecast for the combined OUC and St. Cloud service territories.

Table 1B.4-4
System Peak (Summer and Winter) and
Net Energy Forecast (Total of OUC and St. Cloud)

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	808	731	4,174
1995	861	876	4,377
1996	852	969	4,471
1997	917	849	4,566
1998	988	814	4,909
1999	1,055	965	5,011
2000	1,062	1,051	5,363
2005	1,227	1,239	6,192
2010	1,372	1,386	6,925
2015	1,522	1,539	7,692
2020	1,679	1,697	8,492
Change	percent	percent	percent
95-99	4.1	2.0	2.7
00-05	2.9	3.3	2.9
05-10	2.3	2.3	2.3
10-15	2.1	2.1	2.1
15-20	2.0	2.0	2.0

Figure 1B.4-19
Summer and Winter System Peak Forecasts
(OUC and St. Cloud Combined) (MW)

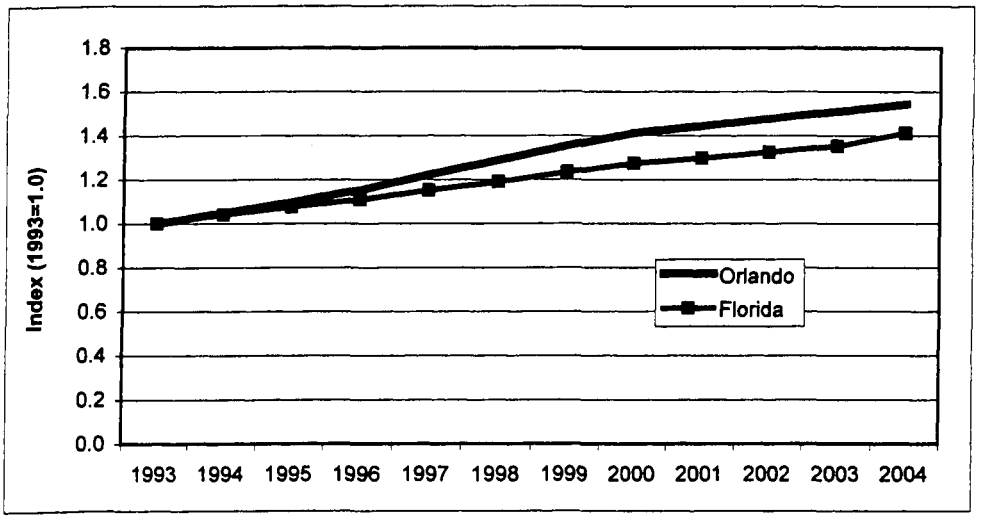


1B.4.3.1 Base Case Economic Outlook

The Orlando area has seen some of the strongest economic growth in the nation. RFA ranked Orlando as number 16 (out of 321 MSAs) in terms of current and expected employment growth. RFA projects continued strong growth for the region well into the next decade.

Between 1995 and 1999, population has grown at an average annual rate of 2.6 percent and real gross output has grown at 5.8 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and nation. Florida, over the same period, experienced population and gross output growth of 1.6 percent and 3.9 percent, respectively. Orlando is expected to exceed overall state economic growth throughout the next 10 years. Figure 1B.4-20 compares relative employment projections of Orlando and Florida. By indexing total employment to 1.0 in 1993, it is easier to compare the growth projected for Orlando and Florida.

Figure 1B.4-20
Relative Employment Performance (RFA) (1993=1.0)



Much of this growth has been fueled by significant gains in the service sector, which has seen employment expand by nearly 100 percent since 1990. Moreover, employment in the service sector accounts for approximately 42 percent of total employment. Hotels and tourism-related activities, as well as call-centers, have continued to grow. OUC is also seeing increasing interest in establishing internet-support and switching centers.

In recent years, the area has reaped the benefits of a booming national economy and the associated upturn in tourism. Two of the largest regional employers are Walt Disney and Universal Studios. Universal Studios has doubled in size with the recent addition of *Islands of Adventure*, *CityWalk*, and the related hotel complex. Several new hotels are currently under construction, with the largest being the new Hard Rock Hotel and complex that will open this year. The new Orlando convention center is expected to open in 2002, further fueling regional convention and tourism activity. In addition, Lockheed Martin is planning to open a commercial flight-training and simulation center, which is expected to draw thousands of pilots seeking training and recertification. Top employers in the Orlando MSA are shown in Table 1B.4-5.

Table 1B.4-5
Largest Regional Employers

Employer	Number of Employees
Walt Disney World Company	55,000
Florida Hospital	11,210
Publix Super Markets, Inc.	<9,000
Winn-Dixie Stores, Inc.	8,978
Orlando Regional Healthcare System	8,200
Universal Studios Escape	7,000
Central Florida Investments, Inc.	5,000
Central Florida Healthcare System	4,500
Sun Trust Bank Central Florida	4,244
Darden Restaurants, Inc.	4,200
Lockheed Martin Electronics & Missiles	3,800
Sprint Communications Company	3,747

Source: RFA

To accommodate growing convention, tourism, and regional business activity, the Orlando International Airport (OIA) is in the process of a major expansion program that will ultimately double the capacity of the airport. In 1999, OIA served 29 million passengers -- nearly 10 percent over the prior year. OIA projects continued strong passenger volume growth for the region well into the next decade.

Economic Projections. While the economy is projected to slow from the torrid pace experienced over the last 5 years, relatively inexpensive labor and housing costs, and strong in-migration from both other states and other nations will continue to fuel the

regional economic expansion long into the future. The number of households in the Orlando MSA is projected to increase from 582,000 in 1999 to 863,000 by 2020, representing an average annual growth rate of 1.9 percent. Employment is projected to grow at 2.1 percent over the long term.

RFA ranks Orlando at 99 percent (with respect to the US average of 100 percent) in terms of the cost of doing business. Similarly, Orlando is ranked at 97 percent for cost of living, implying a slightly lower-than-average cost of living in the area. The combination of these and other factors will sustain Orlando as one of the fastest growing metropolitan areas in the US. Long-term growth will be driven by the high quality of life, the relatively low costs of both doing business and living, strong net migration, and an environment that is conducive to business development. Increasing concentrations of high-tech and defense-related industries will help to diversify the local economy.

Table 1B.4-6 summarizes economic projections for the Orlando MSA. Economic projections are based on RFA's economic outlook for Orlando and the state of Florida. Projections are in line with economic projections by the University of Florida. University of Florida's long-term population projections for the region are used to drive household growth after 2010.

1B.4.3.2 Forecast Results

Based upon the previously discussed economic assumptions, total retail sales for OUC are expect to increase from 4,488 GWh in 1999 to 7,569 GWh by 2020. St. Cloud sales are projected to increase from 320.5 GWh to 573.6 GWh. Sales and customer projections are summarized in Tables 1B.4-7 through 1B.4-10.

Residential Forecast. With high electric end-use saturation, coupled with projected appliance efficiency-gains, residential average use is projected to increase relatively slowly over the forecast period. For OUC, average use per customer is forecasted to grow at 0.8 percent and slow to 0.6 percent by the end of the forecast period. Residential sales growth will be driven largely by the addition of new customers. With relatively strong population projections for the region, residential customers are expected to increase at a 1.8 percent rate for OUC and 2.2 percent rate for St. Cloud between 2000 and 2020. The OUC and St. Cloud residential sales forecasts are shown in Tables 1B.4-11 and 1B.4-12, respectively.

Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 1.9 percent and 2.6 percent for OUC and St. Cloud respectively between 1999 and 2020. Projected GSND sales are driven by regional nonmanufacturing employment and output growth. Average use is projected to be relatively flat (particularly for OUC). Average use growth is partly constrained by size limitation; as

Table 1B.4-6
Orlando MSA Economic Projections

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57724	723	757	4.5	36
1996	534	59487	750	780	3.8	38
1997	551	61079	788	815	3.4	40
1998	567	63582	816	842	3.0	43
1999	582	64343	854	879	2.9	45
2000	596	65684	882	908	2.8	47
2005	655	70545	977	1013	3.5	55
2010	721	74207	1084	1122	3.4	65
2015	791	78478	1205	1248	3.4	76
2020	863	83331	1340	1387	3.4	87
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	2.8	3.1	3.8	3.0	-	5.6
1997	3.1	2.7	4.9	4.5	-	6.4
1998	3.0	4.1	3.7	3.2	-	7.0
1999	2.7	1.2	4.6	4.5	-	4.2
00-05	1.9	1.4	2.1	2.2	-	3.2
05-10	2.0	1.0	2.1	2.1	-	3.5
10-15	1.9	1.1	2.1	2.1	-	3.2
15-20	1.8	1.2	2.1	2.1	-	2.8

Table 1B.4-7
OUC Long-Term Sales Forecast (GWH)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1380	316	2154	27	-	55	3932
1996	1419	318	2211	28	-	61	4037
1997	1377	322	2274	29	-	56	4057
1998	1583	310	2405	27	-	78	4404
1999	1504	308	2570	30	-	76	4488
2000	1606	329	2756	31	-	78	4800
2005	1822	360	3207	33	17	100	5539
2010	2046	386	3561	36	34	122	6185
2015	2298	418	3913	39	51	145	6863
2020	2579	454	4259	42	67	167	7569
Change	percent	percent	percent	percent	percent	percent	percent
1996	2.8	0.5	2.7	3.1	-	11.7	2.7
1997	-3.0	1.2	2.8	2.3	-	-8.4	0.5
1998	15.0	-3.5	5.8	-5.4	-	39.9	8.5
1999	-5.0	-0.8	6.9	11.8	-	-3.1	1.9
00-05	2.5	1.8	3.1	1.8	-	5.2	2.9
05-10	2.3	1.4	2.1	1.7	14.9	4.1	2.2
10-15	2.3	1.6	1.9	1.6	8.4	3.4	2.1
15-20	2.3	1.7	1.7	1.5	5.9	2.9	2.0

Table 1B.4-8
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108845	14572	2970	126387
1996	111241	14855	3120	129216
1997	113808	15065	3445	132319
1998	117868	15168	3799	136836
1999	121173	15659	3871	140703
2000	124484	15779	4074	144337
2005	135530	16524	4560	156615
2010	148822	17474	5151	171448
2015	162621	18682	5753	187056
2020	177054	20107	6351	203512
Change	percent	percent	percent	percent
1996	2.2	1.9	5.0	2.2
1997	2.3	1.4	10.4	2.4
1998	3.6	0.7	10.3	3.4
1999	2.8	3.2	1.9	2.8
00-05	1.7	0.9	2.3	1.6
05-10	1.9	1.1	2.5	1.8
10-15	1.8	1.3	2.2	1.8
15-20	1.7	1.5	2.0	1.7

Table 1B.4-9
St. Cloud Sales Forecast (GWH)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
1995	180	19	56	-	254
1996	190	18	62	-	270
1997	192	19	67	1	278
1998	221	20	72	3	316
1999	221	22	74	3	320
2000	234	23	80	3	340
2005	271	27	94	3	396
2010	309	31	108	3	451
2015	351	34	123	3	511
2020	396	38	136	3	574
Change	percent	percent	percent	percent	percent
1996	5.5	-1.5	11.0	-	6.2
1997	0.8	1.1	9.4	-	3.0
1998	15.2	9.4	7.1	-	13.7
1999	0.2	8.5	2.4	0.5	1.3
00-05	3.0	3.1	3.4	0.4	3.1
05-10	2.7	2.6	2.8	0.4	2.7
10-15	2.6	2.2	2.5	0.4	2.5
15-20	2.5	1.9	2.1	0.4	2.3

Table 1B.4-10
St. Cloud Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	13659	1293	116	15068
1996	14158	1311	132	15602
1997	14527	1359	140	16026
1998	15010	1427	150	16586
1999	15594	1522	152	17268
2000	16092	1553	163	17807
2005	18026	1714	182	19923
2010	20208	1886	203	22296
2015	22472	2037	219	24728
2020	24841	2188	236	27264
Change	percent	percent	percent	percent
1996	3.7	1.4	13.9	3.5
1997	2.6	3.6	6.1	2.7
1998	3.3	5.0	6.9	3.5
1999	3.9	6.6	1.6	4.1
00-05	2.3	2.0	2.3	2.3
05-10	2.3	1.9	2.1	2.3
10-15	2.1	1.6	1.6	2.1
15-20	2.0	1.4	1.5	2.0

Table 1B.4-11
OUC Residential Sales Forecast Summary

Year	Retail Sales	Customers	Average Use (Kwh)
1995	1380	108845	12679
1996	1419	111241	12765
1997	1377	113808	12096
1998	1583	117868	13430
1999	1504	121173	12411
2000	1606	124484	12905
2005	1822	135530	13443
2010	2046	148822	13749
2015	2298	162621	14128
2020	2579	177054	14565
Change	percent	percent	percent
1996	2.8	2.2	0.6
1997	-3.0	2.3	-5.2
1998	15.0	3.6	11.0
1999	-5.0	2.8	-7.6
00-05	2.5	1.7	0.8
05-10	2.3	1.9	0.5
10-15	2.3	1.8	0.5
15-20	2.3	1.7	0.6

Table 1B.4-12
St. Cloud Residential Sales Forecast Summary

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	180	13659	13194
1996	190	14158	13431
1997	192	14527	13191
1998	221	15010	14713
1999	221	15594	14197
2000	234	16092	14522
2005	271	18026	15045
2010	309	20208	15298
2015	351	22472	15606
2020	396	24841	15956
Change	percent	percent	percent
1996	5.5	3.7	1.8
1997	0.8	2.6	-1.8
1998	15.2	3.3	11.5
1999	0.2	3.9	-3.5
00-05	3.0	2.3	0.7
05-10	2.7	2.3	0.3
10-15	2.6	2.1	0.4
15-20	2.5	2.0	0.4

customers exceed the 50 KW rate-class cut-off, they are migrated to the appropriate GSD rate. For OUC, average GSND use has actually trended downward over the last five years. Small commercial customer growth accounts for the most of the GSND sales gains. The GSND customer forecast is driven by regional nonmanufacturing employment projections. The number of GSND customers is projected to grow at an average annual growth rate of 1.2 percent and 1.7 percent respectively for OUC and St. Cloud from 1999 to 2020. Tables 1B.4-13 and 1B.4-14 show annual GSND forecasts for OUC and St. Cloud.

Large Nonresidential Sales Forecast. General Service Demand (GSD) represents the largest commercial and industrial customers. Over the last couple of years, OUC has experienced phenomenal growth from this sector with GSD sales up 5.8 percent in 1998 and 6.9 percent in 1999. While sales are projected to slow significantly from this pace, sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall strong regional output growth. Average use actually declines somewhat over the forecast period as smaller customers migrate from the GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 1B.4-15 and 1B.4-16 summarize the GSD forecast.

1B.4.4 Net Peak Demand and Net Energy for Load

Hourly load models are used to forecast each of the 8,760 hours of each of the forecast years. Underlying hourly load growth is driven by the aggregate energy forecast. Thus, forecasted peaks grow at roughly the same rate as the energy forecast. Tables 1B.4-17 and 1B.4-18 show seasonal peak demands and net energy for load forecasts for OUC and St. Cloud.

1B.4.5 High and Low Case Scenarios

In addition to the base case, two long-term forecast scenarios were developed in order to bound the potential demand outcome. The High and Low Case Scenarios were developed by modifying the Base Case economic assumptions. The primary drivers that were modified are regional population, labor force, employment, output, and income. Table 1B.4-19 shows a comparison of the economic assumptions.

Table 1B.4-13
OUC General Service Nondemand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	316	14572	21713
1996	318	14855	21400
1997	322	15065	21353
1998	310	15168	20465
1999	308	15659	19657
2000	329	15779	20853
2005	360	16524	21764
2010	386	17474	22074
2015	418	18682	22382
2020	454	20107	22577
Change	Percent	Percent	Percent
1996	0.5	1.9	-1.4
1997	1.2	1.4	-0.2
1998	-3.5	0.7	-4.2
1999	-0.8	3.2	-3.9
00-05	1.8	0.9	0.9
05-10	1.4	1.1	0.3
10-15	1.6	1.3	0.3
15-20	1.7	1.5	0.2

Table 1B.4-14
St. Cloud General Service Nondemand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	19	1293	14426
1996	18	1311	14004
1997	19	1359	13660
1998	20	1427	14229
1999	22	1522	14484
2000	23	1553	14967
2005	27	1714	15769
2010	31	1886	16316
2015	34	2037	16813
2020	38	2188	17197
Change	percent	percent	percent
1996	-1.5	1.4	-2.9
1997	1.1	3.6	-2.5
1998	9.4	5.0	4.2
1999	8.5	6.6	1.8
00-05	3.1	2.0	1.0
05-10	2.6	1.9	0.7
10-15	2.2	1.6	0.6
15-20	1.9	1.4	0.5

Table 1B.4-15
OUC Large General Service Demand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	2154	2970	725046
1996	2211	3120	708721
1997	2274	3445	660036
1998	2405	3799	632959
1999	2570	3871	663841
2000	2756	4074	676550
2005	3207	4560	703253
2010	3561	5151	691198
2015	3913	5753	680176
2020	4259	6351	670635
Change	percent	percent	percent
1996	2.7	5.0	-2.3
1997	2.8	10.4	-6.9
1998	5.8	10.3	-4.1
1999	6.9	1.9	4.9
00-05	3.1	2.3	0.8
05-10	2.1	2.5	-0.3
10-15	1.9	2.2	-0.3
15-20	1.7	2.0	-0.3

Table 1B.4-16
St. Cloud Large General Service Demand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	56	116	479495
1996	62	132	467126
1997	67	140	481841
1998	72	150	482554
1999	74	152	486316
2000	80	163	488021
2005	94	182	516042
2010	108	203	534083
2015	123	219	559371
2020	136	236	578504
Change	percent	percent	percent
1996	11.0	13.9	-2.6
1997	9.4	6.1	3.2
1998	7.1	6.9	0.1
1999	2.4	1.6	0.8
00-05	3.4	2.3	1.1
05-10	2.8	2.1	0.7
10-15	2.5	1.6	0.9
15-20	2.1	1.5	0.7

Table 1B.4-17
OUC Net Peak Demand (Summer and Winter) and
Net Energy for Load: History and Forecast

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	749	674	3926
1995	798	800	4103
1996	788	885	4186
1997	846	773	4271
1998	907	746	4578
1999	969	873	4674
2000	973	956	5006
2005	1123	1127	5777
2010	1253	1258	6451
2015	1389	1394	7156
2020	1529	1535	7890
Change	Percent	Percent	Percent
95-00	4.0	3.6	4.1
00-05	2.9	3.3	2.9
05-10	2.2	2.2	2.2
10-15	2.1	2.1	2.1
15-20	1.9	2.0	2.0

Table 1B.4-18
St. Cloud Net Peak Demand (Summer and Winter) and
Net Energy for Load: History and Forecast

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	59	57	249
1995	63	76	274
1996	64	84	285
1997	71	76	295
1998	81	68	331
1999	86	92	337
2000	89	95	357
2005	104	113	415
2010	118	128	474
2015	134	145	536
2020	150	162	602
Change	Percent	Percent	Percent
95-00	7.2	4.7	5.4
00-05	3.1	3.3	3.1
05-10	2.7	2.6	2.7
10-15	2.5	2.5	2.5
15-20	2.3	2.2	2.3

Table 1B.4-19
Economic Assumptions

Economic Projections: Orlando MSA

High Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2.8	47
2005	687	68,479	1,038	1,075	3.5	56
2010	779	70,938	1,188	1,229	3.3	67
2015	875	74,998	1,358	1,404	3.3	81
2020	978	80 575	1 554	1 606	3.3	96
95-00	2.8%	2.6%	4.1%	3.7%	-	5.5%
00-05	2.9%	0.8%	3.3%	3.4%	-	3.6%
05-10	2.5%	0.7%	2.7%	2.7%	-	3.7%
10-15	2.3%	1.1%	2.7%	2.7%	-	3.7%
15-20	2.3%	1.4%	2.7%	2.7%	-	3.5%

Base Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2.8	47
2005	655	70,545	977	1,013	3.5	55
2010	721	74,207	1,084	1,122	3.4	65
2015	791	78,478	1,205	1,248	3.4	76
2020	863	83,331	1,340	1,387	3.4	87
95-00	2.8%	2.6%	4.1%	3.7%	-	5.5%
00-05	1.9%	1.4%	2.1%	2.2%	-	3.2%
05-10	2.0%	1.0%	2.1%	2.1%	-	3.5%
10-15	1.9%	1.1%	2.1%	2.1%	-	3.2%
15-20	1.8%	1.2%	2.1%	2.1%	-	2.8%

Low Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2.8	47
2005	641	65,666	929	988	5.9	50
2010	679	66,812	974	1,047	7.0	55
2015	712	69,916	1,030	1,107	7.0	61
2020	743	74,118	1,085	1,166	7.0	66
95-00	2.8%/	2.6%	4.1%	3.7%	-	5.5%
00-05	1.5%	0.0%	1.0%	1.7%	-	1.3%
05-10	1.1%	0.3%	1.0%	1.2%	-	1.9%
10-15	0.9%	0.9%	1.1%	1.1%	-	2.0%
15-20	0.9%	1.2%	1.1%	1.1%	-	1.8%

1B.4.5.1 High Case Scenarios

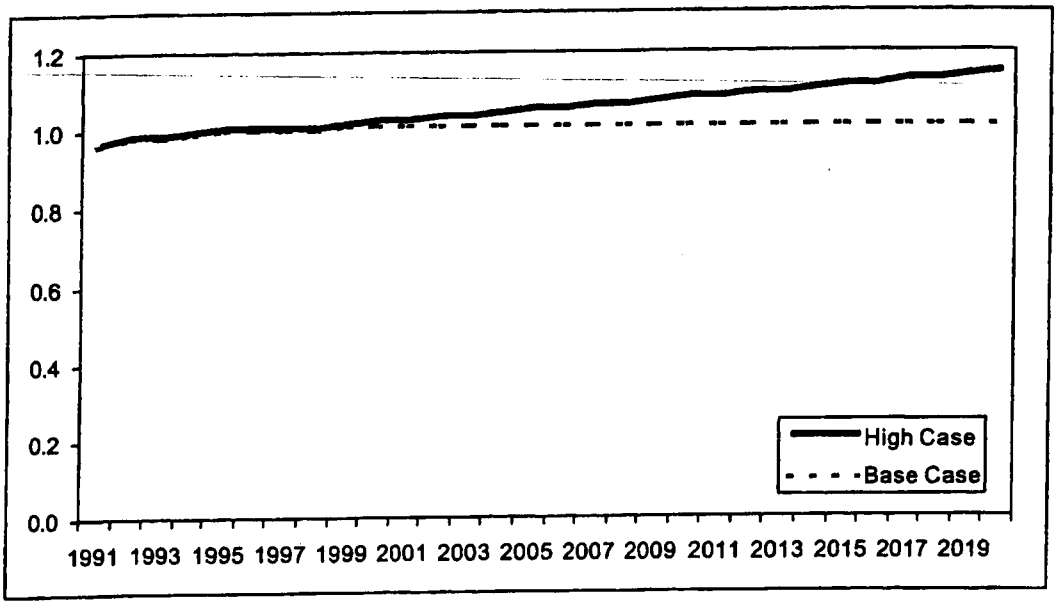
The high scenario is based upon assumptions of continued strong economic growth. We assume that through 2005, area population growth does not slow, but continues to expand at a rate experienced over the last few years. After 2005, the number of households increases 0.5 percent to 0.4 percent faster than the base case. The University of Florida's high and low population projections were used to help bound the population growth assumptions. Stronger population growth allows for continued expansion of the labor force; this in turn translates into stronger employment and total output growth. Employment and regional output in the high case scenario are somewhat constrained by the relatively low unemployment rate already assumed in the base case. We assume that there is only a slight improvement in the unemployment rate, as a relatively high labor force participation rate is already incorporated in RFA's base case forecast. Given that the number of households increases at a faster rate than the population during the first 10 years of the forecast (since household size declines during this period), income per household increases at a slightly lower rate than it does in the base case over the first 10 years. After 2010, household income grows at roughly the same rate as in the base case.

One other assumption was made for the high case: the Orlando area experiences stronger electricity demand due to an increase in computer-related loads. Implicit in the base case "other use" index is that computer loads increase at roughly 3 percent per year over the forecast horizon. This is based on Energy Information Administration (EIA) assumptions that have been incorporated into the EPRI COMMEND forecast model. Recently, there has been some debate as to the contribution of increased "computerization" to electric loads. In the high case scenario, we assume that computer loads increase at 6 percent annually. This results in the "other use" index (which is basically flat in the base case) increasing at a faster rate in the high case. Figure 1B.4-21 shows a comparison of the resulting change in the commercial "other use" index.

1B.4.5.2 Low Case Scenario

In the low case scenario, we assume that there is a significant slowdown in regional population growth. We assume that the growth in the number of households slows to 1.5 percent during the first 5 years, and declines further to a long-term growth rate of 0.9 percent. Moreover, we assume the unemployment rate averages 6.0 percent over the 20 year forecast horizon; this is not beyond the realm of possibility, given that Orlando's unemployment rate approached 8 percent during the summer of 1992. The higher unemployment rate translates into lower employment and economic output growth. Orlando's economic output is projected to increase less than 2 percent through

Figure 1B.4-21
Comparison of Commercial "Other Use" Index



forecast horizon. By way of comparison, growth in Orlando's gross product never dipped below 2.7 percent during the 1990s. Similarly, household income growth slows, with average household income growth remaining unchanged (in real terms) through the first 5 years, and not reaching the base case growth rate until after 2015.

1B.4.5.3 High and Low Forecast Scenario Results

Table 1B.4-20 summarizes the forecast scenario results, Table 1B.4-21 summarizes the total system peak forecast, and both provide a comparison with the base case. Through 2005, high case assumptions result in an overall sales growth rate of 3.6 percent, compared with the base case growth of 2.9 percent. The growth rates narrow somewhat over the longer term, with energy requirements increasing at a 2.8 percent pace in the high case, compared with a 2.1 percent average in the base case.

In the low case, sales slow to a 2.5 percent pace through 2005. Energy requirements further decline as a result of weak population and employment growth to a 1.6 percent growth between 2005 and 2010 and to a 1.3 percent pace after 2010.

Over the 20 year forecast horizon, the average growth rates in total electricity retail sales for the OUC and St. Cloud service territories are: 1.7 percent in the low case, 2.3 percent in the base case, and 3.0 percent in the high case.

Table 1B.4-20
Scenario Energy Forecast

Orlando Utilities Commission & St. Cloud

High Scenario - GWH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts.	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,186	399	3,400	36	17	100	6,139
2010	2,523	444	3,878	39	34	122	7,040
2015	2,905	497	4,429	42	51	145	8,070
2020	3,348	559	5,070	45	67	167	9,258
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	3.5%	2.5%	3.7%	1.6%	-	5.2%	3.6%
05-10	2.9%	2.2%	2.7%	1.6%	14.9%	4.1%	2.8%
10-15	2.9%	2.3%	2.7%	1.5%	8.4%	3.4%	2.8%
15-20	2.9%	2.4%	2.7%	1.4%	5.9%	2.9%	2.8%

Base Scenario - GWH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,093	387	3,301	36	17	100	5,934
2010	2,355	417	3,669	39	34	122	6,636
2015	2,648	452	4,035	42	51	145	7,374
2020	2,975	492	4,396	45	67	167	8,143
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	2.5%	1.8%	3.1%	1.8%	-	5.2%	2.9%
05-10	2.3%	1.4%	2.1%	1.7%	14.9%	4.1%	2.2%
10-15	2.3%	1.6%	1.9%	1.6%	8.4%	3.4%	2.1%
15-20	2.3%	1.7%	1.7%	1.5%	5.9%	2.9%	2.0%

Low Scenario - GWH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,026	361	3,262	36	17	100	5,802
2010	2,177	360	3,535	39	34	122	6,268
2015	2,338	359	3,771	42	51	145	6,705
2020	2,510	360	4,004	45	67	167	7,153
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	1.9%	0.5%	2.9%	1.8%	-	5.2%	2.5%
05-10	1.4%	0.0%	1.6%	1.7%	14.9%	4.1%	1.6%
10-15	1.4%	-0.1%	1.3%	1.6%	8.4%	3.4%	1.3%
15-20	1.4%	0.0%	1.2%	1.5%	5.9%	2.9%	1.3%

Table 1B.4-21
Scenario Peak Forecast

Total System Peak Forecast

High Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,265	1,273	6,384
2010	1,453	1,465	7,333
2015	1,662	1,673	8,392
2020	1,903	1,915	9,623
Average chg	Percent	Percent	Percent
95-00	4.3%	3.7%	4.1 %
00-05	3.6%	3.9%	3.5%
05-10	2.8%	2.8%	2.8%
10-15	2.7%	2.7%	2.7%
15-20	2.8%	2.7%	2.8%

Base Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,227	1,239	6,192
2010	1,372	1,386	6,925
2015	1,522	1,539	7,692
2020	1,679	1,697	8,492
chg			
95-00	4.3%	3.7%	4.1%
00-05	2.9%	3.3%	2.9%
05-10	2.3%	2.3%	2.3%
10-15	2.1%	2.1%	2.1%
15-20	2.0%	2.0%	2.0%

Low Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,177	1,193	5,940
2010	1,259	1,279	6,359
2015	1,338	1,358	6,763
2020	1,419	1,440	7,178
chg			
95-00	4.3%	3.7%	4.1%
00-05	2.1%	2.6%	2.1%
05-10	1.4%	1.4%	1.4%
10-15	1.2%	1.2%	1.2%
15-20	1.2%	1.2%	1.2%

1B.5.0 Demand-Side Analysis

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (FPSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, OUC has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the PSC-approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

Throughout its history, OUC has demonstrated a strong commitment to serve its customers' conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. The demand-side management goals for OUC were approved by the FPSC on March 23, 2000, by Order No. PSC-00-0587-FOF-EG. The evaluations for this docket indicated that there were no cost-effective conservation measures available for OUC. As a result, the FPSC approved zero goals for OUC for the residential and commercial/industrial sectors as presented in Table 1B.5-1. Nevertheless, OUC proposed to continue existing programs feeling that they were in the overall best interest of OUC's customers. The FPSC goals for OUC and the programs, implemented to meet these goals are presented briefly in this section and in greater detail in OUC's 2000 Demand-Side Management Plan filed in Docket No. 990722-EG.

1B.5.1 Existing Conservation Programs

There have been significant changes in the market place in the last 5 years. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Economic conditions have also changed significantly; for example, the cost of power plants and interest rates have decreased drastically. As a result, conservation programs are significantly less cost-effective. OUC's existing programs include the following:

- Residential Energy Survey Program.
- Residential Heat Pump Program.
- Residential Weatherization Program.
- Low Income Home Energy Fixup Program.
- Educational Outreach Program.
- Commercial Energy Survey Program.

Table 1B.5-1
Total Conservation Goals Approved by the FPSC

	Residential			Commercial / Industrial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
1999						
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0

1B.5.1.1 Residential Energy Survey

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. The Residential Energy Survey includes complete attic, air duct, and air return inspections. The customer is given a choice to receive either a low-flow showerhead or compact fluorescent bulb. OUC energy analysts are presently using this walk-through type audit as a means to get OUC customers to participate in other conservation programs and to qualify for appropriate rebates. Customers may also choose to perform their own energy audit by requesting a copy of OUC's home energy audit video. This video will soon be available in an interactive CD format. Beginning in the first quarter of 2001, an Internet interactive home energy audit complete with previous billing information on the customer will be available.

1B.5.1.2 Residential Heat Pump Program

Heat pumps are marketed to the owners of existing residential strip heating systems and older, inefficient central air conditioners and heat pumps. The program requires heat pumps with a SEER of 11 (or greater) and a HSPF of 7.0 (or greater) in order to qualify for rebates. Rebates vary by equipment SEER levels. One of the main

benefits of the program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

1B.5.1.3 Residential Weatherization Program

This program is designed for existing single family homes and promotes R-19 ceiling insulation (or higher), caulking, weather-stripping, window treatment, water heater insulation, and air condition/heating supply and return air duct repair. The customer can receive a $140 rebate for installing R-19 ceiling insulation (or higher), $100 rebate for duct repairs, and up to $110 for other conservation measures specified above. In addition, the customer is allowed to carry payments for ceiling insulation on their electric bill for 12 or 24 months. OUC directly pays the total cost for installation when OUC provides the financing.

The program is promoted through Residential Energy Surveys, trade shows, exhibits, and neighborhood meetings.

1B.5.1.4 Low Income Home Energy Fixup Program

This program targets residential customers with an annual income of less than $20,000. Every customer is eligible for an energy audit. Audit recommendations usually require the customer to spend money replacing or adding energy conservation measures. Low-income customers may not have the discretionary income to make these changes. The program will pay 85 percent of the total contract cost for home weatherization for the following measures:

- Upgrading ceiling insulation to R-19.
- Exterior and interior caulking.
- Weather-stripping doors and windows.
- Air conditioning/heating supply and return air duct repairs.
- Water heater insulation.

The purpose of the program is to reduce the energy cost for low income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy community.

1B.5.1.5 Education Outreach Program

This program is now entering its 15th year of operation. The program is very successful and has won several awards for contributions to education. The program consists of hour long classroom presentations focused on teaching students about energy

and water conservation. Students are taught how electricity is generated and are encouraged to perform mini electric and water audits on their own homes.

1B.5.1.6 Commercial Energy Survey Program

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. The program is focused on commercial customers to increase the energy efficiency and energy conservation. OUC has also developed an alliance with a large performance contractor in order to provide large commercial customers with a more complete solution to their needs.

1B.5.2 Analysis of Demand-Side Management Alternatives

OUC used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8. The results of that analysis are as follows.

1B.5.2.1 FIRE Model Output Analysis

OUC requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, OUC has concluded that there are no cost-effective DSM measures reasonably available that would avoid or defer the need for Stanton A. Table 1B.5-2 presents the FIRE model results of the DSM analysis.

Table 1B.5-2
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.49	1.00	2.33
Commercial			
Off-Peak Battery Charging	0.98	0.04	0.48

The results of the DSM analysis are not surprising due to the previously performed analysis for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for Cane Island Unit 3 (Docket

No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand Side Management Ten Year Plans for Orlando Utilities Commission (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1B.6.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand plus maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development of the reliability criteria used by OUC.

1B.6.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. The methods are discussed below.

1B.6.1.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand}}$$

From the equation, it is seen that should the net capacity or net peak demand deviate from the predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. A weakness with the formula is that it does not indicate what the appropriate reserve margin is for a given system; the appropriate reserve level must be determined elsewhere. The Florida Reliability Coordinating Council (FRCC) has set a minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Fla. Admin. Code as well for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criteria is generally consistent with practice through out much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning methodology.

1B.6.1.2 Loss of Load Probability

The second commonly-used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP) method. This method has the advantage that it can result in a measure of how much capacity (and reserves) are needed to meet a target level of reliability (most utilities adopt a LOLP of 1 day in 10 years). Given the

nature of OUC's relatively small, high interconnected system, LOLP for OUC's system is driven almost entirely by the interconnections. Since the reliability of the interconnections is driven by the capacity from other systems available to the interconnection, the reliability of interconnections is difficult to predict and is generally out of the control of OUC. For these reasons, OUC does not use LOLP as the reliability criterion and instead uses the reserve margin criterion. LOLP is much better suited for measuring reliability of large systems such as FRCC.

1B.6.2 Reliability Need

Since OUC has elected to use a 15 percent reserve margin criterion, OUC applies it to St. Cloud's load as well as partial requirements (PR) purchases and sales. Tables 1B.6-1 and 1B.6-2 display the forecast reserve margins for OUC and St. Cloud for the winter and summer seasons, respectively.

Table 1B.6-1 indicates that additional capacity will not be needed by the winter of 2002. Furthermore, Table 1B.6-2 shows that additional capacity will be necessary to satisfy forecast demand requirements for the summer of 2002. The majority of the capacity required in 2002 and 2003 can be satisfied by exercising the additional 10 percent option on the Reliant contract, which represents 52.5 MW. Regardless, OUC will need a substantial amount of capacity beginning with the expiration of the Reliant agreement on October 1, 2003.

Table 1B.6-1
OUC Winter Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1,051	440	1,491	1,092	608	1,700	208	168	40
2001	1,090	341	1,431	1,092	608	1,700	268	176	93
2002	1,144	323	1,467	1,092	540	1,632	165	184	(19)
2003	1,182	312	1,494	1,092	540	1,632	138	192	(54)
2004	1,210	263	1,473	1,092	15	1,107	-366	198	(564)
2005	1,239	172	1,411	1,071	15	1,086	-325	203	(528)
2006	1,267	139	1,406	1,071	15	1,086	-320	205	(525)
2007	1,292	139	1,431	1,071	15	1,086	-345	212	(558)
2008	1,323	142	1,465	1,071	15	1,086	-379	218	(597)
2009	1,356	144	1,500	1,071	15	1,086	-414	223	(637)
2010	1,386	146	1,532	1,071	15	1,086	-446	228	(673)
2011	1,416	0	1,416	1,071	15	1,086	-330	210	(540)
2012	1,449	0	1,449	1,071	15	1,086	-363	215	(578)
2013	1,480	0	1,480	1,071	0	1,071	-409	222	(631)
2014	1,512	0	1,512	1,071	0	1,071	-441	227	(667)
2015	1,542	0	1,542	1,071	0	1,071	-471	231	(702)
2016	1,572	0	1,572	1,071	0	1,071	-501	236	(737)
2017	1,608	0	1,608	1,071	0	1,071	-537	241	(779)
2018	1,643	0	1,643	1,071	0	1,071	-572	246	(818)
2019	1,675	0	1,675	1,071	0	1,071	-604	251	(855)

1. Includes St. Cloud.

Table 1B.6-2
OUC Summer Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1,062	440	1,502	1,047	608	1,653	153	170	(17)
2001	1,092	341	1,433	1,047	608	1,653	222	176	46
2002	1,136	323	1,459	1,047	540	1,585	128	183	(55)
2003	1,170	312	1,482	1,047	540	1,585	105	190	(85)
2004	1,197	263	1,460	1,047	15	1,060	-398	196	(593)
2005	1,227	172	1,399	1,025	15	1,039	-359	201	(560)
2006	1,254	139	1,393	1,025	15	1,039	-353	203	(557)
2007	1,278	139	1,417	1,025	15	1,039	-377	210	(587)
2008	1,306	142	1,448	1,025	15	1,039	-408	215	(623)
2009	1,339	144	1,483	1,025	15	1,039	-443	220	(663)
2010	1,372	146	1,518	1,025	15	1,039	-478	225	(703)
2011	1,399	0	1,399	1,025	15	1,039	-359	208	(567)
2012	1,428	0	1,428	1,025	15	1,039	-388	212	(600)
2013	1,463	0	1,463	1,025	15	1,039	-438	219	(658)
2014	1,495	0	1,495	1,025	0	1,024	-470	224	(695)
2015	1,526	0	1,526	1,025	0	1,024	-501	229	(730)
2016	1,557	0	1,557	1,025	0	1,024	-532	234	(766)
2017	1,591	0	1,591	1,025	0	1,024	-566	239	(805)
2018	1,625	0	1,625	1,025	0	1,024	-600	244	(844)
2019	1,656	0	1,656	1,025	0	1,024	-631	248	(879)

1. Includes St. Cloud.

1B.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of OUC's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine OUC's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluation analyses are presented in Section 1B.5.0. The proposal evaluations are presented in Section 1A.6. The sensitivity analyses are discussed in Section 1B.8.0.

1B.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan. OUC's and St. Cloud's systems were combined for purposes of expansion planning.

1B.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation represent the conventional alternatives presented in Section 1A.7. Table 1B.7-1 summarizes the expansion alternatives considered for OUC in the optimization study for supply-side alternatives.

Table 1B.7-1
Summary of OUC Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal	513,163	446	3.73	14.17	Coal	9,979	3.0	30	2006
Fluidized Bed	366,076	267	5.53	23.55	Pet. Coke	10,543	3.0	28	2005
501F 2x1 CC (standard)	275,756[4]	514	[redacted]	[redacted]	Nat. Gas	7,074	4.0	[redacted]	2005
501F 2x1 CC (oversized)	288,211[4]	610	[redacted]	[redacted]	Nat. Gas	7,542	4.0	[redacted]	2005
7FA SC	68,615	156	2.33	5.13	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[3]	232,169[4]	488	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[3]	[redacted]	171	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	[redacted]	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. (2003 $)
3. Reflects OUC's portion of total generation alternative capacity.
4. Mixed year dollars to reflect commercial operation date of October 1, 2003.
5. October 1, 2003.

1B.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7 and summarized in Table 1B.7-1. Production costs were modeled at temperatures which closely approximate (within 2 degrees) the average annual temperature for OUC. Winter and summer unit ratings were used to determine capacity requirements.

The expansion plan outlined in Table 1B.7-2 shows that the joint development project with Southern-Florida is the least-cost capacity addition plan for OUC under the base case scenario. For comparison purposes, Table 1B7-3 displays the least-cost expansion capacity addition plan for OUC that does not include the joint-development project with Southern-Florida. The units and power purchases comprising the expansion plans are listed in the tables according to their year of commercial operation. Tables 1B.7-4 through 1B.7-7 present the summer and winter capacity balances for the expansion plans presented in Tables 1B.7-2 and 1B.7-3, respectively. Appendix 1B.B presents tables showing the fuel, O&M, and capital costs for expansion plans on an annual basis.

The addition of the Southern-Florida joint development project and the self-build General Electric 7FA 2x1 combined cycle represent the only two available alternatives that allow OUC to meet OUC's reserve requirements in 2004. In fact, even the self-build General Electric 7FA 2x1 combined cycle is no longer an option because it was based on obtaining the General Electric 7FA combustion turbines that KUA had under option with General Electric. The option for the two General Electric 7FA combustion turbines expired on September 30, 2000. However, the option was available during the time that OUC was evaluating the joint development and purchase power proposals and is presented to demonstrate the prudence of the selection of the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement does not provide sufficient capacity for OUC to meet its capacity requirements in 2004 without the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement would still result in a 93 MW shortfall for OUC in the summer of 2004 as demonstrated by Table 1B.6-2. OUC is precluded from installing other options until at least 2005 as shown in Table 1B.7-1 due to the delivery schedule for combustion turbines.

It is clear from a comparison of Tables 1B.7-2 and 1B.7-3 that the joint development project with Southern-Florida provides the most cost-effective solution to satisfy OUC's forecast capacity requirements. The joint development project with Southern-Florida results in a projected $6.925 million in cumulative present worth savings over the self-build alternative while providing the flexibility and strategic advantages discussed in Section 1A.6.4.

Table 1B.7-2
OUC Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,238	294,507
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,346	441,409
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	182,414	586,216
2004	171 MW Joint Development with Southern – Florida (10/03)	220,125	748,014
	317 MW Southern – Florida Power Purchase (10/03)		
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	221,724	898,915
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	216,619	1,035,422
2007	156 MW GE 7FA Simple Cycle (06/07)	230,334	1,169,819
2008	156 MW GE 7FA Simple Cycle (06/08)	245,040	1,302,207
2009		264,023	1,434,284
2010		271,624	1,560,098
2011		280,395	1,680,355
2012		294,709	1,797,388
2013	Terminate 317 MW Southern – Florida Power Purchase (11/13)	306,249	1,909,995
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		333,329	2,023,481
2015		348,185	2,133,243
2016		360,765	2,238,547
2017		374,692	2,339,814
2018		393,339	2,438,247
2019		413,511	2,534,062

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.7-3
OUC Base Case Expansion Plan – Runner Up #1

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,238	294,507
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,346	441,409
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	183,514	587,088
2004	488 MW Self-Build GE 7FA 2x1 (10/03)	219,155	748,174
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	220,767	898,424
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	218,188	1,035,919
2007	156 MW GE 7FA Simple Cycle (06/07)	233,111	1,171,938
2008	156 MW GE 7FA Simple Cycle (06/08)	243,714	1,303,609
2009		263,213	1,435,281
2010		271,205	1,560,901
2011		278,923	1,680,526
2012		294,851	1,797,616
2013		307,495	1,910,681
2014		339,450	2,026,250
2015		339,155	2,133,166
2016	156 MW GE 7FA Simple Cycle (06/16)	364,773	2,239,640
2017		378,698	2,341,990
2018		406,327	2,443,673
2019		419,978	2,540,987

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.7-4
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1213	465	1679	219	196	23
2005	1227	172	1399	1192	449	1641	242	201	41
2006	1254	139	1393	1192	434	1626	233	203	29
2007	1278	139	1417	1332	324	1656	239	210	28
2008	1306	142	1448	1472	324	1796	348	215	133
2009	1339	144	1483	1472	324	1796	313	220	92
2010	1372	146	1518	1472	324	1796	278	225	53
2011	1399	0	1399	1472	324	1796	396	208	189
2012	1428	0	1428	1472	324	1796	368	212	156
2013	1463	0	1463	1472	309	1781	318	219	98
2014	1495	0	1495	1953	0	1953	457	224	233
2015	1526	0	1526	1953	0	1953	427	229	198
2016	1557	0	1557	1953	0	1953	395	234	162
2017	1591	0	1591	1953	0	1953	361	239	123
2018	1625	0	1625	1953	0	1953	328	244	84
2019	1656	0	1656	1953	0	1953	297	248	48

[1]Includes St. Cloud.

Table 1B.7-5
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1273	492	1765	293	198	95
2005	1239	172	1411	1252	476	1729	317	203	114
2006	1267	139	1406	1252	461	1714	308	205	103
2007	1292	139	1431	1427	351	1779	348	212	135
2008	1323	142	1465	1602	351	1954	489	218	271
2009	1356	144	1500	1602	351	1954	454	223	231
2010	1386	146	1532	1602	351	1954	422	228	194
2011	1416	0	1416	1602	351	1954	537	210	327
2012	1449	0	1449	1602	351	1954	505	215	290
2013	1480	0	1480	1602	336	1939	458	222	236
2014	1512	0	1512	2166	0	2166	655	227	428
2015	1542	0	1542	2166	0	2166	624	231	393
2016	1572	0	1572	2166	0	2166	594	236	358
2017	1608	0	1608	2166	0	2166	558	241	316
2018	1643	0	1643	2166	0	2166	523	246	277
2019	1675	0	1675	2166	0	2166	491	251	240

[1]Includes St. Cloud.

Table 1B.7-6
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1523	156	1679	219	196	23
2005	1227	172	1399	1501	140	1641	242	201	41
2006	1254	139	1393	1501	125	1626	233	203	29
2007	1278	139	1417	1641	15	1656	239	210	28
2008	1306	142	1448	1781	15	1796	348	215	133
2009	1339	144	1483	1781	15	1796	313	220	92
2010	1372	146	1518	1781	15	1796	278	225	53
2011	1399	0	1399	1781	15	1796	396	208	189
2012	1428	0	1428	1781	15	1796	368	212	156
2013	1463	0	1463	1781	0	1781	318	219	98
2014	1495	0	1495	1781	0	1781	285	224	61
2015	1526	0	1526	1781	0	1781	255	229	26
2016	1557	0	1557	1921	0	1921	363	234	130
2017	1591	0	1591	1921	0	1921	330	239	91
2018	1625	0	1625	1921	0	1921	296	244	52
2019	1656	0	1656	1921	0	1921	265	248	17

[1]Includes St. Cloud.

Table 1B.7-7
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1609	156	1765	293	198	95
2005	1239	172	1411	1589	140	1729	317	203	114
2006	1267	139	1406	1589	125	1714	308	205	103
2007	1292	139	1431	1764	15	1779	348	212	135
2008	1323	142	1465	1939	15	1954	489	218	271
2009	1356	144	1500	1939	15	1954	454	223	231
2010	1386	146	1532	1939	15	1954	422	228	194
2011	1416	0	1416	1939	15	1954	537	210	327
2012	1449	0	1449	1939	15	1954	505	215	290
2013	1480	0	1480	1939	0	1939	458	222	236
2014	1512	0	1512	1939	0	1939	427	227	200
2015	1542	0	1542	1939	0	1939	397	231	166
2016	1572	0	1572	1939	0	1939	366	236	130
2017	1608	0	1608	2114	0	2114	505	241	264
2018	1643	0	1643	2114	0	2114	471	246	224
2019	1675	0	1675	2114	0	2114	439	251	187

[1]Includes St. Cloud.

1B.8.0 Sensitivity Analysis

OUC performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1B.8.1 through 1B.8.7 and include low and high fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1B.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1B.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1B.8-2 presents the runner-up expansion plan. The planning including the joint development alternative is $18.9 million lower than the plan with the self-build alternative indicating the benefit of flexibility with the joint development project.

1B.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1B.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1B.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $4.4 million cumulative present worth savings over the self-build plan.

1B.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1B.8-5. Table 1B.8-6 presents the

the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $27 million lower in cumulative present worth cost.

1B.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1B.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1B.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows its increasing value with a $28 million savings over the plan with the self-build project.

1B.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1B.8-9 and Table 1B.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $9 million.

1B.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1B.4. Tables 1B.8-11 and 1B.8-12 indicate the summer and winter need for capacity based upon the high load and energy forecast.

As indicated in Table 1B.8-11, the high load and energy growth scenario results in a 59 MW capacity shortfall in the summer of 2002. Since the only option available to OUC for the summer of 2002 and 2003 is the additional 52.5 MW purchase from the Reliant Agreement, it has been assumed that OUC will purchase power on the spot market to make up the resultant deficit.

As indicated in Table 1B.8-12, the high load and energy growth scenario results in a capacity shortfall in the winter of 2002. The additional 52.5 MW purchase from the Reliant Agreement will satisfy OUC's needs for the winter of 2002 as well as for the winter of 2003.

Table 1B.8-13 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1B.8-14 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the self-build alternative is $24.4 million lower in cost than the plan including joint development project. It is not surprising that continued assured high growth would favor the self-build plan. The joint development project has been structured to provide relatively greater protection to OUC in scenarios that would have negative consequences such as loss of retail load or increases in the cost of fuel than it would be scenarios that would have positive consequences such as higher load growth or lower fuel prices.

1B.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1B.4.0. Tables 1B.8-15 and 1B.8-16 indicate the summer and winter need for capacity based upon the low load and energy forecast.

Capacity is required beginning in the summer of 2002 and the winter of 2004 for the low load and energy forecast. The extension of the 52.5 MW Reliant Agreement option will satisfy OUC's capacity requirements in the summer of 2002 and 2003 for the low load and energy growth scenario.

Table 1B.8-17 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1B.8-18 presents the runner-up expansion plan. Over the entire 20 year planning horizon, the cumulative present worth cost of the joint development alternative is only $68,000 over the cost of the self-build alternative. Notably, closer examination of Tables 1B.8-17 and 1B.8-18 indicate that the joint development alternative was lower in cumulative present worth cost every year until 2019. As discussed in Section 1A.4.1, the PPA has provisions for reducing the contract demand beginning in the sixth year. While this provision has not been explicitly evaluated, it would have significant economic benefit to OUC in a scenario such as this with low load and energy growth.

Table 1B.8-1
OUC High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,289	296,406
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,171	448,301
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	191,164	600,054
2004	171 MW Joint Development with Southern–Florida (10/03)	231,516	770,225
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	235,960	930,815
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	233,733	1,078,107
2007	156 MW GE 7FA SC (06/07)	251,687	1,224,964
2008	156 MW GE 7FA SC (06/08)	270,915	1,371,331
2009		295,247	1,519,028
2010		307,799	1,661,598
2011		323,212	1,800,218
2012		344,259	1,936,929
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	363,258	2,070,498
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		396,384	2,205,451
2015		419,684	2,337,753
2016		441,382	2,466,588
2017		465,221	2,592,323
2018		496,565	2,716,588
2019		529,979	2,839,391

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-2
OUC High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,289	296,406
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,171	448,301
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	192,307	600,961
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	230,839	770,634
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	235,521	930,926
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	235,852	1,079,552
2007	156 MW GE 7FA Simple Cycle (06/07)	254,957	1,228,317
2008	156 MW GE 7FA Simple Cycle (06/08)	270,225	1,374,311
2009		294,810	1,521,790
2010		307,904	1,664,409
2011		322,025	1,802,520
2012		344,937	1,939,499
2013		365,063	2,073,732
2014		405,479	2,211,782
2015		414,694	2,342,511
2016	156 MW GE 7FA Simple Cycle (06/16)	451,016	2,474,158
2017		475,406	2,602,645
2018		518,102	2,732,300
2019		544,055	2,858,364

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-3
OUC Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,185	292,606
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,925	434,002
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,546	571,769
2004	171 MW Joint Development with Southern–Florida (10/03)	209,053	725,429
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	207,624	866,734
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	200,591	993,140
2007	156 MW GE 7FA SC (06/07)	210,874	1,116,183
2008	156 MW GE 7FA SC (06/08)	221,690	1,235,955
2009		236,622	1,354,325
2010		240,421	1,465,687
2011		245,689	1,571,058
2012		254,781	1,672,235
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	261,501	1,768,389
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		283,548	1,864,926
2015		292,001	1,956,977
2016		298,822	2,044,200
2017		306,041	2,126,913
2018		317,550	2,206,380
2019		328,694	2,282,542

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-4
OUC Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,185	292,606
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,925	434,002
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	174,598	572,604
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	208,324	725,728
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	206,980	866,596
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	202,613	994,276
2007	156 MW GE 7FA Simple Cycle (06/07)	213,997	1,119,141
2008	156 MW GE 7FA Simple Cycle (06/08)	220,775	1,238,419
2009		235,859	1,356,407
2010		240,138	1,467,638
2011		244,155	1,572,351
2012		254,857	1,673,558
2013		262,395	1,770,041
2014		288,183	1,868,156
2015		281,862	1,957,010
2016	156 MW GE 7FA Simple Cycle (06/16)	300,532	2,044,733
2017		308,417	2,128,088
2018		326,864	2,209,886
2019		332,718	2,286,980

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,908	118,908
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,708	232,527
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	132,497	346,122
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	151,522	466,405
2004	171 MW Joint Development with Southern–Florida (10/03)	197,457	611,541
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	199,966	747,635
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	193,452	869,543
2007	156 MW GE 7FA Simple Cycle (06/07)	206,116	989,809
2008	156 MW GE 7FA Simple Cycle (06/08)	219,525	1,108,411
2009		240,175	1,228,559
2010		247,005	1,342,970
2011		253,273	1,451,594
2012		265,287	1,556,943
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	276,371	1,658,564
	446 MW Pulverized Coal (11/13)		
2014		304,969	1,762,394
2015		313,858	1,861,336
2016		322,682	1,955,523
2017		330,997	2,044,982
2018		345,025	2,131,324
2019		362,463	2,215,311

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-6
OUC AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,908	118,908
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,708	232,527
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	132,497	346,122
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	152,409	467,109
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	196,586	611,605
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	198,849	746,938
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	195,519	870,148
2007	156 MW GE 7FA Simple Cycle (06/07)	209,159	992,191
2008	156 MW GE 7FA Simple Cycle (06/08)	218,328	1,110,147
2009		239,495	1,229,954
2010		246,794	1,344,267
2011		251,727	1,452,229
2012		265,525	1,557,672
2013		279,765	1,660,541
2014		312,218	1,766,839
2015		311,659	1,865,087
2016	156 MW GE 7FA Simple Cycle (06/16)	335,802	1,963,104
2017		349,077	2,057,449
2018		376,073	2,151,561
2019		391,644	2,242,309

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,459	282,961
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,025	437,303
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	203,037	598,480
2004	171 MW Joint Development with Southern–Florida (10/03)	253,491	784,804
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	257,005	959,717
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	249,138	1,116,716
2007	446 MW Pulverized Coal (06/07)	268,688	1,273,494
2008		287,446	1,428,792
2009		301,604	1,579,669
2010		309,986	1,723,252
2011		315,982	1,858,772
2012		327,314	1,988,753
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	340,116	2,113,813
	156 MW GE 7FA Simple Cycle (11/13)		
2014		338,576	2,229,085
2015		349,387	2,339,226
2016	156 MW GE 7FA Simple Cycle (06/08)	367,064	2,446,368
2017		382,871	2,549,847
2018		402,612	2,650,600
2019		428,000	2,749,773

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,459	282,961
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,025	437,303
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	201,973	597,636
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	251,771	782,695
	100 MW Reliant Power Purchase (10/03 - 09/04)	256,974	957,587
2005	100 MW Reliant Power Purchase (10/04 - 09/05)		
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	251,494	1,116,071
2007	446 MW Pulverized Coal (06/07)	266,697	1,271,686
2008		285,234	1,425,789
2009		301,513	1,576,620
2010		310,517	1,720,450
2011		313,384	1,854,855
2012		327,308	1,984,834
2013		344,237	2,111,409
2014		362,922	2,234,970
2015		369,969	2,351,599
2016		390,049	2,465,451
2017		395,341	2,572,299
2018		412,722	2,675,583
2019		440,339	2,777,614

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	197,052	589,686
2004	171 MW Joint Development with Southern–Florida (10/03)	247,056	771,280
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	251,529	942,466
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	244,615	1,096,615
2007	156 MW GE 7FS Simple Cycle (06/07)	260,608	1,248,677
2008	156 MW GE 7FS Simple Cycle (06/08)	276,878	1,398,266
2009		303,257	1,549,970
2010		311,701	1,694,348
2011		319,979	1,831,581
2012		335,338	1,964,749
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	349,905	2,093,408
	446 MW Pulverized Coal (11/13)		
2014		380,309	2,222,888
2015		392,229	2,346,535
2016		407,450	2,465,466
2017		416,981	2,578,163
2018		431,843	2,686,231
2019		452,146	2,790,999

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	196,022	588,868
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	245,124	769,042
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	250,986	939,859
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	246,819	1,095,397
2007	267 MW Circulating Fluidized Bed (06/07)	270,023	1,252,952
2008		283,728	1,406,242
2009		303,691	1,558,163
2010		311,841	1,702,606
2011		317,723	1,838,872
2012		333,218	1,971,197
2013		350,713	2,100,154
2014		383,039	2,230,564
2015		385,175	2,351,987
2016	156 MW GE 7FA Simple Cycle (06/16)	407,963	2,471,067
2017		418,305	2,584,122
2018		439,226	2,694,038
2019		457,245	2,799,987

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-11
OUC Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1100	341	1441	1047	608	1655	214	177	37
2002	1139	323	1462	1047	540	1587	125	184	(59)
2003	1180	312	1492	1047	540	1587	95	191	(96)
2004	1222	263	1485	1047	15	1062	-423	199	(622)
2005	1265	172	1437	1025	15	1040	-397	207	(604)
2006	1301	139	1440	1025	15	1040	-400	210	(610)
2007	1337	139	1476	1025	15	1040	-436	219	(655)
2008	1375	142	1517	1025	15	1040	-477	225	(702)
2009	1413	144	1557	1025	15	1040	-517	231	(749)
2010	1453	146	1599	1025	15	1040	-559	238	(797)
2011	1493	0	1493	1025	0	1025	-468	224	(691)
2012	1533	0	1533	1025	0	1025	-508	230	(738)
2013	1575	0	1575	1025	0	1025	-550	236	(786)
2014	1618	0	1618	1025	0	1025	-593	243	(836)
2015	1662	0	1662	1025	0	1025	-637	249	(886)
2016	1708	0	1708	1025	0	1025	-683	256	(939)
2017	1755	0	1755	1025	0	1025	-730	263	(993)
2018	1803	0	1803	1025	0	1025	-778	270	(1048)
2019	1852	0	1852	1025	0	1025	-827	278	(1105)

Table 1B.8-12
OUC Winter Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1092	341	1433	1092	608	1700	267	176	91
2002	1135	323	1458	1092	540	1632	174	183	(9)
2003	1179	312	1491	1092	540	1632	141	191	(51)
2004	1225	263	1488	1092	15	1107	-381	200	(581)
2005	1273	172	1445	1071	15	1086	-359	208	(567)
2006	1309	139	1448	1071	15	1086	-362	212	(574)
2007	1347	139	1486	1071	15	1086	-400	221	(621)
2008	1386	142	1528	1071	15	1086	-442	227	(668)
2009	1425	144	1569	1071	15	1086	-483	233	(716)
2010	1466	146	1612	1071	15	1086	-526	240	(766)
2011	1505	0	1505	1071	0	1071	-434	226	(660)
2012	1546	0	1546	1071	0	1071	-475	232	(707)
2013	1587	0	1587	1071	0	1071	-516	238	(755)
2014	1630	0	1630	1071	0	1071	-559	245	(804)
2015	1674	0	1674	1071	0	1071	-603	251	(854)
2016	1720	0	1720	1071	0	1071	-649	258	(907)
2017	1767	0	1767	1071	0	1071	-696	265	(961)
2018	1815	0	1815	1071	0	1071	-744	272	(1017)
2019	1865	0	1865	1071	0	1071	-794	280	(1074)

Table 1B.8-13
OUC High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,315	295,504
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,583	444,324
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,934	593,718
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	224,984	758,088
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	230,989	915,295
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	226,773	1,058,201
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	244,413	1,200,813
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	258,724	1,340,594
2009		286,270	1,483,800
2010		296,837	1,621,293
2011		306,477	1,752,736
2012		322,542	1,880,822
2013		337,271	2,004,836
2014		359,225	2,127,138
2015		370,994	2,244,090
2016		391,488	2,358,362
2017		412,787	2,469,926
2018		433,819	2,578,488
2019	156 MW GE 7FA Simple Cycle (06/19)	459,965	2,685,068

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-14
OUC High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,315	295,504
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,583	444,324
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,878	592,674
2004	171 MW Joint Development with Southern-Florida (10/03)	229,335	761,242
	317 MW Southern-Florida Power Purchase (10/03)		
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	232,478	919,462
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	229,257	1,063,933
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	246,606	1,207,825
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	259,828	1,348,202
2009		288,881	1,492,714
2010		299,302	1,631,349
2011		308,461	1,763,642
2012		324,990	1,892,700
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	336,629	2,016,478
	156 MW GE 7FA Simple Cycle (11/13)		
2014		346,693	2,134,514
2015	156 MW GE 7FA Simple Cycle (06/15)	369,997	2,251,152
2016		391,959	2,365,561
2017		415,571	2,477,877
2018	267 MW Circulating Fluidized Bed (06/18)	459,699	2,592,916
2019		502,907	2,709,446

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-15
OUC Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1084	341	1425	1047	608	1655	230	175	55
2002	1106	323	1429	1047	540	1587	158	179	(21)
2003	1129	312	1441	1047	540	1587	146	184	(38)
2004	1152	263	1415	1047	15	1062	-353	189	(542)
2005	1176	172	1348	1025	15	1040	-308	194	(502)
2006	1192	139	1331	1025	15	1040	-291	194	(485)
2007	1209	139	1348	1025	15	1040	-308	200	(508)
2008	1226	142	1368	1025	15	1040	-328	203	(531)
2009	1243	144	1387	1025	15	1040	-347	206	(552)
2010	1260	146	1406	1025	15	1040	-366	209	(575)
2011	1275	0	1275	1025	0	1025	-250	191	(442)
2012	1291	0	1291	1025	0	1025	-266	194	(460)
2013	1307	0	1307	1025	0	1025	-282	196	(478)
2014	1323	0	1323	1025	0	1025	-298	198	(496)
2015	1339	0	1339	1025	0	1025	-314	201	(515)
2016	1355	0	1355	1025	0	1025	-330	203	(533)
2017	1371	0	1371	1025	0	1025	-346	206	(551)
2018	1387	0	1387	1025	0	1025	-362	208	(570)
2019	1403	0	1403	1025	0	1025	-378	211	(589)

Table 1B.8-16
OUC Winter Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1078	341	1419	1092	608	1700	281	174	107
2002	1106	323	1429	1092	540	1632	203	179	24
2003	1134	312	1446	1092	540	1632	186	184	1
2004	1163	263	1426	1092	15	1107	-319	191	(510)
2005	1193	172	1365	1071	15	1086	-279	196	(475)
2006	1210	139	1349	1071	15	1086	-263	197	(459)
2007	1227	139	1366	1071	15	1086	-280	203	(482)
2008	1244	142	1386	1071	15	1086	-300	206	(506)
2009	1261	144	1405	1071	15	1086	-319	209	(528)
2010	1279	146	1425	1071	15	1086	-339	212	(551)
2011	1294	0	1294	1071	0	1071	-223	194	(418)
2012	1310	0	1310	1071	0	1071	-239	197	(436)
2013	1326	0	1326	1071	0	1071	-255	199	(454)
2014	1342	0	1342	1071	0	1071	-271	201	(472)
2015	1358	0	1358	1071	0	1071	-287	204	(491)
2016	1374	0	1374	1071	0	1071	-303	206	(509)
2017	1390	0	1390	1071	0	1071	-319	209	(528)
2018	1407	0	1407	1071	0	1071	-336	211	(547)
2019	1423	0	1423	1071	0	1071	-352	213	(566)

Table 1B.8-17
OUC Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,757	437,020
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	176,683	577,276
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	211,624	732,826
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,824	878,352
2006		207,424	1,009,064
2007	156 MW GE 7FA SC (06/07)	211,585	1,132,522
2008		220,912	1,251,874
2009		239,899	1,371,883
2010		241,165	1,483,589
2011		246,476	1,589,298
2012		259,106	1,692,193
2013		268,149	1,790,791
2014		299,017	1,892,594
2015		292,159	1,984,695
2016		313,582	2,076,226
2017		307,061	2,159,215
2018		333,532	2,242,682
2019		339,328	2,321,308

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-18
OUC Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,757	437,020
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,098	574,430
2004	171 MW Joint Development with Southern–Florida (10/03)	214,185	731,863
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,374	877,082
2006		203,692	1,005,442
2007	156 MW GE 7FA SC (06/07)	216,845	1,131,969
2008		225,042	1,253,552
2009		237,138	1,372,180
2010		241,196	1,483,901
2011		247,667	1,590,121
2012		259,560	1,693,195
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	264,093	1,790,302
	Extension of 317 MW Southern-Florida Power Purchase (11/13)		
2014		297,971	1,891,750
2015		291,445	1,983,625
2016		313,141	2,075,028
2017		308,630	2,158,441
2018	Terminate 317 MW Southern–Florida Power Purchase (11/18)	331,107	2,241,300
	514 MW WH 501F 2x1 Combined Cycle (11/18)	345,582	2,321,376
2019			

Note: Capacity is stated at average annual temperature for OUC.

1B.9.0 Financial Analysis

OUC has not made a final decision regarding financing OUC's 28 percent equity share of Stanton A. In order to be conservative for evaluation purposes, OUC's weighted average cost of capital of approximately 8 percent was assumed. Actual financing alternatives for Stanton A include either using available cash from the Indian River Steam Unit sale or some form of taxable or tax exempt financing.

OUC's strong financial position will support either mode of financing. OUC's current senior lien bond ratings are AA^+, Aal, and AA from Fitch Investors Services, Moody's Investors Service, and Standard & Poor's, respectively. In 2000, OUC's operating revenues were $501.1 million, with a net income of $51.3 million and a combined debt service coverage rate of 2.23.

Appendix 1B.A
Load Forecast Model Statistics

Appendix 1B.A
Load Forecast Model Statistics

Project:	**D:\2000 Projects\OUC\Ouc Res.NDM**
Model:	**ResCust**
Dependent Variable:	**ResCust**
Date:	**October 03, 2000**
Time:	**09:19 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	5348.693	5290.065	1.011	31%
HH_OR	198.901	9.832	20.231	0%
Nov98	-1199.404	235.434	-5.094	0%
AR(1)	0.874	0.070	12.434	0%

Regression Statistics

Iterations	5
Adjusted Observations	95
Deg. of Freedom for Error	91
R-Squared	0.997
Adjusted R-Squared	0.997
Durbin-Watson Statistic	2.056
Durbin-H Statistic	0.000
AIC	11.532
BIC	11.639
F-Statistic	11158.748
Prob (F-Statistic)	0.000
Log-Likelihood	-671.41
Model Sum of Squares	3273019663
Sum of Squared Errors	8897198
Mean Squared Error	97771.41
Std. Error of Regression	312.68
Mean Abs. Dev. (MAD)	205.10
Mean Abs. % Err. (MAPE)	0.18%
Ljung-Box Statistic	13.56
Prob (Ljung-Box)	0.956

Forecast Statistics

Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
HH_OR	198.901	531.488	0.952
Nov98	-1199.404	0.010	-0.000

Project:	**D:\2000 Projects\OUC\Ouc Res.NDM**
Model:	**ResAveUse**
Dependent Variable:	**ResAveUse**
Date:	**October 03, 2000**
Time:	**09:19 AM**
Estimation Begin Date:	**1990:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
Heating	0.217	0.033	6.660	0%
Cooling	0.126	0.014	9.117	0%
BaseUse	112.798	6.219	18.139	0%
Summer98	108.213	28.371	3.814	0%
January	72.406	24.339	2.975	0%
November	-59.667	23.704	-2.517	1%
Lag_Heating	0.384	0.030	12.604	0%
Lag_Cooling	0.187	0.012	15.768	0%

Regression Statistics	
Iterations	1
Adjusted Observations	95
Deg. of Freedom for Error	87
R-Squared	0.941
Adjusted R-Squared	0.936
Durbin-Watson Statistic	1.778
Durbin-H Statistic	0.000
AIC	7.999
BIC	8.214
F-Statistic	172.911
Prob (F-Statistic)	0.000
Log-Likelihood	-501.43
Model Sum of Squares	3802221
Sum of Squared Errors	239135
Mean Squared Error	2748.68
Std. Error of Regression	52.43
Mean Abs. Dev. (MAD)	38.09
Mean Abs. % Err. (MAPE)	3.62%
Ljung-Box Statistic	27.02
Prob (Ljung-Box)	0.304

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Heating	0.217	206.322	0.043
Cooling	0.126	1477.390	0.180
BaseUse	112.798	3.911	0.427
Summer98	108.213	0.042	0.004
January	72.406	0.074	0.005
November	-59.667	0.084	-0.005
Lag_Heating	0.384	208.644	0.078
Lag_Cooling	0.187	1476.739	0.268

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**GSNDAveUse**
Dependent Variable:	**GSNDAveUse**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1991:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
BaseUse	0.056	0.008	7.284	0%
Heating	0.030	0.014	2.147	3%
LagHeating	0.071	0.014	5.174	0%
Cooling	0.040	0.005	7.335	0%
LagCooling	0.070	0.005	13.094	0%
July94	400.066	74.395	5.378	0%
Aug94	-304.943	74.423	-4.097	0%
Sept97	739.825	75.805	9.760	0%
Jul98	-384.214	76.732	-5.007	0%
GSND_Reclass	-114.014	24.728	-4.611	0%
Mar96	-226.423	76.431	-2.962	0%
July99	3863.365	76.160	50.727	0%
Aug99	-4680.072	76.443	-61.223	0%
BaseUseTrend	-0.056	0.010	-5.370	0%

Regression Statistics	
Iterations	1
Adjusted Observations	95
Deg. of Freedom for Error	81
R-Squared	0.990
Adjusted R-Squared	0.988
Durbin-Watson Statistic	1.933
Durbin-H Statistic	0.777
AIC	8.721
BIC	9.097
F-Statistic	567.021
Prob (F-Statistic)	0.000
Log-Likelihood	-529.39
Model Sum of Squares	42486573
Sum of Squared Errors	433520
Mean Squared Error	5352.10
Std. Error of Regression	73.16
Mean Abs. Dev. (MAD)	50.34
Mean Abs. % Err. (MAPE)	2.82%
Ljung-Box Statistic	43.02
Prob (Ljung-Box)	0.010

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
BaseUse	0.056	88389.056	2.784
Heating	0.030	632.629	0.011
LagHeating	0.071	637.159	0.025
Cooling	0.040	4465.614	0.100
LagCooling	0.070	4463.285	0.176
July94	400.066	0.011	0.002
Aug94	-304.943	0.011	-0.002
Sept97	739.825	0.011	0.004

Variable	Coefficient	Mean	Elast
Jul98	-384.214	0.011	-0.002
GSND_Reclass	-114.014	0.305	-0.020
Mar96	-226.423	0.011	-0.001
July99	3863.365	0.011	0.023
Aug99	-4680.072	0.011	-0.028
BaseUseTrend	-0.056	66291.101	-2.073

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**GSND_Custs**
Dependent Variable:	**GSNDCust**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	9790.486	148.966	65.723	0%
EmpNonMfg	7.669	0.242	31.748	0%
GSND_Reclass	-200.192	36.368	-5.505	0%
Jan99	828.602	30.537	27.134	0%
AR(1)	0.777	0.063	12.345	0%

Regression Statistics	
Iterations	6
Adjusted Observations	110
Deg. of Freedom for Error	105
R-Squared	0.996
Adjusted R-Squared	0.996
Durbin-Watson Statistic	1.994
Durbin-H Statistic	0.000
AIC	7.353
BIC	7.475
F-Statistic	6871.524
Prob (F-Statistic)	0.000
Log-Likelihood	-555.48
Model Sum of Squares	41023002
Sum of Squared Errors	156713
Mean Squared Error	1492.50
Std. Error of Regression	38.63
Mean Abs. Dev. (MAD)	29.71
Mean Abs. % Err. (MAPE)	0.20%
Ljung-Box Statistic	20.03
Prob (Ljung-Box)	0.695

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
EmpNonMfg	7.669	630.827	0.332
GSND_Reclass	-200.192	0.261	-0.004
Jan99	828.602	0.009	0.001

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**GSD_Sales**
Dependent Variable:	**GSD_Sales**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	56947682.454	6698858.495	8.501	0%
Jun98	-45109277.510	7755986.845	-5.816	0%
Jul98	-26399324.042	7718486.933	-3.420	0%
Sept98	41393749.634	7666165.406	5.400	0%
July99	-55153601.306	7738781.619	-7.127	0%
Aug99	79706289.043	8476499.245	9.403	0%
GSD_Base	1399757.574	96781.109	14.463	0%
GSD_Cooling	15108.300	2425.338	6.229	0%
Lag_GSDCooling	16141.098	2331.346	6.924	0%
GSD_Heating	10249.511	5847.980	1.753	8%
Lag_GSDHeating	4604.901	5788.629	0.796	43%
Aug99_Later	5434470.575	4316377.243	1.259	21%

Regression Statistics	
Iterations	1
Adjusted Observations	95
Deg. of Freedom for Error	83
R-Squared	0.944
Adjusted R-Squared	0.937
Durbin-Watson Statistic	2.282
Durbin-H Statistic	0.000
AIC	31.737
BIC	32.060
F-Statistic	127.203
Prob (F-Statistic)	0.000
Log-Likelihood	-1613.16
Model Sum of Squares	75540701850192880
Sum of Squared Errors	4480945093362323
Mean Squared Error	53987290281473.77
Std. Error of Regression	7347604.39
Mean Abs. Dev. (MAD)	4925826.77
Mean Abs. % Err. (MAPE)	2.67%
Ljung-Box Statistic	53.11
Prob (Ljung-Box)	0.001

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Jun98	-45109277.510	0.011	-0.003
Jul98	-26399324.042	0.011	-0.002
Sept98	41393749.634	0.011	0.002
July99	-55153601.306	0.011	-0.003
Aug99	79706289.043	0.011	0.005
GSD_Base	1399757.574	65.779	0.499
GSD_Cooling	15108.300	1056.946	0.087
Lag_GSDCooling	16141.098	1056.297	0.092
GSD_Heating	10249.511	149.572	0.008
Lag_GSDHeating	4604.901	150.156	0.004

Variable	Coefficient	Mean	Elast
Aug99_Later	5434470.575	0.053	0.002

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**StLight_Sales**
Dependent Variable:	**StLts**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	2012876.659	42744.453	47.091	0%
TrendVar	49023.586	5960.946	8.224	0%
Apr96	-1918758.866	75238.299	-25.502	0%
may96	1923975.858	75232.163	25.574	0%
Nov96	4320205.696	75215.113	57.438	0%
Dec96	-4179920.384	75261.754	-55.538	0%
Sept98	-451587.739	75419.185	-5.988	0%
Dec98	1329406.097	75465.734	17.616	0%
oct98	-1806874.006	75424.021	-23.956	0%
Aug93	-488624.427	75800.292	-6.446	0%
SAR(1)	0.255	0.059	4.363	0%

Regression Statistics	
Iterations	5
Adjusted Observations	84
Deg. of Freedom for Error	73
R-Squared	0.991
Adjusted R-Squared	0.990
Durbin-Watson Statistic	0.910
Durbin-H Statistic	0.000
AIC	22.634
BIC	22.952
F-Statistic	831.655
Prob (F-Statistic)	0.000
Log-Likelihood	-1058.82
Model Sum of Squares	49770614244176
Sum of Squared Errors	436870549241
Mean Squared Error	5984528071.80
Std. Error of Regression	77359.73
Mean Abs. Dev. (MAD)	48373.95
Mean Abs. % Err. (MAPE)	2.11%
Ljung-Box Statistic	164.30
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
TrendVar	49023.586	6.042	0.128
Apr96	-1918758.866	0.010	-0.009
may96	1923975.858	0.010	0.009
Nov96	4320205.696	0.010	0.019
Dec96	-4179920.384	0.010	-0.019
Sept98	-451587.739	0.010	-0.002
Dec98	1329406.097	0.010	0.006
oct98	-1806874.006	0.010	-0.008
Aug93	-488624.427	0.010	-0.002

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**OUC_Use**
Dependent Variable:	**OUCUse**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	2735548.121	316080.643	8.655	0%
TrendVar	373651.537	51068.268	7.317	0%
Apr96	8454584.818	562206.729	15.038	0%
Jun98	-2445484.012	697965.815	-3.504	0%
Jul98	-1389289.650	701443.210	-1.981	5%
Sept98	3157306.679	548872.300	5.752	0%
January	-589874.272	245612.725	-2.402	2%
February	-909196.065	327059.646	-2.780	1%
March	-627157.412	327291.895	-1.916	6%
April	-354918.286	253821.606	-1.398	17%
MA(1)	0.798	0.097	8.216	0%
MA(2)	0.323	0.098	3.307	0%

Regression Statistics	
Iterations	22
Adjusted Observations	111
Deg. of Freedom for Error	99
R-Squared	0.849
Adjusted R-Squared	0.832
Durbin-Watson Statistic	1.874
Durbin-H Statistic	0.000
AIC	27.021
BIC	27.313
F-Statistic	50.572
Prob (F-Statistic)	0.000
Log-Likelihood	-1630.32
Model Sum of Squares	272880896985166
Sum of Squared Errors	48562894184925
Mean Squared Error	490534284696.21
Std. Error of Regression	700381.53
Mean Abs. Dev. (MAD)	430723.90
Mean Abs. % Err. (MAPE)	8.93%
Ljung-Box Statistic	13.14
Prob (Ljung-Box)	0.964

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
TrendVar	373651.537	5.417	0.439
Apr96	8454584.818	0.009	0.017
Jun98	-2445484.012	0.009	-0.005
Jul98	-1389289.650	0.009	-0.003
Sept98	3157306.679	0.009	0.006
January	-589874.272	0.081	-0.010
February	-909196.065	0.081	-0.016
March	-627157.412	0.081	-0.011
April	-354918.286	0.081	-0.006

Project:	**D:\2000 Projects\OUC\StCloud Res.NDM**
Model:	**ResAveUse**
Dependent Variable:	**ResAveUse**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:11**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
Heating	0.185	0.051	3.616	0%
Cooling	0.088	0.020	4.352	0%
Lag_Cooling	0.235	0.018	12.985	0%
Lag_Heating	0.354	0.045	7.928	0%
BaseUse	117.809	11.470	10.271	0%
January	75.456	29.020	2.600	1%
November	-52.951	28.639	-1.849	7%
Jun93	-134.633	69.134	-1.947	5%
Summer98	55.184	54.656	1.010	32%
Feb94	186.019	69.851	2.663	1%
After98	105.120	27.483	3.825	0%
MA(1)	0.432	0.104	4.140	0%

Regression Statistics	
Iterations	11
Adjusted Observations	94
Deg. of Freedom for Error	82
R-Squared	0.918
Adjusted R-Squared	0.906
Durbin-Watson Statistic	1.802
Durbin-H Statistic	0.000
AIC	8.754
BIC	9.078
F-Statistic	76.040
Prob (F-Statistic)	0.000
Log-Likelihood	-532.80
Model Sum of Squares	5132552
Sum of Squared Errors	461237
Mean Squared Error	5624.84
Std. Error of Regression	75.00
Mean Abs. Dev. (MAD)	57.91
Mean Abs. % Err. (MAPE)	5.55%
Ljung-Box Statistic	45.10
Prob (Ljung-Box)	0.006

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Heating	0.185	208.644	0.036
Cooling	0.088	1476.866	0.120
Lag_Cooling	0.235	1485.248	0.324
Lag_Heating	0.354	209.801	0.069
BaseUse	117.809	3.907	0.427
January	75.456	0.084	0.006
November	-52.951	0.084	-0.004
Jun93	-134.633	0.011	-0.001
Summer98	55.184	0.042	0.002
Feb94	186.019	0.011	0.002

Variable	Coefficient	Mean	Elast
After98	105.120	0.242	0.024

Project:	**D:\2000 Projects\OUC\StCloud Res.NDM**
Model:	**ResCust**
Dependent Variable:	**ResCust**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:11**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-2811.148	1188.330	-2.366	2%
January	-563.063	510.524	-1.103	27%
February	-466.123	473.617	-0.984	33%
March	567.573	473.630	1.198	23%
April	-636.382	473.761	-1.343	18%
May	-731.206	473.772	-1.543	13%
June	-476.667	473.830	-1.006	32%
July	-900.618	473.979	-1.900	6%
August	-433.281	474.029	-0.914	36%
September	-1319.827	473.699	-2.786	1%
October	12.129	461.947	0.026	98%
November	-1364.388	496.991	-2.745	1%
HH_OR	32.641	2.206	14.799	0%
MA(1)	-0.166	0.101	-1.644	10%
SMA(1)	0.380	0.099	3.846	0%

Regression Statistics	
Iterations	40
Adjusted Observations	110
Deg. of Freedom for Error	95
R-Squared	0.747
Adjusted R-Squared	0.709
Durbin-Watson Statistic	2.079
Durbin-H Statistic	0.000
AIC	13.358
BIC	13.726
F-Statistic	19.988
Prob (F-Statistic)	0.000
Log-Likelihood	-875.76
Model Sum of Squares	156059399
Sum of Squared Errors	52981729
Mean Squared Error	557702.41
Std. Error of Regression	746.79
Mean Abs. Dev. (MAD)	567.66
Mean Abs. % Err. (MAPE)	4.20%
Ljung-Box Statistic	52.57
Prob (Ljung-Box)	0.001

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
January	-563.063	0.082	-0.003
February	-466.123	0.082	-0.003
March	567.573	0.082	0.003
April	-636.382	0.082	-0.004
May	-731.206	0.082	-0.004
June	-476.667	0.082	-0.003
July	-900.618	0.082	-0.005

Variable	Coefficient	Mean	Elast
August	-433.281	0.082	-0.003
September	-1319.827	0.082	-0.008
October	12.129	0.091	0.000
November	-1364.388	0.091	-0.009
HH_OR	32.641	523.698	1.239

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSNDAveUse**
Dependent Variable:	**GSNDAveUse**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
BaseUse	0.153	0.006	24.178	0%
Heating	0.025	0.014	1.772	8%
Cooling	0.008	0.006	1.299	20%
LagHeating	0.009	0.020	0.449	65%
LagCooling	0.048	0.007	7.177	0%
March98	-172.982	66.198	-2.613	1%
Nov97	-222.707	67.501	-3.299	0%
Apr99	88.140	62.128	1.419	16%
Feb98	-140.253	65.995	-2.125	4%
Nov99	-193.779	68.049	-2.848	1%
Dec99	31.395	75.927	0.413	68%
Dec97	-421.379	69.926	-6.026	0%
AR(1)	0.431	0.102	4.249	0%

Regression Statistics	
Iterations	9
Adjusted Observations	95
Deg. of Freedom for Error	82
R-Squared	0.877
Adjusted R-Squared	0.858
Durbin-Watson Statistic	2.234
Durbin-H Statistic	0.777
AIC	8.484
BIC	8.834
F-Statistic	44.781
Prob (F-Statistic)	0.000
Log-Likelihood	-519.29
Model Sum of Squares	2482238
Sum of Squared Errors	349642
Mean Squared Error	4263.93
Std. Error of Regression	65.30
Mean Abs. Dev. (MAD)	46.83
Mean Abs. % Err. (MAPE)	4.05%
Ljung-Box Statistic	17.21
Prob (Ljung-Box)	0.840

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
BaseUse	0.153	5882.272	0.774
Heating	0.025	654.657	0.014
Cooling	0.008	4423.257	0.031
LagHeating	0.009	584.847	0.005
LagCooling	0.048	4543.486	0.187
March98	-172.982	0.010	-0.002
Nov97	-222.707	0.010	-0.002
Apr99	88.140	0.010	0.001
Feb98	-140.253	0.010	-0.001

Variable	Coefficient	Mean	Elast
Nov99	-193.779	0.010	-0.002
Dec99	31.395	0.010	0.000
Dec97	-421.379	0.010	-0.004

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSND_Custs**
Dependent Variable:	**GSNDCust**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1994:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1079.666	122.945	8.782	0%
EmpNonMfg	0.459	0.186	2.473	2%
GSND_Reclass	-1352.179	301.967	-4.478	0%
Employ_GSNDReclass	14.294	3.059	4.673	0%
January	-116.386	52.670	-2.210	3%
February	-94.701	48.369	-1.958	6%
March	69.442	40.761	1.704	9%
April	-140.275	44.830	-3.129	0%
May	-88.172	44.542	-1.980	5%
July	-72.206	44.440	-1.625	11%
August	1.536	44.734	0.034	97%
June	-26.673	42.768	-0.624	54%
September	-149.412	40.117	-3.724	0%
October	18.607	46.354	0.401	69%
November	-196.990	50.930	-3.868	0%
AR(1)	-0.457	0.134	-3.418	0%
AR(2)	-0.285	0.136	-2.103	4%

Regression Statistics	
Iterations	4
Adjusted Observations	70
Deg. of Freedom for Error	53
R-Squared	0.793
Adjusted R-Squared	0.730
Durbin-Watson Statistic	1.846
Durbin-H Statistic	0.000
AIC	8.642
BIC	9.188
F-Statistic	12.671
Prob (F-Statistic)	0.000
Log-Likelihood	-384.79
Model Sum of Squares	933103
Sum of Squared Errors	243942
Mean Squared Error	4602.67
Std. Error of Regression	67.84
Mean Abs. Dev. (MAD)	47.65
Mean Abs. % Err. (MAPE)	3.45%
Ljung-Box Statistic	57.81
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
EmpNonMfg	0.459	681.899	0.229
GSND_Reclass	-1352.179	0.403	-0.398
Employ_GSNDReclass	14.294	40.955	0.428
January	-116.386	0.083	-0.007
February	-94.701	0.083	-0.006

Variable	Coefficient	Mean	Elast
March	69.442	0.083	0.004
April	-140.275	0.083	-0.009
May	-88.172	0.083	-0.005
July	-72.206	0.083	-0.004
August	1.536	0.083	0.000
June	-26.673	0.083	-0.002
September	-149.412	0.083	-0.009
October	18.607	0.083	0.001
November	-196.990	0.083	-0.012

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSD_Sales**
Dependent Variable:	**GSD_TotalSales**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-1863568.838	454565.035	-4.100	0%
GSD_Cooling	359.590	216.204	1.663	10%
Lag_GSD_Cooling	2847.770	802.301	3.550	0%
GSD_Heating	-217.588	371.986	-0.585	56%
Lag_GSD_Heating	1533.459	1545.172	0.992	32%
GSD_Base	190928.776	31408.131	6.079	0%
Apr93	2991202.924	306343.234	9.764	0%
January	-195063.859	367604.241	-0.531	60%
February	-179833.970	416359.445	-0.432	67%
March	-43121.803	279737.317	-0.154	88%
April	-251605.485	237471.426	-1.060	29%
May	-1082473.886	269605.011	-4.015	0%
June	-2616646.564	608454.222	-4.300	0%
July	-3486524.701	859129.892	-4.058	0%
August	-4302445.726	1038405.320	-4.143	0%
September	-3848607.963	1012754.108	-3.800	0%
October	-3116822.110	831525.435	-3.748	0%
November	-2137594.704	436466.133	-4.898	0%
Dec99	825183.583	331124.764	2.492	2%
Nov99	-362433.846	323225.161	-1.121	27%
June93	-1028714.314	292503.875	-3.517	0%
AR(1)	0.163	0.119	1.374	17%
AR(2)	0.087	0.122	0.714	48%
AR(3)	0.221	0.122	1.809	7%

Regression Statistics	
Iterations	11
Adjusted Observations	95
Deg. of Freedom for Error	71
R-Squared	0.940
Adjusted R-Squared	0.921
Durbin-Watson Statistic	2.069
Durbin-H Statistic	0.000
AIC	25.294
BIC	25.939
F-Statistic	48.483
Prob (F-Statistic)	0.000
Log-Likelihood	-1298.46
Model Sum of Squares	86986136116639
Sum of Squared Errors	5538475140717
Mean Squared Error	78006692122.78
Std. Error of Regression	279296.78
Mean Abs. Dev. (MAD)	181254.04
Mean Abs. % Err. (MAPE)	3.69%
Ljung-Box Statistic	25.45
Prob (Ljung-Box)	0.382

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
GSD_Cooling	359.590	1046.882	0.077
Lag_GSD_Cooling	2847.770	1074.910	0.630
GSD_Heating	-217.588	154.523	-0.007
Lag_GSD_Heating	1533.459	137.978	0.044
GSD_Base	190928.776	26.434	1.038
Apr93	2991202.924	0.009	0.006
January	-195063.859	0.081	-0.003
February	-179833.970	0.081	-0.003
March	-43121.803	0.081	-0.001
April	-251605.485	0.081	-0.004
May	-1082473.886	0.081	-0.018
June	-2616646.564	0.081	-0.044
July	-3486524.701	0.081	-0.058
August	-4302445.726	0.081	-0.072
September	-3848607.963	0.081	-0.064
October	-3116822.110	0.090	-0.058
November	-2137594.704	0.090	-0.040
Dec99	825183.583	0.009	0.002
Nov99	-362433.846	0.009	-0.001
June93	-1028714.314	0.009	-0.002

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSD_Custs**
Dependent Variable:	**GSDCust**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-106.857	21.729	-4.918	0%
EmpMfg	2.525	0.237	10.643	0%
AR(1)	0.414	0.081	5.088	0%

Regression Statistics	
Iterations	3
Adjusted Observations	110
Deg. of Freedom for Error	107
R-Squared	0.762
Adjusted R-Squared	0.757
Durbin-Watson Statistic	2.534
Durbin-H Statistic	0.000
AIC	4.734
BIC	4.807
F-Statistic	171.146
Prob (F-Statistic)	0.000
Log-Likelihood	-413.43
Model Sum of Squares	37885
Sum of Squared Errors	11843
Mean Squared Error	110.68
Std. Error of Regression	10.52
Mean Abs. Dev. (MAD)	8.23
Mean Abs. % Err. (MAPE)	6.85%
Ljung-Box Statistic	72.37
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
EmpMfg	2.525	91.246	1.876

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**StLight_Sales**
Dependent Variable:	**StLts**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1997:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	249726.016	7437.356	33.577	0%
TrendVar	1029.968	809.078	1.273	23%
January	-5090.577	2416.910	-2.106	6%
February	-1694.408	2408.431	-0.704	50%
March	6927.762	2401.816	2.884	1%
April	-2863.069	2397.080	-1.194	26%
May	-6513.900	2394.233	-2.721	2%
June	5136.769	2393.284	2.146	5%
July	-1758.061	2394.233	-0.734	48%
August	-965.392	2397.080	-0.403	69%
September	-4012.223	2401.816	-1.670	12%
October	-797.499	2144.861	-0.372	72%
November	-11108.978	2141.680	-5.187	0%

Regression Statistics

Iterations	1
Adjusted Observations	27
Deg. of Freedom for Error	14
R-Squared	0.864
Adjusted R-Squared	0.747
Durbin-Watson Statistic	2.299
Durbin-H Statistic	0.000
AIC	16.049
BIC	16.673
F-Statistic	7.389
Prob (F-Statistic)	0.000
Log-Likelihood	-233.02
Model Sum of Squares	609489100
Sum of Squared Errors	96227177
Mean Squared Error	6873369.80
Std. Error of Regression	2621.71
Mean Abs. Dev. (MAD)	1514.39
Mean Abs. % Err. (MAPE)	0.59%
Ljung-Box Statistic	22.25
Prob (Ljung-Box)	0.564

Forecast Statistics

Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
TrendVar	1029.968	8.917	0.036
January	-5090.577	0.074	-0.001
February	-1694.408	0.074	-0.000
March	6927.762	0.074	0.002
April	-2863.069	0.074	-0.001
May	-6513.900	0.074	-0.002
June	5136.769	0.074	0.001
July	-1758.061	0.074	-0.001
August	-965.392	0.074	-0.000

Variable	Coefficient	Mean	Elast
September	-4012.223	0.074	-0.001
October	-797.499	0.111	-0.000
November	-11108.978	0.111	-0.005

Appendix 1B.B
Economic Evaluation Spreadsheets

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Base Case
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,238	0	162,238	294,507
2002	147,488	20,870	2,989	0	171,346	0	171,346	441,409
2003	147,655	22,448	10,227	(219)	180,121	2,303	182,414	586,216
2004	150,406	26,681	34,710	(882)	210,950	9,210	220,125	748,014
2005	151,675	28,059	33,674	(895)	212,550	9,210	221,724	898,915
2006	149,444	27,781	31,091	(908)	207,446	9,210	216,619	1,035,422
2007	160,655	29,669	26,251	(921)	215,692	14,681	230,334	1,169,819
2008	164,045	30,469	27,266	(935)	220,885	24,195	245,040	1,302,207
2009	176,711	32,318	27,744	(949)	235,864	28,199	264,023	1,434,284
2010	183,009	33,559	27,820	(964)	243,466	28,199	271,624	1,560,098
2011	190,023	35,252	27,898	(978)	252,238	28,199	280,395	1,680,355
2012	202,945	36,580	27,979	(993)	266,553	28,199	294,709	1,797,388
2013	211,868	39,047	24,629	(1,009)	274,580	31,714	306,249	1,909,995
2014	215,826	40,439	7,717	(1,025)	263,002	70,372	333,329	2,023,481
2015	228,606	42,338	7,910	(1,041)	277,860	70,372	348,185	2,133,243
2016	238,852	44,491	8,107	(1,058)	290,441	70,372	360,765	2,238,547
2017	250,954	46,130	8,310	(1,075)	304,369	70,372	374,692	2,339,814
2018	266,997	48,545	8,518	(1,093)	323,017	70,372	393,339	2,438,247
2019	284,860	50,659	8,731	(1,111)	343,191	70,372	413,511	2,534,062

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Base Case
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,238	0	162,238	294,507
2002	147,488	20,870	2,989	0	171,346	0	171,346	441,409
2003	149,581	22,462	4,430	0	176,473	7,040	183,514	587,088
2004	154,145	26,843	10,006	0	190,994	28,161	219,155	748,174
2005	154,206	28,254	10,146	0	192,606	28,161	220,767	898,424
2006	153,519	27,836	8,671	0	190,026	28,161	218,188	1,035,919
2007	166,024	30,032	3,424	0	199,480	33,631	233,111	1,171,938
2008	165,379	30,704	4,486	0	200,569	43,145	243,714	1,303,609
2009	178,683	32,368	5,012	0	216,063	47,150	263,213	1,435,281
2010	185,254	33,664	5,137	0	224,055	47,150	271,205	1,560,901
2011	191,052	35,455	5,265	0	231,773	47,150	278,923	1,680,526
2012	205,553	36,751	5,397	0	247,700	47,150	294,851	1,797,616
2013	215,617	39,196	5,532	0	260,345	47,150	307,495	1,910,681
2014	245,428	41,202	5,670	0	292,300	47,150	339,450	2,026,250
2015	243,011	43,182	5,812	0	292,005	47,150	339,155	2,133,166
2016	258,930	45,207	6,654	0	310,792	53,982	364,773	2,239,640
2017	265,300	47,212	7,325	0	319,836	58,861	378,698	2,341,990
2018	290,162	49,797	7,508	0	347,466	58,861	406,327	2,443,673
2019	301,583	51,839	7,696	0	361,117	58,861	419,978	2,540,987

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	143,272	20,266	751	0	164,289	0	164,289	296,406
2002	153,314	20,868	2,989	0	177,171	0	177,171	448,301
2003	156,402	22,451	10,227	(219)	188,871	2,303	191,164	600,054
2004	161,788	26,689	34,710	(882)	222,341	9,210	231,516	770,225
2005	165,907	28,063	33,674	(895)	226,786	9,210	235,960	930,815
2006	166,476	27,864	31,091	(908)	224,561	9,210	233,733	1,078,107
2007	181,924	29,753	26,251	(921)	237,046	14,681	251,687	1,224,964
2008	189,810	30,579	27,266	(935)	246,760	24,195	270,915	1,371,331
2009	207,820	32,433	27,744	(949)	267,088	28,199	295,247	1,519,028
2010	219,038	33,705	27,820	(964)	279,641	28,199	307,799	1,661,598
2011	232,814	35,278	27,898	(978)	295,055	28,199	323,212	1,800,218
2012	252,380	36,695	27,979	(993)	316,104	28,199	344,259	1,936,929
2013	268,829	39,095	24,629	(1,009)	331,589	31,714	363,258	2,070,498
2014	278,866	40,454	7,717	(1,025)	326,058	70,372	396,384	2,205,451
2015	300,032	42,411	7,910	(1,041)	349,359	70,372	419,684	2,337,753
2016	319,497	44,464	8,107	(1,058)	371,058	70,372	441,382	2,466,588
2017	341,508	46,106	8,310	(1,075)	394,898	70,372	465,221	2,592,323
2018	370,212	48,556	8,518	(1,093)	426,244	70,372	496,565	2,716,588
2019	401,252	50,735	8,731	(1,111)	459,659	70,372	529,979	2,839,391

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	143,272	20,266	751	0	164,289	0	164,289	296,406
2002	153,314	20,868	2,989	0	177,171	0	177,171	448,301
2003	158,374	22,462	4,430	0	185,267	7,040	192,307	600,961
2004	165,819	26,853	10,006	0	202,678	28,161	230,839	770,634
2005	168,955	28,258	10,146	0	207,360	28,161	235,521	930,926
2006	171,107	27,913	8,671	0	207,691	28,161	235,852	1,079,552
2007	187,781	30,120	3,424	0	221,325	33,631	254,957	1,228,317
2008	191,774	30,819	4,486	0	227,079	43,145	270,225	1,374,311
2009	210,166	32,483	5,012	0	247,660	47,150	294,810	1,521,790
2010	221,824	33,793	5,137	0	260,754	47,150	307,904	1,664,409
2011	234,154	35,455	5,265	0	274,875	47,150	322,025	1,802,520
2012	255,516	36,873	5,397	0	297,787	47,150	344,937	1,939,499
2013	273,162	39,218	5,532	0	317,913	47,150	365,063	2,073,732
2014	311,401	41,258	5,670	0	358,329	47,150	405,479	2,211,782
2015	318,413	43,319	5,812	0	367,544	47,150	414,694	2,342,511
2016	345,089	45,291	6,654	0	397,034	53,982	451,016	2,474,158
2017	361,891	47,329	7,325	0	416,544	58,861	475,406	2,602,645
2018	401,865	49,867	7,508	0	459,241	58,861	518,102	2,732,300
2019	425,450	52,048	7,696	0	485,194	58,861	544,055	2,858,364

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,168	20,267	751	0	160,185	0	160,185	292,606
2002	141,069	20,867	2,989	0	164,925	0	164,925	434,002
2003	138,789	22,446	10,227	(219)	171,252	2,303	173,546	571,769
2004	139,339	26,676	34,710	(882)	199,878	9,210	209,053	725,429
2005	137,671	27,963	33,674	(895)	198,450	9,210	207,624	866,734
2006	133,419	27,778	31,091	(908)	191,418	9,210	200,591	993,140
2007	141,198	29,666	26,251	(921)	196,232	14,681	210,874	1,116,183
2008	140,694	30,471	27,266	(935)	197,535	24,195	221,690	1,235,955
2009	149,337	32,291	27,744	(949)	208,463	28,199	236,622	1,354,325
2010	151,791	33,574	27,820	(964)	212,263	28,199	240,421	1,465,687
2011	155,350	35,220	27,898	(978)	217,532	28,199	245,689	1,571,058
2012	163,034	36,563	27,979	(993)	226,625	28,199	254,781	1,672,235
2013	167,163	39,003	24,629	(1,009)	229,832	31,714	261,501	1,768,389
2014	166,066	40,417	7,717	(1,025)	213,222	70,372	283,548	1,864,926
2015	172,350	42,410	7,910	(1,041)	221,676	70,372	292,001	1,956,977
2016	176,910	44,491	8,107	(1,058)	228,498	70,372	298,822	2,044,200
2017	182,329	46,105	8,310	(1,075)	235,718	70,372	306,041	2,126,913
2018	191,214	48,539	8,518	(1,093)	247,229	70,372	317,550	2,206,380
2019	200,034	50,668	8,731	(1,111)	258,374	70,372	328,694	2,282,542

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,168	20,267	751	0	160,185	0	160,185	292,606
2002	141,069	20,867	2,989	0	164,925	0	164,925	434,002
2003	140,672	22,455	4,430	0	167,558	7,040	174,598	572,604
2004	143,317	26,840	10,006	0	180,163	28,161	208,324	725,728
2005	140,511	28,162	10,146	0	178,819	28,161	206,980	866,596
2006	137,954	27,827	8,671	0	174,452	28,161	202,613	994,276
2007	146,915	30,027	3,424	0	180,365	33,631	213,997	1,119,141
2008	142,432	30,712	4,486	0	177,630	43,145	220,775	1,238,419
2009	151,354	32,344	5,012	0	188,709	47,150	235,859	1,356,407
2010	154,170	33,681	5,137	0	192,988	47,150	240,138	1,467,638
2011	156,318	35,421	5,265	0	197,004	47,150	244,155	1,572,351
2012	165,583	36,727	5,397	0	207,707	47,150	254,857	1,673,558
2013	170,557	39,155	5,532	0	215,245	47,150	262,395	1,770,041
2014	194,192	41,171	5,670	0	241,033	47,150	288,183	1,868,156
2015	185,792	43,107	5,812	0	234,711	47,150	281,862	1,957,010
2016	194,753	45,143	6,654	0	246,550	53,982	300,532	2,044,733
2017	195,120	47,112	7,325	0	249,556	58,861	308,417	2,128,088
2018	210,689	49,807	7,508	0	268,003	58,861	326,864	2,209,886
2019	214,445	51,716	7,696	0	273,856	58,861	332,718	2,286,980

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
Pulverized Coal	446	513,163	42	2013.912	767,298	85,861

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,365	19,543	0	0	118,908	0	118,908	118,908
2001	101,697	20,260	751	0	122,708	0	122,708	232,527
2002	108,643	20,864	2,989	0	132,497	0	132,497	346,122
2003	116,744	22,467	10,227	(219)	149,228	2,303	151,522	466,405
2004	127,717	26,702	34,710	(882)	188,283	9,210	197,457	611,541
2005	129,997	27,979	33,674	(895)	190,792	9,210	199,966	747,635
2006	126,268	27,791	31,091	(908)	184,280	9,210	193,452	869,543
2007	136,428	29,678	26,251	(921)	191,474	14,681	206,116	989,809
2008	138,521	30,478	27,266	(935)	195,370	24,195	219,525	1,108,411
2009	152,862	32,319	27,744	(949)	212,016	28,199	240,175	1,228,559
2010	158,387	33,562	27,820	(964)	218,847	28,199	247,005	1,342,970
2011	162,910	35,243	27,898	(978)	225,116	28,199	253,273	1,451,594
2012	173,535	36,568	27,979	(993)	237,131	28,199	265,287	1,556,943
2013	177,491	39,144	25,391	(1,009)	241,061	35,355	276,371	1,658,564
2014	138,190	41,359	12,386	(1,025)	190,955	114,060	304,969	1,762,394
2015	144,603	43,541	12,695	(1,041)	199,845	114,060	313,858	1,861,336
2016	150,981	45,686	13,013	(1,058)	208,670	114,060	322,682	1,955,523
2017	157,295	47,379	13,338	(1,075)	216,986	114,060	330,997	2,044,982
2018	168,370	50,016	13,671	(1,093)	231,016	114,060	345,025	2,131,324
2019	183,030	52,471	14,013	(1,111)	248,455	114,060	362,463	2,215,311

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488	198,985	24	2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,365	19,543	0	0	118,908	0	118,908	118,908
2001	101,697	20,260	751	0	122,708	0	122,708	232,527
2002	108,643	20,864	2,989	0	132,497	0	132,497	346,122
2003	118,473	22,466	4,430	0	145,369	7,040	152,409	467,109
2004	131,551	26,868	10,006	0	168,425	28,161	196,586	611,605
2005	132,369	28,172	10,146	0	170,688	28,161	198,849	746,938
2006	130,834	27,852	8,671	0	167,357	28,161	195,519	870,148
2007	142,062	30,042	3,424	0	175,528	33,631	209,159	992,191
2008	139,981	30,717	4,486	0	175,183	43,145	218,328	1,110,147
2009	154,961	32,372	5,012	0	192,345	47,150	239,495	1,229,954
2010	160,855	33,652	5,137	0	199,644	47,150	246,794	1,344,267
2011	163,870	35,441	5,265	0	204,576	47,150	251,727	1,452,229
2012	176,243	36,734	5,397	0	218,375	47,150	265,525	1,557,672
2013	187,884	39,199	5,532	0	232,615	47,150	279,765	1,660,541
2014	218,196	41,202	5,670	0	265,068	47,150	312,218	1,766,839
2015	215,452	43,245	5,812	0	264,508	47,150	311,659	1,865,087
2016	230,003	45,163	6,654	0	281,820	53,982	335,802	1,963,104
2017	235,624	47,267	7,325	0	290,215	58,861	349,077	2,057,449
2018	259,873	49,830	7,508	0	317,212	58,861	376,073	2,151,561
2019	273,179	51,908	7,696	0	332,783	58,861	391,644	2,242,309

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: OUC 2000 + 2001 AEO Escalators
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,391	20,317	751	0	151,459	0	151,459	282,961
2002	156,083	20,953	2,989	0	180,025	0	180,025	437,303
2003	168,230	22,497	10,227	(219)	200,743	2,303	203,037	598,480
2004	183,675	26,778	34,710	(882)	244,317	9,210	253,491	784,804
2005	186,996	28,020	33,674	(895)	247,832	9,210	257,005	959,717
2006	181,910	27,834	31,091	(908)	239,965	9,210	249,138	1,116,716
2007	157,918	29,721	30,097	(921)	216,853	51,874	268,688	1,273,494
2008	141,517	31,098	33,418	(935)	205,138	82,348	287,446	1,428,792
2009	153,835	32,734	33,636	(949)	219,296	82,348	301,604	1,579,669
2010	160,417	34,325	33,860	(964)	227,679	82,348	309,986	1,723,252
2011	164,593	35,931	34,089	(978)	233,677	82,348	315,982	1,858,772
2012	174,226	37,409	34,324	(993)	245,009	82,348	327,314	1,988,753
2013	187,758	39,479	30,623	(1,009)	256,896	83,266	340,116	2,113,813
2014	193,362	41,627	11,254	(1,025)	245,265	93,357	338,576	2,229,085
2015	201,679	43,858	11,535	(1,041)	256,077	93,357	349,387	2,339,226
2016	209,568	45,845	12,521	(1,058)	266,924	100,188	367,064	2,446,368
2017	218,041	47,500	13,338	(1,075)	277,852	105,068	382,871	2,549,847
2018	234,933	50,033	13,671	(1,093)	297,595	105,068	402,612	2,650,600
2019	257,444	52,586	14,013	(1,111)	322,984	105,068	428,000	2,749,773

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: OUC 2000 + 2001 AEO Escalators
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,391	20,317	751	0	151,459	0	151,459	282,961
2002	156,083	20,953	2,989	0	180,025	0	180,025	437,303
2003	167,983	22,521	4,430	0	194,933	7,040	201,973	597,636
2004	186,676	26,928	10,006	0	223,610	28,161	251,771	782,695
2005	190,467	28,199	10,146	0	228,812	28,161	256,974	957,587
2006	186,644	28,018	8,671	0	223,333	28,161	251,494	1,116,071
2007	158,725	29,876	7,271	0	195,872	70,825	266,697	1,271,686
2008	142,054	31,243	10,638	0	183,935	101,299	285,234	1,425,789
2009	156,366	32,944	10,904	0	200,214	101,299	301,513	1,576,620
2010	163,536	34,505	11,176	0	209,218	101,299	310,517	1,720,450
2011	164,511	36,119	11,456	0	212,085	101,299	313,384	1,854,855
2012	176,766	37,500	11,742	0	226,009	101,299	327,308	1,984,834
2013	191,171	39,732	12,036	0	242,938	101,299	344,237	2,111,409
2014	207,669	41,618	12,337	0	261,623	101,299	362,922	2,234,970
2015	212,633	43,393	12,645	0	268,670	101,299	369,969	2,351,599
2016	229,716	46,073	12,961	0	288,750	101,299	390,049	2,465,451
2017	233,641	47,115	13,285	0	294,042	101,299	395,341	2,572,299
2018	247,845	49,961	13,617	0	311,423	101,299	412,722	2,675,583
2019	273,059	52,023	13,958	0	339,040	101,299	440,339	2,777,614

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Constant 2000 Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
Pulverized Coal PC	446	513,163	42	2013.912	767,298	85,861

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,175	20,265	751	0	151,191	0	151,191	282,712
2002	151,738	20,871	2,989	0	175,598	0	175,598	433,259
2003	162,264	22,477	10,227	(219)	194,759	2,303	197,052	589,686
2004	177,298	26,721	34,710	(882)	237,882	9,210	247,056	771,280
2005	181,557	27,983	33,674	(895)	242,355	9,210	251,529	942,466
2006	177,417	27,804	31,091	(908)	235,442	9,210	244,615	1,096,615
2007	190,899	29,700	26,251	(921)	245,966	14,681	260,608	1,248,677
2008	195,838	30,515	27,266	(935)	252,723	24,195	276,878	1,398,266
2009	215,859	32,404	27,744	(949)	275,098	28,199	303,257	1,549,970
2010	223,039	33,606	27,820	(964)	283,543	28,199	311,701	1,694,348
2011	229,550	35,310	27,898	(978)	291,823	28,199	319,979	1,831,581
2012	243,547	36,607	27,979	(993)	307,182	28,199	335,338	1,964,749
2013	250,922	39,247	25,391	(1,009)	314,595	35,355	349,905	2,093,408
2014	214,003	40,885	12,386	(1,025)	266,295	114,060	380,309	2,222,888
2015	223,640	42,875	12,695	(1,041)	278,216	114,060	392,229	2,346,535
2016	236,313	45,122	13,013	(1,058)	293,438	114,060	407,450	2,465,466
2017	243,872	46,786	13,338	(1,075)	302,971	114,060	416,981	2,578,163
2018	256,042	49,162	13,671	(1,093)	317,833	114,060	431,843	2,686,231
2019	272,696	52,488	14,013	(1,111)	338,138	114,060	452,146	2,790,999

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Constant 2000 Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
CFB PC	267	366,076	36	2007.417	462,363	51,738
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,175	20,265	751	0	151,191	0	151,191	282,712
2002	151,738	20,871	2,989	0	175,598	0	175,598	433,259
2003	162,067	22,485	4,430	0	188,981	7,040	196,022	588,868
2004	180,103	26,854	10,006	0	216,963	28,161	245,124	769,042
2005	184,543	28,135	10,146	0	222,825	28,161	250,986	939,859
2006	182,010	27,977	8,671	0	218,658	28,161	246,819	1,095,397
2007	171,674	32,759	7,248	0	211,681	58,342	270,023	1,252,952
2008	157,562	35,667	10,599	0	203,829	79,900	283,728	1,406,242
2009	175,310	37,617	10,864	0	223,791	79,900	303,691	1,558,163
2010	181,791	39,015	11,136	0	231,941	79,900	311,841	1,702,606
2011	185,652	40,758	11,414	0	237,824	79,900	317,723	1,838,872
2012	199,169	42,450	11,699	0	253,319	79,900	333,218	1,971,197
2013	214,018	44,803	11,992	0	270,814	79,900	350,713	2,100,154
2014	243,947	46,901	12,292	0	303,139	79,900	383,039	2,230,564
2015	244,038	48,638	12,599	0	305,275	79,900	385,175	2,351,987
2016	256,624	50,997	13,611	0	321,232	86,731	407,963	2,471,067
2017	259,753	52,486	14,455	0	326,695	91,611	418,305	2,584,122
2018	277,279	55,520	14,817	0	347,616	91,611	439,226	2,694,038
2019	293,052	57,395	15,187	0	365,634	91,611	457,245	2,799,987

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
WH 501 F 2x1 (large)	630	267,633	24	2008.417	340,709	38,125
GE 7FA SC	156	68,615	12	2019.417	112,703	12,611

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,243	20,321	751	0	163,315	0	163,315	295,504
2002	149,588	21,007	2,989	0	173,583	0	173,583	444,324
2003	151,331	22,627	5,930	0	178,997	7,040	186,934	592,718
2004	153,868	26,959	15,981	0	196,303	28,161	224,984	758,088
2005	157,842	28,631	16,277	0	200,634	28,161	230,989	915,295
2006	153,696	28,342	16,575	0	198,534	28,161	226,773	1,058,201
2007	173,306	30,452	12,435	0	215,490	28,161	244,413	1,200,813
2008	171,395	31,740	5,090	0	206,533	50,401	258,724	1,340,594
2009	179,920	33,280	6,774	0	219,762	66,286	286,270	1,483,800
2010	188,485	35,120	6,944	0	230,247	66,286	296,837	1,621,293
2011	196,135	36,907	7,117	0	239,471	66,286	306,477	1,752,736
2012	210,110	38,797	7,295	0	256,066	66,286	322,542	1,880,822
2013	222,094	41,346	7,478	0	270,580	66,286	337,271	2,004,836
2014	241,706	43,531	7,665	0	289,970	66,286	359,225	2,127,138
2015	250,970	45,823	7,856	0	303,320	66,286	370,994	2,244,090
2016	268,465	48,617	8,053	0	323,131	66,286	391,488	2,358,362
2017	287,674	50,504	8,254	0	342,018	66,286	412,787	2,469,926
2018	305,215	53,710	8,460	0	366,871	66,286	433,819	2,578,488
2019	320,697	56,119	9,423	0	385,697	73,643	459,965	2,685,068

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purhase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
WH 501F 2x1 (large)	630	267,633	24	2008.417	340,709	38,125
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2015.417	102,103	11,425
CFB PC	267	366,076	36	2018.417	606,660	67,885

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,243	20,321	751	0	163,315	0	163,315	295,504
2002	149,588	21,007	2,989	0	173,583	0	173,583	444,324
2003	150,440	22,627	11,728	(219)	184,576	2,303	186,878	592,674
2004	153,363	26,959	40,685	(882)	220,124	9,210	229,335	761,242
2005	155,726	28,631	39,805	(895)	223,267	9,210	232,478	919,462
2006	153,617	28,342	38,996	(908)	220,046	9,210	229,257	1,063,933
2007	172,604	30,452	35,261	(921)	237,395	9,210	246,606	1,207,825
2008	169,703	31,740	27,870	(935)	228,378	31,450	259,828	1,348,202
2009	179,708	33,280	29,507	(949)	241,545	47,336	288,881	1,492,714
2010	188,183	35,120	29,627	(964)	251,966	47,336	299,302	1,631,349
2011	195,446	36,907	29,750	(978)	261,125	47,336	308,461	1,763,642
2012	209,974	38,797	29,877	(993)	277,654	47,336	324,990	1,892,700
2013	221,903	41,417	26,065	(1,009)	288,376	48,253	336,629	2,016,478
2014	239,218	43,574	6,582	(1,025)	288,349	58,344	346,693	2,134,514
2015	252,507	46,095	7,426	(1,041)	304,988	65,009	369,997	2,251,152
2016	266,418	48,726	8,104	(1,058)	322,189	69,770	391,959	2,365,561
2017	287,726	50,844	8,307	(1,075)	345,801	69,770	415,571	2,477,877
2018	279,329	57,829	14,264	(1,093)	350,330	109,369	459,699	2,592,916
2019	284,771	62,813	18,779	(1,111)	365,252	137,655	502,907	2,709,446

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	144,031	20,736	2,989	0	167,757	0	167,757	437,020
2003	143,006	22,207	4,430	0	169,643	7,040	176,683	577,276
2004	147,386	26,071	10,006	0	183,463	28,161	211,624	732,826
2005	149,786	27,309	8,568	0	185,663	28,161	213,824	878,352
2006	148,127	27,133	4,003	0	179,263	28,161	207,424	1,009,064
2007	151,825	28,174	3,424	0	183,423	28,161	211,585	1,132,522
2008	154,361	28,870	3,914	0	187,144	33,768	220,912	1,251,874
2009	167,869	30,246	4,011	0	202,127	37,773	239,899	1,371,883
2010	168,194	31,086	4,112	0	203,392	37,773	241,165	1,483,589
2011	172,166	32,323	4,215	0	208,703	37,773	246,476	1,589,298
2012	183,519	33,494	4,320	0	221,333	37,773	259,106	1,692,193
2013	190,701	35,247	4,428	0	230,376	37,773	268,149	1,790,791
2014	219,961	36,745	4,539	0	261,244	37,773	299,017	1,892,594
2015	211,723	38,011	4,652	0	254,386	37,773	292,159	1,984,695
2016	231,234	39,807	4,768	0	275,809	37,773	313,582	2,076,226
2017	223,657	40,744	4,888	0	269,288	37,773	307,061	2,159,215
2018	247,470	43,280	5,010	0	295,760	37,773	333,532	2,242,682
2019	252,503	43,917	5,135	0	301,555	37,773	339,328	2,321,308

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171	68,792	24	2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
WH 501F 2x1 (small)	514	258,481	24	2018.912	426,403	47,715

Finance

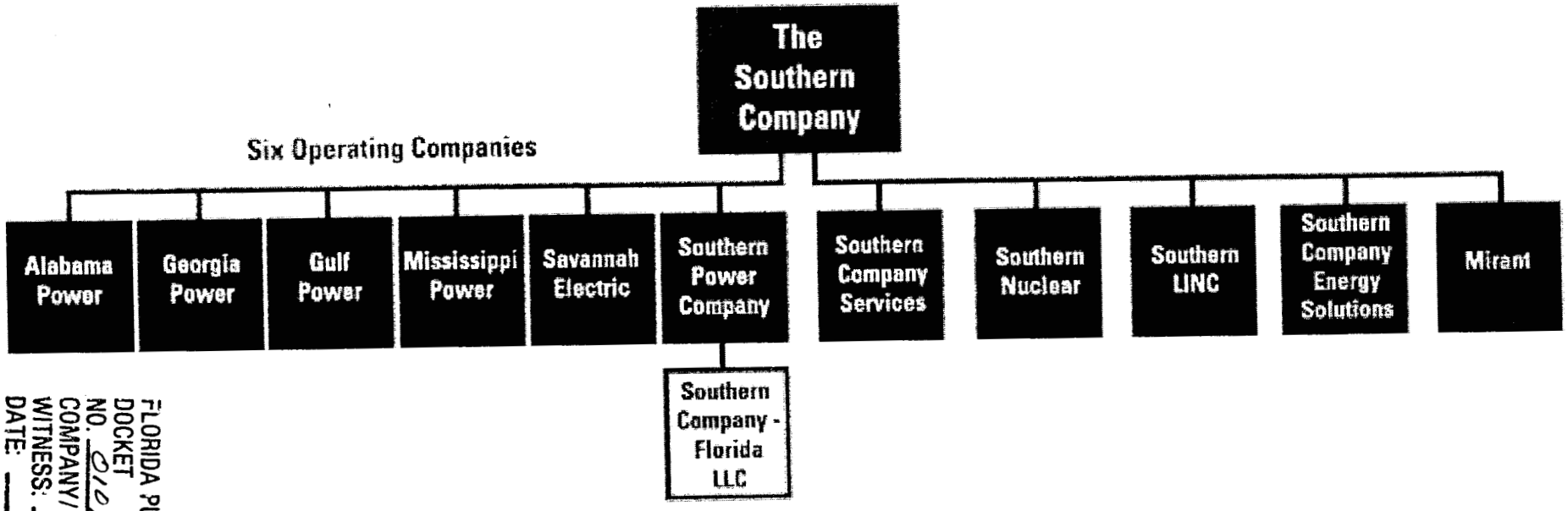
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	144,031	20,736	2,989	0	167,757	0	167,757	437,020
2003	142,874	22,191	5,949	(219)	170,804	2,303	173,098	574,430
2004	145,212	25,935	34,710	(882)	205,010	9,210	214,185	731,863
2005	145,815	27,148	32,095	(895)	204,201	9,210	213,374	877,082
2006	142,133	26,833	26,423	(908)	194,519	9,210	203,692	1,005,442
2007	148,815	28,020	26,251	(921)	202,203	14,681	216,845	1,131,969
2008	152,046	28,650	26,693	(935)	206,494	18,588	225,042	1,253,552
2009	162,720	30,036	26,744	(949)	218,591	18,588	237,138	1,372,180
2010	165,872	30,905	26,795	(964)	222,650	18,588	241,196	1,483,901
2011	171,033	32,177	26,848	(978)	229,122	18,588	247,667	1,590,121
2012	181,861	33,203	26,901	(993)	241,016	18,588	259,560	1,693,195
2013	184,072	34,329	28,114	(1,009)	245,550	18,588	264,093	1,790,302
2014	210,726	35,743	33,940	(1,025)	279,429	18,588	297,971	1,891,750
2015	202,964	36,936	33,998	(1,041)	272,904	18,588	291,445	1,983,625
2016	222,714	38,840	34,057	(1,058)	294,602	18,588	313,141	2,075,028
2017	217,363	39,635	34,119	(1,075)	290,091	18,588	308,630	2,158,441
2018	237,723	42,228	29,683	(1,093)	308,593	22,564	331,107	2,241,300
2019	230,264	42,676	7,450	(1,111)	279,331	66,302	345,582	2,321,376

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010149-EM EXHIBIT NO. 2
COMPANY/
WITNESS: Orlando Utilities Commission
DATE: 4-23-01



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010142-EM EXHIBIT NO. 3
COMPANY/ WITNESS: D. Jones
DATE: 12-13-01

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO 4
COMPANY/
WITNESS: Orlando Utilities Commission
DATE: 4-23-01

Professional Resume of Paul A. Arsuaga

EDUCATIONAL BACKGROUND:

Bachelor of Science Degree in Electrical Engineering
Tulane University. New Orleans, Louisiana, June, 1969

Masters Degree in Business Administration
University of Hawaii. Honolulu, Hawaii, August, 1975

PROFESSIONAL REGISTRATION:

Registered as a Professional Engineer in the States of Florida, Mississippi and Missouri.

EXPERIENCE:

1999-Present	Principal in the firm of R. W. Beck/R. W. Beck, Inc.
1981-1999	Mr. Arsuaga, has been an employee with R. W. Beck, Inc. where his work involved planning electric power facilities. Since joining the Firm in 1981, he has prepared or supervised studies and reports which include numerous market price assessments, independent engineering reviews, evaluation of stranded costs, power supply studies for municipal utilities and joint action agencies, consulting engineer's reports for official statements, financial analyses, acquisitions, damage studies, and power purchase contract negotiations.
1977 - 1981	Employed by Kansas City Power and Light Company. Served as a corporate planning engineer for which he performed generation planning studies and managed a corporate model.
1969-1977	Communications Planning Officer in the United States Air Force. Planned ground and tactical communications – electronic systems for the Air Force. This work involved economic evaluations relating to telephones, microwave and other types of telecommunications systems.

RELEVANT EXPERTISE

WHOLESALE POWER SUPPLY CONTRACTS AND NEGOTIATION

Mr. Arsuaga has been involved with evaluating wholesale power contracts for the Municipal Energy Agency of Mississippi; the City of St. Cloud, Florida; Alabama Municipal Electric Authority; and the Florida Municipal Power Agency.

Mr. Arsuaga has been involved with developing an appropriate methodology for compensating members of a joint action agency for supplying power supply resources to an all-requirements project.

Mr. Arsuaga has been involved in developing stranded cost analyses for two different joint action agencies.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 5
COMPANY/
WITNESS: Arsuaga
DATE: 4-23-01

Mr. Arsuaga has been involved in directing a hold harmless analysis to determine the potential rate impact and hold harmless costs associated with making remaining members of a joint action agency of Mississippi whole after certain members terminate their power supply arrangements.

PLANNING FOR ELECTRIC UTILITY RESTRUCTURING

Mr. Arsuaga has directed two recent analyses for industrial clients relating to assisting them making capital decisions in a deregulated environment. This work involved developing scenarios for long-range sustainable pricing practices in a deregulated electric utility market for generation. It also involved preparing projections of both time-of-day marginal costs and market clearing prices for various market regions of the United States based on these pricing practices. These analyses take into account transmission import and export capabilities between market areas, load and resources in several NERC reliability regions, annual economic conditions, market behavior, reliability standards and other factors.

Mr. Arsuaga was also recently involved in assisting a joint action agency with its input to the Public Service Commission staff's Proposed Transition Plan for Retail Competition in the Electric Industry, and in this capacity, has met with the staff to discuss restructuring.

MARKET PRICE ANALYSES

Mr. Arsuaga has supervised numerous projects involving the preparation and/or review of market price projections for both industrial and joint action agency clients. These projections have been prepared for four market regions in different NERC regions. Some of these projects have included developing and using various computer models of electric utility market regions to simulate various market pricing structures under a market based restructured electric utility environment. He has also reviewed and evaluated numerous market price projections prepared by other consultants as part of independent engineering reviews and work related to rate filings for stranded costs. Mr. Arsuaga is a member of the Firm's Market Pricing Task Force through which he has been involved in understanding, evaluating and communicating issues related to market pricing in the electric utility industry.

ELECTRIC POWER RESOURCE PLANNING

Mr. Arsuaga has an extensive background in preparing electric resource planning studies for municipal utilities and joint action agencies. He has either prepared or directed the preparation of electric resource planning studies for the Florida Municipal Power Agency ("FMPA"), the Municipal Energy Agency of Mississippi ("MEAM"), the Bahamas Electricity Corporation ("BEC"), the City of Tallahassee, Florida, the Utility Board of the City of Key West, Florida, the Sebring Utilities Commission, the Fort Pierce Utilities Authority, the City of Vero Beach, Florida, and a large improvement district. These studies, which make conclusions and recommendations regarding the client's participation in specific power supply projects, have included screening type analyses which focus on identifying a list of reasonably attainable potential alternatives, as well as comprehensive studies which cover power supply related areas such as load forecasts, reliability, environmental impact, economic/financial feasibility, bond requirements, rate impact, and risk analysis.

Mr. Arsuaga's studies have been utilized by clients in making decisions regarding numerous purchased power arrangements. The following are examples of some projects associated with Mr. Arsuaga's power supply studies: MEAM was organized to provide lower cost power to municipal participants in eastern Mississippi; Mr. Arsuaga conducted an RFP process which lowered the electricity costs to the City of Hagerstown, MD and three other municipals by 15 percent.

REQUEST FOR PROPOSAL SERVICES

Mr. Arsuaga has been a lead team member or project manager on power supply solicitations involving the City of Tallahassee; the Florida Municipal Power Agency; City of Hagerstown, MD; the Alabama Municipal Electric Authority; the City of St. Cloud, Florida; Golden Spread Electric Cooperative, Inc. and the Municipal Energy Agency of Mississippi. This process included preparation of the Request for Proposal and evaluation manual, evaluation of the proposals and negotiations with the potential power suppliers. Mr. Arsuaga has also participated in meetings and discussions with state public commission staff's in Florida and Texas, and has testified in a Public Utility Commission Hearing relative to the RFP Process.

RELIABILITY STUDIES

Mr. Arsuaga has been involved in evaluating electric system reliability and determining reliability criteria for electric utilities. These studies have involved estimating various measures of reliability, such as loss of load probability (LOLP), loss of load hours (LOLH), and expected unserved energy (EUE) for isolated and interconnected power systems. He prepared a reliability study for the City of Tallahassee, Florida that involves modeling the reliability of the electric system including peninsular Florida and Georgia.

LITIGATION SUPPORT

Mr. Arsuaga has been involved in litigation support services associated with wholesale electric rate filings, territorial disputes, and damage studies.

He has prepared analyses and testimony for Case No. 87-00103 CIV before the U.S. District Court Southern District of Florida, Miami Division, City of Homestead vs. Imo Delaval and Transamerica Corporation, which was amicably settled. He has also prepared analyses and testimony in cases for the Municipal Electric Authority of Georgia, the City of Tallahassee FMPA, the Municipal Energy Agency of Mississippi and industrial clients relating to wholesale power costs, territorial issues and transmission access and deregulation issues.

Mr. Arsuaga has testified before the Florida Public Service Commission with regard to territorial issues involving the Fort Pierce Utilities Authority and Florida Power & Light; before the Public Utility Commission of Texas with regard to the selection of resources through an RFP.

FINANCIAL PLANNING AND ANALYSIS

Mr. Arsuaga has been involved with the preparation of numerous official statements for bond refunds, and the financing of new electric generation facilities including the North Carolina Eastern Municipal Power Agency ("NCEMPA"), the Utility Board of the City of Key West, the Florida Municipal Power Agency ("FMPA"), the Municipal Energy Agency of Mississippi ("MEAM"), the Municipal Electric Authority of Georgia ("MEAG"), and the City of Tallahassee. Mr. Arsuaga has also assisted financial institutions with the evaluation of a merchant generation project in California; Arizona; Nevada; Texas; Mississippi; and Alberta, Canada. Mr. Arsuaga's experience has enabled him to analyze the financial aspects of municipal projects including proforma results, adequacy of liquidated damages, bond indenture requirements, various financing methodologies, tax-exemption considerations, arbitrage and other financial related factors.

GAS FUEL SUPPLY

Mr. Arsuaga has performed various studies relating to gas fuel supply for Florida municipals to determine the most economic level of firm gas service and the most economic mix of firm transportation versus firm service with the Florida Gas Transmission Company ("FGT"). The analysis involved projecting the daily gas usage for the cities electric production facilities and determining the level of firm gas transportation and firm service that represented the lowest cost —

taking into account the cost of generating on alternative fuels, potential curtailments of interruptible gas, and take or pay gas supply charges. The Authority and City based nominations for FGT's Phase II and III gas pipeline expansions on these analyses.

COMPETITIVE ANALYSES, MERGERS AND ACQUISITIONS

Mr. Arsuaga has performed analyses associated with determining the economic benefits of mergers and acquisitions for electric utilities. One such analysis evaluated the impact of acquiring an additional service territory for a municipal utility. This analysis, which was submitted to the Florida Public Service Commission, indicated the impact on the municipal utility's existing and transferred customers of the proposed acquisition of an additional service territory.

Another analysis evaluated the impact on a municipal utility's customers of a proposed transfer and acquisition of service territories and associated customer accounts between the municipal utility and Florida Power & Light. This analysis included an evaluation of equipment value, incremental and decremental revenues, and potential load growth for the areas involved.

Mr. Arsuaga performed an evaluation for a municipal utility to address potential future events such as the commencement of purchased power contracts for which the City is committed, power supply sales, acquiring additional territory, and potential changes in administration costs.

TRAINING AND INFORMATION PRESENTATIONS

Mr. Arsuaga has made numerous presentations before utility boards and city commissions relating to electric resource planning and was a guest lecturer on Integrated Resource Planning in an IEEE Power Generation Seminar lecture series. He prepared technical papers on the RFP process, and determining the market value of generation capacity in a deregulated utility environment, which were presented at technical conferences.

SELECTED CONSULTING EXPERIENCE

The Coalition for Choice in Electricity (CCE) – Evaluating analysis performed by witnesses for FirstEnergy Corporation regarding generating asset evaluation and the impact of a new electric industry restructuring law on the company (2000).

Calpine Energy – Independent engineering reviews of six different merchant plant combined cycle projects for financial institutions to support financing (1999-2000).

Florida Municipal Power Agency – Prepared stranded cost analysis of generation resources and contracts (1999).

Major Generation Developer – Prepared a power market assessment of the FRCC to determine economic feasibility of new merchant plant generation (1999).

ATCO Power Canada – Evaluated market price projections and methodology by another consultant as part of an independent engineering review of a merchant plant generation project in Canada (1999).

Major Industrial Clients – Prepared market price projections to assist two different industrial clients with making capital decisions in a deregulated electric utility market (1998-1999).

Municipal Energy Agency of Mississippi – Assisted the Municipal Energy Agency of Mississippi with its input to the Mississippi Public Service Commission Staff's proposed Transition Plan for Retail Competition in the Electric Utility Industry (1998).

L.S. Power – Independent engineering review of a merchant plant combined cycle project for financial institutions to support financing (1998).

Municipal Energy Agency of Mississippi – Request for Proposal preparation and evaluations of power supply alternatives to replace existing arrangements (1997-1998).

City of Hagerstown, Maryland – Conducted a power supply solicitation which included the evaluation, solicitation and negotiation of power supply alternatives (1997-1998).

Golden Spread Electric Cooperative, Inc. – Conducted power supply solicitation, evaluated power supply solicitation, evaluated proposals, and testified at the Public Utility Commission hearing in support of certificate of need for an exempt wholesale generator ("EWG") combined cycle project (1995-1996).

City of St. Cloud, Florida – Project manager on power supply solicitation and negotiations for replacing the City's power supply arrangements to be more competitive (1995).

City of Tallahassee – Conducted a reliability study for the City of Tallahassee to determine expected unserved energy (EUE), loss of load probability (LOLP), taking into account interconnections with other utilities (1995).

SELECTED PUBLICATIONS AND SPEAKING ENGAGEMENTS

Arsuaga, P. A. and Davis, R. L. – *"Should You be in the Generation Business, Finding the Hidden Value of Capacity,"* Power Gen Conference, Orlando, Florida, December 1998

Arsuaga, P. A. and Stein, S. - *"Using the Request for Proposal for Procuring Electric Resources in Today's Competitive Environment,"* International Joint Power Generation Conference and Exposition, Denver, Colorado, November 5, 1997

Arsuaga, P. A. – *"Integrated Resource Planning"* Guest lecturer in an IEEE Power Generation Seminar Lecture Series 1992.

RECORD OF TESTIMONY

Regulatory or Judicial Forum	Proceeding	Petitioner/Matter	Client	Subject of Testimony	Date
Public Utility Commission, Texas	SOAH Docket No. 473-95-1820, PUC Docket No. 15100	Golden Spread Electric Cooperative, Inc./ Determinations Required by 32K of the Public Utility Holding Act and for Certification of Contract	Golden Spread Electric Cooperative, Inc.	Independent Evaluation of Requests for Proposals by Section 32K of the Public Utility Holding Act and Certification of Contracts	1996
Florida Public Service Commission	Docket No. 891245-EU, 1992	Fort Pierce Utilities Authority/ Florida Power & Light	Fort Pierce Utilities Authority	Generation Capacity Adequacy relating to a change in service territory	1992

Proposer's Name: _____
Proposal No.: _____

Evaluator: _____
Date: _____

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Proposal Evaluation

ORLANDO UTILITIES COMMISSION

Request for Power Supply Proposals

Dated May 24, 2000

WARNING

This document contains information that must be considered as highly confidential. Information contained herein and other information relating to this evaluation process must not be disclosed to anyone who is not directly associated with the evaluation.

TABLE OF CONTENTS

1.0. Introduction 1

2.0. Receipt, Logging and Handling of Proposals 2

3.0. Stage One Screening 4

4.0. Stage Two Screening 4

5.0. Stage Three Screening 5

6.0. Sensitivity Analysis 7

Appendix A.1 ..... Proposal Receipt Log

Appendix A.2 ..... Proposal Summary Log

Appendix B ..... Stage One Minimum Requirements Checklist

Appendix C ..... Stage Two Busbar Cost Comparison Sheet

Appendix D ..... Stage Three Scoring

This manual has been prepared for the use of the client for the specific purposes identified in the manual. The conclusions, observations and recommendations contained herein attributed to R. W. Beck, Inc. constitute the opinions of R. W. Beck, Inc.. To the extent that statements, information and opinions provided by the client or others have been used in the preparation of this manual, R. W. Beck, Inc. has relied upon the same to be accurate, and for which no assurances are intended and no representations or warranties are made. R. W. Beck, Inc. makes no certification and gives no assurances except as explicitly set forth in this manual.

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1.0. INTRODUCTION

The Orlando Utilities Commission ("OUC") has issued a Request For Proposals ("RFP") for the supply of an aggregate of 750 MW of physically firm, dispatchable capacity and energy beginning on or before October 1, 2003. The 750 MW of capacity will be shared between OUC, Florida Municipal Power Agency ("FMPA") and Kissimmee Utility Authority ("KUA") collectively (the "Participants") as follows:

Participant	Nominated Capacity (MW)
OUC	600
FMPA	75
KUA	75

OUC is acting as the agent for FMPA and KUA in all matters relating to the RFP process including evaluation of the proposals and contract negotiations. OUC is accepting proposals for base, intermediate and/or peaking generating resources that offer a capacity amount of at least 150 MW and an agreement term of at least five years with one five-year extension. The deadline for submission of proposals by companies that submitted a valid Notice of Intent to Propose is July 11, 2000.

Proposals received in response to the RFP will be evaluated in comparison with: (i) each other; (ii) proposals received by OUC in response to a solicitation for joint development of a combined cycle power plant between the Participants and a company at the OUC Stanton and/or KUA/FMPA Cane Island sites; and (iii) the Participants self-build option. This evaluation manual provides the general procedure that will be used to screen and analyze the proposals in accordance with the evaluation procedures outlined in Section 14 of the RFP. The schedule for the RFP process is as follows:

Issue RFP	May 24, 2000
Pre-Proposal Conference (Mandatory)	June 1, 2000 (10:00 A.M.)
Deadline for Proposers' Questions	June 5, 2000 (5:00 P.M.)
Response to Proposers' Questions	June 12, 2000 (5:00 P.M.)
Notice of Intent to Propose	June 15, 2000 (5:00 P.M.)
Proposal Due Date	July 11, 2000 (5:00 P.M.)
Commence Negotiations	August 21, 2000
Contract Approved	October 31, 2000
Commence Power Supply Services	October 1, 2003

R. W. Beck, Inc. ("Beck") will receive, log, and at the appropriate time, open the proposals. Beck will perform the three staged evaluation process, preparing and submitting a letter report to OUC at the conclusion of each stage for decision making by OUC prior to proceeding.

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When the proposals are delivered, Beck will implement a Receipt, Logging and Handling procedure to check whether each proposer has complied with the established deadline for submittal.

- At Stage One Screening, proposals will be examined for general completeness and to verify that all Minimum Requirements set forth in the RFP have been adequately addressed. Proposals that do not satisfy the Minimum Requirements may be recommended for elimination from further consideration.

- Stage Two Screening will compare and rank proposals on a busbar cost basis. Proposals offering peaking, intermediate and base load capacity will be evaluated at appropriate capacity factors. This analysis will reflect only the cost for the proposal being analyzed and will not show the impact that the proposal will have on OUC's overall operational cost.

- Stage Three Screening will consist of a more comprehensive evaluation that will consider both price and non-price factors in a quantitative manner.

OUC will select candidates from the short-list for negotiations.

Questions and requests for clarifications may be issued to proposers at any time during the evaluation process. In cases where proposals are eliminated from the evaluation process, OUC may notify proposers of the elimination.

Since this manual is intended to serve as a guide for ranking the relative merits of proposals submitted, OUC reserves the right to modify the manual to reflect new criteria based on potential benefits offered by innovative proposals.

2.0 Receipt, Logging and Handling

Official submission of proposals will be made at the Beck office in Orlando, Florida. As stated in Sections 2 and 5 of the RFP, proposals are due by 5:00 P.M. Prevailing Eastern Time (PET) on Tuesday, July 11, 2000 ("Proposal Due Date"). When each proposal is received, the designated Beck representative will complete the Proposal Log form in Appendix A.1, noting the date and time of delivery, the carrier and the number of packages. The proposals will be placed in a pre-determined secure location where they will remain unopened until after the Proposal Due Date. Designated Beck representatives will then:

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ORLANDO UTILITIES COMMISSION
PROPOSAL EVALUATION

2.1 Open the proposals in alphabetical order of the bidding company's name.

Each official copy of each proposal will be assigned an identification number which will be affixed to the outside and inside of the front cover. The Arabic numbering system (1, 2, 3, etc.) will be used to identify proposals in alphabetical order of the bidding company's name; and an alpha numeric numbering system (A, B, C, etc.) will be used to identify each of the multiple copies. Labels bearing such identification should be prepared prior to the Proposal Due Date. The original and four copies of the proposal will be distributed as follows.

A. Beck (original)
B. OUC (working copy)
C. OUC (working copy)
D. Beck (working copy)
E. Beck (working copy)

2.2. Summarize the various proposals received on Appendix Form A.2.1 showing the proposal number, company name, type and term of proposal, annual amount of capacity offered, the amount and form of payment for the Proposal fee.

2.3 Place a copy of the following label on the front outside cover of each document.

> *WARNING*
>
> ***This document contains information that must be considered as highly confidential. Information contained herein and other information relating to this evaluation process must not be disclosed to anyone who is not directly associated with the evaluation.***

2.4. File originals of proposals in a secured location.

2.5 Maintain a log of the distribution of each set of copies.

If for any reason a proposal is received after the Proposal Due Date specified in the RFP, it will be returned unopened. When a proposal is returned, the date and time of the receipt by Beck will be recorded on the form in Appendix A.1 and a covering letter signed by an authorized representative of OUC will be included with the returned package. The text of the letter will state that the proposal is being disqualified because it was received after the Proposal Due Date.

After the bids have been opened, OUC may release for public information, a list of those companies that submitted valid proposals and the total amount of megawatts for all proposals received. This information may also be published on the RFP Internet Website.

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It should be noted that in accordance with Section 9 of the RFP, all information stamped "Proprietary Confidential Business Information" in the proposals will not be disclosed to third parties, unless such disclosures are required by law or by order of a court or government agency having appropriate jurisdiction.

3.0 Stage One Screening

The contents of each proposal will be checked against the Minimum Requirements in Section 14 of the RFP to determine if each item has been addressed adequately. A copy of the Minimum Requirements Checklist in Appendix B of this Evaluation Manual will be completed for each proposal.

Any proposer determined to have omitted requested Minimum Requirements information which, if submitted at this stage, will not materially change the original response in the opinion of OUC will be so informed in writing by facsimile or e-mail and will be requested to submit the omitted information in writing to Beck as soon as possible, but no later than three (3) business days from the date of the facsimile, or the proposal may be disqualified.

A Stage One Screening results letter report will be prepared which summarizes the results and identifies proposals determined to be complete with respect to the Minimum Requirements set forth in the RFP. The report will identify proposals which should be considered at the next screening stage and proposals which should no longer be considered by OUC. OUC will make the final decision on any disqualifications.

4.0 Stage Two Screening

At the Stage Two Screening level, a busbar analysis will be conducted to determine the annual cost of each proposal. Each proposal will be evaluated over a range of capacity factors to determine its most economic resources at each capacity factor operating category. As appropriate, comparisons will be made among each capacity factor grouping on an annual or a cumulative present value basis. The annual supply costs for each proposal will be calculated by applying the Delivered Capacity Rates and Delivered Energy Rates from RFP Form 4 - Pricing Proposal form, to the capacity and energy delivered to OUC. Such screening may be accomplished in dollars, dollars per kilowatt, and/or dollars per megawatt hour.

Spreadsheets used for the cost components will be developed by Beck. Adjustments to data will be made if, in the opinion of Beck, such action is warranted in order to maintain consistent assumptions among the proposals. A copy of the individual proposer's spreadsheet may be sent to the respective proposer along with a letter requesting the proposer to verify and/or comment on the interpretations used from the proposal. During the Stage Two Screening,

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proposers will be requested to provide clarifications in a timely manner when such clarifications are required.

OUC may select up to 4 to 6 proposal alternatives for advancement to the Stage Three Screening level. A total of 4 to 6 proposal alternatives (750 MW x 4= 3,000 MW) is anticipated to be selected for Stage 3 screening. A Stage Two Screening result letter report may be prepared to summarize the results of Stage Two Screening.

5.0 STAGE THREE SCREENING

At the Stage Three Screening level, price and non-price factors will be scored for each proposal using a weighted scoring system. The factors along with the maximum scores allocated to each category are summarized below:

5.1 Price Criteria (60 points)

5 year Present Worth Cost	(30 points)
10 year Present Worth Cost	(30 points)

5.2 Non-Price Criteria (40 points)

5.2.1 Components of Power Cost (2 points).
- All fixed costs are recovered in the capacity charge.
- All variable costs are recovered in the energy charge.

5.2.2 Flexibility and Term (10 points).
- OUC's sole option to increase or decrease contract purchases with reasonable notice.
- OUC's sole option to select type of purchases, payment provision, pricing method, etc.
- OUC's sole option to adjust the contract term.

5.2.3 Fuel Type (2 points)
- Fuel type increases OUC's fuel diversity.

5.2.4 Dispatchability (10 points)
- Includes no minimum take provisions (100% dispatchable).
- Available for economy transactions.
- Scheduling provisions allow for change within one hour.

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5.2.5 Firm Supply (8 points)
- Includes suitable arrangements for firming capacity.
- Includes reasonable penalties for non-performance.
- Provides suitable guarantees.

5.2.6 Technology Risk (2 points)
- Offers commercially proven technology.

5.2.7 Environmental Effects (4 points)
- Includes extraordinary measures to minimize any adverse environmental impacts.
- Offers renewable generating resources.

5.2.8 Transmission (2 points)
- Utilizes no intermediate transmission systems.

Each of the above items represents an important factor in selecting the short-list of proposals. The proposals, which are in the best overall interest of OUC, must adequately address each issue.

A range of raw scores has been defined for each of the criteria listed above. Each proposal will be scored for each price and non-price criteria and the raw scores will be weighted such that the relative importance as defined by the maximum amount of points allocated to each factor is reflected in the final score. In situations where proposals are combined in order to provide the required 750 MW, the score for each non-price criterion for the combination of proposals will be calculated as the weighted average of the respective scores for each member proposal based on the amount of megawatts the member proposal contributes to the total megawatts in the combination. Appendix D contains the forms that will be used for scoring the proposals along with a summary scoring sheet.

The development of price scores will involve a two step process. First, each proposal will be evaluated individually based upon its ability to generate cash flows by selling to the electricity market above its variable operating costs. The criterion for ranking proposals under this first step will be the projected internal rate of return over 10 years, under the base case set of assumed market prices.

The second step will involve combining proposals into portfolios with each portfolio containing approximately 750 MW and evaluating and scoring the portfolios on an overall basis. For each proposal a portfolio will be developed by adding additional proposals from the highest ranked remaining proposals which sum to approximately 750 MW. These portfolios will then be scored based on the overall internal rate of return produced by each portfolio over a ten-year period.

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For purposes of the price screening an internal rate of return of 8% for a 750 MW proposal or a portfolio of proposals amounting to 750 MW will be given a score of 60 points. To the extent the overall rate of return is higher or lower than 8% the score will be adjusted on a proportionate basis.

The proposals (and portfolios as applicable) will be ranked according to total weighted scores, beginning with the highest scoring proposal or portfolio. During the Stage Three Screening, proposers may be requested to provide additional clarifications in a timely manner.

The objective of the scoring and ranking system is not to provide a precision indication of the potential value of the proposals, but rather to provide a good relative comparison of the proposals to each other. The short-list will be limited to a number of proposals equal to an amount of capacity that is up to approximately 300 percent of Participant's requirements.

A Stage Three Screening result letter report including sensitivity analysis will be prepared to summarize the results of Stage Three Screening.

6.0 SENSITIVITY ANALYSIS

As an extension of the Stage Three Screening, various scenarios may be simulated to evaluate the potential effect of changes in certain major assumptions, including access to market power, higher and lower fuel costs, generation overbuild, generation underbuild, etc. on the ranking of proposals. The impact on the rankings of the portfolios resulting from these scenarios may be taken into account in developing the short-list.

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ORLANDO UTILITIES COMMISSION
APPENDIX A.1
PROPOSAL RECEIPT LOG

Date and Time Received	Company Name	Carrier/Receipt#	No. of Packages/Type

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ORLANDO UTILITIES COMMISSION
APPENDIX A.2
PROPOSAL SUMMARY LOG

POWER SUPPLY REQUIREMENTS PROPOSALS

Proposal No. *(Arabic No.)*	1. Company Name *(Alphabetical Order)*	2. Type/Term of Proposal *(System or Unit Purchase)*	3. Annual Capacity Amount(s) (MW)	Amount of Proposal Fee $	Payment Form

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ORLANDO UTILITIES COMMISSION
APPENDIX B
MINIMUM REQUIREMENTS CHECKLIST

Proposer's Name:_____ **Proposal No.:**_____

Type of Supply: _____ **Capacity:** _____

Each proposal must meet certain minimum requirements before it will receive further consideration. These Minimum Requirements are intended to demonstrate, to the reasonable satisfaction and at the sole discretion of OUC, that the proposer has the ability to deliver power as proposed.

	Yes	No	N/A	Unknown
1. The proposer attended the Pre-Proposal Conference.....	___	___	___	___
2. The proposer provides a fee of $5,000 for each priced proposal alternative in the form of a cashiers check payable to OUC.....	___	___	___	___
3. The proposer offers to provide a minimum of 150 MW of unit or system capacity.....	___	___	___	___
4. (a) The proposer offers to provide physically firm power, including ancillary services, delivered to OUC's delivery points.	___	___	___	___
(b) The power will be available on a first call non-recallable basis.	___	___	___	___
5. The proposal offer will remain effective through December 31, 2000.	___	___	___	___
6. (a) The initial agreement period extends for at least five (5) years.	___	___	___	___
(b) Provisions are included that permit OUC the sole option to extend the agreement for at least a further five (5) years.....	___	___	___	___

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ORLANDO UTILITIES COMMISSION
APPENDIX B
MINIMUM REQUIREMENTS CHECKLIST

	Yes	No	N/A	Unknown
7. (a) The proposed service commencement date is earlier than or within twelve (12) months later than October 1, 2003.	___	___	___	___
(b) Sufficient information is provided to demonstrate that the service can commence on the date proposed.	___	___	___	___
8. (a) If a unit supply is proposed, the proposal identifies the specific generating units and the contribution that each will make to the sale.	___	___	___	___
(b) If a system sale is proposed, the supply to OUC is equivalent to native load supply....	___	___	___	___
9. The proposer ensures that all emissions allowance requirements will be satisfied and that such costs are included in the Project.	___	___	___	___
10. The proposer declares ownership or contractual status of the unit, plant or system capacity.	___	___	___	___
11. The cost data including fuel cost and escalation rates were prepared using the applicable fuel price indices in RFP Attachment B unless energy prices are guaranteed.	___	___	___	___
12. The price for power provided in the completed Pricing Proposal Form (Form 4) reflects all costs and losses delivered to OUC's delivery points.	___	___	___	___
13. The proposer states a willingness to provide a Negotiation Security in the amount of $250,000 prior to commencing negotiations with OUC.	___	___	___	___

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ORLANDO UTILITIES COMMISSION
APPENDIX B
MINIMUM REQUIREMENTS CHECKLIST

	Yes	No	N/A	Unknown
14. (a) The proposer completed the appropriate RFP Forms 2 through 6.	___	___	___	___
(b) The proposer provided the information requested in Attachment A.	___	___	___	___
(c) All forms requiring a signature were signed by a duly authorized official.	___	___	___	___
15. The proposal includes scheduling provisions for the sale.	___	___	___	___
16. Any must-take provision does not exceed 25% of the proposed sale capacity on an annual basis.	___	___	___	___
17. (a) If proposal includes development of a new project, then the proposer has developed and has had in operation for a minimum of one year, at least one currently operating power supply project that is similar to or larger in size than the project being proposed.	___	___	___	___
(b) If proposal includes power from existing generating resources, then the proposer has successfully provided similar level of services to at least one electric utility for a minimum of one year.	___	___	___	___
18. If proposal includes power from an existing unit, then the proposer owns and operates the unit, plant or system capacity or has the unit(s), plant or system capacity under contract.	___	___	___	___
19. If proposer operates a proposed unit, plant or system capacity, then the proposal provides proof of operating experience as requested in RFP Attachment A.	___	___	___	___

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ORLANDO UTILITIES COMMISSION
APPENDIX B
MINIMUM REQUIREMENTS CHECKLIST

Comments:

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ORLANDO UTILITIES COMMISSION

APPENDIX C

STAGE TWO SCREENING

Busbar Cost Comparison Sheet

Proposer's Name:	Proposal No.:
Evaluator:	Date:

Those proposals and/or alternatives that are declared to be complete at the end of the Stage One Screening process will be further evaluated at the Stage Two Screening level. At this stage, a busbar analysis is conducted to determine the annual cost of each proposal and/or alternative delivered to OUC's transmission system. Each proposal will be evaluated over a range of capacity factors to determine its most economic operating capacity factor category. The calculations for this analysis are performed using electronic spreadsheets.

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Power Supply Requirements

Proposal No. _____
Term _____

Name	Attribute to be Measured	Range of Raw Score	Actual Raw Score	Weighting Factor*	Estimated Maximum Score*	Weighted Score
Pricing Criteria						
0 - 5 years		0-30			30	
0 -10 years		0-30			30	
Subtotal					60	

Note: * *Estimated maximum score shown is based on 8 percent level of savings with respect to the affected costs. Should the projected savings for the proposal exceed this level, the actual score will exceed the estimated maximum score by a similar proportion.*

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Power Supply Requirements

Name	Attribute to be Measured	Range of Raw Score	Actual Raw Score	Weighting Factor	Maximum Score	Weighted Score
Non-Price Criteria						
Components of Power Cost	• All fixed costs are in the demand portion of the rate and all variable costs are in the variable portion of the rate ..... 1 • No ratchet provision included 1	0-2		1	2.0	
Flexibility & Term	• OUC's sole option to increase or decrease contract purchases with reasonable notice ..... 5 • OUC's sole option to select type of purchases, payment provision, pricing method, etc. 5	0-5 0-5		1	10.0	
Fuel Type	Reduces coal as a % of total energy mix over the Study Period • 30% or higher ..... 2.0 • 20% - 29% ..... 1.0 • 10% - 19% 0.5	0-2		1	2.0	
Dispatchability	• Includes no minimum take provisions (100% dispatchable) .... 4 • Available for economy transactions ..... 3 • Scheduling provisions allow for change within one hour. 3	0-4 0-3 0-3		1	10.0	
Firm Supply	• Includes a minimum capacity reserves of 20% and backup *energy or* equivalent arrangement ..... 4 • Includes reasonable penalties for non-performance (dollar amount). ..... 2 • Provides suitable guarantees (instrument). 2	0-4 0-2 0-2		1	8.0	

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Power Supply Requirements

Name	Attribute to be Measured	Range of Raw Score	Actual Raw Score	Weighting Factor	Maximum Score	Weighted Score
Technology Risk	• Commercially proven technology ..... 2 • Relatively new application of existing technology ..... 1 • Relatively new technology ..... 0 • Demonstration project 0	0-2		1	20	
Environmental Effects	• Includes measures beyond regulatory requirements to minimize any adverse environmental impacts. ..... 3 • Offers renewable generating resources 1	0-3 0-1		1	40	
Transmission	• Utilizes no intermediate transmission systems. ..... 2 • Utilizes one intermediate transmission systems. ..... 1 • Utilizes two or more intermediate transmission systems. 0	0-2		1	20	
Subtotal					40	
Proposal Total						

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ORLANDO UTILITIES COMMISSION
APPENDIX D
STAGE THREE SCREENING SUMMARY

Power Supply Requirements **Proposal No. ____**

PRICE SCORE	Maximum Score	Actual Score	
		Raw Score	Weighted Score
Internal Rate of Return	60*	____	____
Subtotal Price Score	60*	____	____

NON-PRICE SCORE	Maximum Score	Actual Score	
		Raw Score	Weighted Score
Components of Power Cost	2.0	____	____
All fixed costs in capacity charge.			
All variable costs in energy charge.		____	____
Flexibility and Term	10.0	____	____
Sole option to change purchases.			
Sole option to select type of purchase, payment provision, pricing method, etc.		____	____
Sole option to adjust the contract term			
Fuel Type	2.0	____	____
Fuel diversity			
Dispatchability	10.0	____	____
No minimum take provisions			
Available for economy transactions			
Scheduling provisions			
Firm Supply	8.0	____	____
Suitable arrangements for firming capacity			
For unit sale: Performance penalty			
Corporate guarantee			
Technology Risk	2.0	____	____
Commercially proven technology			
Environmental Effects	4.0	____	____
Extraordinary measures			
Renewable resources			
Transmission	2.0	____	____
No intermediate transmission systems			
Subtotal Non-Price Score	40	____	____
TOTAL SCORE	100*	____	____

NOTE: * *Price Score and total score may be greater or less than 60 and 100, respectively, depending on the Internal Rate of Return Score.*

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 6
COMPANY/
WITNESS: Orlando Utilities Commission
DATE: 4-23-01

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 7
COMPANY/
WITNESS: Thurmond
DATE: 4-23-01

RESUME OF

STEPHEN L. THUMB

EDUCATION

C.P.A.	West Virginia, 1977
M.B.A.	Finance, American University, 1972 (cum laude)
B.S.	Chemical Engineering, Northwestern University, 1967

EXPERIENCE

Current Position

Stephen Thumb joined Energy Ventures Analysis in 1988 and became a partner in 1990. Mr. Thumb directs EVA's natural gas and oil practice. Mr. Thumb is responsible for the FUELCAST Service, which is a multi-client service providing semi-annual forecasts of demand, supply, and price for natural gas, coal, oil, and emission allowances. The types of projects in which Mr. Thumb has been involved are described below:

Natural Gas Procurement
Evaluates natural gas procurement strategies for consumers taking into account the changing regulatory environment. For example, the procurement must address the mix of long- and short-term supply contracts, the mix of firm and interruptible transportation, and the mix of services.

Natural Gas/Oil Industry Analyses
Evaluates the natural gas and oil industries for clients concerned about supply options and availability. Studies have focused on structural issues such as pipeline capacity.

Forecasting
Provides clients with general or customized forecasts of natural gas and oil prices. Natural gas price forecasts are developed on both a wellhead or burner tip basis. Oil prices are developed for crude and refined oil products.

Acquisition and Divestiture Analysis
Performs analyses for companies considering acquisitions or divestitures. One project involved an acquisition analysis of an independent exploration and production firm with substantial natural gas reserves in the northeastern geological provinces. Another involved the acquisition of an affiliate coal mining operation.

General Industry Studies
Authored or coauthored over 20 reports for EPRI and GRI on a wide variety of topics, including fuel switching, structural issues affecting regional basis differentials, the integration of natural gas within the power industry, the capability of pipelines to meet the requirement of new power generation units, the competition between gas and coal for new capacity and existing generation, and other topics.

Prior Experience

Before joining Energy Ventures Analysis, Mr. Thumb had 15 years of diversified industry experience having worked for three Fortune 100 companies. From 1982 to 1988, Mr. Thumb worked for Burlington Northern, Inc., most recently as Vice President of Planning for Meridian Oil, a wholly-owned subsidiary. Mr. Thumb's responsibilities included acquisitions, economic analysis, strategic plans, annual budgeting. Mr. Thumb's most significant accomplishment was the identification, analysis, and implementation of two major energy-related acquisitions (the El Paso Co. and Southland Royalty).

From 1974 to 1982, Mr. Thumb worked for Ashland Oil, Inc., most recently as Executive Assistant to the Chief Executive Officer. Mr. Thumb managed a number of special projects in the areas of operations and finance such as the development and marketing of a $200 million institutional drilling fund and an analysis of the firm's largest international oil production contract. Mr. Thumb also established a special employee incentive program for an oil and gas subsidiary in consultation with human resources and coordinated the redesign of an exploration and production accounting function.

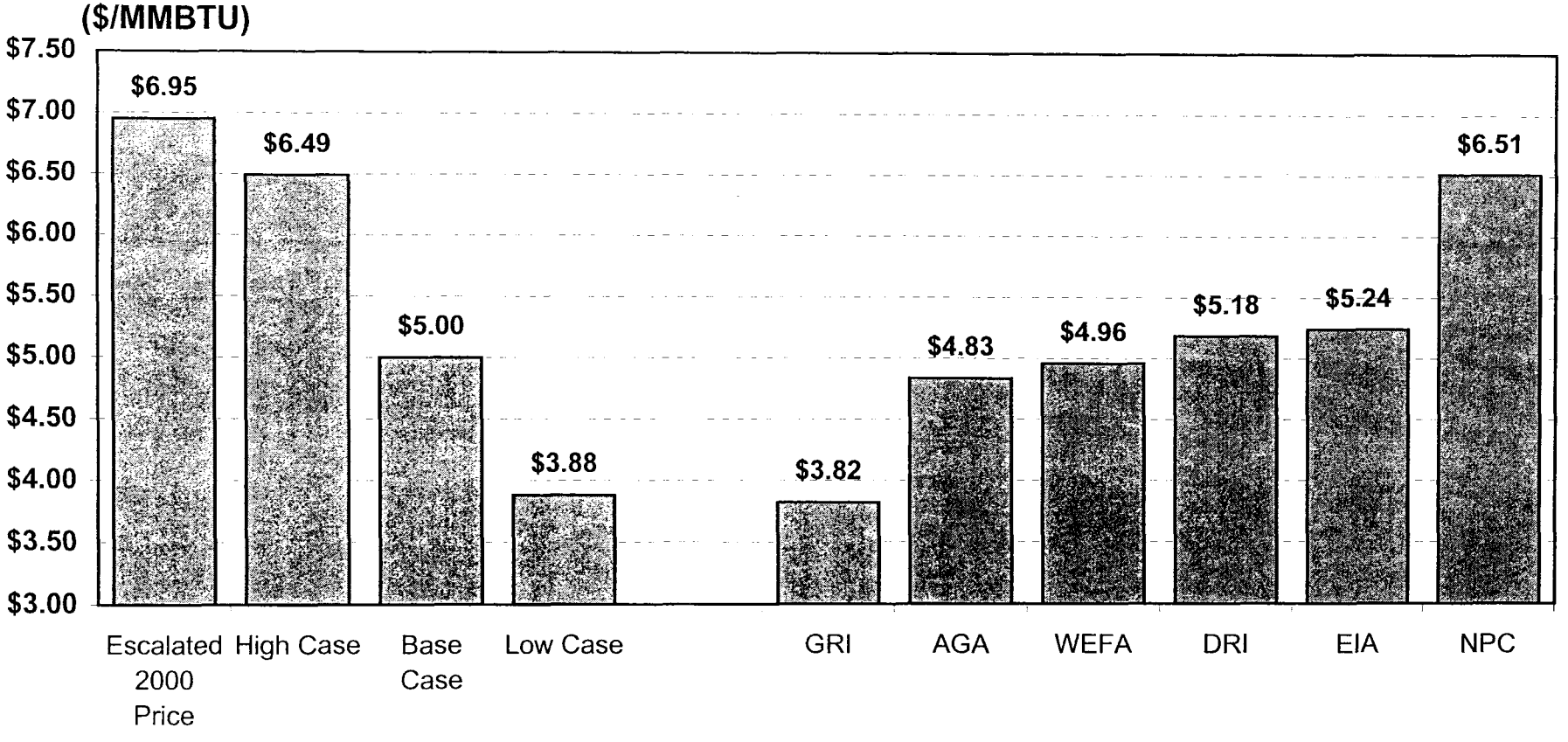
From 1972 to 1974, Mr. Thumb worked for Nuclear Fuel Services, a wholly-owned subsidiary of Getty Oil. Mr. Thumb, as Manager for Financial Planning, was responsible for the preparation of economic analyses and long- and short-term plans. He also assisted the controller in numerous accounting functions.

From 1967 to 1972, Mr. Thumb worked for the Division of Naval Reactors, a joint operation of the Atomic Energy Commission and the U.S. Navy, as an engineer in the fluid design section for surface ships and the radiological and chemical sections. From 1965 to 1967, Mr. Thumb worked at the Naval Ordinance Plant as a chemical and metallurgical technician.

UPDATED PETROLEUM PRODUCTS PRICE FORECAST

Year	1A.5-3 WTI-Constant	
	Initial	Update
2000	$30.26	$30.82
2001	$26.61	$27.36
2002	$23.70	$24.14
2003	$21.00	$21.00
2004	$19.50	$19.50
2005	$18.50	$18.50
2006	$17.50	$18.25
2007	$17.00	$18.25
2008	$16.50	$18.25
2009	$16.00	$18.25
2010	$16.00	$18.50
2011	$15.50	$18.50
2012	$15.50	$18.50
2013	$15.50	$18.50
2014	$15.54	$18.50
2015	$15.58	$18.50
2016	$15.66	$18.75
2017	$15.73	$18.75
2018	$15.81	$18.75
2019	$15.89	$18.75

COMPARISON TO OTHER FORECASTS
(Delivered Natural Gas Price-Current $)
2015



GRI: Gas Research Institute, AGA: American Gas Association, NPC: National Petroleum Council, WEFA: The WEFA Group, DRI: DRI
Source: Energy Information Administration, *Annual Energy Outlook 2001*, December 2000.

FIRE Model Results

Load Shifting Programs

	RIM	Part	TRC
OUC			
Base Case			
Res - DLC	0.49	1.00	2.33
Comm - OPBC	0.98	0.00	0.62
High Fuel Case			
Res - DLC	0.49	1.00	2.34
Comm - OPBC	0.98	0.00	0.62
KUA			
Base Case			
Res - Build Smart	0.44	0.71	0.32
Comm - OPBC	0.37	0.04	0.61
High Fuel Case			
Res - Build Smart	0.51	0.79	0.41
Comm - OPBC	0.38	0.04	0.61
FMPA			
Base Case			
Res - DLC	0.40	1.00	1.81
Comm - OPBC	0.53	0.02	0.49
High Fuel Case			
Res - DLC	0.40	1.00	1.82
Comm - OPBC	0.53	0.02	0.49

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 8
COMPANY/
WITNESS: Schuepbach
DATE: 4-23-01

EXHIBIT NO. 9

Docket No: 010142-EM

Parties: Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, Southern Company-Florida, LLC

Description: FPSC STAFF COMPOSITE EXHIBIT

(1) Deposition Transcript of Frederick F. Haddad, Jr.

(2) Deposition Transcript of Myron Rollins

(3) Exhibit 1 from Deposition of Myron Rollins

(4) Late-filed Exhibit 2 from Deposition of Myron Rollins

(5) Proof of Publication of Newspaper Notice of Hearing and Prehearing

Proffered By: Commission Staff

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 9
COMPANY/
WITNESS: FPSC Staff
DATE: 4-23-01

FPSC STAFF COMPOSITE EXHIBIT
TABLE OF CONTENTS

Deposition Transcripts

Frederick F. Haddad, Jr. 1

Myron Rollins 34

Deposition Exhibits

Exhibit 1 from Deposition of Myron Rollins 63

Late-filed Exhibit 2 from Deposition of Myron Rollins 73

Newspaper Notice

Proof of Publication of Newspaper Notice of Hearing and Prehearing 75

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010142-EM

In the Matter of

JOINT PETITION FOR DETERMINATION OF NEED FOR PROPOSED STANTON ENERGY CENTER COMBINED CYCLE UNIT A BY ORLANDO UTILITIES COMMISSION, KISSIMMEE UTILITY AUTHORITY, FLORIDA MUNICIPAL POWER AGENCY, AND SOUTHERN COMPANY-FLORIDA, LLC.
_____/

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DEPOSITION OF:	FREDERICK F. HADDAD, JR.
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Florida Public Service Commission 2540 Shumard Oak Boulevard Gerald L. Gunter Building Room 362 Tallahassee, Florida 32399
TIME:	Commenced at 11:05 a.m. Concluded at 12:00 p.m.
DATE:	Friday, April 6, 2001
REPORTED BY:	TRICIA DeMARTE Official FPSC Reporter

APPEARANCES:

ROY C. YOUNG, Young, van Assenderp, Varnadoe & Anderson, P. A., appearing on behalf of Orlando Utilities Commission and Kissimmee Utility Authority.

D. BRUCE MAY, Holland & Knight, 315 South Calhoun Street, Suite 600, Tallahassee, Florida 32302, appearing on behalf of Southern Company-Florida, LLC.

WILLIAM COCHRAN KEATING, L-Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

ALSO PRESENT:

MYRON ROLLINS, Black & Veatch Corporation
MARK FUTRELL and LEE COLSON, FPSC Division of Safety & Electric Reliability

INDEX

WITNESS

NAME:	PAGE NO.
FREDERICK F. HADDAD, JR.	
Direct Examination by Mr. Keating	5

MISCELLANEOUS

STIPULATION	4
ERRATA SHEET	31
CERTIFICATE OF OATH	32
CERTIFICATE OF REPORTER	33

STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

FREDERICK F. HADDAD, JR.

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MR. KEATING:

Q Good morning. Let's get started. If I could just get you to state your name and business address for the record.

A My name is Frederick F. Haddad, Jr., Post Office Box 3193, Orlando, Florida, zip code, 32802.

Q Do you have your prefiled testimony with you?

A Yes, I do.

Q If you could, turn to Page 5 of your prefiled testimony. Particularly down around Line 18, you discuss the joint development project. On Line 22, you state that the three utilities – and that is OUC, KUA, and FMPA – agree to pursue a joint development project. When did those three utilities begin discussions that resulted in the decision to pursue a joint development project?

A My recollection is, OUC originally pursued this strategy that we've discussed on its own. And at the time KUA and FMPA's chief executive officers approached me on the possibility of doing another joint development. We've done a number of joint development projects in the past

together. It looked like another opportunity because both needed capacity at the time.

So our agreement was that we would pursue with the structure that OUC was pursuing on its own. It looked like it would fit, and they'd evaluate it. We would be their agent to negotiate it and we would evaluate – they would evaluate individually the package we put together to determine if it fit their needs, and then if it did, then they'd participate.

Q About what time frame?

A May. It would have been May of 2000 would have been when their involvement started, I believe.

Q And was – I guess about what time frame did the three utilities agree to go forward with the joint development project?

A There were a few decision points. The first decision point was to basically participate in the RFP processes that we've outlined for you. And there was a cost-sharing mechanism that we had together there.

The second was, we basically had the fundamentals of the package put together prior to filing our need application. We gave them a last look there.

And then the only other decision point they have is, if at the end of the day, obviously these agreements, although a couple of them are in place, are contingent on

all collateral documents being signed, that would be a final decision point for them.

Q So it was -- let me make sure. It was about May 2000 when discussions began?

A Yes.

Q And again, the time frame for -- there was an agreement to participate in the RFP processes, you said that was sort of the first agreement?

A Yes.

Q About what time frame was that?

A I believe I have a schedule here. Could you repeat the question for me again so I make sure --

Q Sure. What I'm looking for is just the time frame, you know, roughly the month, year, when OUC, KUA, and FMPA agreed to participate in the RFP processes jointly.

A By my records that was May 11th is the closest approximate date. At that time, we had an agreement between the parties to have them participate in the solicitation. We actually had to modify our RFP because in KUA's case we included the Cane Island site as another opportunity if that brought an advantage, an economic advantage, to the joint development partners if that site was better than Stanton for any reason.

Q I think I just need a little bit more

clarification. You said it was roughly -- you said it was May 11th or May 2000 when the utilities came to the agreement to participate in the RFP processes jointly, and what I'm interested in finding out is what time frame the utilities began discussions of pursuing the joint development project. I think previously you'd said it was May 2000, and I'm wondering if those two dates were -- if you had in mind the same activity for those two dates.

A We were well along the way in our process before KUA and FMPA entered in the discussion. So there was a relatively short period of time, because we initially -- our documents went out the 24th of May. So there was a very short time frame. Basically all we had to do was include their data, modify the RFPs accordingly, modify the scope of Black & Veatch's work, and move right along because obviously schedule was critical to us. So it didn't -- there wasn't a lot of time frame. And May was the time frame, I believe, that all of this basically happened.

Q Okay. So that would be the time frame that KUA and FMPA, you know, expressed their interest and began some discussions with OUC about a joint development project, and that's also roughly the same time frame that the three utilities agreed to participate in the project?

A Yes. We moved rather quickly from the initial

expression of interest they had. We did a quick look at our system to see if we could accommodate their needs along with ours and still keep the project viable, and then very quickly, got approval from their boards of a memorandum of understanding, and then moved right into the RFP process.

Q What other options did OUC consider before agreeing to pursue a joint development project with KUA and FMPA?

A Other options, can you give me an example of --

Q Well, I guess essentially what would the -- I think you said that before their involvement OUC had pursued a certain course towards, I guess, finding some additional capacity or some additional power.

A Okay.

Q What sort of options was OUC looking at before KUA and FMPA got involved?

A Our asset restructuring was a three-part program. We sold the Indian River steam units. They were our oldest and least efficient operating units. We put a financial hedging program in place, and then the money from the proceeds of the Indian River sale were set aside by the City of Orlando and the Orlando Utilities Commission for either reduction of generation debt or redeployment into new, more efficient technologies for our

next capacity addition.

So we obviously had a purchased power agreement with Reliant. We have options to extend that. We looked at the economics of that. We looked at where we wanted our generation portfolio to be from a competitive standpoint and taking into account uncertainties of deregulation. And that led to the basic structure of the deal we were working on, the 65/35 percent structure. And we were proceeding to do basically another look. We looked for joint partners when we did the initial solicitation of interest for the Indian River sale. So we found that having a partnership type arrangement gave us some additional flexibility. Particularly, our goal was to get larger economies of scale and have a large partner as we face the uncertainties of deregulation.

So it was consistent with our long-term strategy to go out and look at joint development opportunities, continue to review self-build opportunities, which is always an option to us, and, of course, go out for a third-party request just globally just to see if there was anything else out there that represented a better economic interest for our ratepayers long term. So we decided to do all three of those processes in parallel.

That was on its way prior to -- that was the strategy that was laid out; that was the strategy that OUC

and -- I mean, I'm sorry, KUA and FMPA felt a very good strategy to determine the competitive opportunities in the marketplace. And again, building on the relationships we had before, we felt it was fine. It required us to probably go out for additional capacity because now we had two partners that were taking a piece of the capacity that we could arguably use all ourselves if we wanted to. But we found the joint development arrangements to work well for all the parties involved, diversify the risk a little bit of each of the asset investments that we made, and we are very comfortable with that approach.

Q So, in essence, KUA and FMPA kind of came in at a point in the game where OUC had already taken the certain strategy, and I guess my follow-up question would be: Was there any -- I think you told me that OUC had, you know, analyzed the alternatives available to it before KUA and FMPA came into the picture. Was there any economic analysis after KUA and FMPA joined in the project that said this is -- the joint development project is a good deal, or was it just a matter of going forward with what you had in place? Let me restate it.

What additional analysis would have been done after KUA and FMPA expressed some interest?

A Well, obviously, the biggest concern that we would have is, there's a block of generation, basically

7 percent of this project, between the two of them that would now be someone else's capacity. So the first thing that we had to check was, do we have capacity options -- number one, do we have the load requirement and reserve requirement covered? Do we have sufficient options under our Reliant agreement as a minimum to cover the generation that would now be owned by two other municipalities?

So we had to rerun an analysis. And basically it showed us that we still showed a benefit, even though we basically have to nominate a higher amount off the Reliant option contract to cover the capacity that will now be owned or purchased by FMPA and KUA. But that case and analysis still showed benefit to us. And again -- and the things the cash flow analysis doesn't show you is the value of spreading out risk, take the value of a portfolio of assets as opposed to very large investments and very specific assets and subject to their reliability and fuel pricing and all.

MR. KEATING: Would anybody mind if we went off the record for a minute?

MR. YOUNG: No.

(Discussion off the record.)

BY MR. KEATING:

Q You had mentioned earlier that OUC before KUA and FMPA had expressed interest in this project had -- was

going forward with the 65/35 ownership split with another entity. If you could, just explain how OUC determined that that was the best course of action.

A What we did, when we developed the asset restructuring program, OUC prior to that time had always owned its component of each generating unit that it was involved with. It either fully owned or partially owned with other participants, but it was always full ownership. As we face deregulation and we looked at other industries, the effect in other industries of deregulation itself, it looked reasonable that you probably had 20 to 25 percent of your retail customers exposed; that is, the exposure to the loss of retail customers in an open competitive environment. It seemed to be consistent with the telecommunications industry, for example.

So one of our strategies -- and the implementation of that strategy actually occurred with the Indian River steam sale -- was to get a component of our asset base -- and our target is 20 to 30 percent right now of our asset base -- in purchased power. That then, let's say, in the catastrophic case to our retail customers, which we always want to protect them against, you know, if deregulation came, 20 percent of the customer base went away, we would have the ability to quickly move out of the generation funding obligation for about that much load to

be served so to minimize the burden on the remaining retail customer of an asset that may be stranded in a deregulated environment. So we recognized the cost factors and things associated with that, but we deliberately wanted, as we moved in each transaction, to try to maintain 20 to 30 percent purchased power in our portfolio.

With this deal, the 35/65 did that for us. Our total asset base will be at actually 28 when you include the Reliant purchase components that it will have, but it was consistent with our strategy to target this range of purchased power at least until the market changed or deregulation came, and we knew what the rules would be, and we'd make another assessment. So just allow us to move with the market as it changed.

Q Thank you. Were you involved with the development of the request for proposals?

A Yes.

Q When was the joint development RFP developed and when was it issued?

A I believe I have this. The joint development RFP was issued on May 26th, 2000.

I can go back. There was a solicitation of interest letter that went out on March 20th to determine if firms were interested in participating in that project.

MR. YOUNG: 2000?

THE WITNESS: In 2000; March 20th, 2000.

BY MR. KEATING:

Q Again, what time frame was the joint development RFP developed, not necessarily issued, but prior to that when did you begin developing that?

A We actually started work on that – I'm talking the very generic components working toward the final product – right after the Indian River sale went into effect, in October 1999. Again, the strategy was to – we knew we were going to take those cash proceeds and look for opportunities for reinvestment. The initial term of the Reliant purchased power agreement ends September – the end of September '03. So we were looking for an October '03 start date. We backed up, and when you run that schedule, you immediately have to get to work.

Q Could you explain why two separate RFPs were developed as opposed to one which could have contemplated any type of arrangement for power?

A There were multiple criteria there. The most obvious one is, we felt there's – it's a different project, one that utilizes your site, your resources that your ratepayers have been investing in since day one versus someone that brings their own package, their own site, and their own asset to the table for consideration.

So the first differentiating component was, we wanted to separate on-site activities from off-site activities. And the second was for a joint development partner. Again, relating to our overall asset restructuring, we were looking for an entity that had what appeared to us to be a long-term commitment to the generation business even post-deregulation, a record a success in the generation business, and one that could arguably give us a smaller muni – a larger economy of scale for dealing in the commodities markets as well as parts and services and things like that.

Obviously, if we're using our own site, we're right there. We have an operation right there. That partner we want to select much more carefully than someone we would just physically buy power from as a third-party from another location that just transmit to us. So we're looking for the partnership. We're recognizing that both of us would be on the same site together, so you want someone that shares maybe similar values in operating reliability and approach to the market and serving – understanding the needs of serving retail, things like that.

Q On Page 6 of your prefiled testimony you state that the joint development RFP was sent to 35 utilities and developers. How did you decide who to include in that

list of 35?

A We looked in the periodicals. There's typically rankings that are issued of the largest generators, the largest power marketers both nationally and internationally. We also obviously have -- because we run a wholesale marketing business, we have numerous contacts in the industry that we transact with on a regular basis. Those were the types of activities we used to determine who we use.

Q Was the joint development RFP advertised nationally?

A The joint development RFP was sent to the specific entities. The third-party RFP -- again, we wanted to carefully select the partner if we were going to consider that option. The third-party RFP was advertised nationally and actually placed on the Internet as well.

Q Further down on Page 6, starting at Line 19, you described the power supply RFP process.

MR. YOUNG: Just a second.

(Discussion off the record.)

BY MR. KEATING:

Q Page 6, Line 19, where you begin to discuss or describe the power supply RFP process.

A Okay.

Q I was curious to find out the time frame that

the power supply RFP began development in and the time that it was actually issued.

A Okay. We felt the need to keep those two processes independent. So we commissioned R.W. Beck to both develop that RFP, to issue it, and to evaluate it. It went out in a parallel path with the joint development on the -- I show that going out on May 24th.

Q So was it developed in roughly the same time frame as the joint development RFP --

A Yes.

Q -- i.e., from roughly beginning in October '99 through to the time it was issued?

A I don't have the date we formally commissioned R.W. Beck. They had been doing quite a bit of work for us in wholesale price projections, and we started the process of developing the two both in-house and with R.W. Beck. I don't have the specific date we started with R.W. Beck. They went out -- they were issued within two days of each other.

Q What is the current build-out capacity of the Stanton site?

A The site is currently permitted for 2,000 megawatts.

Q Has this been designated for any particular fuel?

A The -- no.

Q On Page 7 of your testimony, beginning on Line 5, you discuss the self-build alternative that Black & Veatch developed.

A Can I ask Roy question?

MR. YOUNG: Can we go off the record?

MR. KEATING: Sure.

(Discussion off the record.)

BY MR. KEATING:

Q Just to clarify, you said earlier that there was no certain fuel that the site had been permitted for or designated for. Is there any clarification to your response?

A Yes. The site originally envisioned coal and the original certification mentioned coal as the fuel, at least for the particular unit that we were building. We subsequently modified later our certification to include landfill gas and natural gas. So those are the primary fuels designated for the site.

Q Again, looking at Page 7, beginning at Line 5 of the testimony, you discuss the self-build alternative that Black & Veatch developed. Did OUC specifically direct Black & Veatch to provide cost estimates for two configurations of combined cycle units?

A Yes.

Q How did OUC come to the conclusion that combined cycle was the appropriate generation resource to use as the self-build alternative?

A We looked for two things. We looked for -- our attempt is to get the most efficient technology that's reliable and demonstrated reliable in service, number one. The second, and more importantly from our perspective, was to maintain fuel diversity.

We have plenty of coal, and we felt that long term, although that is the most economical fuel at this current time, it's been our experience that the fuel markets change and the ability to have an asset base with fuel diversity has been in the best interest of our customers. So that led us to natural gas. We needed additional natural gas in the portfolio. The second phase of that was to attempt to get the most efficient technology for burning natural gas when we made that decision.

Q I think you've mentioned it before. I assume you are familiar with OUC's power purchase agreement with Reliant.

A Yes.

Q When is this agreement scheduled to end?

A The primary term of the agreement is scheduled to end September 30th, 2003.

Q And is there an option available to OUC to extend the agreement?

A Yes, there is.

Q Okay. Is there a set term for any extension?

A The -- it can be up to four years, nominated each year.

Q Okay. Nominated each year. I'm not sure -- does that mean it would be renewed yearly up to four years?

A The structure allows us the option to nominate up to 500 megawatts for up to four years. We can nominate less than that in hundred megawatt increments. Once we nominate down, we're not allowed to nominate back up.

Q Did OUC evaluate extending the Reliant agreement as an alternative -- or against the alternatives resulting from the RFPs as well as the self-build?

A Yes, we did.

Q What were the results of OUC's analysis?

A The results were that this joint development project was more cost-effective than relying solely on the Reliant option.

Q Page 10 of your testimony, beginning on Line 18, you address alternate fuels. Does the agreement with Southern, well, Southern-Florida allow for modifications to the unit? And particularly what I had in mind was a

conversion to IGCC.

A The IGCC is not a fundamental component of our agreement. The IGCC would have to be a block of equipment separate so that from the project standpoint it's just fuel delivery, which is Btus of gas delivered whether it from coal gasification or the pipeline. That's the way it would be handled with the project boundary. The IGCC would be a separate stand-alone project that would be evaluated against commodity fuel prices as the alternative, continued buying in the market.

Q So you're saying that if the parties wish to convert to an IGCC unit, they would require a separate agreement? It's not contemplated in the existing agreement with Southern?

A It is not contemplated in the existing agreement. That would be a separate independent business transaction.

Q Does OUC have an option to purchase KUA's share of its capacity from Stanton A?

A We have an agreement to purchase for a three-year period the excess capacity from KUA's component of the project.

Q Were the costs of that purchase factored into OUC's evaluation of Stanton A?

A Yes.

Q Maybe I wasn't clear from your response. Has OUC decided to exercise that option?

A Yes.

Q Page 12 of your testimony at Lines 12 and 13, you state that the project will pay OUC an annual lease for the site.

A Yes.

Q What party or parties make up the "project" as you've used that term here?

A OUC actually owns all of the land on the Stanton site except for ownership rights under common facilities on Stanton 1 and 2 that KUA and FMPA have interest in. So this site is basically OUC-owned property, so lease payments flow back to OUC.

Q From which of the parties? From the other three?

A From the project.

Q From the project. And the project consists of which entities?

A Southern, OUC, KUA, and FMPA.

Q So the lease fees are allocated to KUA and FMPA?

A The lease payment obligations are allocated to each in their ownership share of the project.

Q Were the lease fees factored into OUC's evaluation of Stanton A?

A Yes.

Q On the same page at Lines 17 through 19, you state that OUC is in negotiations with FGT and Gulfstream for gas transportation. Do you know what the status of the Gulfstream pipeline project is?

A I believe they have their permits to construct. I'm not aware that they have initiated construction yet of the first phase.

Q Do you know what the current projected in-service date for the Gulfstream pipeline is?

A The projected in-service date for Phase I is the summer of 2002. Phase I goes as far as Intercession City. Gulfstream would have to initiate a Phase II expansion in order to deliver gas to the Stanton site.

Q So just to clarify, is Phase I from Mobile Bay to Intercession City?

A Yes.

Q And I believe you said Phase I has received all the permitting that's required.

A That's what I read in the media. Gulfstream has indicated that to us in formal decisions as well.

Q Do you know when Gulfstream would need to begin construction to meet the summer 2002 projected in-service date?

A Gulfstream cannot meet a summer '02 in-service

date to the Stanton Energy Center. They're projecting they could – if they entered contract in the near term, in the near months, they would have to file. And if they were successful, they could be there as early as summer '03, but there are a lot of variables that would affect that.

Q So that would be about the earliest date that they could get to the Stanton –

A Yes.

Q When would they – when would Gulfstream need to begin construction to complete Phase I with the summer 2002 in-service date?

A I'm not sure.

Q Are you aware of any legal action that could jeopardize the summer 2002 in-service date for Phase I?

A I'm not aware of any specific legal action.

Q Okay. What is the current status of OUC's negotiations with FGT and Gulfstream for transportation?

A OUC has a contract with Florida Gas Transmission that was approved by our Commission at its most recent meeting here in April for the majority of the gas supply for Stanton A. Those contracts have been delivered signed by FGT, and it will be executed shortly by OUC on behalf of the project.

Q About how much of the total gas supply is that?

A It's about 80 to 85 percent of the normal gas supply, the summer volumes.

Q Is that contract entirely for firm transportation, or is there a mix with some firm and nonfirm transportation?

A It's firm.

Q And what is the current status of any negotiations with Gulfstream for transportation?

A We're currently negotiating with Gulfstream to -- we still feel there's an opportunity for them to provide gas transportation to the site. We have some flexibility in our FGT arrangement to allow that to happen. We think in the long-term, best interest of our customers, two pipelines would be best. And we think we have retained enough options in the way we have approached transportation to allow that to happen.

Q How would you describe, I guess, the stage of those negotiations?

A The -- with?

Q With Gulfstream.

A With Gulfstream. They're ongoing. There was some change in the activity when they changed ownership to a degree. We obviously as a project wanted to lock down a transportation commitment to remove that uncertainty. So at this point with Gulfstream, we're comfortable we're in

a good position to negotiate a competitive deal there. And the negotiations are going, they're friendly, they're productive. We've started in, in fact, as of this week with stepping up the pace of those negotiations now that we do have one supply at least under contract.

Q Will OUC or Southern acquire fuel for Stanton A once it's in service?

A OUC will be the fuel agent for the project as long as OUC has the rights to the majority of capacity on the project.

Q And how will the cost of fuel be recovered?

A Cost of fuel will be a direct pass-through to the participants for the capacity that they are taking.

Q So it would just be allocated based on their capacity share?

A On the use.

Q On the use.

A The transportation would be allocated on ownership share of the project and paid by the consumer of the energy from the project. The gas commodity will be paid by whichever of the partners uses the energy off the plant.

Q I think that's it. I don't have any other questions. Well, I may have some other questions.

A Okay.

(Discussion off the record.)

Q According to -- well, is it correct that according to OUC's Ten-Year Site Plans that OUC has elected to use a 15 percent reserve margin criterion?

A That's correct.

Q How critical is the Stanton A project to OUC for maintaining that 15 percent reserve margin?

A We feel it's necessary to maintain that margin.

Q And is it -- let me rephrase it. Is it necessary immediately? And what I mean is, is it necessary as of the date that it's planned to be in service to maintain the 15 percent reserve margin?

A Yes.

Q What options does OUC have in its arrangement with Southern that would help them to maintain the 15 percent reserve margin without new -- without any additional generation or capacity purchases?

A I'm not sure I understand the question.

MR. KEATING: Could we go off the record for just a moment?

MR. YOUNG: Sure.

(Discussion off the record.)

BY MR. KEATING:

Q To rephrase the question. What I'm interested in finding out is, based on the agreements in this joint

project between OUC and Southern and perhaps with KUA and FMPA, what options are available under the structure that would allow OUC to continue to take the additional power it needs to maintain this 15 percent reserve margin without any other additions necessary?

A The options that are included in our contract. Obviously, the plant right now is fully subscribed to OUC, KUA, and FMPA's needs for capacity to maintain its reserves. We have an internal agreement between the three municipals that should either KUA or FMPA not need capacity to meet their own needs, we have the first right to buy that -- their share of that capacity, whatever share is freed up to support our own needs as well.

With the full output of Stanton Energy Center Unit A, we still have to exercise either some component of the Reliant options for extension or other opportunities that may come up in the marketplace to maintain reserves.

Q And I'm not sure if you will be able to tell me the answer to this off the top of your head, but if OUC exercised -- since all the options that were available to -- or had the opportunity to do so under the structure of the arrangement with Southern, KUA, and FMPA, when would OUC need additional generation?

A If OUC let the current term of the Reliant agreement expire in September 2003, we would need capacity

right away. The Stanton Energy Center Unit A does not fulfill our total capacity requirement if we let the Reliant contract expire. We would still need additional capacity to support our reserve margins beyond this project.

MR. KEATING: Okay. I think I can safely say that I have no further questions.

MR. YOUNG: Okay.

MR. KEATING: Thank you.

(Deposition concluded at 12:00 p.m.)

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ERRATA SHEET
DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 010142-EM
NAME: FREDERICK F. HADDAD, JR.
DATE: APRIL 6, 2001

PAGE	LINE	CHANGE

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

_____ _____

DATE **FREDERICK F. HADDAD, JR.**

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that FREDERICK F. HADDAD, JR., personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 11th day of April, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of FREDERICK F. HADDAD, JR.

I FURTHER CERTIFY that this transcript, consisting of 30 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 11th DAY OF APRIL, 2001.

Tricia DeMarte

TRICIA DeMARTE
Official FPSC Reporter
(850)413-6736

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010142-EM

In the Matter of

JOINT PETITION FOR DETERMINATION OF NEED FOR PROPOSED STANTON ENERGY CENTER COMBINED CYCLE UNIT A BY ORLANDO UTILITIES COMMISSION, KISSIMMEE UTILITY AUTHORITY, FLORIDA MUNICIPAL POWER AGENCY, AND SOUTHERN COMPANY-FLORIDA, LLC.

_____/

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DEPOSITION OF:	MYRON ROLLINS
TAKEN AT THE INSTANCE OF:	The Staff of the Florida Public Service Commission
PLACE:	Florida Public Service Commission 2540 Shumard Oak Boulevard Gerald L. Gunter Building Room 362 Tallahassee, Florida 32399
TIME:	Commenced at 12:15 p.m. Concluded at 1:00 p.m.
DATE:	Friday, April 6, 2001
REPORTED BY:	TRICIA DeMARTE Official FPSC Reporter

INDEX

WITNESS

NAME:	PAGE NO.
MYRON ROLLINS	
Direct Examination by Mr. Keating	6

EXHIBITS

NUMBER:		ID.
1	Annual Winter and Summer Reserve Margins for OUC, KUA, and FMPA With and Without Stanton A	10
2	(Late-Filed) Same Gas Cost Estimate for Stanton A	19

MISCELLANEOUS

STIPULATION	5
ERRATA SHEET	27
CERTIFICATE OF OATH	28
CERTIFICATE OF REPORTER	29

APPEARANCES:

ROY C. YOUNG, Young, van Assenderp, Varnadoe & Anderson, P. A., appearing on behalf of Orlando Utilities Commission and Kissimmee Utility Authority.

D. BRUCE MAY, Holland & Knight, 315 South Calhoun Street, Suite 600, Tallahassee, Florida 32302, appearing on behalf of Southern Company-Florida, LLC.

WILLIAM COCHRAN KEATING, L-Florida Public Service Commission, Division of Legal Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0870, appearing on behalf of the Commission Staff.

ALSO PRESENT:

FREDERICK HADDAD, JR., Orlando Utilities Commission
MARK FUTRELL and LEE COLSON, FPSC Division of Safety & Electric Reliability

STIPULATION

IT IS STIPULATED that this deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

IT IS ALSO STIPULATED that any off-the-record conversations are with the consent of the deponent.

PROCEEDINGS

MYRON ROLLINS

appeared as a witness and, after being duly sworn by the court reporter, testified as follows:

DIRECT EXAMINATION

BY MR. KEATING:

Q Good afternoon. Could you state your name and your business address for the record?

A Myron Rollins, 11401 Lamar, Overland Park, Kansas 66211.

Q For my first set of questions I'd like to refer to Volume 1B of OUC's portion of the need for power application. It's Page 6-3 I believe you have in front of you.

A Okay.

Q Are you familiar with this table?

A Somewhat.

Q Would you briefly summarize what that table represents and what the information is on that page?

A The purpose of this table is to show for both -- well, in this particular table it's for winter and the next page is for summer -- to show the capacity requirements for OUC incorporating their load forecast, their firm sales and purchases, and their reserve margin criteria.

Q Is it column -- let's see. About the middle of the table titled "Purchases"--

A Correct.

Q -- could you explain or tell me what the source or the basis for the data in that column is?

A The purchases in that column are the Reliant purchased power agreement, and that extends through September -- October, excuse me, September 30th, 2003, and the 15-megawatt TECO PR purchase that OUC schedules as part of their arrangement with St. Cloud.

Q So for the first two years, 2000, 2001, under "Purchases," that's 15 megawatts from the TECO agreement, and then the balance is from the Reliant purchase?

A Correct.

Q And the same for 2002 and 2003?

A Correct.

Q And then after 2003, that's just the TECO purchase?

A Correct.

Q So I assume then from looking at the table on Page 6-3 that that column assumes OUC will not exercise its option to increase the capacity purchased from Reliant.

A Correct. This table is essentially before alternatives to supply additional capacity are considered

of which some of those are extensions of the Reliant purchase agreement. And there is -- in 2002 and 2003, there is an option that they can increase their Reliant purchase 10 percent from the 525 megawatt.

Q In the table, do you assume that OUC will take that option?

A Not in this table. Further back in the evaluation, we include it as their option, and it's selected as, one, the only real option that they have available in the time frame and, two, the most economic option that they have since it's the only real one.

Q Does OUC use a minimum reserve margin percent as one of its planning criteria?

A Yes, they do.

Q And that's what percent?

A 15 percent.

Q How was that number calculated?

A It's available capacity above their firm system load. It also needs to take into consideration their firm purchases, their PR purchases which include reserves. So reserves are not required on that purchase, and that particular purchase is a TECO 15-megawatt PR purchase. And then it also needs to consider their PR sale to Reedy Creek in which they are also responsible for providing reserves on that PR sale.

Q I'd like – we're still referring to Page 6-3. If you could, just walk through the calculation of the reserve margin for the year 2000.

A Okay. You start out with 1,051 megawatts of retail peak demand. The TECO 15-megawatt PR purchase, which is included in the 608 megawatts of purchase, the fifth column, you subtract that 15 megawatts from the retail peak demand, and then apply – or take that amount times 15 percent, and that is a portion of the required reserves shown in the second column from the left.

Then in the firm sales column, included in that firm sales column is the PR sale to Reedy Creek. You take the amount of that sale and apply 15 percent to it, and then that makes up the rest of the required reserves.

The total sales is just the retail peak demand plus the firm sales. The installed capacity is just their existing installed generating capacity, their ownership share of it.

The purchases are the purchases from TECO and Reedy Creek. Available capacity is the sum of the installed capacity plus the purchases. Available reserves is the difference between available capacity and total sales. And this table is created from a spreadsheet, so there's a one megawatt rounding thing that happens there.

And then required reserves, we have already

discussed the three components of that. That's reserves on their retail demand plus the reserves on the Reedy Creek sale. And I guess I said three; it's really two components, actually.

And then the excessive/deficiency are the difference between the available reserves and the required reserves.

Q Have you prepared any calculations that would show the annual winter and summer reserve margins for OUC, KUA, and FMPA with and without Stanton A?

A Yes, I have.

MR. KEATING: Could we have that marked as -- a copy of that as Deposition Exhibit 1?

(Exhibit 1 marked for identification.)

MR. KEATING: We can title that "Annual Winter and Summer Reserve Margins for OUC, KUA, and FMPA With and Without Stanton A."

(Discussion off the record.)

BY MR. KEATING:

Q Referring to the first page of that exhibit, the OUC and St. Cloud Winter Capacity Balance, including addition of Stanton A, it shows for year 2000 a 19.81 percent reserve margin. And just for clarification, if you could, explain how that's calculated.

A Yes. The reserve margin is simply the available

reserve column divided by the retail peak demand.

Q Do you have knowledge of the capacity resources that are in the state of Florida?

A Some.

Q Okay. I'll pose a hypothetical question. Assuming that Stanton A was not built as proposed, could OUC, KUA, and FMPA meet their capacity needs by purchasing from resources projected to be available in October 2003 in Florida?

A In my opinion, it would be very questionable where they could find the resources in that time frame to be available.

Q Could OUC, KUA, and FMPA purchase from Reliant beginning in October 2003 to meet their capacity needs?

A Certainly OUC can purchase from Reliant because they have an option to extend their agreement. That amount of power would not be enough to meet their full requirements. KUA and FMPA, to my knowledge, have no agreement with Reliant.

Q Would you characterize the need for Stanton A as an economic need?

A No. I would characterize it as a reliability need. OUC, KUA, and FMPA physically need the megawatts to maintain their reserve margins.

Q I have a few questions related to turning to

Page 9 of your prefiled testimony. Starting on Line 21, you state that you evaluated several generating alternatives; is that correct?

A Yes, we did.

Q And those alternatives were evaluated and screened with respect to availability of resources and commercial development; correct?

A Correct.

Q The first question, I just need you to explain what you mean by the phrase "availability of resources" in the context of your testimony.

A Okay. For instance, wind power, for instance. If there isn't adequate wind available for power in the state of Florida, then -- even though you could build a wind generator -- the resource isn't there to support it.

Q So basically would resource be not available if it's just not feasible in this area? Or was there any particular criteria that you used to determine whether a resource was adequately available or an alternative was adequately available?

A No particular criteria other than engineering judgment and knowledge of the situation of the State's resources available, wind, geothermal, those types of things.

Q And then in the context of your testimony, I'd

just like you to explain what -- how you've used the term "commercial development," or what you mean by that term.

A By "commercial development," I mean that the alternative is sufficiently developed to be considered for utility commercial operation. In other words, alternatives that are still in the testing stage and development stage I wouldn't consider to be -- meet the criteria required for commercial development. An example would be fusion. Another example would be MHD. Is it magnetohydrodynamics?

Q I've got a few questions about IGCC technology.

A Okay.

Q Are you familiar with that technology?

A Somewhat.

Q To the extent you can, could you explain the process of how gas is derived from coal and how it's integrated into a power plant?

A I'll try. I won't tell you that that is my strongest suit. But essentially, they process the coal in a gasifier, turn it into a low Btu content fuel gas. There are chemical processes that clean the gas essentially. It is much more like a refinery process than it is a combustion process that you would have in a regular pulverized coal plant or fluidized bed coal plant.

Q Do you know if there are any plants in the U.S.

that are operating with this technology now?

A I believe there are three. There is one at TECO, the Polk station. There is one in Nevada; I think Sierra Pacific had it. And I believe there's one in Illinois or Indiana.

Q Do you know to what extent that technology is being used outside of the U.S.?

A I don't know completely. It's not in heavy use outside of the U.S., but I believe there is, again, a few facilities that are in the development stage.

Q Has Black & Veatch ever been involved with developing an IGCC project?

A To my knowledge, we have not designed and built any IGCC projects. I do know that we were the bank's engineer for one in the Sierra Pacific in Nevada.

Q Was an IGCC alternative considered in this evaluation?

A No, we didn't include it in the list. And I would probably say that that was primarily because of the commercial development criteria. Even though there are a couple in commercial operation, they have both struggled at least at some times in their early lives. It is an alternative. I guess it's awful close to that line where one could consider it to be a commercially viable alternative or, rather, one should still consider it to be

in development.

Q Would you characterize the IGCC technology as an "adequately available" resource as the term is used in your testimony? I think you've told me you wouldn't call it or you wouldn't include it in the -- I guess you've used the term "commercial development" too. You wouldn't necessarily include it in that category yet?

A That's a tough question. I think the technology is probably such that it can be used. But there certainly is much more risk with it than there is conventional -- other solid fuel conventional alternatives.

Q Could Stanton A be converted into an IGCC unit?

A Certainly you could install a gasifier there, yes.

Q Would any other modifications be required?

A There are some modifications required to the combustion turbines in order for them to burn the lower Btu gas.

Q Would those modifications affect the output of the plant?

A It would decrease certainly the efficiency of it some. It may have a detrimental effect on its reliability and availability. I'm not sure to what extent it might change. I think it would change some, the overall output of the plant.

Q Would it have an affect on O&M costs?

A It would likely increase the O&M cost for the plant itself. Plus there's very significant O&M associated with the gasifier portion of the plant.

Q Would the owners of the plant have to require any environmental approvals for a modification to IGCC?

A That's a very interesting question, but in general, it would probably be considered a major modification which would require essentially complete repermitting from their standpoint.

Q Have you looked at the economics of converting Stanton A to an IGCC unit?

A We have, to some degree.

Q What was the result of that analysis?

A Well, the analysis that we looked at is, we looked at three different gasifier technologies and calculated the cost to produce syngas from those technologies, and then one can compare that to the fuel price projections for gas that we've used in our evaluation.

And in those results, the cost for the syngas is in the neighborhood of $5 a million, and that's a 2001 cost. Certainly that cost would escalate through time with increases in the price of coal and increases in O&M cost.

Q And you've prepared a document with that analysis; is that correct?

A Yes, we have.

Q Okay. I understand that --

MR. MAY: Could we go off the record just a second?

MR. KEATING: Yes, let's go off the record.

(Discussion off the record.)

BY MR. KEATING:

Q Could you walk through that document briefly?

A Yes. First, we start out by characterizing the size of the gasifier that we're evaluating. And essentially the size that we're evaluating is for a two-on-one F combined cycle. And we've assumed the 70 percent capacity factor.

Next, we estimate the capital cost of the project, including the three different types of gasifier technologies. We applied the fixed charge rate that we applied in the need for power application for OUC to determine an annual cost of capital.

Next, we have -- evaluate O&M cost for each of the technologies based on staff, other fixed O&M, and then the copy that I have in front of me, we have included insurance, and unfortunately, we have double-counted that, because insurance has been included in a fixed charge rate

above that represents less than a 1 percent increase in the cost. And we have the variable O&M cost excluding fuel, and we, again, come up with a total O&M cost for 2001.

And then we use the 2001 coal cost from the need for power application for Stanton to determine the annual fuel cost.

Finally, we sum those three components, capital, O&M, and coal to get an annual cost to produce to the syngas, and then divide by the volume of gas required with the 70 percent capacity factor to come to a dollars per million Btus.

Q Okay. I'm going to ask you a couple of questions about that analysis. You said that the -- including the insurance and O&M cost, it's essentially been double-counted?

A Right. There's $1 million included for insurance in all three technologies. That insurance has been already included in the 11.19 fixed charge rate, and that is 1 million out of an annual total for the lowest cost alternative of 109.7 million. So it's less than 1 percent.

Q So taking that out, how does that affect the bottom line determination?

A That would reduce the bottom line determination

by less than 1 percent.

Q One other question on the coal cost. You said you used the cost that was used in the need for power application?

A Yes, we did.

Q Okay. If you were to go out and on the market for coal now, do you think that cost would be higher or lower?

A I think that cost would be higher now. The price of coal at the mine has increased significantly in the last few months.

Q I guess Staff would ask for a late-filed deposition exhibit. This exhibit essentially would be the same document with the correction that the insurance would be removed from the analysis.

A Okay. We'll provide it.

MR. KEATING: That would be Late-Filed Deposition Exhibit 2, "Same Gas Cost Estimate for Stanton A."

(Late-Filed Exhibit 2 identified.)

(Discussion off the record.)

BY MR. KEATING:

Q Let me ask, the cost -- the syngas cost amount that you have in dollars per MMBtu at the bottom of that analysis, is that the price that natural gas would have to

reach and maintain in order for a conversion to IGCC to be economical?

A Correct. And one needs to also understand that we've used a 20-year fixed charge rate for the capital cost in here. So that would mean that natural gas would have to be at that price or above for an entire 20-year period for it to be cost-effective.

Q I have a few questions concerning the status of the agreements, purchased power agreements, between Southern and the three utilities: OUC, KUA and FMPA. Has OUC signed the purchased power agreement with Southern?

A Yes, they have.

Q And do you know when that occurred?

A I can probably find it. It's dated as March 19th, 2001.

Q Did the Orlando City Commission approve that agreement?

A Yes, they did.

Q Okay. Has KUA signed a purchased power agreement with Southern-Florida?

A Yes, they had.

Q Do you know when that agreement was signed?

A It appears that it was signed by KUA on March 28th, 2001.

Q Do you know if the Kissimmee City Commission has

approved that agreement?

A Yes, they have.

Q And finally, has FMPA signed the purchased power agreement with Southern?

A I believe they have. I believe they were to have signed it yesterday.

MR. YOUNG: Off the record.

MR. KEATING: Sure.

(Discussion off the record.)

A I understand that they are holding it for the remainder of the collateral documents and have approval to sign it and have signed the ownership agreement.

Q So the FMPA Board of Directors has approved the agreement?

A Yes.

Q I guess let me go through each one individually. For the purchased power agreement with OUC, have there been any changes to the agreement compared to what was provided in Appendix 1.A.A to the need for power application?

A There have been minor changes to the agreement, none of which are substantive.

Q If you can, could you summarize those minor changes?

A I can certainly summarize some of them. The

main one that I'm aware of is, the capacity charge has been adjusted as the adjustment was made in the need for power application. That adjustment stemmed from a $5.5 million allocation for certain things that are now being provided outside of the purchased power agreement so that the numbers in the application and the numbers in the purchased power agreement are the same. They just have an adjustment made in the application and are the final number in the purchased power agreement.

Q Were there any changes to the agreement with Kissimmee that was provided in the need for power application?

A In the need for power application, we provided a generic agreement that was for OUC, KUA, and FMPA. The individual agreements are customized for each utility's purchased power share. So only with respect to those issues and the previous modification of the pricing that reflect the adjustments in the application would be the changes for KUA.

Q Is the same true for FMPA's agreement?

A Yes.

Q You may have answered this at least in part already. Do you know if the governing entities of OUC, KUA, and FMPA are required to approve the respected ownership shares of Stanton A?

A I believe they are required to approve them, yes, and I believe they have approved them.

Q For all three of them?

A For all three.

Q Are there any other agreements between Southern-Florida and OUC, KUA and FMPA that are required as part of the project?

A Yes. There are several collateral agreements required as part of the project.

Q Do you know if those have been approved at this point?

A Some of them have, yes.

Q What are the collateral agreements that remain?

A I'm not sure I can name all of them, but I'll name the ones that I'm aware of. There is the ownership agreement. There is a services agreement, and there is a lease agreement and an operating agreement.

MR. YOUNG: Off the record.

(Discussion off the record.)

BY MR. KEATING:

Q So, to your knowledge, those agreements include the services agreement, lease agreement, and operating agreement, and then there's the ownership agreement. And I believe you told me earlier that the ownership agreements have been approved already.

A Correct.

Q Do you know to what extent the services, lease, and operating agreements have been approved at this point?

A I don't know to what extent they have been approved.

MR. YOUNG: Off the record.

(Discussion off the record.)

BY MR. KEATING:

Q I guess I'll just – I believe my previous question was: To what extent have the services, lease, and operating agreements been approved, or what stage are they in?

A Well, they are substantially complete, and I believe about all that's left is minor legal language.

Q Just a few more questions concerning conservation programs, generally.

A Okay.

Q OUC's conservation goals for the 2000-2009 period are zero; correct?

A Correct.

Q For the 1996-2005 period, the Commission had set some goals for OUC; correct?

A Correct.

Q Something above zero, that is?

A Correct.

Q Are the programs that were developed to meet those goals still being implemented by OUC?

A Some of the programs are still being implemented; some have been discontinued. Conservation programs come and go as the marketplace need for them come and go.

Q Do you know which programs are still being implemented?

A I can look those up. They are in the application, make sure I get the correct terminology. On Page 5-1, Volume 1B of the application, there are six existing programs listed: The residential energy survey program, the residential heat pump program, residential weatherization program, low income home energy fix-up program, educational outreach program, and commercial energy survey program.

Q Do you know what effect those programs have on OUC's future generation plans?

A Well, they certainly help to reduce future requirements, but they do not have a significant effect in lowering future generation requirements.

Q I'm not sure if this is something you can answer or not, but do you know what the cumulative effects, or savings, of – what are the cumulative effects, or savings, of all the conservation programs that OUC has

implemented?

A I don't have that number. And that's a very difficult number really to come by. And a question one might ask is, is cumulative and cumulative from when? OUC started conservation programs back in probably 1979, and programs have come and gone since then, and it would be a very difficult number to try to quantify.

Q If we limited the period to 1995 forward, would that help you at all?

A It would certainly help if one were to limit it to the conservation programs presented in their conservation goals reports for that period of time. Even those reports only dealt with the programs that were in place during that time frame and certainly didn't deal with the programs that had previously been done and discontinued but had accumulated savings. Those numbers are all built into the existing loads and the load forecast.

MR. KEATING: That's all the questions I have.

THE WITNESS: Okay. Thank you.

MR. KEATING: Thank you.

(Deposition concluded at 1:00 p.m.)

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ERRATA SHEET
DO NOT WRITE ON TRANSCRIPT - ENTER CHANGES HERE

IN RE: DOCKET NO. 010142-EM
NAME: MYRON ROLLINS
DATE: APRIL 6, 2001

PAGE	LINE	CHANGE

STATE OF FLORIDA)
: CERTIFICATE OF OATH
COUNTY OF LEON)

I, the undersigned authority, certify that MYRON ROLLINS personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 11th day of April, 2001.

Tricia DeMarte

TRICIA DeMARTE
Notary Public - State of Florida

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, TRICIA DeMARTE, Official FPSC Commission Reporter, do hereby certify that I was authorized to and did stenographically report the foregoing deposition of MYRON ROLLINS.

I FURTHER CERTIFY that this transcript, consisting of 26 pages, constitutes a true record of the testimony given by the witness.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 11th DAY OF APRIL, 2001.

Tricia DeMarte

TRICIA DeMARTE
Official FPSC Reporter
(850)413-6736

OUC and St. Cloud Winter Capacity Balance (including addition of Stanton A)										
Year (Winter)	Retail Peak Demand	Firm Sales	Total Sales	Installed Capacity	Purchases (MW)	Available Capacity	Available Reserves	Required Reserves	Excess (Deficit) to Maintain 15% Reserve Margin (MW)	Reserve Margin (%)
2000	1051	440	1491	1092	608	1700	208	168	40	19.81%
2001	1090	341	1431	1092	608	1700	268	176	93	24.61%
2002	1144	323	1467	1092	540	1632	165	184	(19)	14.43%
2003	1182	312	1494	1092	540	1632	138	192	(54)	11.65%
2004	1210	263	1473	1273	391	1664	192	198	(6)	15.83%
2005	1239	172	1411	1252	376	1629	217	203	14	17.54%
2006	1267	139	1406	1252	361	1614	208	205	3	16.43%
2007	1292	139	1431	1252	351	1604	173	212	(40)	13.35%
2008	1323	142	1465	1252	351	1604	139	218	(79)	10.48%
2009	1356	144	1500	1252	351	1604	104	223	(119)	7.65%
2010	1386	146	1532	1252	351	1604	72	228	(156)	5.19%
2011	1416	0	1416	1252	351	1604	187	210	(23)	13.22%
2012	1449	0	1449	1252	351	1604	155	215	(60)	10.70%
2013	1480	0	1480	1252	336	1589	108	222	(114)	7.32%
2014	1512	0	1512	1252	0	1252	-259	227	(486)	-17.16%
2015	1542	0	1542	1252	0	1252	-290	231	(521)	-18.78%
2016	1572	0	1572	1252	0	1252	-320	236	(556)	-20.36%
2017	1608	0	1608	1252	0	1252	-356	241	(597)	-22.15%
2018	1643	0	1643	1252	0	1252	-391	246	(637)	-23.78%
2019	1675	0	1675	1252	0	1252	-423	251	(674)	-25.24%

EXHIBIT

1

OUC and St. Cloud Summer Capacity Balance (including addition of Stanton A)										
Year (Summer)	Retail Peak Demand	Firm Sales	Total Sales	Installed Capacity	Purchases (MW)	Available Capacity	Available Reserves	Required Reserves	Excess (Deficit) to Maintain 15% Reserve Margin (MW)	Reserve Margin (%)
2000	1062	440	1502	1047	608	1655	153	170	(17)	14.37%
2001	1092	341	1433	1047	608	1655	222	176	46	20.36%
2002	1136	323	1459	1047	540	1587	128	183	(55)	11.25%
2003	1170	312	1482	1047	540	1587	105	190	(85)	8.93%
2004	1197	263	1460	1213	364	1578	118	196	(78)	9.86%
2005	1227	172	1399	1192	348	1540	141	201	(60)	11.49%
2006	1254	139	1393	1192	334	1526	133	203	(71)	10.57%
2007	1278	139	1417	1192	324	1516	99	210	(112)	7.72%
2008	1306	142	1448	1192	324	1516	68	215	(147)	5.18%
2009	1339	144	1483	1192	324	1516	33	220	(188)	2.43%
2010	1372	146	1518	1192	324	1516	-2	225	(227)	-0.14%
2011	1399	0	1399	1192	324	1516	116	208	(91)	8.32%
2012	1428	0	1428	1192	324	1516	88	212	(124)	6.16%
2013	1463	0	1463	1192	309	1501	38	219	(182)	2.56%
2014	1495	0	1495	1192	0	1192	-304	224	(528)	-20.32%
2015	1526	0	1526	1192	0	1192	-334	229	(563)	-21.91%
2016	1557	0	1557	1192	0	1192	-366	234	(599)	-23.49%
2017	1591	0	1591	1192	0	1192	-400	239	(638)	-25.11%
2018	1625	0	1625	1192	0	1192	-433	244	(677)	-26.67%
2019	1656	0	1656	1192	0	1192	-464	248	(713)	-28.04%

OUC and St. Cloud Winter Capacity Balance (before addition of Stanton A)										
Year (Winter)	Retail Peak Demand	Firm Sales	Total Sales	Installed Capacity	Purchases (MW)	Available Capacity	Available Reserves	Required Reserves	Excess (Deficit) to Maintain 15% Reserve Margin (MW)	Reserve Margin (%)
2000	1051	440	1491	1092	608	1700	208	168	40	19.81%
2001	1090	341	1431	1092	608	1700	268	176	93	24.61%
2002	1144	323	1467	1092	540	1632	165	184	(19)	14.43%
2003	1182	312	1494	1092	540	1632	138	192	(54)	11.65%
2004	1210	263	1473	1092	15	1107	-366	198	(564)	-30.26%
2005	1239	172	1411	1071	15	1086	-325	203	(528)	-26.24%
2006	1267	139	1406	1071	15	1086	-320	205	(525)	-25.23%
2007	1292	139	1431	1071	15	1086	-345	212	(558)	-26.71%
2008	1323	142	1465	1071	15	1086	-379	218	(597)	-28.65%
2009	1356	144	1500	1071	15	1086	-414	223	(637)	-30.53%
2010	1386	146	1532	1071	15	1086	-446	228	(673)	-32.16%
2011	1416	0	1416	1071	15	1086	-330	210	(540)	-23.32%
2012	1449	0	1449	1071	15	1086	-363	215	(578)	-25.03%
2013	1480	0	1480	1071	0	1071	-409	222	(631)	-27.65%
2014	1512	0	1512	1071	0	1071	-441	227	(667)	-29.14%
2015	1542	0	1542	1071	0	1071	-471	231	(702)	-30.53%
2016	1572	0	1572	1071	0	1071	-501	236	(737)	-31.89%
2017	1608	0	1608	1071	0	1071	-537	241	(779)	-33.41%
2018	1643	0	1643	1071	0	1071	-572	246	(818)	-34.81%
2019	1675	0	1675	1071	0	1071	-604	251	(855)	-36.06%

OUC and St. Cloud Summer Capacity Balance (before addition of Stanton A)										
Year (Summer)	Retail Peak Demand	Firm Sales	Total Sales	Installed Capacity	Purchases (MW)	Available Capacity	Available Reserves	Required Reserves	Excess (Deficit) to Maintain 15% Reserve Margin (MW)	Reserve Margin (%)
2000	1062	440	1502	1047	608	1655	153	170	(17)	14.37%
2001	1092	341	1433	1047	608	1655	222	176	46	20.36%
2002	1136	323	1459	1047	540	1587	128	183	(55)	11.25%
2003	1170	312	1482	1047	540	1587	105	190	(85)	8.93%
2004	1197	263	1460	1047	15	1062	-398	196	(593)	-33.24%
2005	1227	172	1399	1025	15	1040	-359	201	(560)	-29.24%
2006	1254	139	1393	1025	15	1040	-353	203	(557)	-28.16%
2007	1278	139	1417	1025	15	1040	-377	210	(587)	-29.50%
2008	1306	142	1448	1025	15	1040	-408	215	(623)	-31.24%
2009	1339	144	1483	1025	15	1040	-443	220	(663)	-33.09%
2010	1372	146	1518	1025	15	1040	-478	225	(703)	-34.82%
2011	1399	0	1399	1025	15	1040	-359	208	(567)	-25.68%
2012	1428	0	1428	1025	15	1040	-388	212	(600)	-27.16%
2013	1463	0	1463	1025	0	1025	-438	219	(658)	-29.95%
2014	1495	0	1495	1025	0	1025	-470	224	(695)	-31.45%
2015	1526	0	1526	1025	0	1025	-501	229	(730)	-32.82%
2016	1557	0	1557	1025	0	1025	-532	234	(766)	-34.18%
2017	1591	0	1591	1025	0	1025	-566	239	(805)	-35.58%
2018	1625	0	1625	1025	0	1025	-600	244	(844)	-36.92%
2019	1656	0	1656	1025	0	1025	-631	248	(879)	-38.10%

FMPA Projected Reliability Levels - WInter / Base Case (including addition of Stanton A)

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases that contain reserve margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	401.6	656.9	125.0	0.0	1,183.5	935.8	929.0	30.6	31.7	126.1	133.9
2001	401.6	731.9	85.0	0.0	1,218.5	1,026.2	1,019.0	20.4	21.4	51.1	59.4
2002	550.1	709.9	72.0	0.0	1,332.0	1,046.6	1,039.0	29.3	30.3	139.2	148.0
2003	550.1	648.9	135.0	0.0	1,334.0	1,067.9	1,060.0	28.5	29.6	126.2	135.3
2004	572.8	646.0	135.0	0.0	1,353.7	1,089.2	1,081.0	27.7	28.8	121.4	130.8
2005	572.8	624.0	160.0	0.0	1,356.7	1,109.5	1,101.0	26.0	27.2	104.8	114.6
2006	672.8	603.0	120.0	0.0	1,395.7	1,126.7	1,118.0	26.7	27.8	118.0	128.0
2007	672.8	581.0	120.0	0.0	1,373.7	1,144.9	1,136.0	22.3	23.4	75.1	85.3
2008	672.8	581.0	45.0	0.0	1,298.7	1,162.0	1,153.0	12.2	13.1	-30.9	-20.5
2009	672.8	581.0	45.0	0.0	1,298.7	1,191.0	1,182.0	9.4	10.3	-64.2	-53.9
2010	672.8	581.0	45.0	0.0	1,298.7	1,215.0	1,206.0	7.2	8.0	-91.8	-81.5
2011	672.8	481.0	0.0	0.0	1,153.7	1,230.0	1,221.0	-6.2	-5.5	-260.8	-250.5
2012	672.8	481.0	0.0	0.0	1,153.7	1,245.0	1,236.0	-7.3	-6.7	-278.1	-267.7
2013	672.8	481.0	0.0	0.0	1,153.7	1,258.0	1,249.0	-8.3	-7.6	-293.0	-282.7
2014	672.8	438.9	0.0	0.0	1,111.7	1,271.0	1,262.0	-12.5	-11.9	-350.0	-339.7
2015	672.8	438.9	0.0	0.0	1,111.7	1,284.0	1,275.0	-13.4	-12.8	-365.0	-354.6
2016	672.8	438.9	0.0	0.0	1,111.7	1,295.0	1,286.0	-14.2	-13.6	-377.6	-367.3
2017	672.8	438.9	0.0	0.0	1,111.7	1,306.0	1,297.0	-14.9	-14.3	-390.3	-379.9
2018	672.8	438.9	0.0	0.0	1,111.7	1,317.0	1,308.0	-15.6	-15.0	-402.9	-392.6
2019	672.8	438.9	0.0	0.0	1,111.7	1,326.0	1,317.0	-16.2	-15.6	-413.3	-402.9

FMPA Projected Reliability Levels - Summer / Base Case (including addition of Stanton A)

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases that contain reserve margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 18%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	377.0	675.9	125.0	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	85.0	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	37.6	14.4
2002	525.5	683.8	147.0	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	135.0	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8
2004	546.3	616.5	135.0	0.0	1,297.8	1,167.8	1,163.0	12.6	13.1	-55.9	-50.3
2005	646.3	594.5	160.0	0.0	1,400.8	1,189.0	1,184.0	20.6	21.2	26.5	32.4
2006	646.3	573.5	120.0	0.0	1,339.8	1,209.1	1,204.0	12.0	12.5	-65.4	-59.4
2007	646.3	551.5	120.0	0.0	1,317.8	1,228.2	1,223.0	8.1	8.6	-109.9	-103.8
2008	646.3	551.5	45.0	0.0	1,242.8	1,246.3	1,241.0	-0.3	0.1	-219.8	-213.5
2009	646.3	551.5	45.0	0.0	1,242.8	1,273.3	1,268.0	-2.5	-2.1	-251.6	-245.4
2010	646.3	551.5	45.0	0.0	1,242.8	1,290.0	1,285.0	-3.8	-3.4	-271.3	-265.4
2011	646.3	451.5	0.0	0.0	1,097.8	1,306.0	1,301.0	-15.9	-15.6	-443.3	-437.4
2012	646.3	451.5	0.0	0.0	1,097.8	1,322.0	1,317.0	-17.0	-16.6	-462.2	-456.3
2013	646.3	451.5	0.0	0.0	1,097.8	1,336.0	1,331.0	-17.8	-17.5	-478.7	-472.8
2014	646.3	412.8	0.0	0.0	1,059.1	1,350.0	1,345.0	-21.5	-21.3	-533.9	-528.0
2015	646.3	412.8	0.0	0.0	1,059.1	1,363.0	1,358.0	-22.3	-22.0	-549.2	-543.3
2016	646.3	412.8	0.0	0.0	1,059.1	1,376.0	1,371.0	-23.0	-22.7	-564.6	-558.7
2017	646.3	412.8	0.0	0.0	1,059.1	1,387.0	1,382.0	-23.6	-23.4	-577.5	-571.6
2018	646.3	412.8	0.0	0.0	1,059.1	1,398.0	1,393.0	-24.2	-24.0	-590.5	-584.6
2019	646.3	412.8	0.0	0.0	1,059.1	1,408.0	1,403.0	-24.8	-24.5	-602.3	-596.4

FMPA Projected Reliability Levels - Summer / Base Case (before additon of Stanton A)

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases that contain reserve margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 18%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	377.0	675.9	125.0	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	85.0	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	147.0	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	135.0	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8
2004	525.5	577.8	135.0	0.0	1,238.3	1,167.8	1,163.0	6.8	7.3	-115.4	-109.7
2005	625.5	555.8	160.0	0.0	1,341.3	1,189.0	1,184.0	14.8	15.4	-32.9	-27.0
2006	625.5	534.8	120.0	0.0	1,280.3	1,209.1	1,204.0	6.5	7.0	-124.8	-118.8
2007	625.5	512.8	120.0	0.0	1,258.3	1,228.2	1,223.0	2.7	3.2	-169.4	-163.2
2008	625.5	512.8	45.0	0.0	1,183.3	1,246.3	1,241.0	-5.2	-4.8	-279.2	-273.0
2009	625.5	512.8	45.0	0.0	1,183.3	1,273.3	1,268.0	-7.3	-6.9	-311.1	-304.8
2010	625.5	512.8	45.0	0.0	1,183.3	1,290.0	1,285.0	-8.6	-8.2	-330.8	-324.9
2011	625.5	412.8	0.0	0.0	1,038.3	1,306.0	1,301.0	-20.5	-20.2	-502.8	-496.9
2012	625.5	412.8	0.0	0.0	1,038.3	1,322.0	1,317.0	-21.5	-21.2	-521.7	-515.8
2013	625.5	412.8	0.0	0.0	1,038.3	1,336.0	1,331.0	-22.3	-22.0	-538.2	-532.3
2014	625.5	412.8	0.0	0.0	1,038.3	1,350.0	1,345.0	-23.1	-22.8	-554.7	-548.8
2015	625.5	412.8	0.0	0.0	1,038.3	1,363.0	1,358.0	-23.8	-23.5	-570.0	-564.1
2016	625.5	412.8	0.0	0.0	1,038.3	1,376.0	1,371.0	-24.5	-24.3	-585.4	-579.5
2017	625.5	412.8	0.0	0.0	1,038.3	1,387.0	1,382.0	-25.1	-24.9	-598.4	-592.5
2018	625.5	412.8	0.0	0.0	1,038.3	1,398.0	1,393.0	-25.7	-25.5	-611.3	-605.4
2019	625.5	412.8	0.0	0.0	1,038.3	1,408.0	1,403.0	-26.3	-26.0	-623.1	-617.2

FMPA Projected Reliability Levels - WInter / Base Case (before addition of Stanton A)											
						System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15%	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases that contain reserve margin	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	401.6	656.9	125.0	0.0	1,183.5	935.8	929.0	30.6	31.7	126.1	133.9
2001	401.6	731.9	85.0	0.0	1,218.5	1,026.2	1,019.0	20.4	21.4	51.1	59.4
2002	550.1	709.9	72.0	0.0	1,332.0	1,046.6	1,039.0	29.3	30.3	139.2	148.0
2003	550.1	648.9	135.0	0.0	1,334.0	1,067.9	1,060.0	28.5	29.6	126.2	135.3
2004	550.1	603.9	135.0	0.0	1,289.0	1,089.2	1,081.0	20.9	22.0	56.7	66.1
2005	550.1	581.9	160.0	0.0	1,292.0	1,109.5	1,101.0	19.2	20.3	40.1	49.9
2006	650.1	560.9	120.0	0.0	1,331.0	1,126.7	1,118.0	20.3	21.3	53.3	63.3
2007	650.1	538.9	120.0	0.0	1,309.0	1,144.9	1,136.0	16.0	17.0	10.4	20.6
2008	650.1	538.9	45.0	0.0	1,234.0	1,162.0	1,153.0	6.4	7.3	-95.6	-85.2
2009	650.1	538.9	45.0	0.0	1,234.0	1,191.0	1,182.0	3.8	4.6	-128.9	-118.6
2010	650.1	538.9	45.0	0.0	1,234.0	1,215.0	1,206.0	1.6	2.4	-156.5	-146.2
2011	650.1	438.9	0.0	0.0	1,089.0	1,230.0	1,221.0	-11.5	-10.8	-325.5	-315.2
2012	650.1	438.9	0.0	0.0	1,089.0	1,245.0	1,236.0	-12.5	-11.9	-342.8	-332.4
2013	650.1	438.9	0.0	0.0	1,089.0	1,258.0	1,249.0	-13.4	-12.8	-357.7	-347.4
2014	650.1	438.9	0.0	0.0	1,089.0	1,271.0	1,262.0	-14.3	-13.7	-372.7	-362.3
2015	650.1	438.9	0.0	0.0	1,089.0	1,284.0	1,275.0	-15.2	-14.6	-387.6	-377.3
2016	650.1	438.9	0.0	0.0	1,089.0	1,295.0	1,286.0	-15.9	-15.3	-400.3	-389.9
2017	650.1	438.9	0.0	0.0	1,089.0	1,306.0	1,297.0	-16.6	-16.0	-412.9	-402.6
2018	650.1	438.9	0.0	0.0	1,089.0	1,317.0	1,308.0	-17.3	-16.7	-425.6	-415.2
2019	650.1	438.9	0.0	0.0	1,089.0	1,326.0	1,317.0	-17.9	-17.3	-435.9	-425.6

02

KUA Projected Reliability Levels - Summer / Base Case (before addition of Stanton A)

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Reserve Margin		Excess/ (Deficit) to Maintain 15%		Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)
2000	176	108.1	0	284	252	241	32	43	12.66%	17.80%	(6)	7	13%	18%
2001	297	68.1	0	365	264	254	101	111	38.18%	43.62%	61	73	38%	44%
2002	297	68.1	0	365	282	272	83	93	29.36%	34.12%	41	52	29%	34%
2003	297	68.1	0	365	301	291	64	74	21.20%	25.36%	19	30	21%	25%
2004	297	48.1	0	345	319	309	26	36	8.09%	11.59%	(22)	(11)	8%	12%
2005	297	48.1	0	345	333	323	12	22	3.54%	6.75%	(38)	(27)	4%	7%
2006	297	48.1	0	345	346	336	(1)	9	-0.35%	2.62%	(53)	(42)	0%	3%
2007	297	48.1	0	345	356	346	(11)	(1)	-3.15%	-0.35%	(65)	(53)	-3%	0%
2008	297	48.1	0	345	367	357	(22)	(12)	-6.05%	-3.42%	(77)	(66)	-6%	-3%
2009	297	48.1	0	345	378	368	(33)	(23)	-8.78%	-6.30%	(90)	(78)	-9%	-6%
2010	297	48.1	0	345	389	379	(44)	(34)	-11.36%	-9.02%	(103)	(91)	-11%	-9%
2011	297	48.1	0	345	400	390	(55)	(45)	-13.80%	-11.59%	(115)	(104)	-14%	-12%
2012	297	48.1	0	345	412	402	(67)	(57)	-16.31%	-14.23%	(129)	(118)	-16%	-14%
2013	297	48.1	0	345	423	413	(78)	(68)	-18.49%	-16.51%	(142)	(130)	-18%	-17%
2014	297	48.1	0	345	435	425	(90)	(80)	-20.74%	-18.87%	(155)	(144)	-21%	-19%
2015	297	48.1	0	345	448	438	(103)	(93)	-23.04%	-21.28%	(170)	(159)	-23%	-21%
2016	297	48.1	0	345	460	450	(115)	(105)	-25.04%	-23.38%	(184)	(173)	-25%	-23%
2017	297	48.1	0	345	472	462	(127)	(117)	-26.95%	-25.37%	(198)	(187)	-27%	-25%
2018	297	48.1	0	345	485	475	(140)	(130)	-28.91%	-27.41%	(213)	(201)	-29%	-27%
2019	297	48.1	0	345	498	488	(153)	(143)	-30.76%	-29.34%	(228)	(216)	-31%	-29%

KUA Projected Reliability Levels - Summer / Base Case (including addition of Stanton A)

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Reserve Margin		Excess/ (Deficit) to Maintain 15%		Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)
2000	176	108.1	0	284	252	241	32	43	12.66%	17.80%	(6)	7	13%	18%
2001	297	68.1	0	365	264	254	101	111	38.18%	43.62%	61	73	38%	44%
2002	297	68.1	0	365	282	272	83	93	29.36%	34.12%	41	52	29%	34%
2003	297	68.1	0	365	301	291	64	74	21.20%	25.36%	19	30	21%	25%
2004	318	46.75	0	364	319	309	45	55	14.19%	17.88%	(3)	9	14%	18%
2005	318	62.33	0	380	333	323	47	57	14.07%	17.60%	(3)	8	14%	18%
2006	318	76.98	0	394	346	336	48	58	14.02%	17.41%	(3)	8	14%	17%
2007	318	86.75	0	404	356	346	48	58	13.56%	16.84%	(5)	6	14%	17%
2008	318	86.75	0	404	367	357	37	47	10.15%	13.24%	(18)	(6)	10%	13%
2009	318	86.75	0	404	378	368	26	36	6.95%	9.85%	(30)	(19)	7%	10%
2010	318	86.75	0	404	389	379	15	25	3.92%	6.67%	(43)	(32)	4%	7%
2011	318	86.75	0	404	400	390	4	14	1.07%	3.66%	(56)	(44)	1%	4%
2012	318	86.75	0	404	412	402	(8)	2	-1.88%	0.56%	(70)	(58)	-2%	1%
2013	318	86.75	0	404	423	413	(19)	(9)	-4.43%	-2.12%	(82)	(71)	-4%	-2%
2014	318	48.1	0	366	435	425	(69)	(59)	-15.95%	-13.97%	(135)	(123)	-16%	-14%
2015	318	48.1	0	366	448	438	(82)	(72)	-18.39%	-16.53%	(150)	(138)	-18%	-17%
2016	318	48.1	0	366	460	450	(94)	(84)	-20.52%	-18.75%	(163)	(152)	-21%	-19%
2017	318	48.1	0	366	472	462	(106)	(96)	-22.54%	-20.86%	(177)	(166)	-23%	-21%
2018	318	48.1	0	366	485	475	(119)	(109)	-24.62%	-23.03%	(192)	(181)	-25%	-23%
2019	318	48.1	0	366	498	488	(132)	(122)	-26.58%	-25.08%	(207)	(196)	-27%	-25%

ORIGINAL

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ATTORNEYS AT LAW

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FPSC

MEMORANDUM

TO: Blanca Bayo
Records and Recording

FROM: Roy C. Young RCY/swp

DATE: April 6, 2001

SUBJECT: Docket #010142-EM

Enclosed find original and 15 copies of late file Deposition Exhibit 2 - Syngas Cost Estimate for Stanton A - for filing in the above-captioned docket.

If you have any questions, please call.

Thank you.

RECEIVED & FILED
FPSC-BUREAU OF RECORDS

RCY:swp
Enclosure

cc: Cochran Keating
Mark Futrell

sparrett\ouc\Bayo re Syngas Cost Estimate.Apr. 6

THIS DOCUMENT IS SUBJECT TO PROTECTIVE AGREEMENT

DOCUMENT NUMBER-DATE
04308 APR-6 01
FPSC-RECORDS/REPORTING

Syngas Cost Estimate for Stanton A

Basis	Technology		
	Texaco	E-Gas	Shell
MW gross power generation (394 MW from 2 GE 7FA CTGs and 231 MW from STG)	625	625	625
MW net power generation from CTs only	394	394	394
BTU HHV coal/kwh net electricity heat rate (Shell Coal Gasification)	7,363	7,363	7,363
MMBTU/hr HHV coal consumption	2,901	2,901	2,901
MMBTU/hr LHV syngas production (100% cap for 2 GE 7FA CTs rated at 197 MW each)	3,380	3,380	3,380
Plant Capacity Factor	70%	70%	70%
Capital Cost ($Million)			
Installed cost for Syngas Production Plant	$ 370	$ 410	$ 500
Fixed charge rate (NFP application pg.1A.5-2)	11.19%	11.19%	11.19%
TOTAL	$ 41.4	$ 45.9	$ 56.0
O&M Cost, excluding fuel ($Million)			
Staff Cost	$ 18.0	$ 18.0	$ 17.5
Other Fixed O&M	$ 2.8	$ 2.8	$ 2.8
Variable cost, exluding fuel	$ 12.0	$ 12.8	$ 10.0
TOTAL	$ 32.8	$ 33.6	$ 30.3
Coal Cost (2001)			
/MMBTU HHV (NFP application pg. 1A.5-6)	$ 1.94	$ 1.94	$ 1.94
Annual Cost	$ 34.5	$ 34.5	$ 34.5
Annual Cost Summary			
Capital	$ 41.4	$ 45.9	$ 56.0
O &M	$ 32.8	$ 33.6	$ 30.3
Coal	$ 34.5	$ 34.5	$ 34.5
Annual Total	$ 108.7	$ 114.0	$ 120.8
SYNGAS COST ($/MMBTU)			
LHV	**$ 5.25**	**$ 5.50**	**$ 5.83**
HHV	**$ 4.98**	**$ 5.22**	**$ 5.54**

Orlando Sentinel
communications

ORIGINAL

P.O. Box 2833
633 North Orange Avenue
Orlando, Florida 32802-2833

February 27, 2001

State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

010142-EM

To whom it may concern:

This letter will serve as confirmation that the following advertisement for **State of Florida Public Service Commission** was published in *The Orlando Sentinel*, Orange Editions section:

Date	**Size**	**Cost**
February 25, 2001	3 col. x 10.5 "	$3,417.75

The PO number for this advertisement is 013244.

Sincerely,

Shirley Gibbons

Shirley Gibbons
Account Executive
(407) 420-5332

Shirley Gibbons, who is personally known to me, acknowledged the foregoing instrument before me this 27th day of February 2001.

MAUREEN BRADLEY-ANDREWS
Notary Public, State of Florida
My comm. expires Dec. 21, 2002
No. CC798486
Bonded thru Ashton Agency, Inc.

STATE OF FLORIDA
COUNTY OF ORANGE

Maureen Bradley-Andrews
Notary

ADM/Ellis

DOCUMENT NUMBER-DATE
02869 MAR-5
FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

NOTICE OF HEARING AND PREHEARING CONFERENCE ON PETITION FOR DETERMINATION OF NEED FOR PROPOSED ELECTRICAL POWER PLANT

TO
ORLANDO UTILITIES COMMISSION
KISSIMMEE UTILITY AUTHORITY
FLORIDA MUNICIPAL POWER AGENCY
SOUTHERN COMPANY-FLORIDA, LLC
AND
ALL OTHER INTERESTED PERSONS

DOCKET NO. 010142-EM

IN RE: JOINT PETITION FOR DETERMINATION OF NEED FOR PROPOSED STANTON ENERGY CENTER COMBINED CYCLE UNIT A BY ORLANDO UTILITIES COMMISSION, KISSIMMEE UTILITY AUTHORITY, FLORIDA MUNICIPAL POWER AGENCY, AND SOUTHERN COMPANY-FLORIDA, LLC.

NOTICE is hereby given that the Florida Public Service Commission will hold a hearing in the above docket at the time and place listed below.

9:30 a.m., Monday, April 23, 2001
4075 Esplanade Way
Room 148 - Betty Easley Conference Center
Tallahassee, Florida

Tuesday, April 24, 2001, has also been reserved for continuation of the hearing, if necessary. All persons who wish to be heard are urged to be present at the beginning of the hearing on April 23, 2001. The starting time of the second day's session will be announced at the conclusion of the first day's session. The hearing may be adjourned early if all testimony is concluded.

PURPOSE AND PROCEDURE

The purpose of this hearing will be for the Commission to take final action to determine the need, pursuant to Section 403.519, Florida Statutes, for the electrical power plant and related facilities proposed by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, and Southern Company-Florida, LLC., ("joint petitioners") for construction in Orange County, Florida. This proceeding shall allow the joint petitioners to present evidence and testimony in support of their petition for a determination of need for the proposed plant and related facilities; to permit any intervenors to present testimony and exhibits concerning this matter; to permit members of the public who are not parties to the need determination proceeding the opportunity to present testimony concerning this matter; and for such other purposes as the Commission may deem appropriate. All witnesses shall be subject to cross-examination at the conclusion of their testimony.

The proceedings will be governed by the provisions of Chapter 120, Florida Statutes, Section 403.519, Florida Statutes, and Chapters 25-22 and 25-106, Florida Administrative Code.

Under Section 403.519, the Commission is the sole forum for the determination of need for the electrical power plant and associated facilities. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, and whether the proposed plant is the most cost-effective alternative available. In addition, the Commission must expressly consider the conservation measures taken by or reasonably available to the applicants which might mitigate the need for the proposed plant and may consider other matters within its jurisdiction which it deems relevant. The Commission's determination of need for the Orange County facility shall create a presumption of public need and necessity and shall serve as the Commission's report required by Subsection 403.507(2)(a)(2), Florida Statutes. An order entered by the Commission pursuant to this hearing shall constitute final agency action.

Only issues relating to the need for the power plant and related facilities will be heard at the April 23-24,2001, hearing. Separate public hearings will be held before the Division of Administrative Hearings at a later date to consider environmental and other impacts of the proposed plant and associated facilities.

Members of the public who are not parties to the need determination proceeding will have an opportunity to present testimony regarding the need for the proposed plant and associated facilities. All members of the public who wish to offer testimony should be present at the beginning of the hearing, 9:30 a.m., Monday, April 23, 2001. All witnesses will be sworn in and will be subject to cross-examination at the conclusion of their testimony.

Written comments regarding the need for the proposed plant and associated facilities may be sent to the Commission at the following address:

Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0870
Re: Docket No. 010142-EM

Anyone wishing to become a party to the need determination proceeding should file an appropriate petition pursuant to Rule 25-22.039, Florida Administrative Code, with the Director of the Commission's Division of Records and Reporting at the address listed above. Copies of the petition should be sent by mail to all parties. Those wishing to intervene in these proceedings, unless appearing on their own behalf, must be represented by an attorney or other person who can be determined to be a qualified representative pursuant to Chapter 120, Florida Statutes, and Rule 28-106.106, Florida Administrative Code. Petitions for leave to intervene must be filed at least five (5) days before the final hearing, must conform with Rule 28-106.201(2), Florida Administrative Code, and must include allegations sufficient to demonstrate that the intervenor is entitled to participate in the proceeding as a matter of constitutional or statutory right or pursuant to Commission rule, or that the substantial interests of the intervenor are subject to determination or will be affected through the hearing.

GENERAL LOCATION AND PROJECT DESCRIPTION

The proposed electrical power plant is estimated to produce 633 MW (nominal) of net generating capacity. The proposed plant is to be located at the Curtis H. Stanton Energy Center in eastern Orange County, Florida, approximately 4 3/4 miles south of Highway 50 and one mile north of the Bee Line Expressway. The proposed unit consists of two combustion turbine generators, two heat recovery steam generators, a steam turbine generator, cooling tower, water and wastewater treatment facilities, fuel oil and water storage tanks, and other related facilities. The proposed plant is estimated to commence commercial operation by October 1, 2003.

PREHEARING CONFERENCE

A prehearing conference for this docket is scheduled for:

9:30 a.m., Tuesday, April 10, 2001
Commission Hearing Room 152
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida

The purpose of this prehearing conference will be to: (1) simplify the issues; (2) identify the positions of the parties on the issues; (3) consider the possibility of obtaining admissions of fact and of documents which will avoid unnecessary proof; (4) identify exhibits; (5) establish an order of witnesses; and (6) consider such other matters as may aid in the disposition of the action.

JURISDICTION

Jurisdiction over this matter is vested in the Commission by Section 403.519, Florida Statutes.

APPLICATION

A copy of the Petition for Determination of Need and supporting exhibits is available for public inspection during normal business hours at the following location:

Florida Public Service Commission
Division of Records and Reporting
4075 Esplanade Way
Room 110 - Betty Easley Conference Center
Tallahassee, Florida

Any person requiring some accommodation at the hearing because of a physical impairment should call the Division of Records and Reporting at (850) 413-6770 at least 48 hours prior to the hearing. Any person requiring some accommodation at the prehearing conference because of a physical impairment should call the Division of Records and Reporting at (850) 413-6770 at least 48 hours prior to the prehearing conference. Any person who is hearing or speech impaired should contact the Florida Public Service Commission by using the Florida Relay Service, which can be reached at 1-800-955-8771 (TDD).

By DIRECTION of the Florida Public Service Commission this 25th day of February, 2001.

BLANCA S. BAYO, Director
Division of Records and Reporting

(SEAL)

CONFIDENTIAL AND PROPRIETARY EXECUTION COPY

****THIS AGREEMENT CONTAINS PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION WHICH IS PROTECTED FROM DISCLOSURE TO THE PUBLIC****

POWER PURCHASE AGREEMENT

BETWEEN

KISSIMMEE UTILITY AUTHORITY

AND

SOUTHERN COMPANY - FLORIDA LLC

Dated as of March 19, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 10
COMPANY
WITNESS: Southern Company
DATE: 4-23-01

TABLE OF CONTENTS

Section	Page
SECTION 1 DEFINITIONS AND EXPLANATION OF TERMS	2
SECTION 2 TERM OF AGREEMENT	14
SECTION 3 CONDITIONS PRECEDENT	15
SECTION 4 SALE AND PURCHASE	15
SECTION 5 SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY	30
SECTION 6 REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE	33
SECTION 7 INTERCONNECTION AND TRANSMISSION	34
SECTION 8 RISK OF LOSS; METERING	35
SECTION 9 METHOD OF PAYMENT	37
ARTICLE 10 CHANGE IN LAW; MODIFICATION OF AGREEMENT	38
SECTION 11 FORCE MAJEURE	39
SECTION 12 EVENTS OF DEFAULT; TERMINATION	40
SECTION 13 WAIVER	44
SECTION 14 REPRESENTATIONS AND WARRANTIES	44
SECTION 15 PERFORMANCE ASSURANCE	47
SECTION 16 LIABILITY OF PARTIES	49
SECTION 17 ASSIGNMENT	53
SECTION 18 DISPUTE RESOLUTION	54
SECTION 19 AMENDMENT	55

SECTION 20 NOTICES 55

SECTION 21 APPLICABLE LAW 56

SECTION 22 SEVERABILITY 56

SECTION 23 ENTIRE AGREEMENT 57

SECTION 24 NO THIRD PARTY BENEFICIARIES 57

SECTION 25 COUNTERPARTS 57

SECTION 26 INFORMATION AND CONFIDENTIALITY 57

SECTION 27 PUBLIC STATEMENTS 58

SECTION 28 INSURANCE 59

SECTION 29 TAXES 59

APPENDIX A TECHNICAL LIMITS

APPENDIX B REQUESTS FOR ENERGY

APPENDIX C CAPACITY TESTING PROCEDURE

APPENDIX D EXAMPLE CALCULATIONS

APPENDIX E AFFILIATE GUARANTEE

CONFIDENTIAL AND PROPRIETARY EXECUTION COPY

POWER PURCHASE AGREEMENT

This Power Purchase Agreement (this "Agreement") is made and entered into as of the 19th day of March, 2001, by and between Kissimmee Utility Authority, a statutory legal authority existing under the laws of the State of Florida ("Purchaser"), and Southern Company - Florida LLC, a limited liability company organized and existing under the laws of the State of Delaware ("Seller"). Purchaser and Seller are hereinafter each referred to individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, in addition and supplemental to their other powers, OUC, KUA and FMPA (the "**Public Agencies**"), pursuant to the Florida Interlocal Cooperation Act of 1969, Chapter 163, Part I, Florida Statutes, (the "**Interlocal Act**") are authorized and empowered to cooperate with each other on a basis of mutual advantage and thereby to provide services and facilities in a manner and pursuant to forms of government organizations that will best accord with geographic, economic, electrical generation requirements and other factors; and

WHEREAS, the Ownership Agreement was entered into by the Public Agencies as an interlocal agreement, to invoke all of the powers of the Interlocal Act, for the purpose of providing a structure for the Public Agencies, in participation with Seller, a foreign public utility, to operate, maintain, repair, improve, extend, or otherwise participate jointly in a nominal six hundred thirty-three (633) megawatt combined cycle electric generating facility (the "**Facility**"), which is proposed, and which is to be constructed, owned, and located within the State of Florida by Seller and the Public Agencies; and

WHEREAS, Seller intends to sell to Purchaser, and Purchaser intends to purchase from Seller, a portion of Seller's share of the Capacity and Energy generated by the Facility in accordance with the terms and conditions of this Agreement and in full compliance with the Interlocal Act; and

WHEREAS, Seller and Purchaser acknowledge that this Agreement is one of three substantially similar contracts through which Seller will sell and the three Purchasers will individually purchase their respective designated shares of Seller's share of the Capacity and Energy generated by the Facility; and

WHEREAS, this Agreement and the two substantially similar contracts are entered into to invoke all of the powers of the Interlocal Act for the purpose of obligating Customers, pursuant to such Interlocal Act, to purchase Seller's share of the Capacity of and Energy generated by the Facility in accordance with the terms and conditions of this Agreement.

NOW, THEREFORE, for the purpose of exercising all of the powers enumerated in the Interlocal Act and the Florida Joint Power Act, Part II of Chapter 361, Florida Statutes, (the "**Joint Power Act**") (collectively, the "**Acts**"), Purchaser, hereby designates this Agreement as an interlocal agreement within the meaning and intent of the Interlocal Act, and invokes all powers contained therein with full powers to perform all of the provisions herein authorized to be performed by the Parties; and

FURTHER, NOW, THEREFORE, in consideration of the mutual promises, covenants and agreements set forth herein, and other good and valuable consideration, the receipt, sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound hereby agree as follows:

SECTION 1
DEFINITIONS AND EXPLANATION OF TERMS

1.1 Definitions. When used in this Agreement, the following capitalized terms shall have the meanings set forth below:

1.1.1 "Actual Availability" has the meaning given such term in Section 4.3.3 or 4.3.4, as applicable.

1.1.2 "Actual Capability" means the amount of Capacity the Facility is capable of producing in any given hour.

1.1.3 "AGC" means automatic generation control, which is the capability to make automatic adjustments to load change by generation through the use of a digital computer. This control is based on such factors as frequency, cost and tie line flows.

1.1.4 "Agreement" means this Power Purchase Agreement, including all appendices attached hereto and all amendments hereto that may be made from time to time.

1.1.5 "Alternate Resources" has the meaning given such term in Section 4.4.

1.1.6 "Ancillary Services" means ancillary services customarily provided by an electric generating facility, including voltage/VAR control, load following, regulation and frequency response, spinning reserve and non-spinning reserve.

1.1.7 "Annual Capacity Charge" means (i) [redacted] per kilowatt per month for that portion of the Initial Term before the end of the day of May 31, 2014 , (ii) [redacted] per kilowatt per month for that portion

of the Initial Term after the beginning of the day June 1, 2014 and during the Extended Term, (iii) with respect to the first Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), (iv) with respect to the second Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), and (v) with respect to the third Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3); *provided, however,* that the Annual Capacity Charge shall be (i) increased by [redacted] per kilowatt per month for every [redacted] increase in the BOP Capital Cost Range that occurs pursuant to Sections 6.7.2(b) or 6.7.2(c) of the Ownership Agreement, (ii) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the BOP Capital Costs Range that occurs pursuant to Sections 6.7.2(b) and 6.7.2(c) of the Ownership Agreement, (iii) increased by [redacted] per kilowatt per month for every [redacted] increase in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement, and (iv) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement.

1.1.8 "Annual Purchaser's Capacity Nomination" of the Purchaser means, during the first five Contract Years, [redacted] of the Demonstrated Capability, and thereafter, [redacted] of the Demonstrated Capability reduced by those amounts, if any, that Purchaser elects to subtract from the Capacity available to Purchaser pursuant to the process provided in Section 4.1.4 for the Customers jointly to make such elections.

1.1.9 "Availability Guarantee" has the meaning given such term in Section 4.3.1.

1.1.10 "Availability Incentive Payment" has the meaning given such term in Section 4.3.2.

1.1.11 "Bankruptcy" means, with respect to a Party, (i) an adjudication of bankruptcy or insolvency, or the entry of an order for relief, under any Bankruptcy Law with respect to such Party; (ii) the making by such Party of an assignment for the benefit of its creditors;

(iii) the filing by such Party of a petition in bankruptcy or for relief under any Bankruptcy Law; (iv) the filing by such Party of an answer or pleading admitting or failing to contest the material allegations of any such petition; (v) the filing against such Party of any petition in bankruptcy or for relief under any Bankruptcy Law (unless such petition is dismissed within ninety (90) days from the date of filing thereof); (vi) the appointment of a trustee, conservator or receiver for such Party or for all or substantially all of its assets (unless such appointment is vacated or stayed within ninety (90) days of such appointment); or (vii) the taking by such Party of any action for its winding up or liquidation, or the consent by such Party to any of the actions described in clauses (i) through (vi) being taken against it.

1.1.12 "Bankruptcy Law" means any applicable bankruptcy or insolvency statute.

1.1.13 "Bond Legislation" shall mean the Composite Resolution of Kissimmee Utility Authority, comprised of the Original Resolution No. 5-83, adopted January 20, 1983, as amended by (a) Resolution No. R91-9, adopted December 4, 1991; (b) Resolution No. R91-10, adopted on December 4, 1991; (c) Resolution No. 93-14, adopted December 15, 1993; and (d) Resolution No. 99-12, adopted September 22, 1999.

1.1.14 "BOP Capital Cost Range" has the meaning ascribed to the term in Section 6.7.1 of the Ownership Agreement.

1.1.15 "Business Day" means any day other than Saturday or Sunday on which commercial banks are authorized to open for business in Orlando, Florida.

1.1.16 "Capacity" means electric capacity.

1.1.17 "Capacity Emergency" means, with respect to any hour, that any one or more of Purchaser's resources is unavailable due to a forced outage and the summation of such Purchaser's firm Capacity obligations exceeds the summation of such Purchaser's available resources.

1.1.18 "Capacity Payment" has the meaning given such term in Section 4.1.1.

1.1.19 "Change in Law" has the meaning given such term in Section 10.1.3.

1.1.20 "Collateral Documents" means, collectively, the Ownership Agreement, the Operating Agreement, the Interconnection Agreement, the Power Purchase Agreements of the other Customers, the long term lease of the Facility Site by OUC to and for the benefit of the Participants, the guarantee to be provided by an affiliate of Seller as contemplated in Section 16.3, and the agreement(s) pursuant to which Purchaser and/or the other Customers provide station service and other support services (including but not limited to demineralized water and cooling water supply) to Seller.

1.1.21 "Commencement Date" has the meaning given such term in Section 5.2.

1.1.22 "Commercial Operation Date" has the meaning ascribed to such term in Section 1.1.13 of the Ownership Agreement.

1.1.23 "Confidential Information" has the meaning given such term in Section 26.

1.1.24 "Contract Year" means (i) the period commencing on the Commencement Date or, if Seller elects the option under Section 4.5(ii)(a), the later of the Commencement Date or Scheduled Commencement Date, and ending on the last day of the month in which the first anniversary date of the Commencement Date falls, and (ii) each twelve (12)-month period thereafter, except that for the twelve (12)-month period during which the expiration or termination date of this Agreement occurs, Contract Year shall mean the period commencing on the first day of such twelve (12)-month period and ending on such expiration or termination date.

1.1.25 "Customers" means collectively all of OUC, Kissimmee Utility Authority and Florida Municipal Power Agency (All Requirements Power Supply Project), or their permitted assigns.

1.1.26 "Delivered Energy" means, in respect of a period of time, the amount of Energy from the Facility or from Alternate Resources delivered by Seller to Purchaser at the Delivery Point for sale to Purchaser pursuant to this Agreement.

1.1.27 "Delivery Point" means (a) with respect to Energy delivered from the Facility, the high side of generator step-up transformer, as further described in the Interconnection Agreement, and (b) with respect to Energy delivered from Alternate Resources, any unconstrained point on the Grid.

1.1.28 "Demonstrated Capability" means the net Capacity of the Facility, determined by a periodic Capacity test, adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity.

1.1.29 "Dispute" has the meaning given such term in Section 18.

1.1.30 "Eastern Prevailing Time" or "EPT" means the time prevailing in the Eastern time zone of the United States of America.

1.1.31 "Effective Date" has the meaning given such term in Section 3.1.

1.1.32 "Eligible Collateral" has the meaning given such term in Section 15.1.1.

1.1.33 "Energy" means electric energy (expressed in megawatt-hours).

1.1.34 "Energy Payment" has the meaning given such term in Section 4.2.

1.1.35 "Equipment Breakdown" means a mechanical breakdown of equipment at the Facility that is not the result of a Force Majeure that is an act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted]; storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under Section 1.1.44 if such failure were directly experienced by the applicable Party.

1.1.36 "Equity Capacity" with respect to each Participant means that Participant's percentage share of the Capacity of the Facility corresponding to such Participant's ownership interest in the Facility.

1.1.37 "Event of Default" means any of the events listed in Sections 12.1 and 12.2.

1.1.38 "Facility" means the gas fired combined cycle electric generating unit to be located on the Facility Site and owned by the Participants, and its associated interconnection facilities, as defined in

the Ownership Agreement by the terms "Facility" and "Interconnection Facilities."

1.1.39 "Facility Site" means the parcel of land in Orlando, Florida on which the Facility is to be located, as further described in Appendix A.

1.1.40 "FDEP" means the Florida Department of Environmental Protection or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.41 "FERC" means the Federal Energy Regulatory Commission or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.42 "Firm Transmission Service" means (a) electric transmission service designated firm under the open access transmission tariff of a transmission provider having an open access transmission tariff or (b) if purchased from a transmission provider that does not have an open access transmission tariff, electric transmission service sold by such transmission provider as firm transmission service and generally considered, pursuant to Prudent Utility Practice and FRCC requirements, to be substantially equivalent to the firm transmission service referenced in item (a) of this definition.

1.1.43 "Fixed Amount" has the meaning ascribed to such term in Section 6.7.1 of the Ownership Agreement.

1.1.44 "Force Majeure" as to a Party means each of the following events as affects the Facility: act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted]; storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; shutdown of the Facility by a court order or Governmental Body not resulting from any action or inaction by the applicable Party; strike, lockout or labor difficulty affecting the SEC Site generally [redacted]; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that

such failure would qualify as a Force Majeure under this provision if such failure were directly experienced by the applicable Party; or any other occurrence, nonoccurrence or set of circumstances, whether or not foreseeable, that is beyond the reasonable control of the applicable Party and is not caused or exacerbated by the applicable Party's failure to follow Prudent Utility Practices.

1.1.45 "FRCC" means the Florida Reliability Coordinating Council or any successor organization.

1.1.46 "Fuel Supply Agent" has the meaning given such term in the Operating Agreement.

1.1.47 "Further Extension" has the meaning given such term in Section 2.3.

1.1.48 "Gas Delivery Point" shall have the meaning assigned to it in the Operating Agreement.

1.1.49 "Governmental Body" shall mean, except as provided in the following sentence, (i) any local, state, regional or federal administrative, legal, judicial, or executive agency, court, commission, department or other entity having jurisdiction or binding authority over any element of the Project or the performance of the Parties under this Agreement or the Collateral Documents, but excluding any agency, commission, department or other such entity acting in its capacity as lender, guarantor or mortgagee and (ii) NERC, FRCC and any RTO. Except as expressly provided otherwise in this Agreement, the definition "Governmental Body" shall be deemed to not include OUC, KUA and FMPA for the purposes of this Agreement.

1.1.50 "Grid" means (i) OUC's electric transmission system, or (ii) if ownership or control of and jurisdiction over OUC's electric transmission system is succeeded to by an RTO or other entity, the portion of the electric transmission system of that RTO or other successor entity that most closely resembles the OUC electric transmission system as it existed on the effective date of this Agreement.

1.1.51 "Guaranteed Output" means in any given hour the amount of Capacity (in MWh per hour) determined by adjusting the Demonstrated Capability to the prevailing ambient conditions in such hour and adjusting for degradation. The degradation adjustment shall

be [redacted] The degradation adjustment shall be [redacted]

1.1.52 "Indemnified Parties" has the meaning given such term in Section 16.1.1.

1.1.53 "Indemnifying Party" has the meaning given such term in Section 16.1.1.

1.1.54 "Interconnection Agreement" means that certain Interconnection Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.55 "Interconnection Meters" has the meaning given such term in Section 8.2.

1.1.56 "Lender" has the meaning given such term in Section 12.3.

1.1.57 "Law" shall mean all constitutions, charters, laws, codes, ordinances, orders, judgments, decrees, injunctions, licenses, rules, permits, approvals, regulations and requirements of every Governmental Authority (including OUC) having jurisdiction over the matter in question, whether federal, state or local, which may be applicable to any Party, as required by the context in which used, or to the Facility or OUC Interconnection Facilities, or to the use, manner of use, occupancy, possession, planning, licensing, design, procurement, construction, acquisition, testing, startup, operation, maintenance, management, control, addition, renewal modification, replacement or disposal of the Facility and the OUC Interconnection Facilities or any portion or portions thereof.

1.1.58 "Market Price" shall mean the price established by Seller, or negotiated and agreed upon by the Parties, as the case may be, upon Seller's election pursuant to Section 2.3 with respect to any Further Extension, which shall become the Annual Capacity Charge for Capacity to be delivered by Seller during such Further Extension consistent with all other terms and conditions of this Agreement.

1.1.59 "Meters" means the Interconnection Meters and/or Customers' check-meters, as applicable.

1.1.60 "Minor Maintenance" shall mean maintenance events lasting not greater than [redacted] per occurrence, which have been scheduled and for which Purchaser and the other Customers have given consent in accordance with Section 6.4.

1.1.61 "MMBtu" means one million British thermal units, where one British thermal unit is the amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit from sixty (60) degrees Fahrenheit.

1.1.62 "MW" means megawatt.

1.1.63 "MWh" means megawatt-hour.

1.1.64 "NERC" means the North American Electric Reliability Council or successor organization.

1.1.65 "Non-Performing Party" has the meaning given such term in Section 11.1.

1.1.66 "Notice of Intent to Terminate" has the meaning given such term in Section 12.3.

1.1.67 "Off-Peak Period" means all the days of any given Contract Year other than the Peak Period days.

1.1.68 "Operating Agreement" means that certain Operating Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.69 "Operating Period" means the period from the beginning of the first Contract Year until the end of the last Contract Year.

1.1.70 "OUC" means Orlando Utilities Commission.

1.1.71 "OUC Interconnection Facilities" means the modifications to the Stanton Substation reasonably required for the receipt and delivery of Energy from the Facility onto the Grid consistent with Prudent Utility Practice.

1.1.72 "Ownership Agreement" means that certain Stanton Energy Center Combined Cycle Unit A Construction and Ownership

Participation Agreement entered into among the Participants as of March 19, 2001.

1.1.73 "Participant" or "Participants" mean individually or collectively Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency (All Requirements Power Supply Project) and Seller.

1.1.74 "Parties" has the meaning given such term in the first paragraph of this Agreement.

1.1.75 "Peak Period" means for any given Contract Year the periods that include the days from January 1 through March 15, inclusive, May 15 through September 15, inclusive, and December 15 through December 31, inclusive.

1.1.76 "Permit" means any permit, license, approval, consent, waiver, authorization or other requirement in connection with the Project required from any Governmental Body under applicable Law.

1.1.77 "Person" means any individual, partnership, corporation, limited liability company, association, business, trust, Governmental Body or other entity.

1.1.78 "Planned Major Maintenance" means the Gas Turbine (GT) Combustor Inspection, the GT Hot Gas Path Inspection, and the GT Major Inspection, as these inspections are defined in the maintenance agreement with the GT vendor.

1.1.79 "Power Purchase Agreements" means this Agreement and those certain similar power purchase agreements between Seller and the other Customers respecting the delivery of Capacity and Energy from Seller's ownership share of the Capacity and Energy of the Facility.

1.1.80 "Prime Rate" means the prime rate of interest as published from time to time in the Wall Street Journal or such other comparable successor publication as the Participants may agree upon. The Prime Rate shall be calculated on the basis of a 365-day year for the actual number of days that a payment, reimbursement or adjustment, as the case may be, has not been made.

1.1.81 "Project" means the Facility, the Facility Site and all other appliances, parts, instruments, appurtenances, accessories and other

property that may be incorporated or installed in, or otherwise become part of, any of the foregoing.

1.1.82 "Prudent Utility Practice" means any of the practices, methods and acts engaged in, or approved by, a significant portion of the electric utility industry in the United States [redacted] or any of the practices, methods and acts, which, in the exercise of reasonable judgment in light of the facts known, or that reasonably should have been known, at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with applicable Laws, reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods and acts generally accepted in the United States and having due regard for current editions of the National Electrical Safety Code, the National Electric Code and other applicable electrical, safety and maintenance codes and standards, manufacturers' warranties and applicable Laws.

1.1.83 "Request for Energy" or "Schedule" means a request for the delivery of Energy made by Purchaser and the other Customers in accordance with the process provided in Section 6 and Appendix B for the Customers jointly to Schedule Energy, and any adjustments thereto made in accordance with Appendix B.

1.1.84 "RTO" means a regional transmission organization.

1.1.85 "Scheduled Commencement Date" means the date that is twenty-four (24) months after the receipt of the Site Certification and all other Permits to be obtained by the Customers that are necessary for Seller to commence construction, as such date may be extended under the provisions of Section 5.1, but in no event earlier than October 1, 2003.

1.1.86 "Scheduled Maintenance" means the removal of the Facility or a component thereof from service (which removal reduces the capability of the Facility to operate) to perform maintenance, overhaul, inspection, testing or repair work, as contemplated in Section 6.4.

1.1.87 "SEC Site" means the parcel of land in Orlando, Florida on which the fossil fired generating stations Stanton Unit # 1 and Stanton Unit #2 are located, including the parcel of land on which the Facility is to be located.

1.1.88 "Seller" has the meaning given such term in the first paragraph of this Agreement.

1.1.89 "Site Certification" means (i) the final approval by the applicable Governmental Body of the initial need for power determination and site certification permit applications pursuant to the Florida Electrical Power Plant Siting Act, and (ii) the receipt of the air construction (Prevention of Significant Deterioration) permit by OUC issued by FDEP pursuant to the delegated authority of the United States Environmental Protection Agency under the Clean Air Act Amendments of 1977.

1.1.90 "Technical Limits" means the limits and constraints relating to the operation and maintenance of the Facility, as described in Appendix A.

1.1.91 "Termination Payment" means the payment to be paid by a Defaulting Party to the Non-Defaulting Party under in Section 12.5.1.

1.1.92 "Test Energy" means (i) Energy produced by the Facility during testing of the Facility prior to the Commencement Date; and (ii) Energy produced by the Facility during periodic tests of the Facility's Capacity output capability following the Commencement Date.

1.2 Rules of Construction. In this Agreement, unless the context otherwise requires, the singular shall include the plural, the masculine shall include the feminine and neuter, and vice versa. The terms "include," "includes" and "including" shall be deemed to be followed by the words "without limitation." The term "month" refers to a calendar month, and any period measured by a "month" from a reference date refers to the period beginning on such reference date and ending on the same date of the next succeeding calendar month or, if no such date exists in the next succeeding calendar month, the last day of such next succeeding calendar month. References to a Section, Table or Appendix shall be references to a Section of, Table of or Appendix to this Agreement unless specifically stated otherwise. A reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented and restated through the date as of which such reference is made. The term "or" is not exclusive, the term "shall" is mandatory and the term "may" is permissive. In the event that any index or publication referenced in this Agreement ceases to be published, each such reference shall be deemed to be a reference to a successor or alternate index or publication reasonably agreed by the Parties. Both Parties acknowledge that each was actively involved in

the negotiation and drafting of this Agreement and that no law or rule of construction shall be raised or used in which the provisions of this Agreement shall be construed in favor of or against either Party because one is deemed to be the author thereof.

1.3 Consents. Whenever the consent or approval of either Party is required under this Agreement, such consent or approval shall not be unreasonably withheld, unless this Agreement provides that such consent or approval is to be given by such Party at its sole or absolute discretion or is otherwise qualified.

SECTION 2
TERM OF AGREEMENT

2.1 Initial Term.

2.1.1 This Agreement shall become effective as set forth in Section 3.1, and shall remain in full force and effect, subject to the early termination provisions set forth herein, through the later of (i) the last day of the month in which the tenth (10^{th}) anniversary of the Scheduled Commencement Date occurs or (ii) the last day of the month in which the tenth (10^{th}) anniversary of the Commencement Date occurs (the "Initial Term").

2.1.2 Notwithstanding the provisions of Section 2.1.1, the Initial Term shall terminate on (a) November 30, 2013 if Section 2.1.1 yields an end date falling between December 1, 2013 and April 30, 2014, inclusive, or (b) November 30, 2014 if Section 2.1.1 yields an end date that falls on or after May 1, 2014.

2.2 Extension of Initial Term. The Initial Term shall be automatically extended an additional five (5) years from the end of the Initial Term ("Extended Term"); *provided, however,* that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of the Initial Term by providing written notice of such election to Seller no later than the date that is three (3) years prior to the end of the Initial Term.

2.3 Extensions of Extended Term. The Extended Term shall be automatically extended three (3) successive periods of five (5) years each from the end of the Extended Term (the "Further Extensions"); *provided, however*, that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of any of (i) the Extended Term, (ii) the first Further Extension, or (iii) the second Further Extension, by providing written notice of such election to Seller no later than the date that is, respectively, three (3) years prior to the end of the Extended Term, three (3) years prior to the end of the first Further Extension, or three (3) years prior to the end of the second Further Extension, as the case may be; *provided, further,* that with respect to each Further Extension, Seller shall have the right to establish the Annual Capacity Charge for such Further Extension based on Seller's then-current assessment of market conditions by providing Purchaser written notice of the new proposed Annual Capacity Charge

no later than the date that is three and one-half (3 1/2) years prior to the date that such Further Extension period is scheduled to begin, subject to Purchaser's right to request that Seller negotiate in good faith to agree on any other price that Purchaser believes in good faith reflects current market conditions.

2.4 Survival. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to satisfy the terms and conditions of this Agreement and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing either Party pursuant to this Agreement, repayment of principal and interest associated with security funds, and the indemnifications specified in this Agreement.

SECTION 3
CONDITIONS PRECEDENT

3.1 Condition Precedent to Effectiveness. The Parties agree and acknowledge that this Agreement shall be effective only upon the date on or before which both of the following have occurred (such date, the "Effective Date"): (i) the execution and delivery of the Ownership Agreement and the Operating Agreement and all other Collateral Documents; and (ii) the acknowledgment of the Participants' satisfaction of the foregoing condition and the accuracy of the cross-references to the Collateral Documents contained in this Agreement.

3.2 Conditions Precedent to Obligations. Notwithstanding any provisions of this Agreement to the contrary, the obligations of the Parties to this Agreement shall be subject to the fulfillment of each of the conditions (or the waiver in writing of such conditions by the respective Party or Parties) set forth in Article 8 of the Ownership Agreement.

SECTION 4
SALE AND PURCHASE

4.1 Capacity Delivery and Payment. Subject to the terms and conditions of this Agreement, during the Operating Period, Seller agrees to deliver and sell to Purchaser and Purchaser agrees to receive and purchase from Seller up to [redacted] of the Actual Capability of the Facility in accordance with the following provisions:

4.1.1 The Capacity payment (the "Capacity Payment" or "CP") in respect of each month during the Operating Period shall be an amount equal to: the product of the Annual Purchaser's Capacity Nomination (expressed in kilowatts) multiplied by the Annual Capacity Charge. For any partial month during the Operating Period, the Capacity Payment shall equal the amount determined pursuant to the formula set forth in the preceding sentence multiplied by a fraction, the numerator of which is the number of days of such partial month within the Operating Period, and the denominator of which is the total number of days in such month. If the

Annual Purchaser's Capacity Nomination changes during a month, then the Capacity Payment for such month shall be equal to the product of the Annual Capacity Charge multiplied by the sum of the two results obtained: (i) first by multiplying the old Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) prior to the time of the change over the total number of days in the month; and (ii) second by multiplying the new Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) after the time of the change over the total number of days in the month. The Capacity Payment shall be paid by Purchaser to Seller in accordance with Section 9.1. Notwithstanding the above, if during the first three (3) months of the Operating Period any Governmental Body shall prohibit the Facility from operating because of Seller's failure to obtain, prior to the Commencement Date any Permit required by Law for Seller to operate the Facility, then Purchaser's obligation to make Capacity Payments shall be suspended until the earlier of: (i) the lifting of such prohibition; or (ii) the date that is three (3) months after the Commencement Date.

4.1.2 The initial Demonstrated Capability of the Facility shall be established in accordance with the Capacity testing procedure set forth in Appendix C. Following the first anniversary of the Commencement Date, Seller shall perform Capacity tests [redacted] pursuant to the testing procedures set forth in Appendix C, during the Summer and Winter periods as defined by FRCC; *provided, however*, that Seller shall be entitled to a [redacted] period of maintenance that does not affect calculation of Actual Availability of the Facility (which period shall be prior to any such Capacity test from 9 p.m. Friday to 7 a.m. Monday, unless OUC, in its sole discretion, agrees otherwise). In addition, Seller may retest when a repair or modification of the Facility, or a corrected or improved operational or maintenance activity, results in an increase in the Capacity of the Facility (including adjustments made during initial shakedown), provided that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) is at least one hundred and one percent (101%) of the last Demonstrated Capability test amount. Should any test or retest conducted pursuant this Section 4.1.2 indicate that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) has changed by an amount equal to or greater than one percent (1%) of the last Demonstrated Capability test amount, the Demonstrated Capability shall be reset at such actual full load output for purposes of determining the Capacity Payment as of the time the test is completed; *provided, however*, that if the test is performed during a Force

Majeure event and such Force Majeure event resulted in the reduction of the Demonstrated Capability, the Capacity Payment shall not be reduced thereby until the end of the [redacted] period described in the last paragraph of Section 4.1 below.

4.1.3 Seller shall conduct additional tests as required by the FRCC or as requested by Purchaser pursuant to Purchaser's legal or contractual obligations with third parties; *provided, however*, such additional tests shall be for informational purposes and shall not be used to reset the Demonstrated Capability or otherwise determine the Capacity Payment under this Agreement.

4.1.4 Beginning with the sixth (6^{th}) Contract Year and ending with the tenth (10^{th}) Contract Year, the Customers shall have the irrevocable right to jointly reduce the total of their combined Annual Purchaser's Capacity Nominations, for the remainder of the Initial Term and any Extended Term or Further Extensions, by either twenty-five (25) MW or fifty (50) MW (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) per year; *provided, however*, that such combined total of the Annual Purchaser's Capacity Nominations may not be reduced by more than 200 MW in the aggregate. Purchaser must give Seller notice of any such reduction elected by Purchaser not later than three (3) years prior to the commencement of the Contract Year in which such reduction shall occur; *provided, however*, that such notice shall be effective if and only if either it is made jointly with the other Customers or the other Customers give Seller a similar notice under their respective Power Purchase Agreements with all such notices together satisfying the above criteria; *provided, further,* that such notices shall specify any changes in the percentage of the Annual Purchaser's Capacity Nomination to be purchased by Purchaser under Section 4.1.1 and by the other Customers under the corresponding provisions of their respective Power Purchase Agreements.

Notwithstanding the foregoing provisions of this Section 4.1, if and to the extent that a Force Majeure event affects Seller's ability to deliver and sell to Purchaser the Capacity of the Facility or any portion thereof, Seller shall be excused from any delay in performing or failure to perform any or all of such obligations (and in this regard, the Parties shall follow the procedures contemplated in Section 11.1); *provided, however*, that notwithstanding such reduction or elimination of the Actual Capability of the Facility, Purchaser shall continue to pay Seller the full Capacity Payment attributable to the [redacted] following the date of Seller's notification to Purchaser of any such Force Majeure effect; *provided, further,* that if the effect of a Force Majeure event lasts for longer than [redacted] then Purchaser shall not be required to make Capacity Payments attributable to any continued period of Force Majeure

declaration after the end of such [redacted] period, but Purchaser must resume making Capacity Payments when Seller declares the Force Majeure period over and resumes its obligation for delivery of Energy under this Agreement; *and provided, further,* that the Capacity Payment relief contemplated in the immediately preceding clause shall not apply if the Force Majeure event affecting Seller resulted from a failure of Purchaser or another Customer to fulfill its obligations under this Agreement or any of the Collateral Documents; *and provided, further,* that a Force Majeure event that affects Purchaser's ability to receive Energy from the Facility shall not excuse Purchaser's obligation to make Capacity Payments, except solely to the extent provided for in Section 5.1.3 if and to the extent such provision is applicable.

4.2 Energy Delivery and Payment. Subject to the terms and conditions of this Agreement and, in particular, subject to the provisions of Section 6 and Appendix B, Seller shall sell and deliver, and Purchaser shall purchase and receive, during the Operating Period, Energy requested by Purchaser in a Request for Energy, as well as Energy generated by associated ramp up and ramp down of the Facility and Test Energy; *provided, however,* that Purchaser shall not be required to make any payments for Test Energy produced prior to the Commencement Date. The Customers shall pay for and supply all fuel associated with the Customers' Request for Energy in accordance with the provisions of Section 3.2 of the Operating Agreement. The Energy payment (the "Energy Payment" or "EP") in respect of each month shall be the sum of four (4) components: a variable O&M component for operation on natural gas, a variable O&M component for operation on fuel oil, a start-up component, and a fuel component for Energy delivered from Alternate Resources. The components of the Energy Payment shall be calculated as follows:

4.2.1 Variable O&M Component - Natural Gas. The variable O&M component for operation on natural gas shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} [(DENG_{ij} \times VOMR) + HVOM_{ij}]$$

Where:

$DENG_{ij}$ is Delivered Energy in MWh (other than Test Energy prior to the Commencement Date) from the Facility produced with natural gas during hour j of day i; *provided, however,* that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with natural gas; and

VOMR is the variable O&M rate (in $/MWh), which shall be [redacted] and

HVOM is the hourly variable O&M rate (in $ per hour) as determined from Table A and its accompanying Notes applicable for hour j of day i during which the Facility is operating on natural gas and which is applicable only when $DENG_{ij}$ is > 0.

Table A

Hourly Variable O&M Charges for Operation on Natural Gas

Annual On-Line Factor	Combined Hourly Variable O&M Rate (in $ per hour) for all Customers (see Notes below)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table A:

1) The Hourly Variable O&M Rate in Table A represents the rate applicable for the Annual Purchaser's Capacity Nominations of all Customers. The actual Hourly Variable O&M Rate for Purchaser for an hour in a particular Contract Year shall equal the product of the applicable rate from the table for such Contract Year multiplied by the ratio of Purchaser's portion of the Request for Energy for such hour over the total Request for Energy for such hour.

2) The Hourly Variable O&M Rate for a Contract Year shall be interpolated between the values shown in Table A when the Annual On-Line Factor for the previous Contract Year falls between the specific

percentages shown on Table A. For example, with respect to an Annual On-Line Factor of [redacted], the Hourly Variable O&M Rate shall be [redacted]

3) The dollar amounts shown in Table A are expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

4) The dollar amounts in Table A represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Customers under the Power Purchase Agreements. If Purchaser and the other Customers elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table A shall be proportionately reduced commensurate with such Capacity reduction.

5) The Annual On-Line Factor shall be calculated for each Contract Year, as follows:

Annual On-Line Factor = SH/ (PH – OH)

Where:

SH is the number of hours that the Customers Schedule and Seller delivers Energy in a Contract Year; and

PH is the number of hours in a Contract Year; and

OH is the number of hours in a Contract Year during which (i) the Facility is unavailable due to a forced outage or due to a maintenance outage that Seller has scheduled pursuant to Section 6.4 or, if applicable, that is a permitted [redacted] under Section 4.1.2, and (ii) Seller does not deliver from an Alternate Resource.

6) For the first Contract Year, all monthly Energy billings will be made assuming an Annual On-Line Factor of [redacted] The rate shall be determined annually for each Contract Year based on the Annual On-Line Factor for the previous Contract Year. At the end of each Contract Year, the Annual On-Line Factor for such Contract Year shall be calculated and the Hourly Variable O&M charges for such Contract Year shall be recalculated using such Annual On-Line Factor for such Contract Year. A true-up payment or refund shall be made to adjust the amounts collected by Seller from Purchaser during each

Contract Year to the amount computed by Seller using such Annual On-Line Factor for such Contract Year. Any true-up payments shall be included on an invoice as soon as reasonably practicable following the end of the applicable Contract Year.

4.2.2 Variable O&M Component—Fuel Oil. The variable O&M component for operation on fuel oil when firing the gas turbines shall be calculated as follows:

$$\sum_{i=\text{ Days in the Month}} \sum_{j=\text{ Hours in the Day}} [(DEFO_{ij} \times VOMRFO) + HVOMFO_{ij}]$$

Where:

$DEFO_{ij}$ is Delivered Energy (other than Test Energy prior to the Commencement Date) produced with fuel oil during hour j of day i; provided that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with fuel oil; and

VOMRFO is the variable O&M rate (in $/MWh) for Energy produced with fuel oil, which shall be [redacted], subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations); and

HVOMFO is the hourly variable O&M rate (in $ per hour) for hour j of day i during which the Facility is Operated on fuel oil, which rate shall be [redacted] subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations), and which is applicable only when $DEFO_{ij}$ is > 0.

4.2.3 Start-up Component. The start-up component shall be calculated as follows:

GTS x SUR

Where:

GTS is the number of gas turbine starts required to meet a Request for Energy (other than for Test Energy prior to the Commencement Date) where the amount of Energy delivered from any single gas turbine increases from zero to an amount greater than zero; *provided, however*, that the calculation of GTS shall not include: (i) any starts required to resume delivery to Purchaser due to an interruption caused by a forced outage, or (ii) any starts initiated by Seller in order to make third party sales in any given hour where the Facility would otherwise not have been started in such hour to meet a Request for Energy.

SUR is the Start-up Rate (in $ per start) for each gas turbine as determined from Table B below and its accompanying Notes:

TABLE B

Start-Up Rates

Cumulative Number of Start-ups per Gas Turbine per Contract Year	Combined Start-up Rate per Start per Gas Turbine for all Customers (see Notes)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table B:

1) The SUR in Table B represents the rate applicable to all Customers for each start-up during a Contract Year. [redacted] and the combined rate among all Customers participating in each subsequent start-up during such Contract Year shall be as identified in the Table B. The actual SUR for Purchaser (in $ per start) for any such start-up shall equal the quotient of the applicable rate from the Table B divided by the number of Customers participating in the Request for Energy that requires the start-up (and in which Purchaser is one of those Customers); *provided,*

however, Purchaser will not have to pay for start-ups in which it does not participate.

2) The SUR is expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

3) The dollar amounts in Table B represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Participants under the Power Purchase Agreements. If the Participants elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table B shall be proportionately reduced commensurate with such Capacity reduction.

4.2.4 O&M Rate Adjustment. The rates in Sections 4.2.1, 4.2.2 and 4.2.3 shall be increased or decreased based on good faith negotiation of the Parties (in accordance with Section 18) to reflect and include any actual increase or decrease in Seller's costs of operating the Facility that is caused by any mutually agreed-upon modification or design change or any actual increase or decrease in Purchaser's or another Customers' charges for providing any services to Seller.

4.2.5 Energy Payment for Delivery from Alternate Resources.

4.2.5.1 If Seller elects to deliver Energy from Alternate Resources pursuant to Section 4.4, then the variable O&M component and the start-up component of the Energy Payment shall be calculated in accordance with Sections 4.2.1 and 4.2.3, respectively, for such Alternate Resource Energy as if it were delivered from the Facility. In addition, the fuel component for the Energy delivered from Alternate Resources shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} (MDE_{ij} \times HR_{ij} \times FRP_{ij})$$

Where:

MDE_{ij} = Scheduled Energy in MWhs delivered from an Alternate Resource during hour j of day i;

when the Facility is unavailable, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested

and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs;

when the Facility is available, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs; and

FRP_{ij} = the fuel rate proxy for an hour calculated in dollars per MMBtus in accordance with the applicable provisions of either Section 4.2.5.2 or 4.2.5.3.

4.2.5.2 If the Fuel Supply Agent has not already scheduled the transportation of gas to the Facility to meet the Customers' Schedules for the hour during which Seller elects to deliver the Scheduled Energy from Alternate Resources, then following notification from Seller of its election to deliver the Scheduled Energy from Alternate Resources, Seller shall be obligated to obtain the necessary quantities of gas and necessary gas transportation capacity to accommodate any portion of the Schedule that Seller has elected to satisfy from Alternate Resources. During periods that Seller elects to deliver Energy from Alternate Resources, the Fuel Supply Agent shall make available transportation capacity, within constraints of the pipeline tariffs and operational procedures in effect at the time and at no additional cost to the Fuel Supply Agent, in the amount determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the

determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtus) shall be equal to the sum of: (i) [redacted] and (ii) the applicable firm gas transportation variable cost associated with deliveries to the Facility under such Participant's firm transportation agreement(s). All risks of gas supply and transportation interruption to accommodate deliveries of Energy from Alternate Resources shall be borne by Seller.

4.2.5.3 If the Fuel Supply Agent has already scheduled the transportation of gas to the Facility to meet the Customers' Schedules by the time Seller notifies Purchaser of Seller's election to deliver the Scheduled Energy from Alternate Resources, then at Seller's election:

(i) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to revise its scheduled transportation of gas to the Facility to provide for the delivery of the gas to Seller at any alternate delivery point designated by Seller that is available under the Customers' firm transportation agreement(s). The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time, and the Fuel Supply Agent shall not be required to incur any additional cost as a result of the revision of the schedule of transportation of gas to the alternate delivery point. The amount of scheduled transportation of gas to be delivered to the alternate delivery point shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtu) shall be [redacted]

[redacted] or

(ii) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to remarket to third parties the gas that has been scheduled for delivery to the Facility on the best terms possible under the circumstances. The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time. The amount of scheduled transportation of gas to be remarketed to third parties shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in from paragraph 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has directed the Fuel Supply Agent to remarket the gas under these circumstances, the FRP (in $ per MMBtu) shall be [redacted]

4.3 Availability Guarantee.

4.3.1 Seller guarantees that the Actual Availability of the Facility for [redacted] of each Contract Year will equal or exceed [redacted] ("Availability Guarantee"); *provided, however*, that (i) the [redacted] of operation following the Commencement Date shall be excluded from the Availability Guarantee, (ii) if and to the extent that a Force Majeure event affects Seller's ability to achieve the Availability Guarantee, other than in the case of Equipment Breakdown, Seller shall be excused from the Availability Guarantee (and in this regard the Parties shall follow the procedures contemplated in Section 11), and (iii) to the extent that the Facility is fired with fuel oil in excess of [redacted] per combustion turbine unit in any Contract Year in order to meet Purchaser's Request for Energy, then for every additional [redacted] that the Facility is fired using fuel oil, the lower end of the Availability Guarantee range, and the factors [redacted] in Sections

4.3.5.1 and 4.3.5.2, shall be reduced by [redacted] each, which reductions shall remain in effect until the next Planned Major Maintenance occurs. If either combustion turbine is not fired on oil during any Contract Year for the same number of hours as the other combustion turbine, then for purposes of calculating the adjustment to the Availability Guarantee, each combustion turbine will be deemed to have been fired on oil during such Contract Year for a number of hours that is equal to one half of the summation of the number of hours that each combustion turbine was actually fired on oil during such Contract Year.

4.3.2 In each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, Seller shall be entitled to an availability incentive payment from Purchaser ("Availability Incentive Payment") equal to (a) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Peak Period, and/or (b) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Off-Peak Period.

4.3.3 The Actual Availability for the Peak Period of each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, shall be calculated as follows and then rounded up or down to the nearest tenth of a percentage point [redacted]; *provided, however*, that such Actual Availability shall not exceed one (1.00):

Actual Availability = (PH-OH -EDH+EMH+ARDH)/PH

Where: "PH" (or "Period Hours") shall equal the hours in the Peak Period of such calendar year;

"OH" (or "Outage Hours") in the Peak Period of such Contract Year means all hours the Facility is unavailable for operation; *provided, however*, that OH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day;

"EDH" (or "Equivalent Derated Hours") in the Peak Period of such Contract Year means the summation of EDH for each hour

during the Peak Period; *provided, however*, that EDH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day. In each hour for which the EDH of such hour must be calculated, EDH for the hour will equal (Guaranteed Output - Actual Capability)/Guaranteed Output;

"EMH" (or "Excused Maintenance Hours") shall equal hours that Seller has scheduled maintenance on the Facility in the Peak Period of such calendar year pursuant to Section 6.4 and, if applicable, the [redacted] of pre-testing maintenance allowed prior to a Capacity test under Section 4.1.2; *provided, however*, that in any hour EMH must be zero if there is no Outage Hour in such hour; and

"ARDH" (or "Alternate Resource Delivery Hours") shall equal the number of hours that Seller delivers Energy to Purchaser from Alternate Resources in the Peak Period of such Contract Year to fully or partially make up for shortfalls caused by Facility outages or derates. Seller will not receive any credit for ARDH in any entire day unless Seller is able to deliver at least partial Energy in each hour of such day that Purchaser Schedules Energy, in which case Seller will receive ARDH credit for each hour of the day based on the lowest ratio during any hour of such day of Delivered Energy to Scheduled Energy.

4.3.4 The Actual Availability for the Off-Peak Period of each Contract Year shall be calculated in a fashion similar to Section 4.3.3, substituting "Off-Peak Period" for "Peak Period" where it appears in Section 4.3.3.

4.3.5 In the event that the Actual Availability during the Peak Period or Off-Peak Period, or both, of any given Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, is less than the lower end of the Availability Guarantee range, then Purchaser shall be entitled to receive availability damages ("Availability Damages") from Seller as Purchaser's sole and exclusive remedy for Seller's failure to delivery Capacity and Energy from the Facility due to the unavailability of the Facility.

4.3.5.1 The Availability Damages for the Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Peak Period of any Contract Year = [redacted]

4.3.5.2 The Availability Damages for the Off-Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Off-Peak Period of any Contract Year = [redacted]

4.3.5.3 In both of Sections 4.3.5.1 and 4.3.5.2, the factors [redacted] and [redacted] shall be adjusted for the use of fuel oil pursuant to Section 4.3.1(iii), if applicable.

4.3.6 As soon as reasonably practicable after the first month following the Commencement Date, and each month thereafter, Seller shall submit to Purchaser a statement setting forth in reasonable detail the actual availability of the Facility during the prior month, including the underlying availability data.

4.3.7 As soon as reasonably practicable following each Contract Year, Seller shall submit to the Purchaser a statement setting forth the Actual Availability for the preceding Contract Year together with a calculation of the net amount of any Availability Incentive Payment due to Seller or Availability Damages due to the Purchaser for the preceding Contract Year based on the foregoing calculations, as applicable, with respect to the Peak Period and Off-Peak Period of such Contract Year. Within ten (10) Business Days of (a) receipt of such statement, Purchaser shall pay any Availability Incentive Payment due to Seller by wire transfer in immediately available funds, or (b) transmittal of such statement, Seller shall pay any Availability Damages due to Purchaser by wire transfer in immediately available funds.

4.4 Alternate Resources. In any hour in which the Facility is unavailable, Seller may continue to make deliveries of Energy in the full amount Scheduled by Purchaser from non-Facility sources (including, but not limited to, generating units on Seller's or its Affiliates' systems and Energy purchases available to Seller) ("Alternate Resources") to replace the Energy that would have been provided by the unavailable Facility. In any hour in which the Facility is available, Seller may choose to make deliveries of Energy in the full amount Scheduled by Purchaser, or any portion thereof, from Alternate Resources to replace the Energy that would

have been provided by the available Facility; *provided, however*, that if the Facility is available, Seller must maintain the Facility on-line and committed at least at the Facility's minimum load, and Purchaser may Schedule spinning reserves from the Facility, all in accordance with Appendix B. Seller must deliver Energy from Alternate Resources to Purchaser at an unconstrained point on the Grid, and if Seller is making such delivery at a time when the Facility is unavailable, then Seller will purchase Firm Transmission Service for such delivery to the extent that such Firm Transmission Service is available for the Alternate Resource Energy from the point of its acquisition by Seller to the unconstrained point on the Grid. In utilizing Alternate Resources, Seller shall comply with the notice requirements of Section 3 of Appendix B.

4.5 Purchaser's Right to Capacity and Energy. During the Operating Period, Purchaser shall have the first call to purchase Seller's share of the Capacity and Energy generated by, and Ancillary Services associated with, the Facility (other than the reductions in Capacity elected jointly by the Customers pursuant to Section 4.1.4); *provided, however*, that (i) subject to Purchaser's right to Capacity and Energy under this Agreement and the Operating Agreement, Seller may make sales of any Capacity and Energy generated by, and Ancillary Services associated with, Seller's Equity Capacity when such Capacity and Energy is not Scheduled by Purchaser, and (ii) in the event that Seller determines that the Facility is capable of delivering Energy to the Grid prior to the Scheduled Commencement Date, Seller shall have the option of either (a) utilizing the Capacity and Energy generated by, and Ancillary Services associated with, its percentage ownership share of the Facility prior to the Scheduled Commencement Date for sales to third parties by delivering written notice of its election of this option thirty (30) days prior to the anticipated Commercial Operation Date, in which event Purchaser shall not make Capacity Payments until the later of the Scheduled Commencement Date or the Commencement Date, or (b) initiating delivery of Capacity and Energy to Purchaser under this Agreement on the Commencement Date. If Seller makes sales of either or both Capacity and Energy to third parties under Section 4.5(ii)(a) at a time when the Scheduled Commencement Date has passed but the Commencement Date has not yet occurred, then Seller will pay to Purchaser the portion, if any, of the proceeds of such sales that Seller actually receives.

SECTION 5
SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY

5.1 Scheduled Delivery.

5.1.1 Seller anticipates that, the Facility will achieve the Commencement Date by the Scheduled Commencement Date and shall be fully capable of reliably producing the power and Energy to be provided under this Agreement to Purchaser at the Delivery Point; *provided, however*, that if and to the extent that a Force Majeure event affects Seller's ability to timely comply with the foregoing guarantee, the Scheduled Commencement Date shall be extended by the amount of time Seller reasonably needs to remedy the effects of the Force Majeure that

prevented Seller's performance (and in this regard, the Parties shall follow the procedures contemplated in Section 11).

5.1.2 In the event that Seller fails to achieve the Commencement Date by the date that is two (2) years after the Scheduled Commencement Date, then either (i) Seller shall have the right to simultaneously terminate all of the Power Purchase Agreements by delivering written notice of such election to Purchaser and the other Customers ("Seller's Termination Notice"), or (ii) Purchaser may terminate this Agreement, if and only if each of the other Customers also terminates contemporaneously its respective Power Purchase Agreement for the same reason, by delivering written notice of such election to Seller (collectively, together with the other Customers' similar notices, "Purchasers' Termination Notices"). Within ten (10) Business Days of the date of Seller's Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Seller's Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2. Within ten (10) Business Days of the date of Purchasers' Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Purchasers' Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2.

5.1.3 In the event that Seller's failure to achieve the Commencement Date by the Scheduled Commencement Date is attributable to, in whole or in part, the failure of any Customer to meet any of their respective obligations under this Agreement or their respective Power Purchase Agreements or the Collateral Documents, then (a) the Scheduled Commencement Date shall be extended for such period of Purchaser's or such other Customer's failure, and (b) Purchaser shall make Capacity Payments (assuming a Demonstrated Capability of [redacted] MW and an Availability Performance of [redacted] for the period affected by the delay) beginning as of the initial Scheduled Commencement Date (without any extension); *provided, however*, that Purchaser shall not be required to make any Capacity Payments under this Section 5.1.3 to the extent the delay in achieving the Scheduled Commencement Date is attributable to the concurrent failure of Purchaser or such other Customers and Seller (where such concurrent failures are not co-extensive, such relief from Capacity Payments shall apply only during the period of time that Seller's failure to meet its obligations contributed to the delay); *provided, further*, that in the event

Purchaser's failure to meet its obligation was the result solely of a Force Majeure event that prevented Purchaser's timely completion of such obligation, then Purchaser will be excused from having to make Capacity Payments as contemplated in Section 5.1.3(b) for the [redacted] after the Scheduled Commencement Date (without benefit of any extension thereof allowed under this Agreement), but if the Commencement Date does not occur within such [redacted] period, then Purchaser shall recommence making Capacity Payments starting at the beginning of the [redacted] day after the Scheduled Commencement Date and thereafter continue making Capacity Payments as contemplated in Section 5.1.3(b).

5.2 Conditions to Commencement. Seller will notify Purchaser of the date when the Facility has achieved the following criteria (the "Commencement Date"), which notice will be accompanied by reasonable documentation evidencing satisfaction or occurrence of each of the following; *provided, however,* that Seller shall not be precluded from making third-party sales, in accordance with Section 4.5, of its percentage ownership share of Capacity and Energy from the Facility notwithstanding whether any or all of the following criteria have been met in whole or in part:

5.2.1 successful completion of required testing of the Facility has occurred for purposes of financing, project operation, air permitting, Purchaser's planning and reporting, and manufacturers' warranties, including establishment of the initial Demonstrated Capability of the Facility as contemplated in Section 4.1.2;

5.2.2 the Facility has completed [redacted] successful start-ups without experiencing any abnormal operating conditions and has generated continuously for a period of not less than [redacted] while synchronized to the Grid at a net Capacity output of at least [redacted] of the Demonstrated Capability (adjusted for ambient conditions) without experiencing any abnormal operating conditions;

5.2.3 the Facility is in compliance with the Interconnection Agreement, either is capable of operation in the AGC mode or is capable of responding to manual load change instructions, has achieved initial synchronization with the Grid, and has demonstrated the reliability of its communications systems and communications with the Florida Municipal Power Pool Energy Control Center located in the OUC Pershing Operations Building (or the replacement for such control center if the Customers decide to have their generation control performed at a different location); and

5.2.4 certificates of insurance coverages and/or insurance policies required of Seller have been obtained and submitted to Purchaser as required by Section 28.

5.3 Test Energy. Seller shall coordinate the production and delivery of Test Energy with Purchaser. Purchaser shall cooperate with Seller to facilitate Seller's testing of the Facility, provide the fuel necessary to conduct testing, and shall accept Test Energy delivered to Purchaser in accordance with the provisions of Section 4.2.

SECTION 6
REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE

6.1 Communicating Requests for Energy. Purchaser shall have the right to request deliveries of Energy by providing a Request for Energy to Seller in accordance with this Section 6 and Appendix B; *provided, however*, that Purchaser and the other Customers shall coordinate their Scheduling requirements by jointly submitting a single Request for Energy that covers all of their respective requirements on any given day.

6.1.1 The Customer's joint Requests for Energy may request the full output of the Facility, reduced by those amounts, if any, that Customers jointly elect to subtract from the Capacity available to Customers pursuant to the process provided in Section 4.1.4 of this Agreement and the other Power Purchase Agreements. If the Customer's joint Request for Energy is for less than the full output of the facility, then the request shall be deemed to be a Request for Energy first from Purchaser's Equity Capacity and, if such Equity Capacity is not sufficient, then from Purchaser's purchased Energy under this Agreement.

6.1.2 The Parties hereby consent to the recording of all conversations on the telephone lines used for communicating Requests for Energy and related notices and instructions in accordance with customary industry practice. The contents of such recordings shall be definitive.

6.2 Limitations on Requests for Energy. Notwithstanding anything to the contrary in this Agreement, any Request for Energy, operation in the AGC mode or operation in response to a Capacity Emergency that would require the Facility to operate in a manner inconsistent with the Technical Limits, Prudent Utility Practice or applicable Law and Permit requirements shall be deemed not to comply with the requirements and limitations set forth in this Section 6. If and when a Customers' Request for Energy does not comply with the requirements and limitations of this Section 6 by reason of the previous sentence, Seller will notify Customers of such noncompliance promptly after Seller realizes that the Request for Energy is noncompliant and will modify Customer's Request for Energy to make it consistent with the Technical Limits, Prudent Utility Practice and all applicable Laws and Permits to the extent it is reasonably possible to do so consistent with such standards.

6.3 Operation of the Facility. Seller shall operate and maintain the Facility in accordance with this Agreement, Prudent Utility Practice, the Technical Limits and all applicable Laws and Permit requirements. Any emission allowances required for operation of the Facility as contemplated in this Agreement shall be provided in accordance with the applicable provisions of the Operating Agreement.

6.4 Scheduled Maintenance. Seller agrees to schedule Planned Major Maintenance during the Off-Peak Period, or to obtain Purchaser's consent to schedule such maintenance during the Peak Period. Seller will submit to Purchaser an annual maintenance projection and will make reasonable efforts to coordinate the scheduling of such Planned Major Maintenance with Purchaser, including estimated start dates and return to service dates. Seller must seek the consent of OUC, acting for itself and on behalf of the other Customers (which Purchaser hereby authorizes) in scheduling of any Minor Maintenance; *provided, however,* that Purchaser guarantees Seller will be afforded a minimum of [redacted] such Minor Maintenance events distributed approximately evenly over the Off-Peak Period, with a maximum of [redacted] such Minor Maintenance events during any year; *provided, further,* that requests for Minor Maintenance events during the period from May 15 through September 15 may be granted or withheld in [redacted].

6.5 Transmission Operator. Coordination with an RTO regarding security and reliability of the Grid as it relates to the Facility, or any other entity, having control over the security and reliability of the Grid shall be the responsibility of Seller as the operator of the Facility. Coordination with an RTO, or other entity, having balancing authority or scheduling authority over the Facility should be handled by Purchaser for any schedules to Purchaser from the Facility and by Seller for any other schedules from the Facility. Any orders, directives or operating requirements that Seller is required to follow by Law imposed on Seller by an RTO, or any other entity, having control over the security and reliability of the Grid shall take precedence over this Agreement. To the extent the requirements of such order, directive or operating requirement necessarily prevent Seller from fulfilling its obligations under this Agreement, Seller shall be relieved of its obligations hereunder. To the extent the requirements of such order, directive or operating requirement conflict with Seller's fulfillment of its obligations hereunder, the rights and obligations of the Parties hereunder shall be adjusted as necessary to comply with such orders, directives or operating requirements.

SECTION 7
INTERCONNECTION AND TRANSMISSION

7.1 Interconnection Facilities. The Parties shall execute an Interconnection Agreement pursuant to applicable interconnection policies and procedures of OUC. The Interconnection Agreement shall contain terms and conditions governing the interconnection and parallel operation of the Facility with the Grid.

7.2 Delay in Interconnection. Purchaser shall cause OUC to complete the OUC Interconnection Facilities and ensure that the Grid is capable of providing and receiving Energy by the date that is [redacted] prior to the anticipated Commercial Operation Date, but in no event earlier than [redacted] By the date that Seller has completed the collector bus and the 230 kv line to the OUC Interconnection Facilities, but no earlier than the date that is [redacted] prior to the anticipated Commercial Operation Date, OUC shall provide service to the Facility for the purposes of engineering and testing the collector bus and other systems by either providing 230 kv service at the 230 kv Interconnection Point or by providing service to the 4160 kv SWGR bus. If for any reason, other than the fault of Seller, OUC fails to complete the OUC Interconnection Facilities and/or if the Grid is not capable of providing and receiving Energy (as determined by OUC and as supported by reasonable documentation) in accordance with the preceding sentence and, as a result, OUC cannot accommodate Seller's start-up and testing of the Facility (such a delay, an "IF/Grid Delay"), then the Scheduled Commencement Date shall be extended by that period of time equal to the IF/Grid Delay; *provided, however*, that Purchaser shall make the Capacity Payments as provided in Section 5.1.3(b); *provided, further*, that if Seller would not have been capable of delivering Energy from the Facility to the OUC Interconnection Facilities, even in the absence of an IF/Grid Delay, on the original anticipated Commercial Operating Date ("Seller's Delay"), then extension of the Scheduled Commencement Date and the date on which Purchaser is obligated to make Capacity Payments shall be adjusted by the period of time of Seller's Delay.

7.3 Transmission.

7.3.1 Purchaser shall be responsible for all costs associated with and for making all necessary transmission arrangements for Delivered Energy, including tagging and any required Ancillary Services, with the transmission service provider for delivery from and beyond the Delivery Point.

7.3.2 Seller shall bear all costs and losses and shall be responsible for making all arrangements for transmission service, including tagging and any required ancillary services, with respect to delivery of Capacity and Energy from an Alternate Resource to an unconstrained point on the Grid.

SECTION 8
RISK OF LOSS; METERING

8.1 Risk of Loss. Delivered Energy sold pursuant to this Agreement shall be made available to Purchaser at the Delivery Point. Risk of loss with respect to all such Energy shall pass to Purchaser when such Delivered Energy is made available to Purchaser at the Delivery Point. Risk of loss with respect to the natural gas supply utilized to deliver Energy pursuant to this Agreement shall pass to Seller when such natural gas supply is made available to Seller at the Gas Delivery Point. For purposes of this Agreement, and except to the extent expressly limited in this Agreement, Purchaser shall bear all risk of all occurrences of any nature (including

Force Majeure or any other event beyond the reasonable control of either Party) affecting any interconnection facilities, substations, transmission lines and other facilities on Purchaser's side of the applicable Delivery Point and the Gas Delivery Point.

8.2 Place of Measurement. All Energy from the Facility shall be measured by the Facility's meters (such meters collectively, the "Interconnection Meters"), and the Energy delivered from the Facility shall be the Interconnection Meters' readings of the quantities of Energy, reduced by an amount equal to the applicable Energy quantity necessary to compensate for the loss, if any, between the Interconnection Meters and the Delivery Point.

8.3 Testing and Calibration of Interconnection Meters. Seller shall inspect and calibrate the Interconnection Meters at least once a year. Seller shall give Purchaser reasonable advance notice of any inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to have a representative present at such inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to require, at Purchaser's expense except as set forth in Section 8.4, a test of any of the Interconnection Meters not more often than once every twelve (12) months. If any Interconnection Meter is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such Interconnection Meter shall be deemed accurate, but Seller shall use its reasonable efforts to adjust such Interconnection Meter immediately and accurately. In the event that any Interconnection Meter is found to be inaccurate by more than one half of a percent (0.5%), Energy delivered at the corresponding Delivery Point shall be measured by reference to Customers' check-meters, if installed and registering accurately, or the meter readings at the Delivery Point for the period of inaccuracy shall be adjusted as far as can be reasonably ascertained by Seller from the best available data from both Parties. If the period of the inaccuracy cannot be ascertained reasonably, any such adjustment shall be for a period equal to one half of the time elapsed since the preceding test. Customers' check meters, if installed, shall be subject to Seller's right to require, at Seller's expense except as set forth in Section 8.4, a test of any of the check-meters not more often than once every twelve (12) months. If any of Customers' check meters is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such check meter shall be deemed accurate, but Customers shall use their reasonable efforts to adjust such check meter immediately and accurately.

8.4 Delivered Energy Adjustments. In the event that, due to correction for inaccurate Interconnection Meters with an inaccuracy in excess of one half of a percent (0.5%) (determined in accordance with Section 8.3), the amount of Delivered Energy is increased or decreased, the revised quantity of Delivered Energy shall be used for purposes of calculating the Energy Payment pursuant to Section 4.2. If any Energy Payment has already been calculated using the previous quantity of Delivered Energy, the Energy Payment shall be recalculated using the revised quantity of Delivered Energy. If the recalculation (i) increases the Energy Payment, Purchaser shall pay to Seller the amount of such increase, or (ii) decreases the Energy Payment, Seller shall refund to Purchaser the amount of such decrease. In any such case, the required payment shall be included on the next invoice to be issued and shall be paid at the time payment

of such invoice is required pursuant to Section 9. Any payment required under this Section 8.4 shall bear interest in accordance with Section 9.3 from the original due date (or from the date paid in the case of a refund) until the date paid (or until the date refunded in the case of a refund). In the case of inaccurate Meters with an inaccuracy in excess of one half of a percent (0.5%), the Party which owns such Meters shall promptly cause such Meters to be corrected and, where such inaccuracy was determined pursuant to a test required by the other Party, the Party which owns such Meters shall bear the expense of any such test.

SECTION 9
METHOD OF PAYMENT

9.1 Invoicing and Payment. As soon as reasonably practicable after the first day of each month commencing with the second month or portion thereof during which Test Energy is delivered to Purchaser and continuing for each month until the first month after the end of the Operating Period, Seller shall submit to Purchaser an invoice as described in Section 9.2. If such invoice indicates a net amount payable to Seller, Purchaser shall pay such invoice within ten (10) Business Days of Purchaser's receipt of the invoice. Such payment shall be made in U.S. dollars by wire transfer of immediately available funds prior to 3:00 p.m. Eastern Prevailing Time, on the date of payment in accordance with the invoice instructions. Payments made after 3:00 p.m. Eastern Prevailing Time or on a day that is not a Business Day shall be deemed to be made on the next subsequent Business Day. If such invoice indicates a net amount payable to Purchaser, Seller shall pay such amount within ten (10) Business Days of Purchaser's receipt of the invoice.

9.2 Monthly Invoices. Each monthly invoice shall show the amount and calculation of the following, as applicable: (i) the Capacity Payment and Energy Payment payable by Purchaser to Seller for the preceding month net of any amounts to be credited by Seller to Purchaser for such month; (ii) following each Contract Year, the net amount payable by Purchaser or Seller pursuant to Section 4.3 respecting the Availability Incentive Payment and Availability Damages, as the case may be; and (iii) payments, refunds, credits and reductions, if any, payable by either Party pursuant to Sections 9.3 or 9.4.

9.3 Late Payments. Any amount due from either Party hereunder not paid in full on or before the date such payment is due will incur a delayed payment charge on the unpaid amount from the original due date until the date paid at an annual rate equal to the then current Prime Rate plus six (6) percentage points (or such lesser annual rate as is the maximum rate permitted by applicable Law).

9.4 Billing Disputes. In the event of any dispute as to all or any portion of any monthly invoice, Purchaser shall give notice of the dispute to Seller but shall pay the full amount of the invoiced charges when due (or if applicable, Seller shall give notice to Purchaser of Seller's dispute regarding any information provided by Purchaser that was a factor in any calculation supporting invoiced amounts). Such notice shall state the amount in dispute and set forth a full statement of the grounds on which such dispute is based. Purchaser and Seller shall

give all due and prompt consideration to any such dispute. Upon final determination (whether by agreement, dispute resolution pursuant to Section 18 hereof, or otherwise) of the dispute, any amounts due to Purchaser or Seller, together with interest from the date due until the date paid at the rate specified in Section 9.3, shall be paid no later than thirty (30) days following such final determination. Purchaser and Seller shall have until the end of one hundred eighty (180) days after its receipt of any invoice, statement or information supporting invoice calculations to question or contest the correctness of any charge or credit on such invoice or statement.

9.5 Audit Rights. Until the end of one hundred eighty (180) days after Purchaser's receipt of any invoice, Seller and Purchaser will make available to the other upon written request, and the Purchaser or Seller may audit, such books and records of the other (or other information to which Purchaser or Seller has access) as are reasonably necessary for Purchaser or Seller to calculate and determine the amounts shown on such invoice and thereby to verify the accuracy and appropriateness of the amounts billed or credited to Purchaser or Seller hereunder; *provided, however,* that Purchaser shall coordinate its rights under this section with the other Customers in order to conduct joint, rather than individual, audits pursuant to this provision. The Parties shall maintain their respective books and records in accordance with generally accepted accounting principles applicable from time to time.

ARTICLE 10
CHANGE IN LAW; MODIFICATION OF AGREEMENT

10.1 Change in Law.

10.1.1 The Parties acknowledge that a Change in Law may increase or decrease Seller's costs in providing service under this Agreement. In the event of such a Change in Law, Seller may give notice to Purchaser that Seller's costs of providing service under this Agreement have changed (which notice will include reasonably detailed information about such cost changes) and, in the event such notice is given, this Agreement shall be modified to reflect such changes in costs, subject to Section 18, *provided, however*, that in the event Seller provides notice of such an increase, then Purchaser may provide documentation to Seller of other Changes in Law that have decreased the cost of providing service under this Agreement and Seller shall set-off any such decrease in cost against the increase in cost identified in the Seller's notice.

10.1.2 Purchaser shall pay the adjusted amount calculated pursuant to Section 10.1.1 for the period commencing with the notice of changed cost through the date of termination of this Agreement. The Parties shall make such payments as are appropriate to adjust all prior billings or payments to reflect the adjustments described herein.

10.1.3 A "Change in Law" shall mean a change in Law which constitutes a new environmental or tax Law or a new interpretation of such Law (not including a change in tax Laws that assess taxes only on Seller's net income) or a change in the provisions contained in the Site Certification permits and which generally affects the cost of, or restricts, operation of the Facility.

10.2 Modification of Agreement. In the event the FERC modifies this Agreement, the Parties agree to make all changes necessary to preserve as nearly as possible the bargain contained in this Agreement, including but not limited to, the total amounts of Capacity and Energy delivered to Purchaser and the total amount of revenues to be received by Seller hereunder; *provided, however*, that Seller shall have the right to terminate this Agreement without further obligation to Purchaser in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Seller; *provided, further*, that Purchaser shall have the right to terminate this Agreement without further obligation to Seller in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Purchaser; *and provided, further*, that in the event Seller elects to terminate this Agreement pursuant to this Section 10.2, then Purchaser and Seller agree to expeditiously proceed with a sale [redacted] to Purchaser and the other Customers in accordance with the provisions of the Ownership Agreement. Seller agrees to use good faith efforts, consistent with Prudent Utility Practice, to resist any changes to this Agreement proposed by the FERC or any other Governmental Body or their respective staffs, and Purchaser agrees not to seek, request, promote or support any changes to this Agreement before the FERC or any other Governmental Body.

SECTION 11
FORCE MAJEURE

11.1 Force Majeure Notice and Obligations. With respect to those obligations of the Parties set forth in this Agreement that expressly excuse performance in the event of a Force Majeure, the existence of Force Majeure that causes a Party (the "Non-Performing Party") to delay performance or fail to perform such obligations shall excuse the Non-Performing Party's delay in performing, or failure to perform, such obligations, subject to any express limitations on such excuse provided or referenced in the Section invoking the excuse. In the event of Force Majeure that causes the Non-Performing Party to delay performance or fail to perform its obligations under this Agreement and that excuses such delay or failure:

11.1.1 the Non-Performing Party shall give the other Party written notice and full details as soon as practicable after learning of the Force Majeure;

11.1.2 the Non-Performing Party shall use reasonable dispatch to remedy its inability to perform (except that this provision shall not impose a

requirement on either Party to deliver or receive Energy at a delivery point other than a Delivery Point), and, if Seller is the Non-Performing Party, Seller shall use reasonable efforts to provide Energy from the Facility at a Delivery Point; and

11.1.3 when the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

SECTION 12
EVENTS OF DEFAULT; TERMINATION

12.1 Events of Default of Seller. Except when excused due to a Force Majeure event pursuant to the provisions of Section 11 hereof, an Event of Default shall be deemed to have occurred with respect to Seller upon the occurrence and during the continuance of any of the following events:

12.1.1 The Bankruptcy of Seller;

12.1.2 Seller fails to pay any invoiced amount or undisputed non-invoiced amount when due under this Agreement within five (5) Business Days after receiving notice of such failure;

12.1.3 Seller fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than obligations addressed in Section 12.1.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Purchaser demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot be reasonably accomplished within such 30-day period and Seller diligently commences such cure in such period and continues such cure to completion); or

12.1.4 Any representation or warranty made by Seller herein, in the Ownership Agreement or in any document or certificate furnished by Seller hereunder shall have been false when made and such false representation or warranty has a material and adverse effect on Purchaser and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Purchaser.

12.2 Events of Default of Purchaser. An Event of Default shall be deemed to have occurred with respect to Purchaser upon the occurrence and during the continuance of any of the following events:

12.2.1 The Bankruptcy of Purchaser;

12.2.2 Purchaser fails: (i) to pay any invoiced amount or any undisputed non-invoiced amount when due under this Agreement within ten (10) Business Days after receiving notice of such failure; or (ii) to make any payment of principal or interest under the Bond Legislation or any other bond resolution, indenture or similar secured instrument of the Purchaser when due (at maturity, upon redemption or otherwise), which failure is not cured within ten (10) Business Days;

12.2.3 Purchaser fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than payment obligations, which are addressed in Section 12.2.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Seller demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot reasonably be accomplished within such 30-day period and Purchaser diligently commences such cure in such period and continues such cure to completion);

12.2.4 Any representation or warranty made by Purchaser herein, in the Ownership Agreement or in any document or certificate furnished by Purchaser shall have been false when made and such false representation or warranty has a material and adverse effect on Seller and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Seller; or

12.2.5 Purchaser fails to comply with any of the requirements of Section 15 within thirty (30) days of receipt of Seller's written notice of such failure.

12.3 Remedies; Notice of Intent to Terminate. Subject to the provisions of this Agreement providing for limitations on damages and for exclusive remedies under certain circumstances, upon the occurrence and during the continuation of any Event of Default, the Party not in default (the "Non-Defaulting Party") shall have the right to pursue all remedies available at law or in equity, suspend its performance under this Agreement to the extent of the Event of Default and/or to deliver a notice of intent to terminate ("Notice of Intent to Terminate") this Agreement to the Party in default ("Defaulting Party"). Any Notice of Intent to Terminate shall specify the Event of Default giving rise to such Notice of Intent to Terminate. Following the giving of a Notice of Intent to Terminate, the Parties shall negotiate pursuant to the provisions of Section 18 hereof, following which, unless the Parties shall have otherwise mutually agreed on a remedy or the Defaulting Party or any lender or financing party ("Lender") to the Defaulting Party or its affiliate, or agent on behalf of a Lender, shall have cured such default or is diligently pursuing a remedy to cure the Event of Default, the Non-Defaulting Party

having given the Notice of Intent to Terminate may terminate this Agreement by giving written notice thereof to the Defaulting Party, whereupon this Agreement shall immediately terminate; *provided, however*, that upon a default under Section 12.2.2, the Non-Defaulting Party may serve a notice of termination of this Agreement without having first to deliver a Notice of Intent to Terminate and to negotiate under Section 18, whereupon this Agreement shall terminate immediately upon delivery of such notice of termination, unless such default shall have been cured prior to the delivery of such notice of termination. Except as provided in Sections 2.2, 2.3, 5.1.2, 10.2, 12.4, and 12.5 or in this Section 12.3, or in Section 4.3. of the Ownership Agreement, neither Party shall have any right to terminate this Agreement.

12.4 Notice to Lenders. Any and all notices given by Purchaser to Seller under this Section 12 shall also be given at the same time by Purchaser to any Lender for which Seller provides written notice to Purchaser of the need to provide such notice and the address to which such notice must be sent. No termination of this Agreement by Purchaser will be effective until and unless Purchaser shall have given Seller's Lenders notice of Seller's Event of Default and an opportunity to cure such Event of Default, which notice and cure period shall be as set forth in any consent executed by Purchaser with Seller's Lenders but in any event such notice and cure period shall be at least concurrent with that provided to Seller under this Agreement.

12.5 Termination Payment.

12.5.1 Except in the case of an Event of Default under Section 12.2.2 under the circumstances that are described in Section 12.5.2 below or an Event of Default under Section 12.1.3 under the circumstances that are described in Section 12.5.3 below, in the event that a Non-Defaulting Party terminates this Agreement pursuant to Section 12.3 and provided an Event of Default shall not have occurred and be continuing as to such Non-Defaulting Party, the Defaulting Party shall pay the Non-Defaulting Party the Termination Payment, as defined below, within thirty (30) days of the effective date of the termination. Except as so otherwise provided in Section 12.5.2 or 12.5.3, the Termination Payment (if applicable) shall be the Defaulting Party's sole liability arising out of a termination of this Agreement pursuant to Section 12.3, and neither Party shall have any other liability or obligation to the other Party arising out of a termination of this Agreement pursuant to Section 12.3. The Defaulting Party's Termination Payment (if applicable) to the Non-Defaulting Party resulting from an Event of Default under this Agreement shall be calculated as follows:

Termination Payment = TPR * APCN

Where:

TPR = a termination payment rate in dollar per kilowatt, which is equal to: (i) [redacted] if the Notice of Intent to Terminate is

given between the date of this Agreement's execution and the end of the twelfth (12th) month after the date Purchaser gives notice under Section 2.2 or 2.3 that it has elected to terminate this Agreement; (ii) [redacted] if the Notice of Intent to Terminate is given between the end of such twelfth (12th) month and the end of the twenty-fourth (24th) month after the date Purchaser gives such notice; or (iii) [redacted] if the Notice of Intent to Terminate is given between the end of such twenty-fourth (24th) month and the expected termination of this Agreement twelve (12) months later; and

APCN = the Annual Purchaser's Capacity Nomination, in kilowatts, that is in effect on the date of the Notice of Intent to Terminate.

Delivery of a Notice to Terminate or calculation or payment of the Termination Payment shall not relieve the Defaulting Party of its obligation to pay all other amounts that became or have become due and payable by the Defaulting Party hereunder prior to the effective date of termination.

12.5.2 In the case of an Event of Default under Section 12.2.2 by Purchaser at a time when Purchaser is able to pay its debts generally as they come due, Seller shall be entitled to recover its actual damages, which the Parties recognize may be greater than, or less than, the Termination Payment. In determining actual damages, any amounts actually recovered from Seller's reasonable efforts to mitigate such damages shall be taken into account.

12.5.3 In the case of an Event of Default by Seller under Section 12.1.3 that results from a failure by Seller to deliver Energy from the Facility to Purchaser as required by this Agreement at a time when (i) the Facility was capable of delivering such Energy to Seller as required by this Agreement consistent with Prudent Utility Practice, the Technical Limits and applicable Law and Permit requirements, and (ii) Seller sold such Energy to a third party, then Purchaser shall be entitled to recover the actual damages of Purchaser, which the Parties recognize may be greater than, or less than, the Termination Payment. In determining actual damages, the actual results of Purchaser's reasonable efforts to mitigate such damages shall be taken into account.

12.5.4 In receiving a Termination Payment or recovering actual damages, the Non-Defaulting Party shall also be entitled to recover its reasonable attorney fees in enforcing this provision.

SECTION 13
WAIVER

Failure by either Party to exercise any of its rights under this Agreement shall not constitute a waiver of such rights. Neither Party shall be deemed to have waived any right resulting from any failure to perform by the other Party unless it has made such waiver specifically in writing, and no such waiver shall operate as a waiver of any future failure to perform whether of a like or different character. No single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege hereunder.

SECTION 14
REPRESENTATIONS AND WARRANTIES

14.1 Representations and Warranties of Seller. Seller hereby represents and warrants to Purchaser as follows:

14.1.1 Organization and Existence. Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware, is qualified to transact business in Florida, and has sufficient power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Seller has full power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.1.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Seller has been duly and effectively authorized by all requisite action on the part of Seller. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Seller, enforceable against Seller in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.1.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Seller's knowledge, threatened against Seller or The Southern Company by or before any Governmental Body having jurisdiction over Seller or The Southern Company which, if adversely determined, would have a material adverse effect upon Seller's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents. Neither Seller nor The Southern Company is subject to any

material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Seller or The Southern Company which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents.

14.1.4 No Violation or Conflict. The execution, delivery and performance by Seller of this Agreement and the Collateral Documents do not violate or conflict with Seller's operating agreement, any existing Law applicable to Seller, or any note, bond, indenture, agreement or instrument to which Seller is a party or by which it is bound.

14.1.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment A of the Ownership Agreement, there are no approvals or consents, the absence of which would materially impair Seller's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2 Representations and Warranties of Purchaser. Purchaser hereby represents and warrants to Seller as follows:

14.2.1 Organization and Existence. Purchaser is a statutory utility authority duly organized, validly existing and in good standing under the laws of the State of Florida and has sufficient statutory power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Purchaser has full statutory power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.2.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Purchaser has been duly and effectively authorized by all requisite action on the part of Purchaser's governing board. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Purchaser, enforceable against Purchaser in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.2.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Purchaser's knowledge, threatened against Purchaser by or before any Governmental Body having jurisdiction over Purchaser which,

if adversely determined, would have a material adverse effect upon Purchaser's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents. Purchaser is not subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Purchaser which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents.

14.2.4 No Violation or Conflict. The execution, delivery and performance by Purchaser of this Agreement and the Collateral Documents do not violate or conflict with Purchaser's charter or bylaws, any existing Law applicable to Purchaser, or any note, bond, resolution, indenture, agreement or instrument to which Purchaser is a party or by which it is bound.

14.2.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment A of the Ownership Agreement, there are no approvals or consents, the absence of which would materially impair Purchaser's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2.6 No Immunity. With respect to its contractual obligations hereunder and performance thereof, Purchaser is not entitled to claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from: (a) suit; (b) jurisdiction of any Florida court; or (c) relief by way of injunction, order for specific performance or attachment of property that is subject to execution or levy under Florida Law (including the Eligible Collateral).

14.3 Warranties Regarding Energy, Capacity and Ancillary Services. Seller warrants that the Energy, Capacity and Ancillary Services provided under this Agreement (i) shall have been delivered in accordance with applicable Law, and (ii) meets the requirements set forth in this Agreement. **THE FOREGOING IS IN LIEU OF ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, IN FACT OR BY LAW WITH RESPECT TO THE ENERGY, CAPACITY AND ANCILLARY SERVICES PROVIDED HEREUNDER. SELLER HEREBY DISCLAIMS ANY AND ALL OTHER WARRANTIES WHATSOEVER.**

SECTION 15
PERFORMANCE ASSURANCE

15.1 In the event that Purchaser experiences a Material Adverse Change, as defined below, as security for Purchaser's payment obligations under this Agreement, Purchaser shall deliver to Seller within [redacted] of Seller's written request therefor, Eligible Collateral in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period.

15.1.1 As used in this Section 15.1: (i) a "Material Adverse Change" shall occur (A) when Purchaser's credit rating on its senior securities falls below the lower of (x) [redacted] (Standard & Poors) or [redacted] (Moody's) and (y) the lowest credit rating of Southern Guarantor's senior securities under either Moody's or Standard & Poors, (B) upon an Event of Default by Purchaser under Section 12.2.2, (C) upon a failure by Purchaser to make any required deposit into any sinking fund under the Bond Legislation or any other bond resolution, indenture or similar secured instrument entered into in connection with the issuance of additional debt (each a "Debt Instrument"), or (D) upon a failure by Purchaser to maintain in any debt service account under the Bond Legislation or any Debt Instrument at least [redacted] of the amount required to be maintained in such account requirement; and (ii) "Eligible Collateral" means cash deposited into an operating reserve account from "Revenues", as that term is defined in the Bond Legislation, or an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller; *provided, however*, that for purposes of Sections 15.1.1(i)(C) and 15.1.1(i)(D), Eligible Collateral shall constitute an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller. Costs of a letter of credit shall be borne by Purchaser.

15.1.2 If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Purchaser, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when a "Material Adverse Change" has occurred.

15.2 In the event that legislation is enacted in the State of Florida which contains provisions that will cause an Event of Default by Purchaser at any time during the term of this Agreement, Seller will have the right, from and after the date of enactment of such legislation, to provide Purchaser with written notice requesting Eligible Collateral, as defined above, in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period. Upon receipt

of such notice, in addition to Purchaser's other payment obligations under this Agreement, Purchaser shall within [redacted] provide such Eligible Collateral.

15.3. To the extent Purchaser delivers Eligible Collateral in the form of cash to be held in an operating reserve account pursuant to Sections 15.5 or 15.6, Purchaser hereby grants to Seller a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, such Eligible Collateral, and any and all proceeds resulting therefrom or from the liquidation thereof, and Purchaser agrees to take such action as Seller reasonably requires in order to perfect Seller's first-priority security interest in, and lien on (and right of setoff against), such Eligible Collateral and any and all proceeds resulting therefrom or from the liquidation thereof. This Agreement is intended to, and does, constitute a security agreement between Seller and Purchaser with regard to any cash which may constitute Eligible Collateral.

15.4. Upon or any time after the occurrence and during the continuation of an Event of Default of Purchaser, Seller may (i) exercise any of the rights and remedies of a secured party with respect to the Eligible Collateral, including any such rights and remedies under Law then in effect, such as but not limited to the Uniform Commercial Code, and (ii) liquidate and/or draw on any outstanding Eligible Collateral issued for its benefit (free from any claim or right of any nature whatsoever of Purchaser including any equity or right of purchase or redemption by Purchaser) with respect to Purchaser's obligations under this Agreement. In the event that Seller liquidates or draws on any of the Eligible Collateral, Purchaser shall within [redacted] of notice from Seller of such liquidation or draw, deliver additional cash or increase the amount of the letter of credit, as the case may be, in order to replenish the amount of the Eligible Collateral to the extent of the liquidation or draw.

15.5. If the trigger of a Material Adverse Change was occurrence of the circumstances in Sections 15.1.1(i)(A) or the circumstances described in Section 15.2 occur, then: (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as the circumstances described in Sections 15.1.1(i)(A) and 15.2 no longer apply (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire at such time as the circumstances described in Sections 15.1.1 and 15.2 no longer apply and Seller shall return such letter of credit to Purchaser (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.6 If the trigger of a Material Adverse Change was occurrence of the circumstances described in Section 15.1.1(i)(B), then (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by

Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as Purchaser shall have (A) cured the Event of Default under Section 12.2.2 that triggered the Material Adverse Change and (B) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] days (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire (and Seller shall return such letter of credit) at such time as Purchaser shall have (C) cured the Events of Default under Section 12.2.2 that triggered the Material Adverse Change and (D) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.7 In the event that the Purchaser exercises its right to elect an Extended Term or any Further Extension of this Agreement pursuant to Sections 2.2 and 2.3, and on any day of such Extended Term or Further Extensions the circumstances of either Sections 15.1.1 or 15.2 apply, then, Purchaser shall deliver to Seller within [redacted] of the date of such occurrence, Eligible Collateral, as defined above, in an amount equal to [redacted] of Capacity Payments, and the provisions of Sections 15.3, 15.4, 15.5 and 15.6 shall apply to such Eligible Collateral.

SECTION 16
LIABILITY OF PARTIES

16.1 INDEMNITIES.

16.1.1 **TO THE EXTENT PERMITTED BY LAW, EACH PARTY (THE "INDEMNIFYING PARTY") SHALL FULLY INDEMNIFY AND DEFEND THE OTHER PARTY AND EACH OF THE OTHER PARTY'S SUBSIDIARIES AND AFFILIATES, AND THE PARTNERS, MEMBERS, PARTICIPANTS, PRINCIPALS, REPRESENTATIVES, SHAREHOLDERS, DIRECTORS, OFFICERS, AGENTS, EMPLOYEES, SUCCESSORS AND ASSIGNS OF EACH OF THEM (THE "INDEMNIFIED PARTIES") FROM AND AGAINST ANY AND ALL LOSSES, COSTS, DAMAGES, INJURIES, LIABILITIES, CLAIMS, DEMANDS, PENALTIES AND INTEREST, INCLUDING REASONABLE**

ATTORNEYS' FEES, RESULTING FROM THIRD PARTY CLAIMS DIRECTLY OR INDIRECTLY RELATED TO THIS AGREEMENT, TO THE EXTENT CAUSED OR CONTRIBUTED TO BY THE FAULT, INTENTIONAL ACT, NEGLIGENCE OR STRICT LIABILITY OF THE INDEMNIFYING PARTY OR ITS SUBSIDIARIES, AFFILIATES, CONTRACTORS OR SUBCONTRACTORS OR ANY OF THE OFFICERS, PARTNERS, MEMBERS, PARTICIPANTS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, EMPLOYEES, AGENTS, REPRESENTATIVES, SUCCESSORS OR ASSIGNS OF ANY OF THEM OR BY BREACH BY THE INDEMNIFYING PARTY OF THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT ANY LIABILITY TO THIRD PARTIES INCURRED BY SELLER IN PERFORMANCE OF ITS AGENCY FUNCTIONS PURSUANT TO THE OWNERSHIP AGREEMENT OR THE OPERATING AGREEMENT SHALL BE APPORTIONED IN ACCORDANCE WITH ARTICLE 9 OF THE OWNERSHIP AGREEMENT OR ARTICLE 7 OF THE OPERATING AGREEMENT.

16.1.2 IF ANY INDEMNIFIED PARTY INTENDS TO SEEK INDEMNIFICATION UNDER THIS SECTION 16.1 FROM AN INDEMNIFYING PARTY WITH RESPECT TO ANY ACTION OR CLAIM, THE INDEMNIFIED PARTY SHALL GIVE THE INDEMNIFYING PARTY WRITTEN NOTICE OF SUCH CLAIM OR ACTION PROMPTLY FOLLOWING THE RECEIPT OF ACTUAL KNOWLEDGE OR INFORMATION BY THE INDEMNIFIED PARTY OF A POSSIBLE CLAIM OR OF THE COMMENCEMENT OF A CLAIM OR ACTION, WHICH WRITTEN NOTICE SHALL IN NO EVENT BE DELIVERED LATER THAN THE FIRST TO OCCUR OF (A) FIFTEEN (15) DAYS PRIOR TO THE LAST DAY FOR RESPONDING TO SUCH CLAIM OR ACTION OR (B) THE EXPIRATION OF THE FIRST HALF OF THE PERIOD ALLOWED FOR RESPONDING TO SUCH CLAIM OR ACTION. THE INDEMNIFYING PARTY SHALL HAVE NO LIABILITY UNDER THIS SECTION FOR ANY CLAIM OR ACTION FOR WHICH SUCH NOTICE IS NOT PROVIDED TO THE EXTENT THAT THE FAILURE TO GIVE SUCH WRITTEN NOTICE MATERIALLY PREJUDICES THE INDEMNIFYING PARTY. UPON ACKNOWLEDGMENT OF ITS OBLIGATIONS UNDER THIS SECTION 16.1, THE INDEMNIFYING PARTY SHALL HAVE THE RIGHT TO ASSUME THE DEFENSE OF ANY CLAIM OR ACTION, AT ITS SOLE COST AND EXPENSE, WITH COUNSEL DESIGNATED BY

THE INDEMNIFYING PARTY AND REASONABLY SATISFACTORY TO THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE DEFENDANTS IN ANY SUCH ACTION INCLUDE BOTH THE INDEMNIFIED PARTY AND THE INDEMNIFYING PARTY, AND THE INDEMNIFIED PARTY SHALL HAVE REASONABLY CONCLUDED THAT THERE MAY BE LEGAL DEFENSES AVAILABLE TO IT WHICH ARE DIFFERENT FROM OR ADDITIONAL TO THOSE AVAILABLE TO THE INDEMNIFYING PARTY, THE INDEMNIFIED PARTY SHALL HAVE THE RIGHT TO SELECT SEPARATE COUNSEL, AT THE INDEMNIFYING PARTY'S EXPENSE, TO ASSERT SUCH LEGAL DEFENSES AND TO OTHERWISE PARTICIPATE IN THE DEFENSE OF SUCH ACTION ON BEHALF OF SUCH INDEMNIFIED PARTY.

16.1.3 EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFIED PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT HAS SOUGHT OR INTENDS TO SEEK INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFYING PARTY. SHOULD ANY INDEMNIFIED PARTY BE ENTITLED TO INDEMNIFICATION UNDER THIS SECTION 16.1 AS A RESULT OF A CLAIM OR ACTION BY A THIRD PARTY, AND SHOULD THE INDEMNIFYING PARTY FAIL TO ASSUME THE DEFENSE OF SUCH CLAIM OR ACTION, THE INDEMNIFIED PARTY MAY, AT THE EXPENSE OF THE INDEMNIFYING PARTY, CONTEST (OR, WITH OR WITHOUT THE PRIOR CONSENT OF THE INDEMNIFYING PARTY, SETTLE) SUCH CLAIM OR ACTION. EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFYING PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT MAY BE LIABLE TO PROVIDE INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE INDEMNIFYING PARTY HAS REACHED A BONA FIDE SETTLEMENT AGREEMENT WITH THE PLAINTIFF(S) IN ANY SUCH ACTION AND THE INDEMNIFIED PARTY DOES NOT CONSENT TO SUCH SETTLEMENT AGREEMENT, THEN THE AMOUNT SPECIFIED IN THE SETTLEMENT AGREEMENT, PLUS THE INDEMNIFIED PARTY'S REASONABLE ATTORNEY FEES INCURRED PRIOR TO THE DATE OF SUCH SETTLEMENT AGREEMENT, SHALL ACT AS AN ABSOLUTE

MAXIMUM LIMIT ON THE INDEMNIFICATION OBLIGATION OF THE INDEMNIFYING PARTY WITH RESPECT TO THE CLAIM, OR PORTION THEREOF, THAT IS THE SUBJECT OF SUCH SETTLEMENT AGREEMENT TO THE EXTENT SUCH SETTLEMENT AGREEMENT FULLY RELEASES THE INDEMNIFIED PARTY AND DOES NOT REQUIRE ANY PAYMENT FROM, OR IMPOSE ANY RESTRICTION ON, THE INDEMNIFIED PARTY.

16.2 LIMITATION ON DAMAGES. **NEITHER PARTY NOR ITS SUBSIDIARIES OR AFFILIATES NOR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, SUCCESSORS OR ASSIGNS OF ANY OF THEM SHALL IN ANY EVENT BE LIABLE TO THE OTHER PARTY OR ITS SUBSIDIARIES OR AFFILIATES OR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS OR DIRECTORS OF ANY OF THEM FOR CLAIMS FOR INCIDENTAL, PUNITIVE, CONSEQUENTIAL, EXEMPLARY OR INDIRECT DAMAGES OF ANY NATURE, ARISING AT ANY TIME, FROM ANY CAUSE WHATSOEVER, WHETHER ARISING IN TORT, CONTRACT, WARRANTY, STRICT LIABILITY, BY OPERATION OF LAW OR OTHERWISE, CONNECTED WITH OR RESULTING FROM PERFORMANCE OR NON-PERFORMANCE UNDER THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT THIS SECTION 16.2 IS NOT INTENDED, NOR SHALL IT BE CONSTRUED, TO LIMIT OR ELIMINATE A PARTY'S OBLIGATION TO PAY LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR MAKE ANY OTHER PAYMENTS EXPRESSLY CONTEMPLATED HEREIN, OR IN ANY COLLATERAL DOCUMENT, EVEN IF IT MAY BE POSSIBLE TO CHARACTERIZE SUCH LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR OTHER PAYMENTS AS INCIDENTAL, PUNITIVE, CONSEQUENTIAL OR INDIRECT DAMAGES.**

16.3 Seller Affiliate Guarantee. Seller shall at all times following the Effective Date of this Agreement cause an Affiliate of Seller to maintain in place a payment guarantee in the form attached to this Agreement as Appendix E. For purposes of the previous sentence, an "Affiliate" of Seller shall be any entity controlling, under common control with or controlled by Seller, which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's). If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Seller's affiliates, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when an entity controlling, under common control with or controlled by Seller has sufficient credit-worthiness to qualify as an "Affiliate."

16.4 No Penalty. The Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by Purchaser due to Seller's failure to meet the Availability Guarantee or achieve the schedule provided under Section 5.1.1, that the Availability Damages set forth in Section 4.3 and the liquidated damages set forth in Section 5.1.2 are fair and reasonable determinations of the amount of actual damages which would be suffered by Purchaser or Seller, as the case may be, by reason of such failure, and that the Availability Damages and other liquidated damages do not constitute a penalty. Similarly, the Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by either Party in case of an Event of Default and a termination of this Agreement by the Non-defaulting Party, that the Termination Payment set forth in Section 12.5.1 is a fair and reasonable determination of the amount of actual damages which would be suffered by the Non-defaulting Party in such event, and that the Termination Payment does not constitute a penalty.

SECTION 17
ASSIGNMENT

17.1 Agreement Binding. This Agreement shall be binding upon, and shall inure to the benefit of, the Parties and their successors and permitted assigns.

17.2 Permitted Assignment. This Agreement shall not be assignable by Seller without the prior written consent of Purchaser, except that this Agreement (a) may be assigned by Seller without the requirement for such consent (but with notice to Purchaser) (i) to any Lender from time to time providing financing to Seller or its affiliate with respect to all or any portion of the Project or (iii) to any Lender or its designee in connection with a foreclosure or other exercise of remedies, and (b) unless otherwise waived by Purchaser, shall be assigned in whole or in part by Seller without the requirement for such consent (but with notice to Purchaser) in the event of a sale by Seller of all or a portion of Seller's interest in the Facility, with the purchaser of Seller's interest in the Facility assuming Seller's obligations under this Agreement in the same percentage as the portion of Seller's interest being transferred bears to Seller's entire interest in the Facility. This Agreement shall not be assignable by Purchaser without the prior written consent of Seller, *provided, however*, that Purchaser may assign this Agreement to another Customer without the requirement for such consent (but with notice to Seller) so long as such Customer has not experienced a Material Adverse Change under its PPA. Any such transferee, assignee or purchaser (other than a Lender through collateral assignment in connection with a lease or other financing transaction permitted under Section 6.2.8 of the Ownership Agreement) shall confirm its willingness to accept all of the assigning Party's obligations under this Agreement by writing reasonably acceptable to the non-assigning Party. Any such assignee, transferee or purchaser (other than a Lender through collateral assignment in connection with a lease or other financing transaction permitted under Section 6.2.8 of the Ownership Agreement) must be sufficiently creditworthy and otherwise capable of performing all of the assigning Party's obligations under this Agreement. No assignment or transfer of this Agreement by a Party shall be permitted during any period in which an Event of Default of such Party shall have occurred and be continuing and not cured, unless the other Party shall agree. No assignment of

this Agreement shall relieve the assigning Party of any of its obligations under this Agreement, except that the assignor shall be released from its obligations under this Agreement at such time as all future obligations of the assignor hereunder shall have been assumed by the assignee in a written agreement delivered to the other Party. Any assignment that does not comply with the provisions of this Section 17 shall be null and void.

SECTION 18
DISPUTE RESOLUTION

18.1 Good-Faith Negotiations. The Parties shall first negotiate in good faith to attempt to resolve any dispute, controversy or claim arising out of, under, or relating to this Agreement (a "Dispute"), unless otherwise mutually agreed to by the Parties. In the event that the Parties are unsuccessful in resolving a Dispute through such negotiations, either Party may proceed immediately to litigation concerning the Dispute.

18.1.1 The process of "good-faith negotiations" requires that each Party set out in writing to the other its reason(s) for adopting a specific conclusion or for selecting a particular course of action, together with the sequence of subordinate facts leading to the conclusion or course of action. The Parties shall attempt to agree on a mutually agreeable resolution of the Dispute. A Party shall not be required as part of these negotiations to provide any information which is confidential or proprietary in nature unless it is satisfied in its discretion that the other Party will maintain the confidentiality of and will not misuse such information or any information subject to attorney-client or other privilege under applicable Law regarding discovery and production of documents.

18.1.2 The negotiation process shall include at least two (2) meetings to discuss any Dispute. Unless otherwise mutually agreed, the first meeting shall take place within ten days after either Party has received notice from the other of the desire to commence formal negotiations concerning the Dispute. Unless otherwise mutually agreed, the second meeting shall take place no more than ten days later. In the event a Party refuses to attend a negotiation meeting, either Party may proceed immediately to litigation concerning the Dispute.

18.2 Confidentiality and Non-Admissibility of Statements Made in, and Evidence Specifically Prepared for, Good Faith Negotiations. Each Party hereby agrees that all statements made in the course of good faith negotiations, as contemplated in Section 18.1, shall be confidential and shall not be disclosed to or shared with any third parties (other than any person whose presence is necessary to facilitate the negotiation process). Each Party agrees and acknowledges that no statements made in or evidence specifically prepared for good faith negotiations under Section 18.1 shall be admissible for any purpose in any subsequent litigation.

SECTION 19
AMENDMENT

This Agreement cannot be amended, modified or supplemented except by written agreement making specific reference hereto executed by both Parties.

SECTION 20
NOTICES

Other than telephonic notices required or permitted under Section 6.1 or Appendix B, any notice required or permitted to be given hereunder shall be in writing and shall be: (i) personally delivered; (ii) transmitted by postage prepaid registered mail; (iii) transmitted by a recognized overnight courier service; or (iv) transmitted by facsimile to the receiving Party as follows, as elected by the Party giving such notice:

20.1 In the case of Purchaser:

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Attention: Vice-President of Power Resources
Telephone: 407-244-8372
Facsimile: 407-275-4120

With a copy to:

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741
Attention: Manager Bulk System Planning
Telephone: 407-933-7777 ext. 1235
Facsimile: 407-847-0787

20.2 In the case of Seller:

Southern Company Services, Inc.
270 Peachtree Street, Bin 935
Atlanta, Georgia 30303
Attention: Director of Contract Administration
Telephone: 404-506-5100
Facsimile: 404-506-0304

With a copy to:

Troutman Sanders LLP
Bank of America Plaza
600 Peachtree Street N.E.
Atlanta, Georgia 30308
Attention: Robert H. Forry, Esq.
Telephone: 404-885-3142
Facsimile: 404-962-6559

All notices and other communications shall be deemed to have been duly given on (i) the date of receipt if delivered personally, (ii) five (5) days after the date of posting if transmitted by mail, (iii) the Business Day following delivery to the courier if transmitted by overnight delivery service, or (iv) the date of transmission with confirmation if transmitted by facsimile, whichever shall first occur. Any Party may change its address for purposes hereof by notice to the other Party.

SECTION 21
APPLICABLE LAW

This Agreement shall be governed by, and construed in accordance with, the laws of the State of Florida, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction. The Parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Middle District of Florida, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Circuit Court of the State of Florida sitting in Orange County, Florida, and the Parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

SECTION 22
SEVERABILITY

The invalidity or unenforceability of any provision or portion of this Agreement will not affect the validity of the remainder of this Agreement. If any provision of this Agreement is determined to be invalid or unenforceable, the Parties will negotiate in good faith to agree upon substitute provisions to carry out the purpose and intent of the invalid or unenforceable provision. If the economic or legal substance of the transactions contemplated hereby is affected in any manner adverse to any Party as a result thereof, the Parties shall negotiate in good faith in an effort to agree upon a suitable and equitable substitute provision to effect the original intent of the Parties.

SECTION 23
ENTIRE AGREEMENT

This Agreement and the Collateral Documents contain the complete agreement of the Parties hereto with respect to the matters contained herein and supersede all other agreements, understandings and negotiations, whether written or oral, with respect to the matters contained herein.

SECTION 24
NO THIRD PARTY BENEFICIARIES

This Agreement is intended to be solely for the benefit of Purchaser and Seller and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any Person not a signatory hereto.

SECTION 25
COUNTERPARTS

This Agreement may be executed in one or more counterparts, each of which shall constitute an original but all of which, when taken together, shall constitute only one legal instrument.

SECTION 26
INFORMATION AND CONFIDENTIALITY

Where a Party makes any calculation of costs or damages under this Agreement, such Party shall provide, upon the reasonable request of the other Party, documentation supporting such calculation. Neither Party shall disclose or otherwise make available to any other party any information of a technical, commercial or business nature regarding the Project or this Agreement that has been marked or identified as confidential or proprietary ("Confidential Information") without the prior written consent of the other Party, except that (a) Seller or its affiliate may provide Confidential Information to its or any such affiliate's prospective Lenders, underwriters, investors, affiliates, advisors, employees, officers and directors to the extent reasonably required in connection with the administration of this Agreement, the issuance of debt or equity or other financing activities of Seller or its affiliate, or the performance of any duties relating to this Agreement; (b) Purchaser may provide Confidential Information to its advisors, employees, officers, directors and Lenders to the extent reasonably required in connection with the administration of this Agreement or the performance of any such Person's duties relating to this Agreement; (c) any Party may disclose any such Confidential Information in any litigation or proceeding to enforce or recover damages under this Agreement; (d) any Party (or its affiliate) may disclose any such Confidential Information as may be required by any applicable Law, regulation or governmental order; and (e) any Party (or its affiliate) may disclose such Confidential Information to any person or entity succeeding to all or substantially all the assets of such Party (or its affiliate) or all or a substantial portion of its interest in the Facility; *provided,*

that in the case of (e), any such successor shall agree to be bound by the provisions of this Section 26. Confidential Information shall not include information that: (i) the receiving Party can demonstrate was known to it prior to its disclosure by the other Party; (ii) is, or later becomes, public knowledge without breach of this Agreement by the receiving Party; (iii) was received by the receiving Party from a third party without obligation of confidentiality; or (iv) is developed by the receiving Party independently from Confidential Information received from the other Party, as evidenced by appropriate documentation. In the event that disclosure is required by a valid order of a court or Governmental Body, the Party subject to such requirement may disclose Confidential Information to the extent so required, but shall promptly notify the other Party and shall cooperate with the other Party's efforts to obtain protective orders or similar restraints with respect to such disclosure. The provisions of this Section 26 shall continue in effect until three years after the end of the Operating Period.

The Parties understand that under the Florida Public Records Law (Section 119.10, Florida Statutes), any Party or all of them may be subject to statutory fines and penalties, including but not limited to a requesting Party's costs and attorney's fees for failure to make public records available for public inspection upon request (Chapter 119, Florida Statutes). In addition, each Party may be subject to its own costs and expenses of litigation. With this understanding in mind, the Parties agree that in the event Purchaser in an attempt to comply with this Agreement, refuses to honor a public records request under Chapter 119, Florida Statutes, for examination or inspection of a confidential document of Seller or any affiliate of Seller and is forced to defend its actions in a court of competent jurisdiction, Seller shall indemnify, defend, and hold Purchaser harmless from and against any fines, penalties, costs, attorney's fees and expenses, including, but not by way of limitation, attorney's fees, expert fees, court costs and other costs arising from or related to defending any lawsuit bought pursuant to Chapter 119, Florida Statutes; *provided, however,* Seller's consent with such refusal shall be obtained before Seller can be liable under this Section *26.* In addition, the Parties shall cooperate to provide witnesses to support the Parties' declarations and certification that the Confidential Information is a valid trade secret under the above cited Florida law and meets all definitional requirements therein or is exempt from disclosure under other applicable Florida law.

SECTION 27
PUBLIC STATEMENTS

Seller and Purchaser shall consult with each other and neither of them shall issue a press release or make a statement intended for release to the general public with respect to the transactions contemplated hereby without the consent of the other Party, which consent shall not be unreasonably withheld, unless the Party desiring to make such statement or press release is advised by legal counsel that a statement or press release is required by applicable Law (including information provided pursuant to a request for public information under the Florida Public Records Law, Section 119.10, Florida Statutes); *provided, however,* that in this event the Party making the public statement or press release shall notify the other Party in advance of such statement or press release and allow the other Party reasonable time to comment on such

statement or press release. Notwithstanding the immediately preceding sentence, the Parties acknowledge that certain meetings of the Orlando Utilities Commission and the City of Orlando are open to the public, and nothing in this Agreement shall be deemed to require that the proceedings of such meetings not be made public or to restrict the reporting by the media of such proceedings.

SECTION 28
INSURANCE

Seller and Purchaser, and all contractors and subcontractors performing any services in connection with the operation or maintenance of the Facility, shall obtain and maintain in force comprehensive general liability insurance, and property insurance for injury to persons and property, automobile liability insurance and workman's compensation insurance, all in amounts and under terms as required by the Operating Agreement.

SECTION 29
TAXES

Purchaser shall reimburse Seller for, or pay to Seller, all sales, use, personal property and other taxes of every kind paid or collected by Seller, if any, that are not currently levied and are hereafter levied on the purchase, sale or use of fuel consumed by the Facility to provide Energy or Ancillary Services in accordance with this Agreement or the purchase, sale or use of Capacity, Energy or Ancillary Services under this Agreement, but excluding any taxes levied on Seller's net income. Purchaser shall pay directly for all such sales, use, personal property and other taxes which it is legally obligated and empowered to pay. In the event Seller, on behalf of Purchaser, pays any taxes that are the responsibility of Purchaser to reimburse or pay, under the first two sentences of this Section *29*, the amount so paid by Seller shall be added to a monthly invoice submitted by Seller to Purchaser under Section 9, and Purchaser shall pay such amount in accordance with Section 9. Upon the reasonable request of Purchaser, Seller agrees to (i) provide documents related to taxes or assessments to be reimbursed or paid by Purchaser under this Agreement and (ii) cooperate with Purchaser at Purchaser's expense should Purchaser seek to obtain from the entity to which taxes were paid a refund of any taxes paid by Seller and/or reimbursed or paid by Purchaser.

IN WITNESS WHEREOF, the Parties, intending to be legally bound, have caused this Agreement to be executed by their duly authorized representatives as of the day and year first written above.

Signed, sealed and delivered in the presence of:

CAROLYN S. SCOTT
Notary Public - State of Florida
My Comm. Expires July 11, 2002
Comm. #CC 756857
Bonded By Lupfer-Frakes Ins

Notary Public

KISSIMMEE UTILITY AUTHORITY

By: _____

Name: _____

Title: _____

FOR THE USE AND RELIANCE OF KUA ONLY - APPROVED AS TO FORM AND LEGALITY

Attorney for KUA

Date: Mar 28 2001

Attest: _____

Name: _____

Title: _____

Signed, sealed and delivered in the presence of:

NOTARY PUBLIC STATE OF ALABAMA AT LARGE
MY COMMISSION EXPIRES: Nov 25, 2004
BONDED THRU NOTARY PUBLIC UNDERWRITERS

Notary Public

SOUTHERN COMPANY - FLORIDA LLC

By: Southern Power Company, its sole member

By: _____
Douglas E. Jones, Vice President

Attest: _____
Anthony J. Topazi, Vice President

APPENDIX A

TECHNICAL LIMITS

Unit Operating Modes

1. **Definition of Operating Modes**.

The Facility will have several different operating modes.

- Mode 1: Normal Operation—both gas turbines (CTs) operating with no supplemental firing of the Heat Recovery Steam Generator (HRSG) and no gas turbine power augmentation.

- Mode 2: Supplemental Firing Operation—both gas turbines operating at full load with supplemental firing of the HRSG.

- Mode 3: Power Augmentation Operation—both gas turbines operating at full load with supplemental firing of the HRSG's (Mode 2 Supplemental Firing Operation) to produce both steam for full steam turbine-generator output with the maximum allowed continuous throttle flow at the maximum allowed continuous throttle pressure and steam for full gas turbine power augmentation (steam injection.)

- Mode 4: Part-load Operation—one or both gas turbines operating at less than full load.

2. **Natural Gas Requirements**.

The Facility will require "pipeline quality gas" meeting the requirements of GE fuel specification "GEI 41040E - Process Specification Fuel Gases for Combustion in Heavy Duty Gas Turbines".

Natural gas is to be delivered to the Facility by pipeline and the pipeline and gas must meet the following equipment characteristics and requirements:

- Nominal Maximum N.G. Flow (HHV) per Block (2x1) [redacted] MMBtu/hr*
- Nominal N.G. Higher Heating Value [redacted] Btu/lb
- Minimum Fuel Supply Temperature (after PRV) [redacted] °F
- Fuel Pressure at Gas Control Valve** [redacted] PSIG (nominal)
  [redacted] PSIG maximum

* Based on Winter Peaking [redacted] Power during Full Pressure Operation.

** Reference GE Pub. GEI 41040E.

3. **Fuel Oil Requirements**.

The Facility will require fuel oil that is in compliance with ASTM Standard Specification D-2880 (as revised) and "GE Gas Turbine Liquid Fuel Specifications" (document number GEI 41047H). This No. 2 GT Grade Gas Turbine Fuel Oil must be in compliance with the specifications and procedures for No. 2 Fuel Oil as defined in ASTM D396.

Note that environmental permitting may create conditions for sulfur, fuel bound nitrogen and other specifications which could affect or add minimum specifications, such as, but not limited to, those identified in the following table:

	SPECIFICATIONS	**ASTM TEST METHOD**
Sulfur, % Wt., Max.	0.05	D – 1266
Fuel Bound Nitrogen	0.050% Max.	

4. **Dispatch and Operational Requirements**.

- The Facility will be capable of operating with fuel oil. The Facility may fire oil in the gas turbines only and not in the HRSG duct burners. During these periods, the Facility shall operate in Mode 1 (Normal Operation) only.

- The Facility will require shutdown for a minimum of one hour prior to switching from natural gas to oil firing. The fuel oil forwarding system will not be operated during normal gas firing, but operation of the fuel forwarding system will be initiated upon proper notice of a requirement for fuel switching. The Facility will be capable of switching from oil to natural gas without shutdown; however, the Facility may be required to decrease to a minimum load and stabilize prior to ramping to full load.

- The Facility will be capable of being controlled via Automatic Generation Control (AGC) in Mode 1 (Normal Operation). The AGC load range and ramp rate will be set by the Facility's operator based on the actual capability of the CTs as determined through testing. With the duct burners firing (Mode 2 – Supplemental Firing Operation), the load range and ramp rate will be set and manually controlled by the Facility's operator based on the capabilities of the duct burners. No load following capability is available in Mode 3 (Power Augmentation Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) only at ambient temperatures of [redacted] and higher.

- The Facility will require [redacted] of de-mineralized water for Mode 1 (Normal Operation).

- The expected maximum allowable rate of load increase for the Facility will be [redacted] Actual maximum load increase rate will be determined by actual testing and in light of final permit restrictions and emissions tests.

- The Facility will be expected to be capable of operating minimum load with one CT at [redacted] load or two CTs each at part of [redacted] load. Actual minimum load will be determined in light of final NOx emissions and permit restrictions and testing.

- Required startup times for the Facility shall be as follows:

  Mode 1 (Normal Operation): refer to Attachment 1 – Time to Dispatch Curve. Note: Actual Curve to be determined by testing.

  Mode 2 (Supplemental Firing Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation).

  Mode 3 (Power Augmentation Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation) or [redacted] from one hundred percent (100%) Mode 2 (Supplemental Firing Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) a maximum of [redacted] based on the LTSA contract with GE.

- The Facility will not be allowed to operate in a traditional CT only mode (no simple cycle operation, *i.e.*, no bypass stack). However, the CTs will be capable of operating independently of the steam turbine utilizing the steam bypass systems for a limited time. Most major plant equipment (such as HRSG BFP's, condenser, cooling tower and circulating water pumps) will be required during operation in this mode. The HRSG duct burners will not be available in this mode. The maximum generation capability of the Facility operating in this mode will be [redacted] CT load.

- The Facility's CT evaporative coolers should not be operated at ambient temperatures less than [redacted] to prevent freezing at the CT compressor inlet.

APPENDIX B

REQUESTS FOR ENERGY

1.1 Schedules for Requested Quantities of Energy. Purchaser and each other Customer shall provide Seller with a single Request for Energy in order to schedule requested quantities of each category of unit output as follows:

1.1.1 Day Ahead Daily Schedule. Customers shall communicate the day ahead Request for Energy for each day to Seller at or before [redacted] Eastern Prevailing Time of the immediately preceding day before delivery is to be made, or such other earlier time that may be required by an RTO.

1.1.1.1 When AGC mode is available, during each hour the unit is scheduled to be in AGC mode, the Request for Energy shall specify the maximum amount of Energy desired for each of the twenty-four (24) hours. During each hour the unit is in AGC mode, the Customers shall not be permitted to reduce the Request for Energy to an amount less than [redacted] MW of the maximum Energy scheduled during that hour in the Request for Energy from the Customers' aggregate Equity Capacity and the Customers' aggregate capacity available under the Power Purchase Agreements (Customers' "PPA Capacity"). If in any hour, should the Customers reduce the Request for Energy amount by more than [redacted] MW, the Customers shall pay Seller [redacted] for the difference between the amount of the Delivered Energy and the amount that is [redacted] MW below the Request for Energy amount.

1.1.1.2 During each hour the Facility is not scheduled to be in AGC mode or the AGC mode is unavailable, the Request for Energy shall specify the amount of Energy from the Customers' aggregate PPA Capacity and aggregate Equity Capacity for each of the twenty-four (24) hours. Requests for Energy shall be submitted in [redacted] MW increments in a total amount that falls between the Facility's minimum capability and its maximum capability as described in the Technical Limits.

1.2. Hourly Changes to the Daily Schedule. The Customers jointly shall be entitled to make changes to a Request for Energy by communicating such changes to Seller no later than [redacted] prior to the beginning of the hour in which such changes are to become effective. The Customers shall be responsible for any costs associated with OASIS notifications and NERC tagging requirements.

1.3. Capacity Emergency. During any periods in which the Customers experience a Capacity Emergency, the Customers shall be entitled to increase the Request for Energy on shorter notice than that provided in paragraph 1.2 above by an amount not to exceed the Customers' unavailable resources that were the cause of the Capacity Emergency and Seller shall endeavor to comply with the request consistent with the Technical Limits, Prudent Utility Practice, applicable Law and Permit requirements.

1.4. Minimum Start-up Time. If the Customers have scheduled a zero amount of Capacity in any hour and the Facility is not on-line, the Customers shall provide notice consistent with the Technical Limits prior to scheduling any Request for Energy.

1.5. Load Following Service. The Customers shall have the ability to control the output of the Facility using the AGC mode, if available, only to the extent that the Facility has the ability to operate in the AGC mode consistent with the Technical Limits, Prudent Utility Practice, and applicable Law and Permit requirements.

1.6 Electronic Scheduling. The Customers shall use electronic scheduling for Requests for Energy under this Agreement, if and to the extent that Seller's electronic scheduling capability is operational. To the extent it is not, the Parties will use other mutually agreed-upon communication procedures (such as fax).

2.1 Shortfall Conditions; Oversupply Conditions.

2.1.1 If the Facility is in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the Facility is not within [redacted] MW of the Request for Energy, OUC shall communicate to Seller the amount of error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the Request for Energy within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.1.1 If the actual output of the Facility is greater than the Request for Energy (an "Oversupply Condition"), the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the Facility equals the Request for Energy. OUC, acting for itself and on behalf of the other Customers, shall coordinate with Seller during the period that the

actual output of the Facility exceeds the Request for Energy. The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition. Seller shall compensate OUC, on its own behalf and as agent for KUA and FMPA, for any such Oversupply Condition.

2.1.1.2 If the actual output of the unit is less than the Request for Energy (an "Undersupply Condition"), the provisions of Section 4.3 will apply if applicable.

2.1.2 If the Facility is not in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the unit is not within [redacted] MW of the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy pursuant to Section 4.5 of this Agreement), then OUC shall communicate to Seller the amount of the error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.2.1 If an Oversupply Condition exists, the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the unit equals the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy). The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition.

2.1.2.2 If an Undersupply Condition exists, the provisions of Section 4.3 will apply if applicable.

3.1 Notification Requirements for Delivery of Energy from Alternate Resources.

3.1.1 When the Facility is available and running at minimum load and spinning reserves are available, Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of Customers' Schedule at least [redacted] (or the amount of time in which an RTO has determined that the Physical Transmission Rights ("PTRs") may be recalled) prior to the scheduled commencement of

delivery of such Energy. For purposes of paragraph 3.1, the phrase "has scheduled delivery" means that Seller has scheduled and arranged the OASIS, tagging, and any transmission rights required by an RTO. If an RTO is established in Florida, and under such condition the RTO determines that Physical Transmission Rights (PTRs) may be recalled if not utilized, then Seller will notify OUC if Seller has so scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.2 When the Facility is unavailable and is not scheduled to return to service in time for Seller to serve the Customers' Schedule, Seller will notify OUC within [redacted] after Seller's receipt of Customers' Schedule if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customers' Schedule. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.3 When the Facility becomes unavailable while Seller is serving Customers' Schedule, Seller will notify OUC within [redacted] after the Facility is deemed unavailable if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of the remainder of Customers' Schedule. If Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than the top of the next full hour following the hour that Seller notified OUC of Seller's election. (Example: The Facility becomes unavailable at [redacted] Seller gives notice no later than [redacted] if Seller will arrange to deliver Energy from Alternate Resources. Delivery from Alternate Resources should begin no later than [redacted]) At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.4 When the Facility is expected to return from an outage, but does not, Seller will notify OUC within [redacted] of Seller's realization that the Facility will not be available as expected to meet the start of a Customer's Schedule. If the start of such Customer's Schedule is to begin

within [redacted] or less from the time of such notice, Seller will notify OUC at the same time if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule. Otherwise Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule at least [redacted] prior to the start of such Schedule and preferably at least [redacted]. If Seller notifies OUC that Seller has scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than [redacted] that Seller notified OUC of Seller's election (but not earlier than the original start of such Customers' Schedule). If an RTO develops in Florida, and under such condition the RTO determines that PTRs may be recalled if not utilized, then Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

APPENDIX C

CAPACITY TESTING PROCEDURE

The capability of the Facility will be required to be demonstrated prior to the Commencement Date. The demonstration of the capability of the Facility following the Commencement Date shall be scheduled in accordance with the provisions of Section 4.1.2. As provided in Section 4.1.3, Participants may also request additional tests of the Facility which shall not be used as the basis for determining the Demonstrated Capability of the Facility. Purchaser shall have the right to monitor (either on-Site or otherwise) all performance tests.

All Capacity testing will be adjusted to the Rated Conditions using correction curves supplied by Seller. "Rated Conditions" means seventy (70) degrees Fahrenheit (°F) and forty five percent (45%) relative humidity. The demonstrated net output of the Facility will be as measured by the Meters.

On the date of the Capacity test, Seller shall bring the Facility to maximum full load capability within the Technical Limits of the Facility for the ambient conditions for that day. The test shall be scheduled between the weekday hours of [redacted] (prevailing Eastern Time) and will be conducted over [redacted] period (or a lesser period if mutually agreed upon). Seller must notify Customers when the Facility is at maximum full load capability, at which time the Capacity test shall begin. The Demonstrated Capability will be the average net hourly output over the test period corrected to Rated Conditions.

APPENDIX D

Example Calculations of Quantities of Gas Transportation and/or Commodity Required for Delivery from Alternate Resources

Listed below are examples of the determination of the amount of gas transportation and/or commodity that the Fuel Supply Agent shall provide to Seller pursuant to Section 4.2.5.2 or 4.2.5.3 when Seller elects to deliver Energy from Alternate Resources.

Example 1

The facility is unavailable. The Customers have Scheduled 400 MWh of Energy in an hour. Seller notifies OUC that Seller will supply the 400 MWh of Energy for the subject hour from Alternate Resources.

In Example 1, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 2

The facility is unavailable. The Customers have Scheduled 610 MWh of Energy in an hour. Seller notifies OUC that Seller will supply 550 MWh of Energy for the subject hour from Alternate Resources.

In Example 2, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 3

The facility is available. The Customers have Scheduled 450 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 100 MWh of Energy for the subject hour from Alternate Resources and 350 MWh from the Facility.

In Example 3, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 4

The facility is available. The Customers have Scheduled 600 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 200 MWh of Energy for the subject hour from Alternate Resources and 400 MWh from the Facility.

In Example 4, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

APPENDIX E

FORM OF PAYMENT GUARANTY

This Guaranty Agreement (the "Guaranty") is made by The Southern Company ("Guarantor"), a Delaware corporation, in favor of Kissimmee Utility Authority ("KUA"), a public body corporate organized and existing under the laws of the State of Florida.

WHEREAS, Southern Company - Florida LLC ("Principal Obligor"), a Delaware limited liability company, and KUA entered into that certain Power Purchase Agreement, dated as of March 19, 2001 (the "PPA");

WHEREAS, Guarantor has agreed to provide assurance for the payment of Principal Obligor's obligations in connection with the PPA as provided in this Guaranty; and

WHEREAS, the execution and delivery of this Guaranty by Guarantor is pursuant to the terms of the PPA in order to satisfy the requirement that Principal Obligor cause an Affiliate to maintain in place a guaranty of Principal Obligor's obligations under the PPA.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the adequacy, receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. **Guaranty.** Guarantor hereby irrevocably, unconditionally and absolutely guarantees the punctual payment when due of Principal Obligor's payment obligations arising under the PPA, as amended or modified from time to time, together with any interest thereon, including, without limitation, any interest amounts accruing under the PPA during the pendency of insolvency, bankruptcy, reorganization or other similar proceedings affecting Principal Obligor or its assets; provided, however, that the maximum liability of Guarantor under this Guaranty with respect to Principal Obligor's obligations under the PPA shall be limited to the amount that is equal to the then-current Termination Payment (as defined in the PPA), which shall not exceed in any event [redacted] (collectively, the "Guaranteed Obligations"); provided, further, that the cap on Guarantor's liability under this Guaranty established in the immediately preceding clause creates an absolute cap on Guarantor's liability to KUA in relation to the PPA and, if and when Guarantor's liability under this Guaranty has reached such cap, then from and after such time, Guarantor shall have no further liability under this Guaranty whatsoever to KUA and this Guaranty shall thereupon terminate; provided, further, that costs incurred by Guarantor under Section 4 hereof shall not be counted for purposes of determining whether Guarantor has reached such cap, unless and to the extent that Guarantor's costs under such Section 4, together with costs incurred by Guarantor under the corresponding provisions of Guarantor's other three Payment Guarantees of contemporaneous date to one or more of OUC, FMPA and KUA, exceed [redacted]

2. **Guaranty Absolute.** The liability of Guarantor under this Guaranty shall be irrevocable, absolute and unconditional irrespective of:

(a) any lack of validity or enforceability of or defect or deficiency in the PPA or any other documents executed in connection with the PPA;

(b) any assignment, transfer, modification, extension or waiver of any of the terms of the PPA;

(c) any change in the time, manner, terms of payment of or in any other term of, all or any of the Guaranteed Obligations, or any other amendment or waiver of or any consent to departure from any agreement or instrument executed in connection therewith;

(d) any sale, exchange, release or non-perfection of any property standing as security for the liabilities hereby guaranteed or any liabilities incurred directly or indirectly hereunder or any set off against any of said liabilities, or any release or amendment or waiver of or consent to departure from any other guaranty, for all or any of the Guaranteed Obligations;

(e) applicable statutes of limitation, failure, omission, delay, waiver or refusal by KUA to exercise, in whole or in part, any right or remedy held by KUA with respect to the PPA or any transaction under the PPA; or

(f) any change in the existence, structure or ownership of Guarantor or Principal Obligor, or any insolvency, bankruptcy, reorganization or other similar proceeding affecting Principal Obligor or its assets.

The obligations of the Guarantor hereunder are several from the Principal Obligor or any other person, and are primary obligations concerning which the Guarantor is the principal obligor. There are no conditions precedent to the enforcement of this Guaranty, except as expressly contained herein.

This Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations are annulled, set aside, invalidated, declared to be fraudulent or preferential, rescinded or must otherwise be returned, refunded or repaid by KUA upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of Principal Obligor or any other guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, Principal Obligor or any other guarantor or any substantial part of its property or otherwise, all as though such payment or payments had not been made.

3. **Waiver.** This is a guaranty of payment and not of collection. Guarantor hereby waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of any of the Guaranteed Obligations and of any action by KUA in reliance hereon or in connection herewith;

(b) except as expressly set forth herein, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to the Guaranteed Obligations; and

(c) any requirement that suit be brought against Principal Obligor or any other person as a condition to Guarantor's liability for the Guaranteed Obligations under this Guaranty or as a condition to the enforcement of this Guaranty against Guarantor.

Notwithstanding anything to the contrary set forth herein, Guarantor shall have the same defenses available to it as Principal Obligor may have with respect to any payment obligations arising under the PPA.

4. **Expenses.** Guarantor agrees to pay on demand any and all costs, including reasonable legal fees, and other expenses incurred by KUA in enforcing Guarantor's payment obligations under this Guaranty; provided that the Guarantor shall not be liable for any expenses of KUA if no payment under this Guaranty is due.

5. **Subrogation.** Guarantor shall be subrogated to all rights of KUA against Principal Obligor in respect of any amounts paid by Guarantor pursuant to the Guaranty, provided that Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise, until all of the Guaranteed Obligations shall have been irrevocably paid to KUA in full. If any amount shall be paid to the Guarantor on account of such subrogation rights at any time when all the Guaranteed Obligations shall not have been paid in full, such amount shall be held in trust for the benefit of KUA and shall forthwith be paid to KUA to be applied to the Guaranteed Obligations. If (a) the Guarantor shall perform and shall make payment to KUA of all or any part of the Guaranteed Obligations and (b) all the Guaranteed Obligations shall have been paid in full, KUA shall, at the Guarantor's request, execute and deliver to the Guarantor appropriate documents necessary to evidence the transfer by subrogation to the Guarantor of any interest in the Guaranteed Obligations resulting from such payment by Guarantor.

6. **Notices.** All demands, notices and other communications provided for hereunder shall, unless otherwise specifically provided herein, (a) be in writing addressed to the party receiving the notice at the address set forth below or at such other address as may be designated by written notice, from time to time, to the other party, and (b) be effective upon delivery, when mailed by U.S. mail, registered or certified, return receipt requested, postage prepaid, or personally delivered. Notices shall be sent to the following addresses:

If to KUA:

Kissimmee Utility Authority

1701 West Carroll Street

Kissimmee, FL 34741

Attention: Director of Power Supply

Tel: 407-933-7777 ext. 1235

Fax: 407-847-0787

With a copy to:

Kissimmee Utility Authority

1701 West Carroll Street

Kissimmee, Florida 34742-3219

Attention: Manager Bulk System Planning

Telephone: 407-933-7777 ext. 1235

Facsimile: 407-847-0787

If to Guarantor:

The Southern Company

c/o Southern Company Services, Inc.

270 Peachtree Street NW

Suite 2000

Atlanta, GA 30303

Attention: Allen L. Leverett, Vice President and Treasurer

Tel: 404-506-0710

Fax: 404-506-0712

With a copy to:

Robert H. Forry, Esq.

Troutman Sanders LLP

Bank of America Plaza

600 Peachtree Street, N.E.

Suite 5200

Atlanta, Georgia 30308-2216

Tel: 404-885-3142

Fax: 404-962-6559

If to Principal Obligor:

Southern Company - Florida LLC

c/o Southern Company Services, Inc.

270 Peachtree Street NW

Suite 2000

Atlanta, GA 30303

Attention: Allen L. Leverett, Vice President and Treasurer

Tel: 404-506-0710

Fax: 404-506-0712

With a copy to:

Robert H. Forry, Esq.

Troutman Sanders LLP

Bank of America Plaza

600 Peachtree Street, N.E.

Suite 5200

Atlanta, Georgia 30308-2216

Tel: 404-885-3142

Fax: 404-962-6559

7. **Demand and Payment.** Any demand by KUA for payment hereunder shall be in writing, signed by a duly authorized officer of KUA and delivered to the Guarantor pursuant to Section 6 hereof, and shall (a) reference this Guaranty, (b) specifically identify the Principal Obligor, the Guaranteed Obligations to be paid and the amount of such Guaranteed Obligations and (c) set forth payment instructions. There are no other requirements of notice, presentment or demand. Guarantor shall pay, or cause to be paid, such Guaranteed Obligations within three (3) business days of receipt of such demand.

8. **No Waiver; Remedies.** Except as to applicable statutes of limitation, no failure on the part of KUA to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

9. **Replacement of Guarantor and Termination.**

(a) Guarantor may assign and delegate its rights and obligations under this Guarantee, in whole or in part, as follows: (i) without the consent of KUA, to Southern Power Company, a Delaware corporation and parent company of Principal Obligor, or other Affiliate of Principal Obligor, if Southern Power Company or such other Affiliate has achieved the following three characteristics: (1) a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's), (2) Net Equity (as hereinafter defined) of at least [redacted], as reflected on its most recent audited balance sheet, and (3) Gross Equity (as hereinafter defined) of at least [redacted] provided, however, that the date on which Guarantor causes such a replacement of this Guaranty under this Section 9(a)(i) may not be earlier than the Commercial Operation Date (as defined in the Ownership Agreement); or (ii) with the consent of KUA, which consent may not be unreasonably withheld, to an assignee which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's) and which meets other reasonable financial criteria similar to those identified in Section 9(a)(i), provided, however, that if Guarantor requests KUA's consent to such an assignment and delegation in connection with a permitted transfer or

assignment of the PPA, then KUA may not withhold such consent if the assignee meets the financial criteria in Section 9(a)(ii). An assignment and delegation of Guarantor's rights and obligations under this Section 9 shall become effective when the replacement guarantor executes and delivers to KUA a replacement guaranty on terms and conditions substantially similar to this Guaranty.

(b) For purposes of this Guaranty, the following terms shall have the following meanings:

"Net Equity" shall mean the aggregate of the capital stock and other equity accounts (including retained earnings and paid-in capital) of Southern Power Company or other Affiliate of Principal Obligor, as the case may be.

"Gross Equity" shall mean Net Equity plus Guaranteed Debt plus loans to Southern Power Company from its parent corporation.

"Guaranteed Debt" shall mean any obligations of Southern Power Company or other Affiliate of Principal Obligor, as the case may be, for or in respect of (a) moneys borrowed or raised (whether or not for cash) by whatever means (including acceptances, deposits, discounting, letters of credit, factoring (other than on a non-recourse basis), finance leases, and any other form of financing which is recognized in Southern Power Company's or other Affiliate of Principal Obligor's, as the case may be, financial statements as being in the nature of a borrowing (excluding for the avoidance of doubt, share capital, share premium account and any capital prepayment reserve), which has been guaranteed by Guarantor, and (b) the deferred purchase price of assets or services (other than goods and services obtained on normal commercial terms in the ordinary course of business or operations), which has been guaranteed by Guarantor.

"Affiliate" of an Entity shall mean any other entity controlled by, controlling or under common control with such entity, where control of an entity means the ability to direct the policies of such entity through election of a majority of such entity's board of directors or other governing body or by contract or otherwise.

(c) This Guaranty shall terminate, and upon the effective date of such termination Guarantor shall have no further liability hereunder, on the earliest to occur of: (i) the satisfaction of all of the Guaranteed Obligations, (ii) the termination or expiration of the PPA, (iii) the date on which the liability cap is reached, as provided in Section 1 hereof, or (iv) the date on which an assignment and delegation by Guarantor of its rights and obligations hereunder becomes effective under Section 9(a) hereof.

10. **Assignment by KUA; Successors and Assigns.** KUA may, upon notice to Guarantor, assign its rights hereunder only to a subsequent owner of all of KUA's interest in the Facility and the Interconnection Facilities (as defined in the PPA) without the consent of Guarantor. Subject to the foregoing, this Guaranty shall be binding upon and inure to the

benefit of the parties hereto and their respective successors, permitted assigns, and legal representatives.

11. **Amendments, Etc.** No amendment of this Guaranty shall be effective unless in writing and signed by Guarantor and KUA. No waiver of any provisions of this Guaranty or consent to any departure by Guarantor therefrom shall in any event be effective unless such waiver shall be in writing and signed by KUA. Any such waiver shall be effective only in the specific instance and for the specific purpose for which it was given.

12. **Captions.** The captions in this Guaranty have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Guaranty.

13. **Representations and Warranties.**

The Guarantor represents and warrants as follows:

(a) The Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets.

(c) This Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting KUA's rights and to general equity principles.

(d) The financial statements of Guarantor for the year ended December 31, 2000 (the "Financial Statements"), heretofore delivered to KUA or filed with the United States Securities Exchange Commission by Guarantor present fairly the financial condition and results of operations of Guarantor and its consolidated subsidiaries as of the dates and for the period specified therein in conformity with generally accepted accounting principles, and, except as otherwise expressly stated therein, consistently applied.

14. **Limitation by Law.** All rights, remedies and powers provided in this Guaranty may be exercised only to the extent that the exercise thereof does not violate any applicable provision of law, and all the provisions of this Guaranty are intended to be subject to all applicable mandatory provisions of law that may be controlling and to be limited to the extent necessary so that they will not render this Guaranty invalid, unenforceable, in

whole or in part, or not entitled to be recorded, registered or filed under the provisions of any applicable law.

15. **Governing Law; Submission to Jurisdiction.** This Guaranty shall be governed by, and construed in accordance with, the laws of the State of Georgia, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction. The parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Northern District of Georgia, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Superior Court of the State of Georgia sitting in Fulton County, Georgia and the parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized officer effective as of this ___ day of _____, 2001.

"Guarantor"

THE SOUTHERN COMPANY

By:_____

Name:_____

Title:_____

CONFIDENTIAL AND PROPRIETARY EXECUTION COPY

****THIS AGREEMENT CONTAINS PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION WHICH IS PROTECTED FROM DISCLOSURE TO THE PUBLIC****

POWER PURCHASE AGREEMENT

BETWEEN

FLORIDA MUNICIPAL POWER AGENCY (ALL REQUIREMENTS POWER SUPPLY PROJECT)

AND

SOUTHERN COMPANY - FLORIDA LLC

Dated as of March 19, 2001

TABLE OF CONTENTS

Section	Page
SECTION 1 DEFINITIONS AND EXPLANATION OF TERMS	2
SECTION 2 TERM OF AGREEMENT	15
SECTION 3 CONDITIONS PRECEDENT	16
SECTION 5 SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY	32
SECTION 6 REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE	35
SECTION 7 INTERCONNECTION AND TRANSMISSION	37
SECTION 8 RISK OF LOSS; METERING	38
SECTION 9 METHOD OF PAYMENT	39
ARTICLE 10 CHANGE IN LAW; MODIFICATION OF AGREEMENT	40
SECTION 11 FORCE MAJEURE	42
SECTION 12 EVENTS OF DEFAULT; TERMINATION	42
SECTION 13 WAIVER	46
SECTION 14 REPRESENTATIONS AND WARRANTIES	46
SECTION 15 PERFORMANCE ASSURANCE	49
SECTION 16 LIABILITY OF PARTIES	52
SECTION 17 ASSIGNMENT	56
SECTION 18 DISPUTE RESOLUTION	57
SECTION 19 AMENDMENT	58

SECTION 20 NOTICES 58

SECTION 21 APPLICABLE LAW 59

SECTION 22 SEVERABILITY 60

SECTION 23 ENTIRE AGREEMENT 60

SECTION 24 NO THIRD PARTY BENEFICIARIES 60

SECTION 25 COUNTERPARTS 60

SECTION 26 INFORMATION AND CONFIDENTIALITY 60

SECTION 27 PUBLIC STATEMENTS 62

SECTION 28 INSURANCE 62

SECTION 29 TAXES 62

APPENDIX A TECHNICAL LIMITS

APPENDIX B REQUESTS FOR ENERGY

APPENDIX C CAPACITY TESTING PROCEDURE

APPENDIX D EXAMPLE CALCULATIONS

APPENDIX E AFFILIATE GUARANTEE

CONFIDENTIAL AND PROPRIETARY EXECUTION COPY

POWER PURCHASE AGREEMENT

This Power Purchase Agreement (this "Agreement") is made and entered into as of the 19th day of March, 2001, by and between Florida Municipal Power Agency (All Requirements Power Supply Project), a governmental legal entity existing under the laws of the State of Florida ("Purchaser"), and Southern Company - Florida LLC, a limited liability company organized and existing under the laws of the State of Delaware ("Seller"). Purchaser and Seller are hereinafter each referred to individually as a "Party" and collectively as the "Parties." Seller acknowledges that in executing and delivering this Agreement and performing its obligations hereunder Purchaser is acting on behalf of its All-Requirements Power Supply Project.

RECITALS

WHEREAS, in addition and supplemental to their other powers, OUC, KUA and FMPA (the "Public Agencies"), pursuant to the Florida Interlocal Cooperation Act of 1969, Chapter 163, Part I, Florida Statutes, (the "Interlocal Act") are authorized and empowered to cooperate with each other on a basis of mutual advantage and thereby to provide services and facilities in a manner and pursuant to forms of government organizations that will best accord with geographic, economic, electrical generation requirements and other factors; and

WHEREAS, the Ownership Agreement was entered into by the Public Agencies as an interlocal agreement, to invoke all of the powers of the Interlocal Act, for the purpose of providing a structure for the Public Agencies, in participation with Seller, a foreign public utility, to operate, maintain, repair, improve, extend, or otherwise participate jointly in a nominal six hundred thirty-three (633) megawatt combined cycle electric generating facility (the "Facility"), which is proposed, and which is to be constructed, owned, and located within the State of Florida by Seller and the Public Agencies; and

WHEREAS, Seller intends to sell to Purchaser, and Purchaser intends to purchase from Seller, a portion of Seller's share of the Capacity and Energy generated by the Facility in accordance with the terms and conditions of this Agreement and in full compliance with the Interlocal Act; and

WHEREAS, Seller and Purchaser acknowledge that this Agreement is one of three substantially similar contracts through which Seller will sell and the three Purchasers will individually purchase their respective designated shares of Seller's share of the Capacity and Energy generated by the Facility; and

WHEREAS, this Agreement and the two substantially similar contracts are entered into to invoke all of the powers of the Interlocal Act for the purpose of obligating

Customers, pursuant to such Interlocal Act, to purchase Seller's share of the Capacity of the Energy generated by the Facility in accordance with the terms and conditions of this Agreement.

NOW, THEREFORE, for the purpose of exercising all of the powers enumerated in the Interlocal Act and the Florida Joint Power Act, Part II of Chapter 361, Florida Statutes, (the "Joint Power Act") (collectively, the "Acts"), Purchaser hereby designates this Agreement as an interlocal agreement within the meaning and intent of the Interlocal Act, and invokes all powers contained therein with full powers to perform all of the provisions herein authorized to be performed by the Parties; and

FURTHER, NOW, THEREFORE, in consideration of the mutual promises, covenants and agreements set forth herein, and other good and valuable consideration, the receipt, sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound hereby, agree as follows:

SECTION 1
DEFINITIONS AND EXPLANATION OF TERMS

1.1 Definitions. When used in this Agreement, the following capitalized terms shall have the meanings set forth below:

1.1.1 "Actual Availability" has the meaning given such term in Section 4.3.3 or 4.3.4, as applicable.

1.1.2 "Actual Capability" means the amount of Capacity the Facility is capable of producing in any given hour.

1.1.3 "AGC" means automatic generation control, which is the capability to make automatic adjustments to load change by generation through the use of a digital computer. This control is based on such factors as frequency, cost and tie line flows.

1.1.4 "Agreement" means this Power Purchase Agreement, including all appendices attached hereto and all amendments hereto that may be made from time to time.

1.1.5 "Alternate Resources" has the meaning given such term in Section 4.4.

1.1.6 "Ancillary Services" means ancillary services customarily provided by an electric generating facility, including voltage/VAR control, load following, regulation and frequency response, spinning reserve and non-spinning reserve.

1.1.7 "Annual Capacity Charge" means (i) [redacted] per kilowatt per month for that portion of the Initial Term before the end of the day of May 31, 2014 , (ii) [redacted] per kilowatt per month for that portion of the Initial Term after the beginning of the day June 1, 2014 and during the Extended Term, (iii) with respect to the first Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), (iv) with respect to the second Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), and (v) with respect to the third Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3); *provided, however,* that the Annual Capacity Charge shall be (i) increased by [redacted] per kilowatt per month for every [redacted] increase in the BOP Capital Cost Range that occurs pursuant to Sections 6.7.2(b) or 6.7.2(c) of the Ownership Agreement, (ii) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the BOP Capital Costs Range that occurs pursuant to Sections 6.7.2(b) and 6.7.2(c) of the Ownership Agreement, (iii) increased by [redacted] per kilowatt per month for every [redacted] increase in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement, and (iv) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement.

1.1.8 "Annual Purchaser's Capacity Nomination" of the Purchaser means, during the first five Contract Years, [redacted] percent [redacted] of the Demonstrated Capability, and thereafter, [redacted] of the Demonstrated Capability reduced by those amounts, if any, that Purchaser elects to subtract from the Capacity available to Purchaser pursuant to the process provided in Section 4.1.4 for the Customers jointly to make such elections.

1.1.9 "Availability Guarantee" has the meaning given such term in Section 4.3.1.

1.1.10 "Availability Incentive Payment" has the meaning given such term in Section 4.3.2.

1.1.11 "Bankruptcy" means, with respect to a Party, (i) an adjudication of bankruptcy or insolvency, or the entry of an order for relief, under any Bankruptcy Law with respect to such Party; (ii) the making by such Party of an assignment for the benefit of its creditors; (iii) the filing by such Party of a petition in bankruptcy or for relief under any Bankruptcy Law; (iv) the filing by such Party of an answer or pleading admitting or failing to contest the material allegations of any such petition; (v) the filing against such Party of any petition in bankruptcy or for relief under any Bankruptcy Law (unless such petition is dismissed within ninety (90) days from the date of filing thereof); (vi) the appointment of a trustee, conservator or receiver for such Party or for all or substantially all of its assets (unless such appointment is vacated or stayed within ninety (90) days of such appointment); or (vii) the taking by such Party of any action for its winding up or liquidation, or the consent by such Party to any of the actions described in clauses (i) through (vi) being taken against it.

1.1.12 "Bankruptcy Law" means any applicable bankruptcy or insolvency statute.

1.1.13 "Bond Legislation" shall mean the Florida Municipal Power Agency All-Requirements Power Supply Project Revenue Bond Resolution duly adopted March 22, 1985, as amended by All-Requirements Power Supply Project Subordinated Debt Resolution No. 1, adopted May 24, 1985; All-Requirements Power Supply Project Subordinated Debt Resolution No. 2, adopted June 15, 1988; All-Requirements Power Supply Project Subordinated Debt Resolution No. 3, adopted March 23, 1990; All-Requirements Power Supply Project Subordinated Debt Resolution No. 4, adopted July 18, 1996; All-Requirements Power Supply Project Subordinated Debt Resolution No. 5, adopted July 2, 1998; First Supplemental and Amendatory All-Requirements Power Supply Project Revenue Bond Resolution, adopted May 24, 1985; Second Supplemental and Amendatory All-Requirements Power Supply Project Revenue Bond Resolution, adopted June 19, 1985; Third Supplemental and Amendatory All-Requirements Power Supply Project Revenue Bond Resolution, adopted January 23, 1987; Fourth Supplemental and Amendatory All-Requirements Power Supply Project Revenue Bond Resolution, adopted March 23, 1990; Fifth Supplemental and Amendatory All-Requirements Power Supply Project Revenue Bond Resolution, adopted June 27, 1990; Sixth Supplemental and Amendatory All-

Requirements Power Supply Project Revenue Bond Resolution, adopted September 20, 1991; Seventh Supplemental and Amendatory All-Requirements Power Supply Project Revenue Bond Resolution, adopted May 15, 1992; Series 1993 Supplemental All-Requirements Power Supply Project Revenue Bond Resolution, adopted October 22, 1993; Series 2000 Supplemental All-Requirements Power Supply Project Subordinated Debt Resolution, adopted May 5, 2000; Series 2000 Supplemental All-Requirements Power Supply Project Subordinated Debt Resolution, adopted May 5, 2000, as amended and supplemented pursuant to the Initial Bond Series Certificate dated June 21, 2000; and Series 2000-2 Supplemental All-Requirements Power Supply Project Subordinated Debt Resolution, adopted July 13, 2000.

1.1.14 "BOP Capital Cost Range" has the meaning ascribed to the term in Section 6.7.1 of the Ownership Agreement.

1.1.15 "Business Day" means any day other than Saturday or Sunday on which commercial banks are authorized to open for business in Orlando, Florida.

1.1.16 "Capacity" means electric capacity.

1.1.17 "Capacity Emergency" means, with respect to any hour, that any one or more of Purchaser's resources is unavailable due to a forced outage and the summation of such Purchaser's firm Capacity obligations exceeds the summation of such Purchaser's available resources.

1.1.18 "Capacity Payment" has the meaning given such term in Section 4.1.1.

1.1.19 "Change in Law" has the meaning given such term in Section 10.1.3.

1.1.20 "Collateral Documents" means, collectively, the Ownership Agreement, the Operating Agreement, the Interconnection Agreement, the Power Purchase Agreements of the other Customers, the long term lease of the Facility Site by OUC to and for the benefit of the Participants, the guarantee to be provided by an affiliate of Seller as contemplated in Section 16.3, and the agreement(s) pursuant to which Purchaser and/or the other Customers provide station service and other

support services (including but not limited to demineralized water and cooling water supply) to Seller.

1.1.21 "Commencement Date" has the meaning given such term in Section 5.2.

1.1.22 "Commercial Operation Date" has the meaning ascribed to such term in Section 1.1.13 of the Ownership Agreement.

1.1.23 "Confidential Information" has the meaning given such term in Section 26.

1.1.24 "Contract Year" means (i) the period commencing on the Commencement Date or, if Seller elects the option under Section 4.5(ii)(a), the later of the Commencement Date or Scheduled Commencement Date, and ending on the last day of the month in which the first anniversary date of the Commencement Date falls, and (ii) each twelve (12)-month period thereafter, except that for the twelve (12)-month period during which the expiration or termination date of this Agreement occurs, Contract Year shall mean the period commencing on the first day of such twelve (12)-month period and ending on such expiration or termination date.

1.1.25 "Customers" means collectively all of OUC, Kissimmee Utility Authority and Florida Municipal Power Agency (All Requirements Power Supply Project), or their permitted assigns.

1.1.26 "Delivered Energy" means, in respect of a period of time, the amount of Energy from the Facility or from Alternate Resources delivered by Seller to Purchaser at the Delivery Point for sale to Purchaser pursuant to this Agreement.

1.1.27 "Delivery Point" means (a) with respect to Energy delivered from the Facility, the high side of generator step-up transformer, as further described in the Interconnection Agreement, and (b) with respect to Energy delivered from Alternate Resources, any unconstrained point on the Grid.

1.1.28 "Demonstrated Capability" means the net Capacity of the Facility, determined by a periodic Capacity test, adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity.

1.1.29 "Dispute" has the meaning given such term in Section 18.

1.1.30 "Eastern Prevailing Time" or "EPT" means the time prevailing in the Eastern time zone of the United States of America.

1.1.31 "Effective Date" has the meaning given such term in Section 3.1.

1.1.32 "Eligible Collateral" has the meaning given such term in Section 15.1.1.

1.1.33 "Energy" means electric energy (expressed in megawatt-hours).

1.1.34 "Energy Payment" has the meaning given such term in Section 4.2.

1.1.35 "Equipment Breakdown" means a mechanical breakdown of equipment at the Facility that is not the result of a Force Majeure that is an act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted]; storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under Section 1.1.44 if such failure were directly experienced by the applicable Party.

1.1.36 "Equity Capacity" with respect to each Participant means that Participant's percentage share of the Capacity of the Facility corresponding to such Participant's ownership interest in the Facility.

1.1.37 "Event of Default" means any of the events listed in Sections 12.1 and 12.2.

1.1.38 "Facility" means the gas fired combined cycle electric generating unit to be located on the Facility Site and owned by the Participants, and its associated interconnection facilities, as defined in the Ownership Agreement by the terms "Facility" and "Interconnection Facilities."

1.1.39 "Facility Site" means the parcel of land in Orlando, Florida on which the Facility is to be located, as further described in Appendix A.

1.1.40 "FDEP" means the Florida Department of Environmental Protection or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.41 "FERC" means the Federal Energy Regulatory Commission or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.42 "Firm Transmission Service" means (a) electric transmission service designated firm under the open access transmission tariff of a transmission provider having an open access transmission tariff or (b) if purchased from a transmission provider that does not have an open access transmission tariff, electric transmission service sold by such transmission provider as firm transmission service and generally considered, pursuant to Prudent Utility Practice and FRCC requirements, to be substantially equivalent to the firm transmission service referenced in item (a) of this definition.

1.1.43 "Fixed Amount" has the meaning ascribed to such term in Section 6.7.1 of the Ownership Agreement.

1.1.44 "Force Majeure" as to a Party means each of the following events as affects the Facility: act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted]; storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; shutdown of the Facility by a court order or Governmental Body not resulting from any action or inaction by the applicable Party; strike, lockout or labor difficulty affecting the SEC Site generally [redacted]; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under this provision if

such failure were directly experienced by the applicable Party; or any other occurrence, nonoccurrence or set of circumstances, whether or not foreseeable, that is beyond the reasonable control of the applicable Party and is not caused or exacerbated by the applicable Party's failure to follow Prudent Utility Practices.

1.1.45 "FRCC" means the Florida Reliability Coordinating Council or any successor organization.

1.1.46 "Fuel Supply Agent" has the meaning given such term in the Operating Agreement.

1.1.47 "Further Extension" has the meaning given such term in Section 2.3.

1.1.48 "Gas Delivery Point" shall have the meaning assigned to it in the Operating Agreement.

1.1.49 "Governmental Body" shall mean, except as provided in the following sentence, (i) any local, state, regional or federal administrative, legal, judicial, or executive agency, court, commission, department or other entity having jurisdiction or binding authority over any element of the Project or the performance of the Parties under this Agreement or the Collateral Documents, but excluding any agency, commission, department or other such entity acting in its capacity as lender, guarantor or mortgagee and (ii) NERC, FRCC and any RTO. Except as expressly provided otherwise in this Agreement, the definition "Governmental Body" shall be deemed to not include OUC, KUA and FMPA for the purposes of this Agreement.

1.1.50 "Grid" means (i) OUC's electric transmission system, or (ii) if ownership or control of and jurisdiction over OUC's electric transmission system is succeeded to by an RTO or other entity, the portion of the electric transmission system of that RTO or other successor entity that most closely resembles the OUC electric transmission system as it existed on the effective date of this Agreement.

1.1.51 "Guaranteed Output" means in any given hour the amount of Capacity (in MWh per hour) determined by adjusting the Demonstrated Capability to the prevailing ambient conditions in such hour and adjusting for degradation. The degradation adjustment shall

be [redacted] The degradation adjustment shall be [redacted]

1.1.52 "Indemnified Parties" has the meaning given such term in Section 16.1.1.

1.1.53 "Indemnifying Party" has the meaning given such term in Section 16.1.1.

1.1.54 "Interconnection Agreement" means that certain Interconnection Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.55 "Interconnection Meters" has the meaning given such term in Section 8.2.

1.1.56 "Law" shall mean all constitutions, charters, laws, codes, ordinances, orders, judgments, decrees, injunctions, licenses, rules, permits, approvals, regulations and requirements of every Governmental Body (including OUC) having jurisdiction over the matter in question, whether federal, state or local, which may be applicable to any Party, as required by the context in which used, or to the Facility or OUC Interconnection Facilities, or to the use, manner of use, occupancy, possession, planning, licensing, design, procurement, construction, acquisition, testing, startup, operation, maintenance, management, control, addition, renewal, modification, replacement or disposal of the Facility and the OUC Interconnection Facilities or any portion or portions thereof.

1.1.57 "Lender" has the meaning given such term in Section 12.3.

1.1.58 "Market Price" shall mean the price established by Seller, or negotiated and agreed upon by the Parties, as the case may be, upon Seller's election pursuant to Section 2.3 with respect to any Further Extension, which shall become the Annual Capacity Charge for Capacity to be delivered by Seller during such Further Extension consistent with all other terms and conditions of this Agreement.

1.1.59 "Meters" means the Interconnection Meters and/or Customers' check-meters, as applicable.

1.1.60 "Minor Maintenance" shall mean maintenance events lasting not greater than [redacted] per occurrence, which have been scheduled and for which Purchaser and the other Customers have given consent in accordance with Section 6.4.

1.1.61 "MMBtu" means one million British thermal units, where one British thermal unit is the amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit from sixty (60) degrees Fahrenheit.

1.1.62 "MW" means megawatt.

1.1.63 "MWh" means megawatt-hour.

1.1.64 "NERC" means the North American Electric Reliability Council or successor organization.

1.1.65 "Non-Performing Party" has the meaning given such term in Section 11.1.

1.1.66 "Notice of Intent to Terminate" has the meaning given such term in Section 12.3.

1.1.67 "Off-Peak Period" means all the days of any given Contract Year other than the Peak Period days.

1.1.68 "Operating Agreement" means that certain Operating Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.69 "Operating Period" means the period from the beginning of the first Contract Year until the end of the last Contract Year.

1.1.70 "OUC" means Orlando Utilities Commission.

1.1.71 "OUC Interconnection Facilities" means the modifications to the Stanton Substation reasonably required for the receipt and delivery of Energy from the Facility onto the Grid consistent with Prudent Utility Practice.

1.1.72 "Ownership Agreement" means that certain Stanton Energy Center Combined Cycle Unit A Construction and Ownership Participation Agreement entered into among the Participants as of March 19, 2001.

1.1.73 "Participant" or "Participants" mean individually or collectively Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency (All Requirements Power Supply Project) and Seller.

1.1.74 "Parties" has the meaning given such term in the first paragraph of this Agreement.

1.1.75 "Peak Period" means for any given Contract Year the periods that include the days from January 1 through March 15, inclusive, May 15 through September 15, inclusive, and December 15 through December 31, inclusive.

1.1.76 "Permit" means any permit, license, approval, consent, waiver, authorization or other requirement in connection with the Project required from any Governmental Body under applicable Law.

1.1.77 "Person" means any individual, partnership, corporation, limited liability company, association, business, trust, Governmental Body or other entity.

1.1.78 "Planned Major Maintenance" means the Gas Turbine (GT) Combustor Inspection, the GT Hot Gas Path Inspection, and the GT Major Inspection, as these inspections are defined in the maintenance agreement with the GT vendor.

1.1.79 "Power Purchase Agreements" means this Agreement and those certain similar power purchase agreements between Seller and the other Customers respecting the delivery of Capacity and Energy from Seller's ownership share of the Capacity and Energy of the Facility.

1.1.80 "Prime Rate" means the prime rate of interest as published from time to time in the Wall Street Journal or such other comparable successor publication as the Participants may agree upon. The Prime Rate shall be calculated on the basis of a 365-day year for the actual

number of days that a payment, reimbursement or adjustment, as the case may be, has not been made.

1.1.81 "Project" means the Facility, the Facility Site and all other appliances, parts, instruments, appurtenances, accessories and other property that may be incorporated or installed in, or otherwise become part of, any of the foregoing.

1.1.82 "Prudent Utility Practice" means any of the practices, methods and acts engaged in, or approved by, a significant portion of the electric utility industry in the United States [redacted] or any of the practices, methods and acts, which, in the exercise of reasonable judgment in light of the facts known, or that reasonably should have been known, at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with applicable Laws, reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods and acts generally accepted in the United States and having due regard for current editions of the National Electrical Safety Code, the National Electric Code and other applicable electrical, safety and maintenance codes and standards, manufacturers' warranties and applicable Laws.

1.1.83 "Request for Energy" or "Schedule" means a request for the delivery of Energy made by Purchaser and the other Customers in accordance with the process provided in Section 6 and Appendix B for the Customers jointly to Schedule Energy, and any adjustments thereto made in accordance with Appendix B.

1.1.84 "RTO" means a regional transmission organization.

1.1.85 "Scheduled Commencement Date" means the date that is twenty-four (24) months after the receipt of the Site Certification and all other Permits to be obtained by the Customers that are necessary for Seller to commence construction, as such date may be extended under the provisions of Section 5.1, but in no event earlier than October 1, 2003.

1.1.86 "Scheduled Maintenance" means the removal of the Facility or a component thereof from service (which removal reduces the capability of the Facility to operate) to perform maintenance, overhaul, inspection, testing or repair work, as contemplated in Section 6.4.

1.1.87 "SEC Site" means the parcel of land in Orlando, Florida on which the fossil fired generating stations Stanton Unit # 1 and Stanton Unit #2 are located, including the parcel of land on which the Facility is to be located.

1.1.88 "Seller" has the meaning given such term in the first paragraph of this Agreement.

1.1.89 "Site Certification" means (i) the final approval by the applicable Governmental Body of the initial need for power determination and site certification permit applications pursuant to the Florida Electrical Power Plant Siting Act, and (ii) the receipt of the air construction (Prevention of Significant Deterioration) permit by OUC issued by FDEP pursuant to the delegated authority of the United States Environmental Protection Agency under the Clean Air Act Amendments of 1977.

1.1.90 "Technical Limits" means the limits and constraints relating to the operation and maintenance of the Facility, as described in Appendix A.

1.1.91 "Termination Payment" means the payment to be paid by a Defaulting Party to the Non-Defaulting Party under in Section 12.5.1.

1.1.92 "Test Energy" means (i) Energy produced by the Facility during testing of the Facility prior to the Commencement Date; and (ii) Energy produced by the Facility during periodic tests of the Facility's Capacity output capability following the Commencement Date.

1.2 Rules of Construction. In this Agreement, unless the context otherwise requires, the singular shall include the plural, the masculine shall include the feminine and neuter, and vice versa. The terms "include," "includes" and "including" shall be deemed to be followed by the words "without limitation." The term "month" refers to a calendar month, and any period measured by a "month" from a reference date refers to the period beginning on such reference date and ending on the same date of the next succeeding calendar month or, if no such date exists in the next succeeding calendar month, the last day of such next succeeding calendar month.

References to a Section, Table or Appendix shall be references to a Section of, Table of or Appendix to this Agreement unless specifically stated otherwise. A reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented and restated through the date as of which such reference is made. The term "or" is not exclusive, the term "shall" is mandatory and the term "may" is permissive. In the event that any index or publication referenced in this Agreement ceases to be published, each such reference shall be deemed to be a reference to a successor or alternate index or publication reasonably agreed by the Parties. Both Parties acknowledge that each was actively involved in the negotiation and drafting of this Agreement and that no law or rule of construction shall be raised or used in which the provisions of this Agreement shall be construed in favor of or against either Party because one is deemed to be the author thereof.

1.3 Consents. Whenever the consent or approval of either Party is required under this Agreement, such consent or approval shall not be unreasonably withheld, unless this Agreement provides that such consent or approval is to be given by such Party at its sole or absolute discretion or is otherwise qualified.

SECTION 2
TERM OF AGREEMENT

2.1 Initial Term.

2.1.1 This Agreement shall become effective as set forth in Section 3.1, and shall remain in full force and effect, subject to the early termination provisions set forth herein, through the later of (i) the last day of the month in which the tenth (10^{th}) anniversary of the Scheduled Commencement Date occurs or (ii) the last day of the month in which the tenth (10^{th}) anniversary of the Commencement Date occurs (the "Initial Term").

2.1.2 Notwithstanding the provisions of Section 2.1.1, the Initial Term shall terminate on (a) November 30, 2013 if Section 2.1.1 yields an end date falling between December 1, 2013 and April 30, 2014, inclusive, or (b) November 30, 2014 if Section 2.1.1 yields an end date that falls on or after May 1, 2014.

2.2 Extension of Initial Term. The Initial Term shall be automatically extended an additional five (5) years from the end of the Initial Term ("Extended Term"); *provided, however*, that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of the Initial Term by providing written notice of such election to Seller no later than the date that is three (3) years prior to the end of the Initial Term.

2.3 Extensions of Extended Term. The Extended Term shall be automatically extended three (3) successive periods of five (5) years each from the end of the Extended Term (the "Further Extensions"); *provided, however,* that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of any of (i) the Extended Term, (ii) the first Further Extension, or (iii) the second Further Extension, by providing written notice of such election to Seller no later than the date that is, respectively, three (3) years prior to the end of the Extended Term, three (3) years prior to the end of the first Further Extension, or three (3) years prior to the end of the second Further Extension, as the case may be; *provided, further,* that with respect to each Further Extension, Seller shall have the right to establish the Annual Capacity Charge for such Further Extension based on Seller's then-current assessment of market conditions by providing Purchaser written notice of the new proposed Annual Capacity Charge no later than the date that is three and one-half (3 1/2) years prior to the date that such Further Extension period is scheduled to begin, subject to Purchaser's right to request that Seller negotiate in good faith to agree on any other price that Purchaser believes in good faith reflects current market conditions.

2.4 Survival. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to satisfy the terms and conditions of this Agreement and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing either Party pursuant to this Agreement, repayment of principal and interest associated with security funds, and the indemnifications specified in this Agreement.

SECTION 3
CONDITIONS PRECEDENT

3.1 Condition Precedent to Effectiveness. The Parties agree and acknowledge that this Agreement shall be effective only upon the date on or before which both of the following have occurred (such date, the "Effective Date"): (i) the execution and delivery of the Ownership Agreement and the Operating Agreement and all other Collateral Documents; and (ii) the acknowledgment of the Participants' satisfaction of the foregoing condition and the accuracy of the cross-references to the Collateral Documents contained in this Agreement.

3.2 Conditions Precedent to Obligations. Notwithstanding any provisions of this Agreement to the contrary, the obligations of the Parties to this Agreement shall be subject to the fulfillment of each of the conditions (or the waiver in writing of such conditions by the respective Party or Parties) set forth in Article 8 of the Ownership Agreement.

SECTION 4
SALAE AND PURCHASE

4.1 Capacity Delivery and Payment. Subject to the terms and conditions of this Agreement, during the Operating Period, Seller agrees to deliver and sell to Purchaser and Purchaser agrees to receive and purchase from Seller up to [redacted] of the Actual Capability of the Facility in accordance with the following provisions:

4.1.1 The Capacity payment (the "Capacity Payment" or "CP") in respect of each month during the Operating Period shall be an amount equal to: the product of the Annual Purchaser's Capacity Nomination (expressed in kilowatts) multiplied by the Annual Capacity Charge. For any partial month during the Operating Period, the Capacity Payment shall equal the amount determined pursuant to the formula set forth in the preceding sentence multiplied by a fraction, the numerator of which is the number of days of such partial month within the Operating Period, and the denominator of which is the total number of days in such month. If the Annual Purchaser's Capacity Nomination changes during a month, then the Capacity Payment for such month shall be equal to the product of the Annual Capacity Charge multiplied by the sum of the two results obtained: (i) first by multiplying the old Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) prior to the time of the change over the total number of days in the month; and (ii) second by multiplying the new Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) after the time of the change over the total number of days in the month. The Capacity Payment shall be paid by Purchaser to Seller in accordance with Section 9.1. Notwithstanding the above, if during the first three (3) months of the Operating Period any Governmental Body shall prohibit the Facility from operating because of Seller's failure to obtain, prior to the Commencement Date any Permit required by Law for Seller to operate the Facility, then Purchaser's obligation to make Capacity Payments shall be suspended until the earlier of: (i) the lifting of such prohibition; or (ii) the date that is three (3) months after the Commencement Date.

4.1.2 The initial Demonstrated Capability of the Facility shall be established in accordance with the Capacity testing procedure set forth in Appendix C. Following the first anniversary of the Commencement Date, Seller shall perform Capacity tests [redacted] pursuant to the testing procedures set forth in Appendix C, during the Summer and Winter

periods as defined by FRCC; *provided, however*, that Seller shall be entitled to a [redacted] period of maintenance that does not affect calculation of Actual Availability of the Facility (which period shall be prior to any such Capacity test from 9 p.m. Friday to 7 a.m. Monday, unless OUC, in its sole discretion, agrees otherwise). In addition, Seller may retest when a repair or modification of the Facility, or a corrected or improved operational or maintenance activity, results in an increase in the Capacity of the Facility (including adjustments made during initial shakedown), provided that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) is at least one hundred and one percent (101%) of the last Demonstrated Capability test amount. Should any test or retest conducted pursuant this Section 4.1.2 indicate that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) has changed by an amount equal to or greater than one percent (1%) of the last Demonstrated Capability test amount, the Demonstrated Capability shall be reset at such actual full load output for purposes of determining the Capacity Payment as of the time the test is completed; *provided, however*, that if the test is performed during a Force Majeure event and such Force Majeure event resulted in the reduction of the Demonstrated Capability, the Capacity Payment shall not be reduced thereby until the end of the [redacted] period described in the last paragraph of Section 4.1 below.

4.1.3 Seller shall conduct additional tests as required by the FRCC or as requested by Purchaser pursuant to Purchaser's legal or contractual obligations with third parties; *provided, however*, such additional tests shall be for informational purposes and shall not be used to reset the Demonstrated Capability or otherwise determine the Capacity Payment under this Agreement.

4.1.4 Beginning with the sixth (6^{th}) Contract Year and ending with the tenth (10^{th}) Contract Year, the Customers shall have the irrevocable right to jointly reduce the total of their combined Annual Purchaser's Capacity Nominations, for the remainder of the Initial Term and any Extended Term or Further Extensions, by either twenty-five (25) MW or fifty (50) MW (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) per year; *provided, however*, that such combined total of the Annual Purchaser's Capacity Nominations may not be reduced by more than 200 MW in the aggregate. Purchaser must give Seller notice of any such reduction elected by Purchaser not later than three (3) years prior

to the commencement of the Contract Year in which such reduction shall occur; *provided, however,* that such notice shall be effective if and only if either it is made jointly with the other Customers or the other Customers give Seller a similar notice under their respective Power Purchase Agreements with all such notices together satisfying the above criteria; *provided, further,* that such notices shall specify any changes in the percentage of the Annual Purchaser's Capacity Nomination to be purchased by Purchaser under Section 4.1.1 and by the other Customers under the corresponding provisions of their respective Power Purchase Agreements.

Notwithstanding the foregoing provisions of this Section 4.1, if and to the extent that a Force Majeure event affects Seller's ability to deliver and sell to Purchaser the Capacity of the Facility or any portion thereof, Seller shall be excused from any delay in performing or failure to perform any or all of such obligations (and in this regard, the Parties shall follow the procedures contemplated in Section 11.1); *provided, however,* that notwithstanding such reduction or elimination of the Actual Capability of the Facility, Purchaser shall continue to pay Seller the full Capacity Payment attributable to the [redacted] following the date of Seller's notification to Purchaser of any such Force Majeure effect; *provided, further,* that if the effect of a Force Majeure event lasts for longer than [redacted] then Purchaser shall not be required to make Capacity Payments attributable to any continued period of Force Majeure declaration after the end of such [redacted] period, but Purchaser must resume making Capacity Payments when Seller declares the Force Majeure period over and resumes its obligation for delivery of Energy under this Agreement; *and provided, further,* that the Capacity Payment relief contemplated in the immediately preceding clause shall not apply if the Force Majeure event affecting Seller resulted from a failure of Purchaser or another Customer to fulfill its obligations under this Agreement or any of the Collateral Documents; *and provided, further,* that a Force Majeure event that affects Purchaser's ability to receive Energy from the Facility shall not excuse Purchaser's obligation to make Capacity Payments, except solely to the extent provided for in Section 5.1.3 if and to the extent such provision is applicable.

4.2 Energy Delivery and Payment. Subject to the terms and conditions of this Agreement and, in particular, subject to the provisions of Section 6 and Appendix B, Seller shall sell and deliver, and Purchaser shall purchase and receive, during the Operating Period, Energy requested by Purchaser in a Request for Energy, as well as Energy generated by associated ramp up and ramp down of the Facility and Test Energy; *provided, however,* that Purchaser shall not be required to make any payments for Test Energy produced prior to the Commencement Date. The Customers shall pay for and supply all fuel associated with the Customers' Request for Energy in accordance with the provisions of Section 3.2 of the Operating Agreement. The Energy payment (the "Energy Payment" or "EP") in respect of each month shall be the sum of four (4) components: a variable O&M component for operation on natural gas, a variable O&M

component for operation on fuel oil, a start-up component, and a fuel component for Energy delivered from Alternate Resources. The components of the Energy Payment shall be calculated as follows:

4.2.1 Variable O&M Component—Natural Gas. The variable O&M component for operation on natural gas shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} [(DENG_{ij} \times VOMR) + HVOM_{ij}]$$

Where:

$DENG_{ij}$ is Delivered Energy in MWh (other than Test Energy prior to the Commencement Date) from the Facility produced with natural gas during hour j of day i; *provided, however,* that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with natural gas; and

VOMR is the variable O&M rate (in $/MWh), which shall be [redacted]; and

HVOM is the hourly variable O&M rate (in $ per hour) as determined from Table A and its accompanying Notes applicable for hour j of day i during which the Facility is operating on natural gas and which is applicable only when $DENG_{ij}$ is > 0.

Table A

Hourly Variable O&M Charges for Operation on Natural Gas

Annual On-Line Factor	Combined Hourly Variable O&M Rate (in $ per hour) for all Customers (see Notes below)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table A:

1) The Hourly Variable O&M Rate in Table A represents the rate applicable for the Annual Purchaser's Capacity Nominations of all Customers. The actual Hourly Variable O&M Rate for Purchaser for an hour in a particular Contract Year shall equal the product of the applicable rate from the table for such Contract Year multiplied by the ratio of Purchaser's portion of the Request for Energy for such hour over the total Request for Energy for such hour.

2) The Hourly Variable O&M Rate for a Contract Year shall be interpolated between the values shown in Table A when the Annual On-Line Factor for the previous Contract Year falls between the specific percentages shown on Table A. For example, with respect to an Annual On-Line Factor of [redacted], the Hourly Variable O&M Rate shall be [redacted]

3) The dollar amounts shown in Table A are expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

4) The dollar amounts in Table A represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Customers under the Power Purchase Agreements. If Purchaser and the other Customers elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table A shall be proportionately reduced commensurate with such Capacity reduction.

5) The Annual On-Line Factor shall be calculated for each Contract Year, as follows:

Annual On-Line Factor = SH/ (PH – OH)

Where:

SH is the number of hours that the Customers Schedule and Seller delivers Energy in a Contract Year; and

PH is the number of hours in a Contract Year; and

OH is the number of hours in a Contract Year during which (i) the Facility is unavailable due to a forced outage or due to a maintenance outage that Seller has scheduled pursuant to Section 6.4 or, if applicable, that is a permitted [redacted] under Section 4.1.2, and (ii) Seller does not deliver from an Alternate Resource.

6) For the first Contract Year, all monthly Energy billings will be made assuming an Annual On-Line Factor of [redacted] The rate shall be determined annually for each Contract Year based on the Annual On-Line Factor for the previous Contract Year. At the end of each Contract Year, the Annual On-Line Factor for such Contract Year shall be calculated and the Hourly Variable O&M charges for such Contract Year shall be recalculated using such Annual On-Line Factor for such Contract Year. A true-up payment or refund shall be made to adjust the amounts collected by Seller from Purchaser during each Contract Year to the amount computed by Seller using such Annual On-Line Factor for such Contract Year. Any true-up payments shall be included on an invoice as soon as reasonably practicable following the end of the applicable Contract Year.

4.2.2 Variable O&M Component—Fuel Oil. The variable O&M component for operation on fuel oil when firing the gas turbines shall be calculated as follows:

$$\sum_{i=\text{ Days in the Month}} \sum_{j=\text{ Hours in the Day}} [(DEFO_{ij} \times VOMRFO) + HVOMFO_{ij}]$$

Where:

$DEFO_{ij}$ is Delivered Energy (other than Test Energy prior to the Commencement Date) produced with fuel oil during hour j of day i; provided that if the Facility uses both natural gas and fuel oil in a

given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with fuel oil; and

VOMRFO is the variable O&M rate (in $/MWh) for Energy produced with fuel oil, which shall be [redacted] subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations); and

HVOMFO is the hourly variable O&M rate (in $ per hour) for hour j of day i during which the Facility is Operated on fuel oil, which rate shall be [redacted] subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations), and which is applicable only when $DEFO_{ij}$ is > 0.

4.2.3 Start-up Component. The start-up component shall be calculated as follows:

GTS x SUR

Where:

GTS is the number of gas turbine starts required to meet a Request for Energy (other than for Test Energy prior to the Commencement Date) where the amount of Energy delivered from any single gas turbine increases from zero to an amount greater than zero; *provided, however*, that the calculation of GTS shall not include: (i) any starts required to resume delivery to Purchaser due to an interruption caused by a forced outage, or (ii) any starts initiated by Seller in order to make third party sales in any given hour where the Facility would otherwise not have been started in such hour to meet a Request for Energy.

SUR is the Start-up Rate (in $ per start) for each gas turbine as determined from Table B below and its accompanying Notes:

TABLE B

Start-Up Rates

Cumulative Number of Start-ups per Gas Turbine per Contract Year	Combined Start-up Rate per Start per Gas Turbine for all Customers (see Notes)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table B:

1) The SUR in Table B represents the rate applicable to all Customers for each start-up during a Contract Year. [redacted] and the combined rate among all Customers participating in each subsequent start-up during such Contract Year shall be as identified in the Table B. The actual SUR for Purchaser (in $ per start) for any such start-up shall equal the quotient of the applicable rate from the Table B divided by the number of Customers participating in the Request for Energy that requires the start-up (and in which Purchaser is one of those Customers); *provided, however,* Purchaser will not have to pay for start-ups in which it does not participate.

2) The SUR is expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

3) The dollar amounts in Table B represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Participants under the Power Purchase Agreements. If the Participants elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table B shall be proportionately reduced commensurate with such Capacity reduction.

4.2.4 O&M Rate Adjustment. The rates in Sections 4.2.1, 4.2.2 and 4.2.3 shall be increased or decreased based on good faith negotiation of the Parties (in accordance with Section 18) to reflect and include any actual increase or decrease in Seller's costs of operating the Facility that is caused by any mutually agreed-upon modification or design change or any actual increase or decrease in Purchaser's or another Customers' charges for providing any services to Seller.

4.2.5 Energy Payment for Delivery from Alternate Resources.

4.2.5.1 If Seller elects to deliver Energy from Alternate Resources pursuant to Section 4.4, then the variable O&M component and the start-up component of the Energy Payment shall be calculated in accordance with Sections 4.2.1 and 4.2.3, respectively, for such Alternate Resource Energy as if it were delivered from the Facility. In addition, the fuel component for the Energy delivered from Alternate Resources shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} (MDE_{ij} \times HR_{ij} \times FRP_{ij})$$

Where:

MDE_{ij} = Scheduled Energy in MWhs delivered from an Alternate Resource during hour j of day i;

when the Facility is unavailable, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs;

when the Facility is available, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or

less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs; and

FRP_{ij} = the fuel rate proxy for an hour calculated in dollars per MMBtus in accordance with the applicable provisions of either Section 4.2.5.2 or 4.2.5.3.

4.2.5.2 If the Fuel Supply Agent has not already scheduled the transportation of gas to the Facility to meet the Customers' Schedules for the hour during which Seller elects to deliver the Scheduled Energy from Alternate Resources, then following notification from Seller of its election to deliver the Scheduled Energy from Alternate Resources, Seller shall be obligated to obtain the necessary quantities of gas and necessary gas transportation capacity to accommodate any portion of the Schedule that Seller has elected to satisfy from Alternate Resources. During periods that Seller elects to deliver Energy from Alternate Resources, the Fuel Supply Agent shall make available transportation capacity, within constraints of the pipeline tariffs and operational procedures in effect at the time and at no additional cost to the Fuel Supply Agent, in the amount determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtus) shall be equal to the sum of: (i) [redacted] and (ii) the applicable firm gas transportation variable cost associated with deliveries to the Facility under such Participant's firm transportation agreement(s). All risks of gas supply and transportation interruption to accommodate deliveries of Energy from Alternate Resources shall be borne by Seller.

4.2.5.3 If the Fuel Supply Agent has already scheduled the transportation of gas to the Facility to meet the Customers' Schedules by the time Seller notifies Purchaser of Seller's election to deliver the Scheduled Energy from Alternate Resources, then at Seller's election:

(i) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to revise its scheduled transportation of gas to the Facility to provide for the delivery of the gas to Seller at any alternate delivery point designated by Seller that is available under the Customers' firm transportation agreement(s). The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time, and the Fuel Supply Agent shall not be required to incur any additional cost as a result of the revision of the schedule of transportation of gas to the alternate delivery point. The amount of scheduled transportation of gas to be delivered to the alternate delivery point shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtu) shall be [redacted] or

(ii) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to remarket to third parties the gas that has been scheduled for delivery to the Facility on the best terms possible under the circumstances. The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time. The amount of scheduled transportation of gas to be

remarketed to third parties shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in from paragraph 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has directed the Fuel Supply Agent to remarket the gas under these circumstances, the FRP (in $ per MMBtu) shall be [redacted]

4.3 Availability Guarantee.

4.3.1 Seller guarantees that the Actual Availability of the Facility for [redacted] of each Contract Year will equal or exceed [redacted] ("Availability Guarantee"); *provided, however*, that (i) the [redacted] of operation following the Commencement Date shall be excluded from the Availability Guarantee, (ii) if and to the extent that a Force Majeure event affects Seller's ability to achieve the Availability Guarantee, other than in the case of Equipment Breakdown, Seller shall be excused from the Availability Guarantee (and in this regard the Parties shall follow the procedures contemplated in Section 11), and (iii) to the extent that the Facility is fired with fuel oil in excess of [redacted] per combustion turbine unit in any Contract Year in order to meet Purchaser's Request for Energy, then for every additional [redacted] that the Facility is fired using fuel oil, the lower end of the Availability Guarantee range, and the factors [redacted] in Sections 4.3.5.1 and 4.3.5.2, shall be reduced by [redacted] each, which reductions shall remain in effect until the next Planned Major Maintenance occurs. If either combustion turbine is not fired on oil during any Contract Year for the same number of hours as the other combustion turbine, then for purposes of calculating the adjustment to the Availability Guarantee, each combustion turbine will be deemed to have been fired on oil during such Contract Year for a number of hours that is equal to one

half of the summation of the number of hours that each combustion turbine was actually fired on oil during such Contract Year.

4.3.2 In each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, Seller shall be entitled to an availability incentive payment from Purchaser ("Availability Incentive Payment") equal to (a) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Peak Period, and/or (b) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Off-Peak Period.

4.3.3 The Actual Availability for the Peak Period of each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, shall be calculated as follows and then rounded up or down to the nearest tenth of a percentage point [redacted] *provided, however*, that such Actual Availability shall not exceed one (1.00):

Actual Availability = (PH-OH -EDH+EMH+ARDH)/PH

Where: "PH" (or "Period Hours") shall equal the hours in the Peak Period of such calendar year;

"OH" (or "Outage Hours") in the Peak Period of such Contract Year means all hours the Facility is unavailable for operation; *provided, however*, that OH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day;

"EDH" (or "Equivalent Derated Hours") in the Peak Period of such Contract Year means the summation of EDH for each hour during the Peak Period; *provided, however*, that EDH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day. In each hour for which the EDH of such hour must be

calculated, EDH for the hour will equal (Guaranteed Output - Actual Capability)/Guaranteed Output;

"EMH" (or "Excused Maintenance Hours") shall equal hours that Seller has scheduled maintenance on the Facility in the Peak Period of such calendar year pursuant to Section 6.4 and, if applicable, the [redacted] of pre-testing maintenance allowed prior to a Capacity test under Section 4.1.2; *provided, however*, that in any hour EMH must be zero if there is no Outage Hour in such hour; and

"ARDH" (or "Alternate Resource Delivery Hours") shall equal the number of hours that Seller delivers Energy to Purchaser from Alternate Resources in the Peak Period of such Contract Year to fully or partially make up for shortfalls caused by Facility outages or derates. Seller will not receive any credit for ARDH in any entire day unless Seller is able to deliver at least partial Energy in each hour of such day that Purchaser Schedules Energy, in which case Seller will receive ARDH credit for each hour of the day based on the lowest ratio during any hour of such day of Delivered Energy to Scheduled Energy.

4.3.4 The Actual Availability for the Off-Peak Period of each Contract Year shall be calculated in a fashion similar to Section 4.3.3, substituting "Off-Peak Period" for "Peak Period" where it appears in Section 4.3.3.

4.3.5 In the event that the Actual Availability during the Peak Period or Off-Peak Period, or both, of any given Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, is less than the lower end of the Availability Guarantee range, then Purchaser shall be entitled to receive availability damages ("Availability Damages") from Seller as Purchaser's sole and exclusive remedy for Seller's failure to delivery Capacity and Energy from the Facility due to the unavailability of the Facility.

4.3.5.1 The Availability Damages for the Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Peak Period of any Contract Year = [redacted]

[redacted]

4.3.5.2 The Availability Damages for the Off-Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Off-Peak Period of any Contract Year = [redacted]

4.3.5.3 In both of Sections 4.3.5.1 and 4.3.5.2, the factors [redacted] and [redacted] shall be adjusted for the use of fuel oil pursuant to Section 4.3.1(iii), if applicable.

4.3.6 As soon as reasonably practicable after the first month following the Commencement Date, and each month thereafter, Seller shall submit to Purchaser a statement setting forth in reasonable detail the actual availability of the Facility during the prior month, including the underlying availability data.

4.3.7 As soon as reasonably practicable following each Contract Year, Seller shall submit to the Purchaser a statement setting forth the Actual Availability for the preceding Contract Year together with a calculation of the net amount of any Availability Incentive Payment due to Seller or Availability Damages due to the Purchaser for the preceding Contract Year based on the foregoing calculations, as applicable, with respect to the Peak Period and Off-Peak Period of such Contract Year. Within ten (10) Business Days of (a) receipt of such statement, Purchaser shall pay any Availability Incentive Payment due to Seller by wire transfer in immediately available funds, or (b) transmittal of such statement, Seller shall pay any Availability Damages due to Purchaser by wire transfer in immediately available funds.

4.4 Alternate Resources. In any hour in which the Facility is unavailable, Seller may continue to make deliveries of Energy in the full amount Scheduled by Purchaser from non-Facility sources (including, but not limited to, generating units on Seller's or its Affiliates' systems and Energy purchases available to Seller) ("Alternate Resources") to replace the Energy that would have been provided by the unavailable Facility. In any hour in which the Facility is available, Seller may choose to make deliveries of Energy in the full amount Scheduled by Purchaser, or any portion thereof, from Alternate Resources to replace the Energy that would

have been provided by the available Facility; *provided, however*, that if the Facility is available, Seller must maintain the Facility on-line and committed at least at the Facility's minimum load, and Purchaser may Schedule spinning reserves from the Facility, all in accordance with Appendix B. Seller must deliver Energy from Alternate Resources to Purchaser at an unconstrained point on the Grid, and if Seller is making such delivery at a time when the Facility is unavailable, then Seller will purchase Firm Transmission Service for such delivery to the extent that such Firm Transmission Service is available for the Alternate Resource Energy from the point of its acquisition by Seller to the unconstrained point on the Grid. In utilizing Alternate Resources, Seller shall comply with the notice requirements of Section 3 of Appendix B.

4.5 Purchaser's Right to Capacity and Energy. During the Operating Period, Purchaser shall have the first call to purchase Seller's share of the Capacity and Energy generated by, and Ancillary Services associated with, the Facility (other than the reductions in Capacity elected jointly by the Customers pursuant to Section 4.1.4); *provided, however*, that (i) subject to Purchaser's right to Capacity and Energy under this Agreement and the Operating Agreement, Seller may make sales of any Capacity and Energy generated by, and Ancillary Services associated with, Seller's Equity Capacity when such Capacity and Energy is not Scheduled by Purchaser, and (ii) in the event that Seller determines that the Facility is capable of delivering Energy to the Grid prior to the Scheduled Commencement Date, Seller shall have the option of either (a) utilizing the Capacity and Energy generated by, and Ancillary Services associated with, its percentage ownership share of the Facility prior to the Scheduled Commencement Date for sales to third parties by delivering written notice of its election of this option thirty (30) days prior to the anticipated Commercial Operation Date, in which event Purchaser shall not make Capacity Payments until the later of the Scheduled Commencement Date or the Commencement Date, or (b) initiating delivery of Capacity and Energy to Purchaser under this Agreement on the Commencement Date. If Seller makes sales of either or both Capacity and Energy to third parties under Section 4.5(ii)(a) at a time when the Scheduled Commencement Date has passed but the Commencement Date has not yet occurred, then Seller will pay to Purchaser the portion, if any, of the proceeds of such sales that Seller actually receives.

SECTION 5
SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY

5.1 Scheduled Delivery.

5.1.1 Seller anticipates that, the Facility will achieve the Commencement Date by the Scheduled Commencement Date and shall be fully capable of reliably producing the power and Energy to be provided under this Agreement to Purchaser at the Delivery Point; *provided, however*, that if and to the extent that a Force Majeure event affects Seller's ability to timely comply with the foregoing guarantee, the Scheduled

Commencement Date shall be extended by the amount of time Seller reasonably needs to remedy the effects of the Force Majeure that prevented Seller's performance (and in this regard, the Parties shall follow the procedures contemplated in Section 11).

5.1.2 In the event that Seller fails to achieve the Commencement Date by the date that is two (2) years after the Scheduled Commencement Date, then either (i) Seller shall have the right to simultaneously terminate all of the Power Purchase Agreements by delivering written notice of such election to Purchaser and the other Customers ("Seller's Termination Notice"), or (ii) Purchaser may terminate this Agreement, if and only if each of the other Customers also terminates contemporaneously its respective Power Purchase Agreement for the same reason, by delivering written notice of such election to Seller (collectively, together with the other Customers' similar notices, "Purchasers' Termination Notices"). Within ten (10) Business Days of the date of Seller's Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Seller's Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2. Within ten (10) Business Days of the date of Purchasers' Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Purchasers' Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2.

5.1.3 In the event that Seller's failure to achieve the Commencement Date by the Scheduled Commencement Date is attributable to, in whole or in part, the failure of any Customer to meet any of their respective obligations under this Agreement or their respective Power Purchase Agreements or the Collateral Documents, then (a) the Scheduled Commencement Date shall be extended for such period of Purchaser's or such other Customer's failure, and (b) Purchaser shall make Capacity Payments (assuming a Demonstrated Capability of [redacted] MW and an Availability Performance of [redacted] for the period affected by the delay) beginning as of the initial Scheduled Commencement Date (without any extension); *provided, however*, that Purchaser shall not be required to make any Capacity Payments under this Section 5.1.3 to the extent the delay in achieving the Scheduled Commencement Date is attributable to the concurrent failure of

Purchaser or such other Customers and Seller (where such concurrent failures are not co-extensive, such relief from Capacity Payments shall apply only during the period of time that Seller's failure to meet its obligations contributed to the delay); *provided, further*, that in the event Purchaser's failure to meet its obligation was the result solely of a Force Majeure event that prevented Purchaser's timely completion of such obligation, then Purchaser will be excused from having to make Capacity Payments as contemplated in Section 5.1.3(b) for the [redacted] after the Scheduled Commencement Date (without benefit of any extension thereof allowed under this Agreement), but if the Commencement Date does not occur within such [redacted] period, then Purchaser shall recommence making Capacity Payments starting at the beginning of the [redacted] day after the Scheduled Commencement Date and thereafter continue making Capacity Payments as contemplated in Section 5.1.3(b).

5.2 Conditions to Commencement. Seller will notify Purchaser of the date when the Facility has achieved the following criteria (the "Commencement Date"), which notice will be accompanied by reasonable documentation evidencing satisfaction or occurrence of each of the following; *provided, however,* that Seller shall not be precluded from making third-party sales, in accordance with Section 4.5, of its percentage ownership share of Capacity and Energy from the Facility notwithstanding whether any or all of the following criteria have been met in whole or in part:

5.2.1 successful completion of required testing of the Facility has occurred for purposes of financing, project operation, air permitting, Purchaser's planning and reporting, and manufacturers' warranties, including establishment of the initial Demonstrated Capability of the Facility as contemplated in Section 4.1.2;

5.2.2 the Facility has completed [redacted] successful start-ups without experiencing any abnormal operating conditions and has generated continuously for a period of not less than [redacted] while synchronized to the Grid at a net Capacity output of at least [redacted] of the Demonstrated Capability (adjusted for ambient conditions) without experiencing any abnormal operating conditions;

5.2.3 the Facility is in compliance with the Interconnection Agreement, either is capable of operation in the AGC mode or is capable of responding to manual load change instructions, has achieved initial synchronization with the Grid, and has demonstrated the reliability of its communications

systems and communications with the Florida Municipal Power Pool Energy Control Center located in the OUC Pershing Operations Building (or the replacement for such control center if the Customers decide to have their generation control performed at a different location); and

5.2.4 certificates of insurance coverages and/or insurance policies required of Seller have been obtained and submitted to Purchaser as required by Section 28.

5.3 Test Energy. Seller shall coordinate the production and delivery of Test Energy with Purchaser. Purchaser shall cooperate with Seller to facilitate Seller's testing of the Facility, provide the fuel necessary to conduct testing, and shall accept Test Energy delivered to Purchaser in accordance with the provisions of Section 4.2.

SECTION 6
REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE

6.1 Communicating Requests for Energy. Purchaser shall have the right to request deliveries of Energy by providing a Request for Energy to Seller in accordance with this Section 6 and Appendix B; *provided, however*, that Purchaser and the other Customers shall coordinate their Scheduling requirements by jointly submitting a single Request for Energy that covers all of their respective requirements on any given day.

6.1.1 The Customer's joint Requests for Energy may request the full output of the Facility, reduced by those amounts, if any, that Customers jointly elect to subtract from the Capacity available to Customers pursuant to the process provided in Section 4.1.4 of this Agreement and the other Power Purchase Agreements. If the Customer's joint Request for Energy is for less than the full output of the facility, then the request shall be deemed to be a Request for Energy first from Purchaser's Equity Capacity and, if such Equity Capacity is not sufficient, then from Purchaser's purchased Energy under this Agreement.

6.1.2 The Parties hereby consent to the recording of all conversations on the telephone lines used for communicating Requests for Energy and related notices and instructions in accordance with customary industry practice. The contents of such recordings shall be definitive.

6.2 Limitations on Requests for Energy. Notwithstanding anything to the contrary in this Agreement, any Request for Energy, operation in the AGC mode or operation in response to a Capacity Emergency that would require the Facility to operate in a manner inconsistent with the Technical Limits, Prudent Utility Practice or applicable Law and Permit requirements shall

be deemed not to comply with the requirements and limitations set forth in this Section 6. If and when a Customers' Request for Energy does not comply with the requirements and limitations of this Section 6 by reason of the previous sentence, Seller will notify Customers of such noncompliance promptly after Seller realizes that the Request for Energy is noncompliant and will modify Customer's Request for Energy to make it consistent with the Technical Limits, Prudent Utility Practice and all applicable Laws and Permits to the extent it is reasonably possible to do so consistent with such standards.

6.3 Operation of the Facility. Seller shall operate and maintain the Facility in accordance with this Agreement, Prudent Utility Practice, the Technical Limits and all applicable Laws and Permit requirements. Any emission allowances required for operation of the Facility as contemplated in this Agreement shall be provided in accordance with the applicable provisions of the Operating Agreement.

6.4 Scheduled Maintenance. Seller agrees to schedule Planned Major Maintenance during the Off-Peak Period, or to obtain Purchaser's consent to schedule such maintenance during the Peak Period. Seller will submit to Purchaser an annual maintenance projection and will make reasonable efforts to coordinate the scheduling of such Planned Major Maintenance with Purchaser, including estimated start dates and return to service dates. Seller must seek the consent of OUC, acting for itself and on behalf of the other Customers (which Purchaser hereby authorizes) in scheduling of any Minor Maintenance; *provided, however*, that Purchaser guarantees Seller will be afforded a minimum of [redacted] such Minor Maintenance events distributed approximately evenly over the Off-Peak Period, with a maximum of [redacted] such Minor Maintenance events during any year; *provided, further,* that requests for Minor Maintenance events during the period from May 15 through September 15 may be granted or withheld in [redacted].

6.5 Transmission Operator. Coordination with an RTO regarding security and reliability of the Grid as it relates to the Facility, or any other entity, having control over the security and reliability of the Grid shall be the responsibility of Seller as the operator of the Facility. Coordination with an RTO, or other entity, having balancing authority or scheduling authority over the Facility should be handled by Purchaser for any schedules to Purchaser from the Facility and by Seller for any other schedules from the Facility. Any orders, directives or operating requirements that Seller is required to follow by Law imposed on Seller by an RTO, or any other entity, having control over the security and reliability of the Grid shall take precedence over this Agreement. To the extent the requirements of such order, directive or operating requirement necessarily prevent Seller from fulfilling its obligations under this Agreement, Seller shall be relieved of its obligations hereunder. To the extent the requirements of such order, directive or operating requirement conflict with Seller's fulfillment of its obligations hereunder, the rights and obligations of the Parties hereunder shall be adjusted as necessary to comply with such orders, directives or operating requirements.

SECTION 7
INTERCONNECTION AND TRANSMISSION

7.1 Interconnection Facilities. The Parties shall execute an Interconnection Agreement pursuant to applicable interconnection policies and procedures of OUC. The Interconnection Agreement shall contain terms and conditions governing the interconnection and parallel operation of the Facility with the Grid.

7.2 Delay in Interconnection. Purchaser shall cause OUC to complete the OUC Interconnection Facilities and ensure that the Grid is capable of providing and receiving Energy by the date that is [redacted] prior to the anticipated Commercial Operation Date, but in no event earlier than [redacted] By the date that Seller has completed the collector bus and the 230 kv line to the OUC Interconnection Facilities, but no earlier than the date that is [redacted] prior to the anticipated Commercial Operation Date, OUC shall provide service to the Facility for the purposes of engineering and testing the collector bus and other systems by either providing 230 kv service at the 230 kv Interconnection Point or by providing service to the 4160 kv SWGR bus. If for any reason, other than the fault of Seller, OUC fails to complete the OUC Interconnection Facilities and/or if the Grid is not capable of providing and receiving Energy (as determined by OUC and as supported by reasonable documentation) in accordance with the preceding sentence and, as a result, OUC cannot accommodate Seller's start-up and testing of the Facility (such a delay, an "IF/Grid Delay"), then the Scheduled Commencement Date shall be extended by that period of time equal to the IF/Grid Delay; *provided, however*, that Purchaser shall make the Capacity Payments as provided in Section 5.1.3(b); *provided, further*, that if Seller would not have been capable of delivering Energy from the Facility to the OUC Interconnection Facilities, even in the absence of an IF/Grid Delay, on the original anticipated Commercial Operating Date ("Seller's Delay"), then extension of the Scheduled Commencement Date and the date on which Purchaser is obligated to make Capacity Payments shall be adjusted by the period of time of Seller's Delay.

7.3 Transmission.

7.3.1 Purchaser shall be responsible for all costs associated with and for making all necessary transmission arrangements for Delivered Energy, including tagging and any required Ancillary Services, with the transmission service provider for delivery from and beyond the Delivery Point.

7.3.2 Seller shall bear all costs and losses and shall be responsible for making all arrangements for transmission service, including tagging and any required ancillary services, with respect to delivery of Capacity and Energy from an Alternate Resource to an unconstrained point on the Grid.

SECTION 8
RISK OF LOSS; METERING

8.1 Risk of Loss. Delivered Energy sold pursuant to this Agreement shall be made available to Purchaser at the Delivery Point. Risk of loss with respect to all such Energy shall pass to Purchaser when such Delivered Energy is made available to Purchaser at the Delivery Point. Risk of loss with respect to the natural gas supply utilized to deliver Energy pursuant to this Agreement shall pass to Seller when such natural gas supply is made available to Seller at the Gas Delivery Point. For purposes of this Agreement, and except to the extent expressly limited in this Agreement, Purchaser shall bear all risk of all occurrences of any nature (including Force Majeure or any other event beyond the reasonable control of either Party) affecting any interconnection facilities, substations, transmission lines and other facilities on Purchaser's side of the applicable Delivery Point and the Gas Delivery Point.

8.2 Place of Measurement. All Energy from the Facility shall be measured by the Facility's meters (such meters collectively, the "Interconnection Meters"), and the Energy delivered from the Facility shall be the Interconnection Meters' readings of the quantities of Energy, reduced by an amount equal to the applicable Energy quantity necessary to compensate for the loss, if any, between the Interconnection Meters and the Delivery Point.

8.3 Testing and Calibration of Interconnection Meters. Seller shall inspect and calibrate the Interconnection Meters at least once a year. Seller shall give Purchaser reasonable advance notice of any inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to have a representative present at such inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to require, at Purchaser's expense except as set forth in Section 8.4, a test of any of the Interconnection Meters not more often than once every twelve (12) months. If any Interconnection Meter is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such Interconnection Meter shall be deemed accurate, but Seller shall use its reasonable efforts to adjust such Interconnection Meter immediately and accurately. In the event that any Interconnection Meter is found to be inaccurate by more than one half of a percent (0.5%), Energy delivered at the corresponding Delivery Point shall be measured by reference to Customers' check-meters, if installed and registering accurately, or the meter readings at the Delivery Point for the period of inaccuracy shall be adjusted as far as can be reasonably ascertained by Seller from the best available data from both Parties. If the period of the inaccuracy cannot be ascertained reasonably, any such adjustment shall be for a period equal to one half of the time elapsed since the preceding test. Customers' check meters, if installed, shall be subject to Seller's right to require, at Seller's expense except as set forth in Section 8.4, a test of any of the check-meters not more often than once every twelve (12) months. If any of Customers' check meters is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such check meter shall be

deemed accurate, but Customers shall use their reasonable efforts to adjust such check meter immediately and accurately.

8.4 Delivered Energy Adjustments. In the event that, due to correction for inaccurate Interconnection Meters with an inaccuracy in excess of one half of a percent (0.5%) (determined in accordance with Section 8.3), the amount of Delivered Energy is increased or decreased, the revised quantity of Delivered Energy shall be used for purposes of calculating the Energy Payment pursuant to Section 4.2. If any Energy Payment has already been calculated using the previous quantity of Delivered Energy, the Energy Payment shall be recalculated using the revised quantity of Delivered Energy. If the recalculation (i) increases the Energy Payment, Purchaser shall pay to Seller the amount of such increase, or (ii) decreases the Energy Payment, Seller shall refund to Purchaser the amount of such decrease. In any such case, the required payment shall be included on the next invoice to be issued and shall be paid at the time payment of such invoice is required pursuant to Section 9. Any payment required under this Section 8.4 shall bear interest in accordance with Section 9.3 from the original due date (or from the date paid in the case of a refund) until the date paid (or until the date refunded in the case of a refund). In the case of inaccurate Meters with an inaccuracy in excess of one half of a percent (0.5%), the Party which owns such Meters shall promptly cause such Meters to be corrected and, where such inaccuracy was determined pursuant to a test required by the other Party, the Party which owns such Meters shall bear the expense of any such test.

SECTION 9
METHOD OF PAYMENT

9.1 Invoicing and Payment. As soon as reasonably practicable after the first day of each month commencing with the second month or portion thereof during which Test Energy is delivered to Purchaser and continuing for each month until the first month after the end of the Operating Period, Seller shall submit to Purchaser an invoice as described in Section 9.2. If such invoice indicates a net amount payable to Seller, Purchaser shall pay such invoice within ten (10) Business Days of Purchaser's receipt of the invoice. Such payment shall be made in U.S. dollars by wire transfer of immediately available funds prior to 3:00 p.m. Eastern Prevailing Time, on the date of payment in accordance with the invoice instructions. Payments made after 3:00 p.m. Eastern Prevailing Time or on a day that is not a Business Day shall be deemed to be made on the next subsequent Business Day. If such invoice indicates a net amount payable to Purchaser, Seller shall pay such amount within ten (10) Business Days of Purchaser's receipt of the invoice.

9.2 Monthly Invoices. Each monthly invoice shall show the amount and calculation of the following, as applicable: (i) the Capacity Payment and Energy Payment payable by Purchaser to Seller for the preceding month net of any amounts to be credited by Seller to Purchaser for such month; (ii) following each Contract Year, the net amount payable by Purchaser or Seller pursuant to Section 4.3 respecting the Availability Incentive Payment and

Availability Damages, as the case may be; and (iii) payments, refunds, credits and reductions, if any, payable by either Party pursuant to Sections 9.3 or 9.4.

9.3 Late Payments. Any amount due from either Party hereunder not paid in full on or before the date such payment is due will incur a delayed payment charge on the unpaid amount from the original due date until the date paid at an annual rate equal to the then current Prime Rate plus six (6) percentage points (or such lesser annual rate as is the maximum rate permitted by applicable Law).

9.4 Billing Disputes. In the event of any dispute as to all or any portion of any monthly invoice, Purchaser shall give notice of the dispute to Seller but shall pay the full amount of the invoiced charges when due (or if applicable, Seller shall give notice to Purchaser of Seller's dispute regarding any information provided by Purchaser that was a factor in any calculation supporting invoiced amounts). Such notice shall state the amount in dispute and set forth a full statement of the grounds on which such dispute is based. Purchaser and Seller shall give all due and prompt consideration to any such dispute. Upon final determination (whether by agreement, dispute resolution pursuant to Section 18 hereof, or otherwise) of the dispute, any amounts due to Purchaser or Seller, together with interest from the date due until the date paid at the rate specified in Section 9.3, shall be paid no later than thirty (30) days following such final determination. Purchaser and Seller shall have until the end of one hundred eighty (180) days after its receipt of any invoice, statement or information supporting invoice calculations to question or contest the correctness of any charge or credit on such invoice or statement.

9.5 Audit Rights. Until the end of one hundred eighty (180) days after Purchaser's receipt of any invoice, Seller and Purchaser will make available to the other upon written request, and the Purchaser or Seller may audit, such books and records of the other (or other information to which Purchaser or Seller has access) as are reasonably necessary for Purchaser or Seller to calculate and determine the amounts shown on such invoice and thereby to verify the accuracy and appropriateness of the amounts billed or credited to Purchaser or Seller hereunder; *provided, however,* that Purchaser shall coordinate its rights under this section with the other Customers in order to conduct joint, rather than individual, audits pursuant to this provision. The Parties shall maintain their respective books and records in accordance with generally accepted accounting principles applicable from time to time.

ARTICLE 10
CHANGE IN LAW; MODIFICATION OF AGREEMENT

10.1 Change in Law.

10.1.1 The Parties acknowledge that a Change in Law may increase or decrease Seller's costs in providing service under this Agreement. In the event of such a Change in Law, Seller may give notice to Purchaser that Seller's

costs of providing service under this Agreement have changed (which notice will include reasonably detailed information about such cost changes) and, in the event such notice is given, this Agreement shall be modified to reflect such changes in costs, subject to Section 18, *provided, however*, that in the event Seller provides notice of such an increase, then Purchaser may provide documentation to Seller of other Changes in Law that have decreased the cost of providing service under this Agreement and Seller shall set-off any such decrease in cost against the increase in cost identified in the Seller's notice.

10.1.2 Purchaser shall pay the adjusted amount calculated pursuant to Section 10.1.1 for the period commencing with the notice of changed cost through the date of termination of this Agreement. The Parties shall make such payments as are appropriate to adjust all prior billings or payments to reflect the adjustments described herein.

10.1.3 A "Change in Law" shall mean a change in Law which constitutes a new environmental or tax Law or a new interpretation of such Law (not including a change in tax Laws that assess taxes only on Seller's net income) or a change in the provisions contained in the Site Certification permits and which generally affects the cost of, or restricts, operation of the Facility.

10.2 Modification of Agreement. In the event the FERC modifies this Agreement, the Parties agree to make all changes necessary to preserve as nearly as possible the bargain contained in this Agreement, including but not limited to, the total amounts of Capacity and Energy delivered to Purchaser and the total amount of revenues to be received by Seller hereunder; *provided, however*, that Seller shall have the right to terminate this Agreement without further obligation to Purchaser in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Seller; *provided, further*, that Purchaser shall have the right to terminate this Agreement without further obligation to Seller in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Purchaser; *and provided, further*, that in the event Seller elects to terminate this Agreement pursuant to this Section 10.2, then Purchaser and Seller agree to expeditiously proceed with a sale [redacted] to Purchaser and the other Customers in accordance with the provisions of the Ownership Agreement. Seller agrees to use good faith efforts, consistent with Prudent Utility Practice, to resist any changes to this Agreement proposed by the FERC or any other Governmental Body or their respective staffs, and Purchaser agrees not to seek, request, promote or support any changes to this Agreement before the FERC or any other Governmental Body.

SECTION 11
FORCE MAJEURE

11.1 Force Majeure Notice and Obligations. With respect to those obligations of the Parties set forth in this Agreement that expressly excuse performance in the event of a Force Majeure, the existence of Force Majeure that causes a Party (the "Non-Performing Party") to delay performance or fail to perform such obligations shall excuse the Non-Performing Party's delay in performing, or failure to perform, such obligations, subject to any express limitations on such excuse provided or referenced in the Section invoking the excuse. In the event of Force Majeure that causes the Non-Performing Party to delay performance or fail to perform its obligations under this Agreement and that excuses such delay or failure:

11.1.1 the Non-Performing Party shall give the other Party written notice and full details as soon as practicable after learning of the Force Majeure;

11.1.2 the Non-Performing Party shall use reasonable dispatch to remedy its inability to perform (except that this provision shall not impose a requirement on either Party to deliver or receive Energy at a delivery point other than a Delivery Point), and, if Seller is the Non-Performing Party, Seller shall use reasonable efforts to provide Energy from the Facility at a Delivery Point; and

11.1.3 when the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

SECTION 12
EVENTS OF DEFAULT; TERMINATION

12.1 Events of Default of Seller. Except when excused due to a Force Majeure event pursuant to the provisions of Section 11 hereof, an Event of Default shall be deemed to have occurred with respect to Seller upon the occurrence and during the continuance of any of the following events:

12.1.1 The Bankruptcy of Seller;

12.1.2 Seller fails to pay any invoiced amount or any undisputed non-invoiced amount when due under this Agreement within five (5) Business Days after receiving notice of such failure;

12.1.3 Seller fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement

(other than payment obligations addressed in Section 12.1.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Purchaser demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot be reasonably accomplished within such 30-day period and Seller diligently commences such cure in such period and continues such cure to completion); or

12.1.4 Any representation or warranty made by Seller herein, in the Ownership Agreement or in any document or certificate furnished by Seller hereunder shall have been false when made and such false representation or warranty has a material and adverse effect on Purchaser and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Purchaser.

12.2 Events of Default of Purchaser. An Event of Default shall be deemed to have occurred with respect to Purchaser upon the occurrence and during the continuance of any of the following events:

12.2.1 The Bankruptcy of Purchaser;

12.2.2 Purchaser fails: (i) to pay any invoiced amount or any undisputed non-invoiced amount when due under this Agreement within ten (10) Business Days after receiving notice of such failure; or (ii) to make any payment of principal or interest under the Bond Legislation or any other bond resolution, indenture or similar secured instrument of the Purchaser relating to the All Requirements Project when due (at maturity, upon redemption or otherwise), which failure is not cured within ten (10) Business Days;

12.2.3 Purchaser fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than payment obligations, which are addressed in Section 12.2.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Seller demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot reasonably be accomplished within such 30-day period and Purchaser diligently commences such cure in such period and continues such cure to completion);

12.2.4 Any representation or warranty made by Purchaser herein, in the Ownership Agreement or in any document or certificate furnished by

Purchaser shall have been false when made and such false representation or warranty has a material and adverse effect on Seller and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Seller; or

12.2.5 Purchaser fails to comply with any of the requirements of Section 15 within thirty (30) days of receipt of Seller's written notice of such failure.

12.3 Remedies; Notice of Intent to Terminate. Subject to the provisions of this Agreement providing for limitations on damages and for exclusive remedies under certain circumstances, upon the occurrence and during the continuation of any Event of Default, the Party not in default (the "Non-Defaulting Party") shall have the right to pursue all remedies available at law or in equity, suspend its performance under this Agreement to the extent of the Event of Default and/or to deliver a notice of intent to terminate ("Notice of Intent to Terminate") this Agreement to the Party in default ("Defaulting Party"). Any Notice of Intent to Terminate shall specify the Event of Default giving rise to such Notice of Intent to Terminate. Following the giving of a Notice of Intent to Terminate, the Parties shall negotiate pursuant to the provisions of Section 18 hereof, following which, unless the Parties shall have otherwise mutually agreed on a remedy or the Defaulting Party or any lender or financing party ("Lender") to the Defaulting Party or its affiliate, or agent on behalf of a Lender, shall have cured such default or is diligently pursuing a remedy to cure the Event of Default, the Non-Defaulting Party having given the Notice of Intent to Terminate may terminate this Agreement by giving written notice thereof to the Defaulting Party, whereupon this Agreement shall immediately terminate; *provided, however*, that upon a default under Section 12.2.2, the Non-Defaulting Party may serve a notice of termination of this Agreement, without having first to deliver a Notice of Intent to Terminate and to negotiate under Section 18, whereupon this Agreement shall terminate immediately upon delivery of such notice of termination, unless such default shall have been cured prior to the delivery of such notice of termination. Except as provided in Sections 2.2, 2.3, 5.1.2, 10.2, 12.4, and 12.5 or in this Section 12.3, or in Section 4.3 of the Ownership Agreement, neither Party shall have any right to terminate this Agreement.

12.4 Notice to Lenders. Any and all notices given by Purchaser to Seller under this Section 12 shall also be given at the same time by Purchaser to any Lender for which Seller provides written notice to Purchaser of the need to provide such notice and the address to which such notice must be sent. No termination of this Agreement by Purchaser will be effective until and unless Purchaser shall have given Seller's Lenders notice of Seller's Event of Default and an opportunity to cure such Event of Default, which notice and cure period shall be as set forth in any consent executed by Purchaser with Seller's Lenders but in any event such notice and cure period shall be at least concurrent with that provided to Seller under this Agreement.

12.5 Termination Payment.

12.5.1 Except in the case of an Event of Default under Section 12.2.2 under the circumstances that are described in Section 12.5.2 below or an Event of Default under Section 12.1.3 under the circumstances that are described in Section 12.5.3 below, in the event that a Non-Defaulting Party terminates this Agreement pursuant to Section 12.3 and provided an Event of Default shall not have occurred and be continuing as to such Non-Defaulting Party, the Defaulting Party shall pay the Non-Defaulting Party the Termination Payment, as defined below, within thirty (30) days of the effective date of the termination. Except as so otherwise provided in Section 12.5.2 or 12.5.3, the Termination Payment (if applicable) shall be the Defaulting Party's sole liability arising out of a termination of this Agreement pursuant to Section 12.3, and neither Party shall have any other liability or obligation to the other Party arising out of a termination of this Agreement pursuant to Section 12.3. The Defaulting Party's Termination Payment (if applicable) to the Non-Defaulting Party resulting from an Event of Default under this Agreement shall be calculated as follows:

Termination Payment = TPR * APCN

Where:

TPR = a termination payment rate in dollar per kilowatt, which is equal to: (i) [redacted] if the Notice of Intent to Terminate is given between the date of this Agreement's execution and the end of the twelfth (12th) month after the date Purchaser gives notice under Section 2.2 or 2.3 that it has elected to terminate this Agreement; (ii) [redacted] if the Notice of Intent to Terminate is given between the end of such twelfth (12th) month and the end of the twenty-fourth (24th) month after the date Purchaser gives such notice; or (iii) [redacted] if the Notice of Intent to Terminate is given between the end of such twenty-fourth (24th) month and the expected termination of this Agreement twelve (12) months later; and

APCN = the Annual Purchaser's Capacity Nomination, in kilowatts, that is in effect on the date of the Notice of Intent to Terminate.

Delivery of a Notice to Terminate or calculation or payment of the Termination Payment shall not relieve the Defaulting Party of its obligation to pay all other amounts that became or have become due and

payable by the Defaulting Party hereunder prior to the effective date of termination.

12.5.2 In the case of an Event of Default under Section 12.2.2 by Purchaser at a time when Purchaser is able to pay its debts generally as they come due, Seller shall be entitled to recover its actual damages, which the Parties recognize may be greater than, or less than, the Termination Payment. In determining actual damages, any amounts actually recovered from Seller's reasonable efforts to mitigate such damages shall be taken into account.

12.5.3 In the case of an Event of Default by Seller under Section 12.1.3 that results from a failure by Seller to deliver Energy from the Facility to Purchaser as required by this Agreement at a time when (i) the Facility was capable of delivering such Energy to Seller as required by this Agreement consistent with Prudent Utility Practice, the Technical Limits and applicable Law and Permit requirements, and (ii) Seller sold such Energy to a third party, then Purchaser shall be entitled to recover the actual damages of Purchaser, which the Parties recognize may be greater than, or less than, the Termination Payment. In determining actual damages, the actual results of Purchaser's reasonable efforts to mitigate such damages shall be taken into account.

12.5.4 In receiving a Termination Payment or recovering actual damages, the Non-Defaulting Party shall also be entitled to recover its reasonable attorney fees in enforcing this provision.

SECTION 13
WAIVER

Failure by either Party to exercise any of its rights under this Agreement shall not constitute a waiver of such rights. Neither Party shall be deemed to have waived any right resulting from any failure to perform by the other Party unless it has made such waiver specifically in writing, and no such waiver shall operate as a waiver of any future failure to perform whether of a like or different character. No single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege hereunder.

SECTION 14
REPRESENTATIONS AND WARRANTIES

14.1 Representations and Warranties of Seller. Seller hereby represents and warrants to Purchaser as follows:

14.1.1 Organization and Existence. Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware, is qualified to transact business in Florida, and has sufficient power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Seller has full power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.1.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Seller has been duly and effectively authorized by all requisite action on the part of Seller. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Seller, enforceable against Seller in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.1.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Seller's knowledge, threatened against Seller or The Southern Company by or before any Governmental Body having jurisdiction over Seller or The Southern Company which, if adversely determined, would have a material adverse effect upon Seller's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents. Neither Seller nor The Southern Company is subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Seller or The Southern Company which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents.

14.1.4 No Violation or Conflict. The execution, delivery and performance by Seller of this Agreement and the Collateral Documents do not violate or conflict with Seller's operating agreement, any existing Law applicable to Seller, or any note, bond, indenture, agreement or instrument to which Seller is a party or by which it is bound.

14.1.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment A of the Ownership Agreement, there are no

approvals or consents, the absence of which would materially impair Seller's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2 Representations and Warranties of Purchaser. Purchaser hereby represents and warrants to Seller as follows:

14.2.1 Organization and Existence. Purchaser is a governmental legal entity duly organized, validly existing and in good standing under the laws of the State of Florida and has sufficient statutory power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Purchaser has full statutory power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.2.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Purchaser has been duly and effectively authorized by all requisite action on the part of Purchaser's governing board. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Purchaser, enforceable against Purchaser in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.2.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Purchaser's knowledge, threatened against Purchaser by or before any Governmental Body having jurisdiction over Purchaser which, if adversely determined, would have a material adverse effect upon Purchaser's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents. Purchaser is not subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Purchaser which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents.

14.2.4 No Violation or Conflict. The execution, delivery and performance by Purchaser of this Agreement and the Collateral Documents do not violate or conflict with Purchaser's charter or bylaws, any existing Law applicable to Purchaser, or any note, bond, resolution, indenture, agreement or instrument to which Purchaser is a party or by which it is bound.

14.2.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment C of the Ownership Agreement, there are no approvals or consents, the absence of which would materially impair Purchaser's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2.6 No Immunity. With respect to its contractual obligations hereunder and performance thereof, Purchaser is not entitled to claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from: (a) suit; (b) jurisdiction of any Florida court; or (c) relief by way of injunction, order for specific performance or attachment of property that is subject to execution or levy under Florida Law (including the Eligible Collateral).

14.3 Warranties Regarding Energy, Capacity and Ancillary Services. Seller warrants that the Energy, Capacity and Ancillary Services provided under this Agreement (i) shall have been delivered in accordance with applicable Law, and (ii) meets the requirements set forth in this Agreement. **THE FOREGOING IS IN LIEU OF ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, IN FACT OR BY LAW WITH RESPECT TO THE ENERGY, CAPACITY AND ANCILLARY SERVICES PROVIDED HEREUNDER. SELLER HEREBY DISCLAIMS ANY AND ALL OTHER WARRANTIES WHATSOEVER.**

SECTION 15
PERFORMANCE ASSURANCE

15.1 In the event that Purchaser experiences a Material Adverse Change, as defined below, as security for Purchaser's payment obligations under this Agreement, Purchaser shall deliver to Seller within [redacted] of Seller's written request therefor, Eligible Collateral in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period.

15.1.1 As used in this Section 15.1: (i) a "Material Adverse Change" shall occur (A) when Purchaser's credit rating on its senior securities falls below the

lower of (x) [redacted] (Standard & Poors) or [redacted] (Moody's) and (y) the lowest credit rating of Southern Guarantor's senior securities under either Moody's or Standard & Poors, (B) upon an Event of Default by Purchaser under Section 12.2.2, (C) upon a failure by Purchaser to make any required deposit into any debt service account under the Bond Legislation or any other bond resolution, indenture or similar secured instrument entered into in connection with the issuance of additional debt (each a "Debt Instrument"), or (D) upon a failure by Purchaser to maintain in any debt service reserve account under the Bond Legislation or any Debt Instrument at least [redacted] of amount required to be maintained in such account requirement; and (ii) "Eligible Collateral" means cash deposited into an operating reserve account from "Revenues", as that term is defined in the Bond Legislation, or an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller; *provided, however*, that for purposes of Sections 15.1.1(i)(C) and 15.1.1(i)(D), Eligible Collateral shall constitute an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller. Costs of a letter of credit shall be borne by Purchaser.

15.1.2 If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Purchaser, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when a "Material Adverse Change" has occurred.

15.2 In the event that legislation is enacted in the State of Florida which contains provisions that will cause an Event of Default by Purchaser at any time during the term of this Agreement, Seller will have the right, from and after the date of enactment of such legislation, to provide Purchaser with written notice requesting Eligible Collateral, as defined above, in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period. Upon receipt of such notice, in addition to Purchaser's other payment obligations under this Agreement, Purchaser shall within [redacted] provide such Eligible Collateral.

15.3. To the extent Purchaser delivers Eligible Collateral in the form of cash to be held in an operating reserve account pursuant to Sections 15.5 or 15.6, Purchaser hereby grants to Seller a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, such Eligible Collateral, and any and all proceeds resulting therefrom or from the liquidation thereof, and Purchaser agrees to take such action as Seller reasonably requires in

order to perfect Seller's first-priority security interest in, and lien on (and right of setoff against), such Eligible Collateral and any and all proceeds resulting therefrom or from the liquidation thereof. This Agreement is intended to, and does, constitute a security agreement between Seller and Purchaser with regard to any cash which may constitute Eligible Collateral.

15.4. Upon or any time after the occurrence and during the continuation of an Event of Default of Purchaser, Seller may (i) exercise any of the rights and remedies of a secured party with respect to the Eligible Collateral, including any such rights and remedies under Law then in effect, such as but not limited to the Uniform Commercial Code, and (ii) liquidate and/or draw on any outstanding Eligible Collateral issued for its benefit (free from any claim or right of any nature whatsoever of Purchaser including any equity or right of purchase or redemption by Purchaser) with respect to Purchaser's obligations under this Agreement. In the event that Seller liquidates or draws on any of the Eligible Collateral, Purchaser shall within [redacted] of notice from Seller of such liquidation or draw, deliver additional cash or increase the amount of the letter of credit, as the case may be, in order to replenish the amount of the Eligible Collateral to the extent of the liquidation or draw.

15.5. If the trigger of a Material Adverse Change was occurrence of the circumstances in Sections 15.1.1(i)(A) or the circumstances described in Section 15.2 occur, then: (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as the circumstances described in Sections 15.1.1(i)(A) and 15.2 no longer apply (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire at such time as the circumstances described in Sections 15.1.1 and 15.2 no longer apply and Seller shall return such letter of credit to Purchaser (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.6 If the trigger of a Material Adverse Change was occurrence of the circumstances described in Section 15.1.1(i)(B), then (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as Purchaser shall have (A) cured the Event of Default under Section 12.2.2 that triggered the Material Adverse Change and (B) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to receive any funds in such operating reserve

account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire (and Seller shall return such letter of credit) at such time as Purchaser shall have (C) cured the Events of Default under Section 12.2.2 that triggered the Material Adverse Change and (D) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.7 In the event that the Purchaser exercises its right to elect an Extended Term or any Further Extension of this Agreement pursuant to Sections 2.2 and 2.3, and on any day of such Extended Term or Further Extensions the circumstances of either Sections 15.1.1 or 15.2 apply, then, Purchaser shall deliver to Seller within [redacted] of the date of such occurrence, Eligible Collateral, as defined above, in an amount equal to [redacted] of Capacity Payments, and the provisions of Sections 15.3, 15.4, 15.5 and 15.6 shall apply to such Eligible Collateral.

SECTION 16
LIABILITY OF PARTIES

16.1 INDEMNITIES.

16.1.1 **TO THE EXTENT PERMITTED BY LAW, EACH PARTY (THE "INDEMNIFYING PARTY") SHALL FULLY INDEMNIFY AND DEFEND THE OTHER PARTY AND EACH OF THE OTHER PARTY'S SUBSIDIARIES AND AFFILIATES, AND THE PARTNERS, MEMBERS, PARTICIPANTS, PRINCIPALS, REPRESENTATIVES, SHAREHOLDERS, DIRECTORS, OFFICERS, AGENTS, EMPLOYEES, SUCCESSORS AND ASSIGNS OF EACH OF THEM (THE "INDEMNIFIED PARTIES") FROM AND AGAINST ANY AND ALL LOSSES, COSTS, DAMAGES, INJURIES, LIABILITIES, CLAIMS, DEMANDS, PENALTIES AND INTEREST, INCLUDING REASONABLE ATTORNEYS' FEES, RESULTING FROM THIRD PARTY CLAIMS DIRECTLY OR INDIRECTLY RELATED TO THIS AGREEMENT, TO THE EXTENT CAUSED OR CONTRIBUTED TO BY THE FAULT, INTENTIONAL ACT, NEGLIGENCE OR STRICT LIABILITY OF THE INDEMNIFYING PARTY OR ITS SUBSIDIARIES, AFFILIATES, CONTRACTORS OR SUBCONTRACTORS OR ANY OF THE OFFICERS, PARTNERS,**

MEMBERS, PARTICIPANTS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, EMPLOYEES, AGENTS, REPRESENTATIVES, SUCCESSORS OR ASSIGNS OF ANY OF THEM OR BY BREACH BY THE INDEMNIFYING PARTY OF THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT ANY LIABILITY TO THIRD PARTIES INCURRED BY SELLER IN PERFORMANCE OF ITS AGENCY FUNCTIONS PURSUANT TO THE OWNERSHIP AGREEMENT OR THE OPERATING AGREEMENT SHALL BE APPORTIONED IN ACCORDANCE WITH ARTICLE 9 OF THE OWNERSHIP AGREEMENT OR ARTICLE 7 OF THE OPERATING AGREEMENT.

16.1.2 **IF ANY INDEMNIFIED PARTY INTENDS TO SEEK INDEMNIFICATION UNDER THIS SECTION 16.1 FROM AN INDEMNIFYING PARTY WITH RESPECT TO ANY ACTION OR CLAIM, THE INDEMNIFIED PARTY SHALL GIVE THE INDEMNIFYING PARTY WRITTEN NOTICE OF SUCH CLAIM OR ACTION PROMPTLY FOLLOWING THE RECEIPT OF ACTUAL KNOWLEDGE OR INFORMATION BY THE INDEMNIFIED PARTY OF A POSSIBLE CLAIM OR OF THE COMMENCEMENT OF A CLAIM OR ACTION, WHICH WRITTEN NOTICE SHALL IN NO EVENT BE DELIVERED LATER THAN THE FIRST TO OCCUR OF (A) FIFTEEN (15) DAYS PRIOR TO THE LAST DAY FOR RESPONDING TO SUCH CLAIM OR ACTION OR (B) THE EXPIRATION OF THE FIRST HALF OF THE PERIOD ALLOWED FOR RESPONDING TO SUCH CLAIM OR ACTION. THE INDEMNIFYING PARTY SHALL HAVE NO LIABILITY UNDER THIS SECTION FOR ANY CLAIM OR ACTION FOR WHICH SUCH NOTICE IS NOT PROVIDED TO THE EXTENT THAT THE FAILURE TO GIVE SUCH WRITTEN NOTICE MATERIALLY PREJUDICES THE INDEMNIFYING PARTY. UPON ACKNOWLEDGMENT OF ITS OBLIGATIONS UNDER THIS SECTION 16.1, THE INDEMNIFYING PARTY SHALL HAVE THE RIGHT TO ASSUME THE DEFENSE OF ANY CLAIM OR ACTION, AT ITS SOLE COST AND EXPENSE, WITH COUNSEL DESIGNATED BY THE INDEMNIFYING PARTY AND REASONABLY SATISFACTORY TO THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE DEFENDANTS IN ANY SUCH ACTION INCLUDE BOTH THE INDEMNIFIED PARTY AND THE INDEMNIFYING PARTY, AND THE INDEMNIFIED PARTY**

SHALL HAVE REASONABLY CONCLUDED THAT THERE MAY BE LEGAL DEFENSES AVAILABLE TO IT WHICH ARE DIFFERENT FROM OR ADDITIONAL TO THOSE AVAILABLE TO THE INDEMNIFYING PARTY, THE INDEMNIFIED PARTY SHALL HAVE THE RIGHT TO SELECT SEPARATE COUNSEL, AT THE INDEMNIFYING PARTY'S EXPENSE, TO ASSERT SUCH LEGAL DEFENSES AND TO OTHERWISE PARTICIPATE IN THE DEFENSE OF SUCH ACTION ON BEHALF OF SUCH INDEMNIFIED PARTY.

16.1.3 **EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFIED PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT HAS SOUGHT OR INTENDS TO SEEK INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFYING PARTY. SHOULD ANY INDEMNIFIED PARTY BE ENTITLED TO INDEMNIFICATION UNDER THIS SECTION 16.1 AS A RESULT OF A CLAIM OR ACTION BY A THIRD PARTY, AND SHOULD THE INDEMNIFYING PARTY FAIL TO ASSUME THE DEFENSE OF SUCH CLAIM OR ACTION, THE INDEMNIFIED PARTY MAY, AT THE EXPENSE OF THE INDEMNIFYING PARTY, CONTEST (OR, WITH OR WITHOUT THE PRIOR CONSENT OF THE INDEMNIFYING PARTY, SETTLE) SUCH CLAIM OR ACTION. EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFYING PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT MAY BE LIABLE TO PROVIDE INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFIED PARTY; *PROVIDED*, *HOWEVER*, THAT IF THE INDEMNIFYING PARTY HAS REACHED A BONA FIDE SETTLEMENT AGREEMENT WITH THE PLAINTIFF(S) IN ANY SUCH ACTION AND THE INDEMNIFIED PARTY DOES NOT CONSENT TO SUCH SETTLEMENT AGREEMENT, THEN THE AMOUNT SPECIFIED IN THE SETTLEMENT AGREEMENT, PLUS THE INDEMNIFIED PARTY'S REASONABLE ATTORNEY FEES INCURRED PRIOR TO THE DATE OF SUCH SETTLEMENT AGREEMENT, SHALL ACT AS AN ABSOLUTE MAXIMUM LIMIT ON THE INDEMNIFICATION OBLIGATION OF THE INDEMNIFYING PARTY WITH RESPECT TO THE CLAIM, OR PORTION THEREOF, THAT IS THE SUBJECT OF**

SUCH SETTLEMENT AGREEMENT TO THE EXTENT SUCH SETTLEMENT AGREEMENT FULLY RELEASES THE INDEMNIFIED PARTY AND DOES NOT REQUIRE ANY PAYMENT FROM, OR IMPOSE ANY RESTRICTION ON, THE INDEMNIFIED PARTY.

16.2 LIMITATION ON DAMAGES. **NEITHER PARTY NOR ITS SUBSIDIARIES OR AFFILIATES NOR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, SUCCESSORS OR ASSIGNS OF ANY OF THEM SHALL IN ANY EVENT BE LIABLE TO THE OTHER PARTY OR ITS SUBSIDIARIES OR AFFILIATES OR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS OR DIRECTORS OF ANY OF THEM FOR CLAIMS FOR INCIDENTAL, PUNITIVE, CONSEQUENTIAL, EXEMPLARY OR INDIRECT DAMAGES OF ANY NATURE, ARISING AT ANY TIME, FROM ANY CAUSE WHATSOEVER, WHETHER ARISING IN TORT, CONTRACT, WARRANTY, STRICT LIABILITY, BY OPERATION OF LAW OR OTHERWISE, CONNECTED WITH OR RESULTING FROM PERFORMANCE OR NON-PERFORMANCE UNDER THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT THIS SECTION 16.2 IS NOT INTENDED, NOR SHALL IT BE CONSTRUED, TO LIMIT OR ELIMINATE A PARTY'S OBLIGATION TO PAY LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR MAKE ANY OTHER PAYMENTS EXPRESSLY CONTEMPLATED HEREIN, OR IN ANY COLLATERAL DOCUMENT, EVEN IF IT MAY BE POSSIBLE TO CHARACTERIZE SUCH LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR OTHER PAYMENTS AS INCIDENTAL, PUNITIVE, CONSEQUENTIAL OR INDIRECT DAMAGES.**

16.3 Seller Affiliate Guarantee. Seller shall at all times following the Effective Date of this Agreement cause an Affiliate of Seller to maintain in place a payment guarantee in the form attached to this Agreement as Appendix E. For purposes of the previous sentence, an "Affiliate" of Seller shall be any entity controlling, under common control with or controlled by Seller, which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's). If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Seller's affiliates, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when an entity controlling, under common control with or controlled by Seller has sufficient credit-worthiness to qualify as an "Affiliate."

16.4 No Penalty. The Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by Purchaser due to Seller's failure

to meet the Availability Guarantee or achieve the schedule provided under Section 5.1.1, that the Availability Damages set forth in Section 4.3 and the liquidated damages set forth in Section 5.1.2 are fair and reasonable determinations of the amount of actual damages which would be suffered by Purchaser or Seller, as the case may be, by reason of such failure, and that the Availability Damages and other liquidated damages do not constitute a penalty. Similarly, the Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by either Party in case of an Event of Default and a termination of this Agreement by the Non-defaulting Party, that the Termination Payment set forth in Section 12.5.1 is a fair and reasonable determination of the amount of actual damages which would be suffered by the Non-defaulting Party in such event, and that the Termination Payment does not constitute a penalty.

SECTION 17
ASSIGNMENT

17.1 Agreement Binding. This Agreement shall be binding upon, and shall inure to the benefit of, the Parties and their successors and permitted assigns.

17.2 Permitted Assignment. This Agreement shall not be assignable by Seller without the prior written consent of Purchaser, except that this Agreement (a) may be assigned by Seller without the requirement for such consent (but with notice to Purchaser) (i) to any Lender from time to time providing financing to Seller or its affiliate with respect to all or any portion of the Project or (ii) to any Lender or its designee in connection with a foreclosure or other exercise of remedies, and (b) unless otherwise waived by Purchaser, shall be assigned in whole or in part by Seller without the requirement for such consent (but with notice to Purchaser) in the event of a sale by Seller of all or a substantial portion of Seller's interest in the Facility, with the purchaser of Seller's interest in the Facility assuming Seller's obligations under this Agreement in the same percentage as the portion of Seller's interest being transferred bears to Seller's entire interest in the Facility. This Agreement shall not be assignable by Purchaser without the prior written consent of Seller, *provided, however*, that Purchaser may assign this Agreement to another Customer without the requirement for such consent (but with notice to Seller) so long as such Customer has not experienced a Material Adverse Change under its PPA. Any such transferee, assignee or purchaser (other than a Lender through collateral assignment in connection with a lease or other financing transaction permitted under Section 6.2.8 of the Ownership Agreement) shall confirm its willingness to accept all of the assigning Party's obligations under this Agreement by writing reasonably acceptable to the non-assigning Party. Any such assignee, transferee or purchaser (other than a Lender through collateral assignment in connection with a lease or other financing transaction permitted under Section 6.2.8 of the Ownership Agreement) must be sufficiently creditworthy and otherwise capable of performing all of the assigning Party's obligations under this Agreement. No assignment or transfer of this Agreement by a Party shall be permitted during any period in which an Event of Default of such Party shall have occurred and be continuing and not cured, unless the other Party shall agree. No assignment of

this Agreement shall relieve the assigning Party of any of its obligations under this Agreement, except that the assignor shall be released from its obligations under this Agreement at such time as all future obligations of the assignor hereunder shall have been assumed by the assignee in a written agreement delivered to the other Party. Any assignment that does not comply with the provisions of this Section 17 shall be null and void.

SECTION 18
DISPUTE RESOLUTION

18.1 Good-Faith Negotiations. The Parties shall first negotiate in good faith to attempt to resolve any dispute, controversy or claim arising out of, under, or relating to this Agreement (a "Dispute"), unless otherwise mutually agreed to by the Parties. In the event that the Parties are unsuccessful in resolving a Dispute through such negotiations, either Party may proceed immediately to litigation concerning the Dispute.

18.1.1 The process of "good-faith negotiations" requires that each Party set out in writing to the other its reason(s) for adopting a specific conclusion or for selecting a particular course of action, together with the sequence of subordinate facts leading to the conclusion or course of action. The Parties shall attempt to agree on a mutually agreeable resolution of the Dispute. A Party shall not be required as part of these negotiations to provide any information which is confidential or proprietary in nature unless it is satisfied in its discretion that the other Party will maintain the confidentiality of and will not misuse such information or any information subject to attorney-client or other privilege under applicable Law regarding discovery and production of documents.

18.1.2 The negotiation process shall include at least two (2) meetings to discuss any Dispute. Unless otherwise mutually agreed, the first meeting shall take place within ten days after either Party has received notice from the other of the desire to commence formal negotiations concerning the Dispute. Unless otherwise mutually agreed, the second meeting shall take place no more than ten days later. In the event a Party refuses to attend a negotiation meeting, either Party may proceed immediately to litigation concerning the Dispute.

18.2 Confidentiality and Non-Admissibility of Statements Made in, and Evidence Specifically Prepared for, Good Faith Negotiations. Each Party hereby agrees that all statements made in the course of good faith negotiations, as contemplated in Section 18.1, shall be confidential and shall not be disclosed to or shared with any third parties (other than any person whose presence is necessary to facilitate the negotiation process). Each Party agrees and

acknowledges that no statements made in or evidence specifically prepared for good faith negotiations under Section 18.1 shall be admissible for any purpose in any subsequent litigation.

SECTION 19
AMENDMENT

This Agreement cannot be amended, modified or supplemented except by written agreement making specific reference hereto executed by both Parties.

SECTION 20
NOTICES

Other than telephonic notices required or permitted under Section 6.1 or Appendix B, any notice required or permitted to be given hereunder shall be in writing and shall be: (i) personally delivered; (ii) transmitted by postage prepaid registered mail; (iii) transmitted by a recognized overnight courier service; or (iv) transmitted by facsimile to the receiving Party as follows, as elected by the Party giving such notice:

20.1 In the case of Purchaser:

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Attention: Vice-President of Power Resources
Telephone: 407-244-8372
Facsimile: 407-275-4120

With a copy to:

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819-9002
Attention: General Manager
Telephone: 407-355-7767
Facsimile: 407-355-5793

20.2 In the case of Seller:

Southern Company Services, Inc.
270 Peachtree Street, Bin 935
Atlanta, Georgia 30303
Attention: Director of Contract Administration
Telephone: 404-506-5100
Facsimile: 404-506-0304

With a copy to:

Troutman Sanders LLP
Bank of America Plaza
600 Peachtree Street N.E.
Atlanta, Georgia 30308
Attention: Robert H. Forry, Esq.
Telephone: 404-885-3142
Facsimile: 404-962-6559

All notices and other communications shall be deemed to have been duly given on (i) the date of receipt if delivered personally, (ii) five (5) days after the date of posting if transmitted by mail, (iii) the Business Day following delivery to the courier if transmitted by overnight delivery service, or (iv) the date of transmission with confirmation if transmitted by facsimile, whichever shall first occur. Any Party may change its address for purposes hereof by notice to the other Party.

SECTION 21
APPLICABLE LAW

This Agreement shall be governed by, and construed in accordance with, the laws of the State of Florida, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction. The Parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Middle District of Florida, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Circuit Court of the State of Florida sitting in Orange County, Florida, and the Parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

SECTION 22
SEVERABILITY

The invalidity or unenforceability of any provision or portion of this Agreement will not affect the validity of the remainder of this Agreement. If any provision of this Agreement is determined to be invalid or unenforceable, the Parties will negotiate in good faith to agree upon substitute provisions to carry out the purpose and intent of the invalid or unenforceable provision. If the economic or legal substance of the transactions contemplated hereby is affected in any manner adverse to any Party as a result thereof, the Parties shall negotiate in good faith in an effort to agree upon a suitable and equitable substitute provision to effect the original intent of the Parties.

SECTION 23
ENTIRE AGREEMENT

This Agreement and the Collateral Documents contain the complete agreement of the Parties hereto with respect to the matters contained herein and supersede all other agreements, understandings and negotiations, whether written or oral, with respect to the matters contained herein.

SECTION 24
NO THIRD PARTY BENEFICIARIES

This Agreement is intended to be solely for the benefit of Purchaser and Seller and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any Person not a signatory hereto.

SECTION 25
COUNTERPARTS

This Agreement may be executed in one or more counterparts, each of which shall constitute an original but all of which, when taken together, shall constitute only one legal instrument.

SECTION 26
INFORMATION AND CONFIDENTIALITY

Where a Party makes any calculation of costs or damages under this Agreement, such Party shall provide, upon the reasonable request of the other Party, documentation supporting such calculation. Neither Party shall disclose or otherwise make available to any other party any information of a technical, commercial or business nature regarding the Project or this Agreement that has been marked or identified as confidential or proprietary ("Confidential

Information") without the prior written consent of the other Party, except that (a) Seller or its affiliate may provide Confidential Information to its or any such affiliate's prospective Lenders, underwriters, investors, affiliates, advisors, employees, officers and directors to the extent reasonably required in connection with the administration of this Agreement, the issuance of debt or equity or other financing activities of Seller or its affiliate, or the performance of any duties relating to this Agreement; (b) Purchaser may provide Confidential Information to its advisors, employees, officers, directors and Lenders to the extent reasonably required in connection with the administration of this Agreement or the performance of any such Person's duties relating to this Agreement; (c) any Party may disclose any such Confidential Information in any litigation or proceeding to enforce or recover damages under this Agreement; (d) any Party (or its affiliate) may disclose any such Confidential Information as may be required by any applicable Law, regulation or governmental order; and (e) any Party (or its affiliate) may disclose such Confidential Information to any person or entity succeeding to all or substantially all the assets of such Party (or its affiliate) or all or a substantial portion of its interest in the Facility; *provided*, that in the case of (e), any such successor shall agree to be bound by the provisions of this Section 26. Confidential Information shall not include information that: (i) the receiving Party can demonstrate was known to it prior to its disclosure by the other Party; (ii) is, or later becomes, public knowledge without breach of this Agreement by the receiving Party; (iii) was received by the receiving Party from a third party without obligation of confidentiality; or (iv) is developed by the receiving Party independently from Confidential Information received from the other Party, as evidenced by appropriate documentation. In the event that disclosure is required by a valid order of a court or Governmental Body, the Party subject to such requirement may disclose Confidential Information to the extent so required, but shall promptly notify the other Party and shall cooperate with the other Party's efforts to obtain protective orders or similar restraints with respect to such disclosure. The provisions of this Section 26 shall continue in effect until three years after the end of the Operating Period.

The Parties understand that under the Florida Public Records Law (Section 119.10, Florida Statutes), any Party or all of them may be subject to statutory fines and penalties, including but not limited to a requesting Party's costs and attorney's fees for failure to make public records available for public inspection upon request (Chapter 119, Florida Statutes). In addition, each Party may be subject to its own costs and expenses of litigation. With this understanding in mind, the Parties agree that in the event Purchaser in an attempt to comply with this Agreement, refuses to honor a public records request under Chapter 119, Florida Statutes, for examination or inspection of a confidential document of Seller or any affiliate of Seller and is forced to defend its actions in a court of competent jurisdiction, Seller shall indemnify, defend, and hold Purchaser harmless from and against any fines, penalties, costs, attorney's fees and expenses, including, but not by way of limitation, attorney's fees, expert fees, court costs and other costs arising from or related to defending any lawsuit bought pursuant to Chapter 119, Florida Statutes; *provided, however,* Seller's consent with such refusal shall be obtained before Seller can be liable under this Section 26. In addition, the Parties shall cooperate to provide witnesses to support the Parties' declarations

and certification that the Confidential Information is a valid trade secret under the above cited Florida law and meets all definitional requirements therein or is exempt from disclosure under other applicable Florida law.

SECTION 27
PUBLIC STATEMENTS

Seller and Purchaser shall consult with each other and neither of them shall issue a press release or make a statement intended for release to the general public with respect to the transactions contemplated hereby without the consent of the other Party, which consent shall not be unreasonably withheld, unless the Party desiring to make such statement or press release is advised by legal counsel that a statement or press release is required by applicable Law (including information provided pursuant to a request for public information under the Florida Public Records Law, Section 119.10, Florida Statutes); *provided, however,* that in this event the Party making the public statement or press release shall notify the other Party in advance of such statement or press release and allow the other Party reasonable time to comment on such statement or press release. Notwithstanding the immediately preceding sentence, the Parties acknowledge that certain meetings of the Orlando Utilities Commission and the City of Orlando are open to the public, and nothing in this Agreement shall be deemed to require that the proceedings of such meetings not be made public or to restrict the reporting by the media of such proceedings.

SECTION 28
INSURANCE

Seller and Purchaser, and all contractors and subcontractors performing any services in connection with the operation or maintenance of the Facility, shall obtain and maintain in force comprehensive general liability insurance, and property insurance for injury to persons and property, automobile liability insurance and workman's compensation insurance, all in amounts and under terms as required by the Operating Agreement.

SECTION 29
TAXES

Purchaser shall reimburse Seller for, or pay to Seller, all sales, use, personal property and other taxes of every kind, paid or collected by Seller, if any, that are not currently levied and are hereafter levied on the purchase, sale or use of fuel consumed by the Facility to provide Energy or Ancillary Services in accordance with this Agreement or the purchase, sale or use of Capacity, Energy or Ancillary Services under this Agreement, but excluding any taxes levied on Seller's net income. Purchaser shall pay directly for all such sales, use, personal property and other taxes which it is legally obligated and empowered to pay. In the event Seller, on behalf of Purchaser, pays any taxes that are the responsibility of Purchaser to reimburse or pay, under the first two

sentences of this Section *29*, the amount so paid by Seller shall be added to a monthly invoice submitted by Seller to Purchaser under Section 9, and Purchaser shall pay such amount in accordance with Section 9. Upon the reasonable request of Purchaser, Seller agrees to (i) provide documents related to taxes or assessments to be reimbursed or paid by Purchaser under this Agreement and (ii) cooperate with Purchaser at Purchaser's expense should Purchaser seek to obtain from the entity to which taxes were paid a refund of any taxes paid by Seller and/or reimbursed or paid by Purchaser.

IN WITNESS WHEREOF, the Parties, intending to be legally bound, have caused this Agreement to be executed by their duly authorized representatives as of the day and year first written above.

Signed, sealed and delivered in the presence of:

Dana L Schult

Dana L Schult
My Commission CC975843
Expires October 17 2004

Notary Public

Orange Cty, FL

FLORIDA MUNICIPAL POWER AGENCY (ALL REQUIREMENTS POWER SUPPLY PROJECT)

By: _____

Name: Roger A. Fontes

Title: General Manager/CEO

FOR THE USE AND RELIANCE OF FMPA ONLY - APPROVED AS TO FORM AND LEGALITY

_____
Attorney for FMPA

Date: 4/6/01

Attest: _____

Name: Mary Ann Davis, CGFM

Title: Director of Finance

Signed, sealed and delivered in the presence of:

_____

NOTARY PUBLIC STATE OF ALABAMA AT LARGE
MY COMMISSION EXPIRES: Nov 25, 2004
BONDED THRU NOTARY PUBLIC UNDERWRITERS

Notary Public

SOUTHERN COMPANY - FLORIDA LLC

By: Southern Power Company, its sole member

By: _____
Douglas E. Jones, Vice President

Attest: _____
Anthony J. Topazi, Vice President

APPENDIX A

TECHNICAL LIMITS

Unit Operating Modes

1. **Definition of Operating Modes**.

The Facility will have several different operating modes.

- Mode 1: Normal Operation—both gas turbines (CTs) operating with no supplemental firing of the Heat Recovery Steam Generator (HRSG) and no gas turbine power augmentation.

- Mode 2: Supplemental Firing Operation—both gas turbines operating at full load with supplemental firing of the HRSG.

- Mode 3: Power Augmentation Operation—both gas turbines operating at full load with supplemental firing of the HRSG's (Mode 2 Supplemental Firing Operation) to produce both steam for full steam turbine-generator output with the maximum allowed continuous throttle flow at the maximum allowed continuous throttle pressure and steam for full gas turbine power augmentation (steam injection.)

- Mode 4: Part-load Operation—one or both gas turbines operating at less than full load.

2. **Natural Gas Requirements**.

The Facility will require "pipeline quality gas" meeting the requirements of GE fuel specification "GEI 41040E - Process Specification Fuel Gases for Combustion in Heavy Duty Gas Turbines".

Natural gas is to be delivered to the Facility by pipeline and the pipeline and gas must meet the following equipment characteristics and requirements:

- Nominal Maximum N.G. Flow (HHV) per Block (2x1) [redacted] MMBtu/hr*
- Nominal N.G. Higher Heating Value [redacted] Btu/lb
- Minimum Fuel Supply Temperature (after PRV) [redacted] °F
- Fuel Pressure at Gas Control Valve** [redacted] PSIG (nominal)

[redacted] PSIG maximum

* Based on Winter Peaking [redacted] Power during Full Pressure Operation.

** Reference GE Pub. GEI 41040E.

3. **Fuel Oil Requirements**.

The Facility will require fuel oil that is in compliance with ASTM Standard Specification D-2880 (as revised) and "GE Gas Turbine Liquid Fuel Specifications" (document number GEI 41047H). This No. 2 GT Grade Gas Turbine Fuel Oil must be in compliance with the specifications and procedures for No. 2 Fuel Oil as defined in ASTM D396.

Note that environmental permitting may create conditions for sulfur, fuel bound nitrogen and other specifications which could affect or add minimum specifications, such as, but not limited to, those identified in the following table:

	SPECIFICATIONS	**ASTM TEST METHOD**
Sulfur, % Wt., Max.	0.05	D – 1266
Fuel Bound Nitrogen	0.050% Max.	

4. **Dispatch and Operational Requirements**.

- The Facility will be capable of operating with fuel oil. The Facility may fire oil in the gas turbines only and not in the HRSG duct burners. During these periods, the Facility shall operate in Mode 1 (Normal Operation) only.

- The Facility will require shutdown for a minimum of one hour prior to switching from natural gas to oil firing. The fuel oil forwarding system will not be operated during normal gas firing, but operation of the fuel forwarding system will be initiated upon proper notice of a requirement for fuel switching. The Facility will be capable of switching from oil to natural gas without shutdown; however, the Facility may be required to decrease to a minimum load and stabilize prior to ramping to full load.

- The Facility will be capable of being controlled via Automatic Generation Control (AGC) in Mode 1 (Normal Operation). The AGC load range and ramp rate will be set by the Facility's operator based on the actual capability of the CTs as determined through testing. With the duct burners firing (Mode 2 – Supplemental Firing Operation), the load range and ramp rate

will be set and manually controlled by the Facility's operator based on the capabilities of the duct burners. No load following capability is available in Mode 3 (Power Augmentation Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) only at ambient temperatures of [redacted] and higher.

- The Facility will require [redacted] of de-mineralized water for Mode 1 (Normal Operation).

- The expected maximum allowable rate of load increase for the Facility will be [redacted]. Actual maximum load increase rate will be determined by actual testing and in light of final permit restrictions and emissions tests.

- The Facility will be expected to be capable of operating minimum load with one CT at [redacted] load or two CTs each at part of [redacted] load. Actual minimum load will be determined in light of final NOx emissions and permit restrictions and testing.

- Required startup times for the Facility shall be as follows:

  Mode 1 (Normal Operation): refer to Attachment 1 – Time to Dispatch Curve. Note: Actual Curve to be determined by testing.

  Mode 2 (Supplemental Firing Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation).

  Mode 3 (Power Augmentation Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation) or [redacted] from one hundred percent (100%) Mode 2 (Supplemental Firing Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) a maximum of [redacted] based on the LTSA contract with GE.

- The Facility will not be allowed to operate in a traditional CT only mode (no simple cycle operation, *i.e.*, no bypass stack). However, the CTs will be capable of operating independently of the steam turbine utilizing the steam bypass systems for a limited time. Most major plant equipment (such as HRSG BFP's, condenser, cooling tower and circulating water pumps) will be required during operation in this mode. The HRSG duct burners will not be available in this mode. The maximum generation capability of the Facility operating in this mode will be [redacted] CT load.

- The Facility's CT evaporative coolers should not be operated at ambient temperatures less than [redacted] to prevent freezing at the CT compressor inlet.

APPENDIX B

REQUESTS FOR ENERGY

1.1 Schedules for Requested Quantities of Energy. Purchaser and each other Customer shall provide Seller with a single Request for Energy in order to schedule requested quantities of each category of unit output as follows:

1.1.1 Day Ahead Daily Schedule. Customers shall communicate the day ahead Request for Energy for each day to Seller at or before [redacted] Eastern Prevailing Time of the immediately preceding day before delivery is to be made, or such other earlier time that may be required by an RTO.

1.1.1.1 When AGC mode is available, during each hour the unit is scheduled to be in AGC mode, the Request for Energy shall specify the maximum amount of Energy desired for each of the twenty-four (24) hours. During each hour the unit is in AGC mode, the Customers shall not be permitted to reduce the Request for Energy to an amount less than [redacted] MW of the maximum Energy scheduled during that hour in the Request for Energy from the Customers' aggregate Equity Capacity and the Customers' aggregate capacity available under the Power Purchase Agreements (Customers' "PPA Capacity"). If in any hour, should the Customers reduce the Request for Energy amount by more than [redacted] MW, the Customers shall pay Seller [redacted] for the difference between the amount of the Delivered Energy and the amount that is [redacted] MW below the Request for Energy amount.

1.1.1.2 During each hour the Facility is not scheduled to be in AGC mode or the AGC mode is unavailable, the Request for Energy shall specify the amount of Energy from the Customers' aggregate PPA Capacity and aggregate Equity Capacity for each of the twenty-four (24) hours. Requests for Energy shall be submitted in [redacted] MW increments in a total amount that falls between the Facility's minimum capability and its maximum capability as described in the Technical Limits.

1.2. Hourly Changes to the Daily Schedule. The Customers jointly shall be entitled to make changes to a Request for Energy by communicating such changes to Seller no later than [redacted] prior to the beginning of the hour in which such changes are to become effective. The Customers shall

be responsible for any costs associated with OASIS notifications and NERC tagging requirements.

1.3. Capacity Emergency. During any periods in which the Customers experience a Capacity Emergency, the Customers shall be entitled to increase the Request for Energy on shorter notice than that provided in paragraph 1.2 above by an amount not to exceed the Customers' unavailable resources that were the cause of the Capacity Emergency and Seller shall endeavor to comply with the request consistent with the Technical Limits, Prudent Utility Practice, applicable Law and Permit requirements.

1.4. Minimum Start-up Time. If the Customers have scheduled a zero amount of Capacity in any hour and the Facility is not on-line, the Customers shall provide notice consistent with the Technical Limits prior to scheduling any Request for Energy.

1.5. Load Following Service. The Customers shall have the ability to control the output of the Facility using the AGC mode, if available, only to the extent that the Facility has the ability to operate in the AGC mode consistent with the Technical Limits, Prudent Utility Practice, and applicable Law and Permit requirements.

1.6 Electronic Scheduling. The Customers shall use electronic scheduling for Requests for Energy under this Agreement, if and to the extent that Seller's electronic scheduling capability is operational. To the extent it is not, the Parties will use other mutually agreed-upon communication procedures (such as fax).

2.1 Shortfall Conditions; Oversupply Conditions.

2.1.1 If the Facility is in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the Facility is not within [redacted] MW of the Request for Energy, OUC shall communicate to Seller the amount of error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the Request for Energy within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.1.1 If the actual output of the Facility is greater than the Request for Energy (an "Oversupply Condition"), the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the Facility equals the Request for Energy. OUC, acting for itself and on behalf of the other Customers, shall coordinate with Seller during the period that the actual output of the Facility exceeds the Request for Energy. The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition. Seller shall compensate OUC, on its own behalf and as agent for KUA and FMPA, for any such Oversupply Condition.

2.1.1.2 If the actual output of the unit is less than the Request for Energy (an "Undersupply Condition"), the provisions of Section 4.3 will apply if applicable.

2.1.2 If the Facility is not in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the unit is not within [redacted] MW of the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy pursuant to Section 4.5 of this Agreement), then OUC shall communicate to Seller the amount of the error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.2.1 If an Oversupply Condition exists, the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the unit equals the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy). The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition.

2.1.2.2 If an Undersupply Condition exists, the provisions of Section 4.3 will apply if applicable.

3.1 Notification Requirements for Delivery of Energy from Alternate Resources.

3.1.1 When the Facility is available and running at minimum load and spinning reserves are available, Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of Customers' Schedule at least [redacted] (or the amount of time in which an RTO has determined that the Physical Transmission Rights ("PTRs") may be recalled) prior to the scheduled commencement of delivery of such Energy. For purposes of paragraph 3.1, the phrase "has scheduled delivery" means that Seller has scheduled and arranged the OASIS, tagging, and any transmission rights required by an RTO. If an RTO is established in Florida, and under such condition the RTO determines that Physical Transmission Rights (PTRs) may be recalled if not utilized, then Seller will notify OUC if Seller has so scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.2 When the Facility is unavailable and is not scheduled to return to service in time for Seller to serve the Customers' Schedule, Seller will notify OUC within [redacted] after Seller's receipt of Customers' Schedule if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customers' Schedule. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.3 When the Facility becomes unavailable while Seller is serving Customers' Schedule, Seller will notify OUC within [redacted] after the Facility is deemed unavailable if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of the remainder of Customers' Schedule. If Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than the top of the next full hour following the hour that Seller notified OUC of Seller's election. (Example: The Facility becomes unavailable at [redacted] Seller gives notice no later than [redacted] if Seller will arrange to deliver Energy from

Alternate Resources. Delivery from Alternate Resources should begin no later than [redacted]) At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.4 When the Facility is expected to return from an outage, but does not, Seller will notify OUC within [redacted] of Seller's realization that the Facility will not be available as expected to meet the start of a Customer's Schedule. If the start of such Customer's Schedule is to begin within [redacted] or less from the time of such notice, Seller will notify OUC at the same time if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule. Otherwise Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule at least [redacted] prior to the start of such Schedule and preferably at least [redacted] If Seller notifies OUC that Seller has scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than [redacted] that Seller notified OUC of Seller's election (but not earlier than the original start of such Customers' Schedule). If an RTO develops in Florida, and under such condition the RTO determines that PTRs may be recalled if not utilized, then Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

APPENDIX C

CAPACITY TESTING PROCEDURE

The capability of the Facility will be required to be demonstrated prior to the Commencement Date. The demonstration of the capability of the Facility following the Commencement Date shall be scheduled in accordance with the provisions of Section 4.1.2. As provided in Section 4.1.3, Participants may also request additional tests of the Facility which shall not be used as the basis for determining the Demonstrated Capability of the Facility. Purchaser shall have the right to monitor (either on-Site or otherwise) all performance tests.

All Capacity testing will be adjusted to the Rated Conditions using correction curves supplied by Seller. "Rated Conditions" means seventy (70) degrees Fahrenheit (°F) and forty five percent (45%) relative humidity. The demonstrated net output of the Facility will be as measured by the Meters.

On the date of the Capacity test, Seller shall bring the Facility to maximum full load capability within the Technical Limits of the Facility for the ambient conditions for that day. The test shall be scheduled between the weekday hours of [redacted] (prevailing Eastern Time) and will be conducted over [redacted] period (or a lesser period if mutually agreed upon). Seller must notify Customers when the Facility is at maximum full load capability, at which time the Capacity test shall begin. The Demonstrated Capability will be the average net hourly output over the test period corrected to Rated Conditions.

APPENDIX D

Example Calculations of Quantities of Gas Transportation and/or Commodity Required for Delivery from Alternate Resources

Listed below are examples of the determination of the amount of gas transportation and/or commodity that the Fuel Supply Agent shall provide to Seller pursuant to Section 4.2.5.2 or 4.2.5.3 when Seller elects to deliver Energy from Alternate Resources.

Example 1

The facility is unavailable. The Customers have Scheduled 400 MWh of Energy in an hour. Seller notifies OUC that Seller will supply the 400 MWh of Energy for the subject hour from Alternate Resources.

In Example 1, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 2

The facility is unavailable. The Customers have Scheduled 610 MWh of Energy in an hour. Seller notifies OUC that Seller will supply 550 MWh of Energy for the subject hour from Alternate Resources.

In Example 2, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 3

The facility is available. The Customers have Scheduled 450 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 100 MWh of Energy for the subject hour from Alternate Resources and 350 MWh from the Facility.

In Example 3, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 4

The facility is available. The Customers have Scheduled 600 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 200 MWh of Energy for the subject hour from Alternate Resources and 400 MWh from the Facility.

In Example 4, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

APPENDIX E

FORM OF PAYMENT GUARANTY

This Guaranty Agreement (the "Guaranty") is made by The Southern Company ("Guarantor"), a Delaware corporation, in favor of Florida Municipal Power Agency (All Requirements Power Supply Project) ("FMPA"), a governmental legal entity organized and existing under the laws of the State of Florida.

WHEREAS, Southern Company - Florida LLC ("Principal Obligor"), a Delaware limited liability company, and FMPA entered into that certain Power Purchase Agreement, dated as of March 26, 2001 (the "PPA");

WHEREAS, Guarantor has agreed to provide assurance for the payment of Principal Obligor's obligations in connection with the PPA as provided in this Guaranty; and

WHEREAS, the execution and delivery of this Guaranty by Guarantor is pursuant to the terms of the PPA in order to satisfy the requirement that Principal Obligor cause an Affiliate to maintain in place a guaranty of Principal Obligor's obligations under the PPA.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the adequacy, receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. **Guaranty.** Guarantor hereby irrevocably, unconditionally and absolutely guarantees the punctual payment when due of Principal Obligor's payment obligations arising under the PPA, as amended or modified from time to time, together with any interest thereon, including, without limitation, any interest amounts accruing under the PPA during the pendency of insolvency, bankruptcy, reorganization or other similar proceedings affecting Principal Obligor or its assets; provided, however, that the maximum liability of Guarantor under this Guaranty with respect to Principal Obligor's obligations under the PPA shall be limited to the amount that is equal to the then-current Termination Payment (as defined in the PPA), which shall not exceed in any event [redacted] (collectively, the "Guaranteed Obligations"); provided, further, that the cap on Guarantor's liability under this Guaranty established in the immediately preceding clause creates an absolute cap on Guarantor's liability to FMPA in relation to the PPA and, if and when Guarantor's liability under this Guaranty has reached such cap, then from and after such time, Guarantor shall have no further liability under this Guaranty whatsoever to FMPA and this Guaranty shall thereupon terminate; provided, further, that costs incurred by Guarantor under Section 4 hereof shall not be counted for purposes of determining whether Guarantor has reached

such cap, unless and to the extent that Guarantor's costs under such Section 4, together with costs incurred by Guarantor under the corresponding provisions of Guarantor's other three Payment Guarantees of contemporaneous date to one or more of OUC, FMPA and KUA, exceed [redacted].

2. **Guaranty Absolute.** The liability of Guarantor under this Guaranty shall be irrevocable, absolute and unconditional irrespective of:

(a) any lack of validity or enforceability of or defect or deficiency in the PPA or any other documents executed in connection with the PPA;

(b) any assignment, transfer, modification, extension or waiver of any of the terms of the PPA;

(c) any change in the time, manner, terms of payment of or in any other term of, all or any of the Guaranteed Obligations, or any other amendment or waiver of or any consent to departure from any agreement or instrument executed in connection therewith;

(d) any sale, exchange, release or non-perfection of any property standing as security for the liabilities hereby guaranteed or any liabilities incurred directly or indirectly hereunder or any set off against any of said liabilities, or any release or amendment or waiver of or consent to departure from any other guaranty, for all or any of the Guaranteed Obligations;

(e) applicable statutes of limitation, failure, omission, delay, waiver or refusal by FMPA to exercise, in whole or in part, any right or remedy held by FMPA with respect to the PPA or any transaction under the PPA; or

(f) any change in the existence, structure or ownership of Guarantor or Principal Obligor, or any insolvency, bankruptcy, reorganization or other similar proceeding affecting Principal Obligor or its assets.

The obligations of the Guarantor hereunder are several from the Principal Obligor or any other person, and are primary obligations concerning which the Guarantor is the principal obligor. There are no conditions precedent to the enforcement of this Guaranty, except as expressly contained herein.

This Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations are annulled, set aside, invalidated, declared to be fraudulent or preferential, rescinded or must otherwise be returned, refunded or repaid by FMPA upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of

Principal Obligor or any other guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, Principal Obligor or any other guarantor or any substantial part of its property or otherwise, all as though such payment or payments had not been made.

3. **Waiver.** This is a guaranty of payment and not of collection. Guarantor hereby waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of any of the Guaranteed Obligations and of any action by FMPA in reliance hereon or in connection herewith;

(b) except as expressly set forth herein, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to the Guaranteed Obligations; and

(c) any requirement that suit be brought against Principal Obligor or any other person as a condition to Guarantor's liability for the Guaranteed Obligations under this Guaranty or as a condition to the enforcement of this Guaranty against Guarantor.

Notwithstanding anything to the contrary set forth herein, Guarantor shall have the same defenses available to it as Principal Obligor may have with respect to any payment obligations arising under the PPA.

4. **Expenses.** Guarantor agrees to pay on demand any and all costs, including reasonable legal fees, and other expenses incurred by FMPA in enforcing Guarantor's payment obligations under this Guaranty; provided that the Guarantor shall not be liable for any expenses of FMPA if no payment under this Guaranty is due.

5. **Subrogation.** Guarantor shall be subrogated to all rights of FMPA against Principal Obligor in respect of any amounts paid by Guarantor pursuant to the Guaranty, provided that Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise, until all of the Guaranteed Obligations shall have been irrevocably paid to FMPA in full. If any amount shall be paid to the Guarantor on account of such subrogation rights at any time when all the Guaranteed Obligations shall not have been paid in full, such amount shall be held in trust for the benefit of FMPA and shall forthwith be paid to FMPA to be applied to the Guaranteed Obligations. If (a) the Guarantor shall perform and shall make payment to FMPA of all or any part of the Guaranteed Obligations and (b) all the Guaranteed Obligations shall have been paid in full, FMPA shall, at the Guarantor's request, execute and deliver to the Guarantor appropriate documents necessary to evidence the transfer by subrogation to the Guarantor of any interest in the Guaranteed Obligations resulting from such payment by Guarantor.

6. **Notices.** All demands, notices and other communications provided for hereunder shall, unless otherwise specifically provided herein, (a) be in writing addressed to the party receiving the notice at the address set forth below or at such other address as may be designated by written notice, from time to time, to the other party, and (b) be effective upon delivery, when mailed by U.S. mail, registered or certified, return receipt requested, postage prepaid, or personally delivered. Notices shall be sent to the following addresses:

If to FMPA:

Florida Municipal Power Agency

7201 Lake Ellenor Drive

Orlando, FL 32809

Attention: General Manager

Tel: 407-355-7767

Fax: 407-355-5793

With a copy to:

Frederick M. Bryant

General Counsel, Florida Municipal Power Agency

P. O. Box 3209

Tallahassee, FL 32315-3209

Telephone: 850-297-2011

Facsimile: 850-297-2014

If to Guarantor:

The Southern Company

c/o Southern Company Services, Inc.

270 Peachtree Street NW

Suite 2000

Atlanta, GA 30303

Attention: Allen L. Leverett, Vice President and Treasurer

Tel: 404-506-0710

Fax: 404-506-0712

With a copy to:

Robert H. Forry, Esq.

Troutman Sanders LLP

Bank of America Plaza

600 Peachtree Street, N.E.

Suite 5200

Atlanta, Georgia 30308-2216

Tel: 404-885-3142

Fax: 404-962-6559

If to Principal Obligor:

Southern Company - Florida LLC

c/o Southern Company Services, Inc.

270 Peachtree Street NW

Suite 2000

Atlanta, GA 30303

Attention: Allen L. Leverett, Vice President and Treasurer

Tel: 404-506-0710

Fax: 404-506-0712

With a copy to:

Robert H. Forry, Esq.

Troutman Sanders LLP

Bank of America Plaza

600 Peachtree Street, N.E.

Suite 5200

Atlanta, Georgia 30308-2216

Tel: 404-885-3142

Fax: 404-962-6559

7. **Demand and Payment.** Any demand by FMPA for payment hereunder shall be in writing, signed by a duly authorized officer of FMPA and delivered to the Guarantor pursuant to Section 6 hereof, and shall (a) reference this Guaranty, (b) specifically identify the Principal Obligor, the Guaranteed Obligations to be paid and the amount of such Guaranteed Obligations and (c) set forth payment instructions. There are no other requirements of notice, presentment or demand. Guarantor shall pay, or cause to be paid, such Guaranteed Obligations within three (3) business days of receipt of such demand.

8. **No Waiver; Remedies.** Except as to applicable statutes of limitation, no failure on the part of FMPA to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

9. **Replacement of Guarantor and Termination.**

(a) Guarantor may assign and delegate its rights and obligations under this Guarantee, in whole or in part, as follows: (i) without the consent of FMPA, to Southern Power Company, a Delaware corporation and parent company of Principal Obligor, or other Affiliate of Principal Obligor, if Southern Power Company or such other Affiliate has achieved the following three characteristics: (1) a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's), (2) Net Equity (as hereinafter defined) of at least [redacted], as reflected on its

most recent audited balance sheet, and (3) Gross Equity (as hereinafter defined) of at least [redacted], provided, however, that the date on which Guarantor causes such a replacement of this Guaranty under this Section 9(a)(i) may not be earlier than the Commercial Operation Date (as defined in the Ownership Agreement); or (ii) with the consent of FMPA, which consent may not be unreasonably withheld, to an assignee which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's) and which meets other reasonable financial criteria similar to those identified in Section 9(a)(i), provided, however, that if Guarantor requests FMPA's consent to such an assignment and delegation in connection with a permitted transfer or assignment of the PPA, then FMPA may not withhold such consent if the assignee meets the financial criteria in Section 9(a)(ii). An assignment and delegation of Guarantor's rights and obligations under this Section 9 shall become effective when the replacement guarantor executes and delivers to FMPA a replacement guaranty on terms and conditions substantially similar to this Guaranty.

(b) For purposes of this Guaranty, the following terms shall have the following meanings:

"Net Equity" shall mean the aggregate of the capital stock and other equity accounts (including retained earnings and paid-in capital) of Southern Power Company or other Affiliate of Principal Obligor, as the case may be.

"Gross Equity" shall mean Net Equity plus Guaranteed Debt plus loans to Southern Power Company from its parent corporation.

"Guaranteed Debt" shall mean any obligations of Southern Power Company or other Affiliate of Principal Obligor, as the case may be, for or in respect of (a) moneys borrowed or raised (whether or not for cash) by whatever means (including acceptances, deposits, discounting, letters of credit, factoring (other than on a non-recourse basis), finance leases, and any other form of financing which is recognized in Southern Power Company's or other Affiliate of Principal Obligor's, as the case may be, financial statements as being in the nature of a borrowing (excluding for the avoidance of doubt, share capital, share premium account and any capital prepayment reserve), which has been guaranteed by Guarantor, and (b) the deferred purchase price of assets or services (other than goods and services obtained on normal commercial terms in the ordinary course of business or operations), which has been guaranteed by Guarantor.

"Affiliate" of an Entity shall mean any other entity controlled by, controlling or under common control with such entity, where control of an entity means the ability to direct the policies of such entity through election of a majority of such entity's board of directors or other governing body or by contract or otherwise.

(c) This Guaranty shall terminate, and upon the effective date of such termination Guarantor shall have no further liability hereunder, on the earliest to occur of: (i) the satisfaction of all of the Guaranteed Obligations, (ii) the termination or expiration of the PPA, (iii) the date on which the liability cap is reached, as provided in Section 1 hereof, or (iv) the date on which an assignment and delegation by Guarantor of its rights and obligations hereunder becomes effective under Section 9(a) hereof.

10. **Assignment by FMPA; Successors and Assigns.** FMPA may, upon notice to Guarantor, assign its rights hereunder only to a subsequent owner of all of FMPA's interest in the Facility and the Interconnection Facilities (as defined in the PPA) without the consent of Guarantor. Subject to the foregoing, this Guaranty shall be binding upon and inure to the benefit of the parties hereto and their respective successors, permitted assigns, and legal representatives.

11. **Amendments, Etc.** No amendment of this Guaranty shall be effective unless in writing and signed by Guarantor and FMPA. No waiver of any provisions of this Guaranty or consent to any departure by Guarantor therefrom shall in any event be effective unless such waiver shall be in writing and signed by FMPA. Any such waiver shall be effective only in the specific instance and for the specific purpose for which it was given.

12. **Captions.** The captions in this Guaranty have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Guaranty.

13. **Representations and Warranties.**

The Guarantor represents and warrants as follows:

(a) The Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets.

(c) This Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting FMPA's rights and to general equity principles.

(d) The financial statements of Guarantor for the year ended December 31, 2000 (the "Financial Statements"), heretofore delivered to FMPA or filed with the United States Securities Exchange Commission by Guarantor present fairly the financial condition and results of operations of Guarantor and its consolidated subsidiaries as of the dates and for the period specified therein in conformity with generally accepted accounting principles, and, except as otherwise expressly stated therein, consistently applied.

14. **Limitation by Law.** All rights, remedies and powers provided in this Guaranty may be exercised only to the extent that the exercise thereof does not violate any applicable provision of law, and all the provisions of this Guaranty are intended to be subject to all applicable mandatory provisions of law that may be controlling and to be limited to the extent necessary so that they will not render this Guaranty invalid, unenforceable, in whole or in part, or not entitled to be recorded, registered or filed under the provisions of any applicable law.

15. **Governing Law; Submission to Jurisdiction.** This Guaranty shall be governed by, and construed in accordance with, the laws of the State of Georgia, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction. The parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Northern District of Georgia, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Superior Court of the State of Georgia sitting in Fulton County, Georgia and the parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized officer effective as of this ___ day of _____, 2001.

"Guarantor"

THE SOUTHERN COMPANY

By:_____

Name:_____

Title:_____

CONFIDENTIAL AND PROPRIETARY EXECUTION COPY

****THIS AGREEMENT CONTAINS PROPRIETARY CONFIDENTIAL BUSINESS INFORMATION WHICH IS PROTECTED FROM DISCLOSURE TO THE PUBLIC****

POWER PURCHASE AGREEMENT

BETWEEN

ORLANDO UTILITIES COMMISSION

AND

SOUTHERN COMPANY - FLORIDA LLC

Dated as of March 19, 2001

TABLE OF CONTENTS

Section	Page
SECTION 1 DEFINITIONS AND EXPLANATION OF TERMS	2
SECTION 2 TERM OF AGREEMENT	15
SECTION 3 CONDITIONS PRECEDENT	16
SECTION 4 SALE AND PURCHASE	16
SECTION 5 SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY	32
SECTION 6 REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE	34
SECTION 7 INTERCONNECTION AND TRANSMISSION	36
SECTION 8 RISK OF LOSS; METERING	37
SECTION 9 METHOD OF PAYMENT	39
ARTICLE 10 CHANGE IN LAW; MODIFICATION OF AGREEMENT	40
SECTION 11 FORCE MAJEURE	41
SECTION 12 EVENTS OF DEFAULT; TERMINATION	42
SECTION 13 WAIVER	46
SECTION 14 REPRESENTATIONS AND WARRANTIES	46
SECTION 15 PERFORMANCE ASSURANCE	49
SECTION 16 LIABILITY OF PARTIES	52
SECTION 17 ASSIGNMENT	55
SECTION 18 DISPUTE RESOLUTION	56

SECTION 19 AMENDMENT 57

SECTION 20 NOTICES 57

SECTION 21 APPLICABLE LAW 59

SECTION 22 SEVERABILITY 59

SECTION 23 ENTIRE AGREEMENT 59

SECTION 24 NO THIRD PARTY BENEFICIARIES 59

SECTION 25 COUNTERPARTS 60

SECTION 26 INFORMATION AND CONFIDENTIALITY 60

SECTION 27 PUBLIC STATEMENTS 61

SECTION 28 INSURANCE 61

SECTION 29 TAXES 62

APPENDIX A TECHNICAL LIMITS

APPENDIX B REQUESTS FOR ENERGY

APPENDIX C CAPACITY TESTING PROCEDURE

APPENDIX D EXAMPLE CALCULATIONS

APPENDIX E AFFILIATE GUARANTEE

CONFIDENTIAL AND PROPRIETARY EXECUTION COPY

POWER PURCHASE AGREEMENT

This Power Purchase Agreement (this "Agreement") is made and entered into as of the 19th day of March, 2001, by and between the Orlando Utilities Commission, a statutory utilities commission organized and existing under the laws of the State of Florida ("Purchaser"), and Southern Company - Florida LLC, a limited liability company organized and existing under the laws of the State of Delaware ("Seller"). Purchaser and Seller are hereinafter each referred to individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, in addition and supplemental to their other powers, OUC, KUA and FMPA (the "Public Agencies"), pursuant to the Florida Interlocal Cooperation Act of 1969, Chapter 163, Part I, Florida Statutes, (the "Interlocal Act") are authorized and empowered to cooperate with each other on a basis of mutual advantage and thereby to provide services and facilities in a manner and pursuant to forms of government organizations that will best accord with geographic, economic, electrical generation requirements and other factors; and

WHEREAS, the Ownership Agreement was entered into by the Public Agencies as an interlocal agreement, to invoke all of the powers of the Interlocal Act, for the purpose of providing a structure for the Public Agencies, in participation with Seller, a foreign public utility, to operate, maintain, repair, improve, extend, or otherwise participate jointly in a nominal six hundred thirty-three (633) megawatt combined cycle electric generating facility (the "Facility"), which is proposed, and which is to be constructed, owned, and located within the State of Florida by Seller and the Public Agencies; and

WHEREAS, Seller intends to sell to Purchaser, and Purchaser intends to purchase from Seller, a portion of Seller's share of the Capacity and Energy generated by the Facility in accordance with the terms and conditions of this Agreement and in full compliance with the Interlocal Act;

WHEREAS, this Agreement and the two substantially similar contracts are being entered into to invoke all of the powers of the Interlocal Act for the purpose of obligating Customers, pursuant to such Interlocal Act, to purchase Seller's share of the Capacity of and Energy generated by the Facility in accordance with the terms and conditions of this Agreement; and

WHEREAS, Seller and Purchaser acknowledge that this Agreement is one of three substantially similar contracts through which Seller will sell and the three Purchasers will individually purchase their respective designated shares of Seller's share of the Capacity and Energy generated by the Facility.

NOW, THEREFORE, for the purpose of exercising all of the powers enumerated in the Interlocal Act and the Florida Joint Power Act, Part II of Chapter 361, Florida Statutes, (the "Joint Power Act") (collectively, the "Acts"), Purchaser hereby designates this Agreement as an interlocal agreement within the meaning and intent of the Interlocal Act, and invokes all powers contained therein with full powers to perform all of the provisions herein authorized to be performed by the Parties; and

FURTHER, NOW, THEREFORE, in consideration of the mutual promises, covenants and agreements set forth herein, and other good and valuable consideration, the receipt, sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound hereby, agree as follows:

SECTION 1
DEFINITIONS AND EXPLANATION OF TERMS

1.1 Definitions. When used in this Agreement, the following capitalized terms shall have the meanings set forth below:

1.1.1 "Actual Availability" has the meaning given such term in Section 4.3.3 or 4.3.4, as applicable.

1.1.2 "Actual Capability" means the amount of Capacity the Facility is capable of producing in any given hour.

1.1.3 "AGC" means automatic generation control, which is the capability to make automatic adjustments to load change by generation through the use of a digital computer. This control is based on such factors as frequency, cost and tie line flows.

1.1.4 "Agreement" means this Power Purchase Agreement, including all appendices attached hereto and all amendments hereto that may be made from time to time.

1.1.5 "Alternate Resources" has the meaning given such term in Section 4.4.

1.1.6 "Ancillary Services" means ancillary services customarily provided by an electric generating facility, including voltage/VAR control, load following, regulation and frequency response, spinning reserve and non-spinning reserve.

1.1.7 "Annual Capacity Charge" means (i) [redacted] per kilowatt per month for that portion of the Initial Term before the end of the day

of May 31, 2014 , (ii) [redacted] per kilowatt per month for that portion of the Initial Term after the beginning of the day June 1, 2014 and during the Extended Term, (iii) with respect to the first Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), (iv) with respect to the second Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3), and (v) with respect to the third Further Extension, the higher of [redacted] per kilowatt per month or the Market Price (if Seller elects the Market Price pursuant to the provisions of Section 2.3); *provided, however,* that the Annual Capacity Charge shall be (i) increased by [redacted] per kilowatt per month for every [redacted] increase in the BOP Capital Cost Range that occurs pursuant to Sections 6.7.2(b) or 6.7.2(c) of the Ownership Agreement, (ii) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the BOP Capital Costs Range that occurs pursuant to Sections 6.7.2(b) and 6.7.2(c) of the Ownership Agreement, (iii) increased by [redacted] per kilowatt per month for every [redacted] increase in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement, and (iv) decreased by [redacted] per kilowatt per month for every [redacted] decrease in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement.

1.1.8 "Annual Purchaser's Capacity Nomination" of the Purchaser means, during the first five Contract Years, [redacted] of the Demonstrated Capability, and thereafter, [redacted] of the Demonstrated Capability reduced by those amounts, if any, that Purchaser elects to subtract from the Capacity available to Purchaser pursuant to the process provided in Section 4.1.4 for the Customers jointly to make such elections.

1.1.9 "Availability Guarantee" has the meaning given such term in Section 4.3.1.

1.1.10 "Availability Incentive Payment" has the meaning given such term in Section 4.3.2.

1.1.11 "Bankruptcy" means, with respect to a Party, (i) an adjudication of bankruptcy or insolvency, or the entry of an order for

relief, under any Bankruptcy Law with respect to such Party; (ii) the making by such Party of an assignment for the benefit of its creditors; (iii) the filing by such Party of a petition in bankruptcy or for relief under any Bankruptcy Law; (iv) the filing by such Party of an answer or pleading admitting or failing to contest the material allegations of any such petition; (v) the filing against such Party of any petition in bankruptcy or for relief under any Bankruptcy Law (unless such petition is dismissed within ninety (90) days from the date of filing thereof); (vi) the appointment of a trustee, conservator or receiver for such Party or for all or substantially all of its assets (unless such appointment is vacated or stayed within ninety (90) days of such appointment); or (vii) the taking by such Party of any action for its winding up or liquidation, or the consent by such Party to any of the actions described in clauses (i) through (vi) being taken against it.

1.1.12 "Bankruptcy Law" means any applicable bankruptcy or insolvency statute.

1.1.13 "Bond Legislation" shall mean the Junior Lien Resolution, the Senior Lien Resolution and the Master Note Resolution.

1.1.14 "BOP Capital Cost Range" has the meaning ascribed to the term in Section 6.7.1 of the Ownership Agreement.

1.1.15 "Business Day" means any day other than Saturday or Sunday on which commercial banks are authorized to open for business in Orlando, Florida.

1.1.16 "Capacity" means electric capacity.

1.1.17 "Capacity Emergency" means, with respect to any hour, that any one or more of Purchaser's resources is unavailable due to a forced outage and the summation of such Purchaser's firm Capacity obligations exceeds the summation of such Purchaser's available resources.

1.1.18 "Capacity Payment" has the meaning given such term in Section 4.1.1.

1.1.19 "Change in Law" has the meaning given such term in Section 10.1.3.

1.1.20 "Collateral Documents" means, collectively, the Ownership Agreement, the Operating Agreement, the Interconnection Agreement, the Power Purchase Agreements of the other Customers, the long term lease of the Facility Site by OUC to and for the benefit of the Participants, the guarantee to be provided by an affiliate of Seller as contemplated in Section 16.3, and the agreement(s) pursuant to which Purchaser and/or the other Customers provide station service and other support services (including but not limited to demineralized water and cooling water supply) to Seller.

1.1.21 "Commencement Date" has the meaning given such term in Section 5.2.

1.1.22 "Commercial Operation Date" has the meaning ascribed to such term in Section 1.1.13 of the Ownership Agreement.

1.1.23 "Confidential Information" has the meaning given such term in Section 26.

1.1.24 "Contract Year" means (i) the period commencing on the Commencement Date or, if Seller elects the option under Section 4.5(ii)(a), the later of the Commencement Date or Scheduled Commencement Date, and ending on the last day of the month in which the first anniversary date of the Commencement Date falls, and (ii) each twelve (12)-month period thereafter, except that for the twelve (12)-month period during which the expiration or termination date of this Agreement occurs, Contract Year shall mean the period commencing on the first day of such twelve (12)-month period and ending on such expiration or termination date.

1.1.25 "Customers" means collectively all of OUC, Kissimmee Utility Authority and Florida Municipal Power Agency (All Requirements Power Supply Project), or their permitted assigns.

1.1.26 "Delivered Energy" means, in respect of a period of time, the amount of Energy from the Facility or from Alternate Resources delivered by Seller to Purchaser at the Delivery Point for sale to Purchaser pursuant to this Agreement.

1.1.27 "Delivery Point" means (a) with respect to Energy delivered from the Facility, the high side of generator step-up transformer, as further described in the Interconnection Agreement,

and (b) with respect to Energy delivered from Alternate Resources, any unconstrained point on the Grid.

1.1.28 "Demonstrated Capability" means the net Capacity of the Facility, determined by a periodic Capacity test, adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity.

1.1.29 "Dispute" has the meaning given such term in Section 18.

1.1.30 "Eastern Prevailing Time" or "EPT" means the time prevailing in the Eastern time zone of the United States of America.

1.1.31 "Effective Date" has the meaning given such term in Section 3.1.

1.1.32 "Eligible Collateral" has the meaning given such term in Section 15.1.1.

1.1.33 "Energy" means electric energy (expressed in megawatt-hours).

1.1.34 "Energy Payment" has the meaning given such term in Section 4.2.

1.1.35 "Equipment Breakdown" means a mechanical breakdown of equipment at the Facility that is not the result of a Force Majeure that is an act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted] storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under Section 1.1.44 if such failure were directly experienced by the applicable Party.

1.1.36 "Equity Capacity" with respect to each Participant means that Participant's percentage share of the Capacity of the Facility corresponding to such Participant's ownership interest in the Facility.

1.1.37 "Event of Default" means any of the events listed in Sections 12.1 and 12.2.

1.1.38 "Facility" means the gas fired combined cycle electric generating unit to be located on the Facility Site and owned by the Participants, and its associated interconnection facilities, as defined in the Ownership Agreement by the terms "Facility" and "Interconnection Facilities."

1.1.39 "Facility Site" means the parcel of land in Orlando, Florida on which the Facility is to be located, as further described in Appendix A.

1.1.40 "FDEP" means the Florida Department of Environmental Protection or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.41 "FERC" means the Federal Energy Regulatory Commission or any successor Governmental Body exercising the same or equivalent jurisdiction.

1.1.42 "Firm Transmission Service" means (a) electric transmission service designated firm under the open access transmission tariff of a transmission provider having an open access transmission tariff or (b) if purchased from a transmission provider that does not have an open access transmission tariff, electric transmission service sold by such transmission provider as firm transmission service and generally considered, pursuant to Prudent Utility Practice and FRCC requirements, to be substantially equivalent to the firm transmission service referenced in item (a) of this definition.

1.1.43 "Fixed Amount" has the meaning ascribed to such term in Section 6.7.1 of the Ownership Agreement.

1.1.44 "Force Majeure" as to a Party means each of the following events as affects the Facility: act of God or public enemy; landslide; sinkhole; lightning; earthquake; fire [redacted] storm; ice; snow; hurricane; tornado; wind; flood; riot; civil disturbance; insurrection; war; sabotage; terrorism; shutdown of the Facility by a court order or Governmental Body not resulting from any action or inaction by the applicable Party; strike, lockout or labor difficulty affecting the SEC Site generally [redacted]

[redacted]; failure of contractors or suppliers (including, in the case of Seller, OUC and other Customers providing services to Seller) to provide fuel, equipment, material or services, provided that such failure would qualify as a Force Majeure under this provision if such failure were directly experienced by the applicable Party; or any other occurrence, nonoccurrence or set of circumstances, whether or not foreseeable, that is beyond the reasonable control of the applicable Party and is not caused or exacerbated by the applicable Party's failure to follow Prudent Utility Practices.

1.1.45 "FRCC" means the Florida Reliability Coordinating Council or any successor organization.

1.1.46 "Fuel Supply Agent" has the meaning given such term in the Operating Agreement.

1.1.47 "Further Extension" has the meaning given such term in Section 2.3.

1.1.48 "Gas Delivery Point" shall have the meaning assigned to it in the Operating Agreement.

1.1.49 "Governmental Body" shall mean, except as provided in the following sentence, (i) any local, state, regional or federal administrative, legal, judicial, or executive agency, court, commission, department or other entity having jurisdiction or binding authority over any element of the Project or the performance of the Parties under this Agreement or the Collateral Documents, but excluding any agency, commission, department or other such entity acting in its capacity as lender, guarantor or mortgagee and (ii) NERC, FRCC and any RTO. Except as expressly provided otherwise in this Agreement, the definition "Governmental Body" shall be deemed to not include OUC, KUA and FMPA for the purposes of this Agreement.

1.1.50 "Grid" means (i) OUC's electric transmission system, or (ii) if ownership or control of and jurisdiction over OUC's electric transmission system is succeeded to by an RTO or other entity, the portion of the electric transmission system of that RTO or other successor entity that most closely resembles the OUC electric

transmission system as it existed on the effective date of this Agreement.

1.1.51 "Guaranteed Output" means in any given hour the amount of Capacity (in MWh per hour) determined by adjusting the Demonstrated Capability to the prevailing ambient conditions in such hour and adjusting for degradation. The degradation adjustment shall be [redacted] The degradation adjustment shall be [redacted]

1.1.52 "Indemnified Parties" has the meaning given such term in Section 16.1.1.

1.1.53 "Indemnifying Party" has the meaning given such term in Section 16.1.1.

1.1.54 "Interconnection Agreement" means that certain Interconnection Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.55 "Interconnection Meters" has the meaning given such term in Section 8.2.

1.1.56 "Junior Lien Resolution" shall mean the OUC resolution duly adopted on May 16, 1998, as supplemented and amended, authorizing the issuance of OUC's Water and Electric Subordinate Revenue Bonds.

1.1.57 "Lender" has the meaning given such term in Section 12.3.

1.1.58 "Law" shall mean all constitutions, charters, laws, codes, ordinances, orders, judgments, decrees, injunctions, licenses, rules, permits, approvals, regulations and requirements of every Governmental Authority (including OUC) having jurisdiction over the matter in question, whether federal, state or local, which may be applicable to any Party, as required by the context in which used, or to the Facility or OUC Interconnection Facilities, or to the use, manner of use, occupancy, possession, planning, licensing, design, procurement,

construction, acquisition, testing, startup, operation, maintenance, management, control, addition, renewal, modification, replacement or disposal of the Facility and the OUC Interconnection Facilities or any portion of portions thereof.

1.1.59 "Market Price" shall mean the price established by Seller, or negotiated and agreed upon by the Parties, as the case may be, upon Seller's election pursuant to Section 2.3 with respect to any Further Extension, which shall become the Annual Capacity Charge for Capacity to be delivered by Seller during such Further Extension consistent with all other terms and conditions of this Agreement.

1.1.60 "Master Note Resolution" shall mean the OUC resolution duly adopted on August 25, 1998, as supplemented and amended, authorizing the issuance of OUC's Water and Electric Revenue Application Notes.

1.1.61 "Meters" means the Interconnection Meters and/or Customers' check-meters, as applicable.

1.1.62 "Minor Maintenance" shall mean maintenance events lasting not greater than [redacted] per occurrence, which have been scheduled and for which Purchaser and the other Customers have given consent in accordance with Section 6.4.

1.1.63 "MMBtu" means one million British thermal units, where one British thermal unit is the amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit from sixty (60) degrees Fahrenheit.

1.1.64 "MW" means megawatt.

1.1.65 "MWh" means megawatt-hour.

1.1.66 "NERC" means the North American Electric Reliability Council or successor organization.

1.1.67 "Non-Performing Party" has the meaning given such term in Section 11.1.

1.1.68 "Notice of Intent to Terminate" has the meaning given such term in Section 12.3.

1.1.69 "Off-Peak Period" means all the days of any given Contract Year other than the Peak Period days.

1.1.70 "Operating Agreement" means that certain Operating Agreement expected to be entered into among the Participants in 2001, the entry into of which is a condition precedent to the effectiveness of this Agreement.

1.1.71 "Operating Period" means the period from the beginning of the first Contract Year until the end of the last Contract Year.

1.1.72 "OUC" means Orlando Utilities Commission.

1.1.73 "OUC Interconnection Facilities" means the modifications to the Stanton Substation reasonably required for the receipt and delivery of Energy from the Facility onto the Grid consistent with Prudent Utility Practice.

1.1.74 "Ownership Agreement" means that certain Stanton Energy Center Combined Cycle Unit A Construction and Ownership Participation Agreement entered into among the Participants as of March 19, 2001.

1.1.75 "Participant" or "Participants" mean individually or collectively Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency (All Requirements Power Supply Project) and Seller.

1.1.76 "Parties" has the meaning given such term in the first paragraph of this Agreement.

1.1.77 "Peak Period" means for any given Contract Year the periods that include the days from January 1 through March 15, inclusive, May 15 through September 15, inclusive, and December 15 through December 31, inclusive.

1.1.78 "Permit" means any permit, license, approval, consent, waiver, authorization or other requirement in connection with the Project required from any Governmental Body under applicable Law.

1.1.79 "Person" means any individual, partnership, corporation, limited liability company, association, business, trust, Governmental Body or other entity.

1.1.80 "Planned Major Maintenance" means the Gas Turbine (GT) Combustor Inspection, the GT Hot Gas Path Inspection, and the GT Major Inspection, as these inspections are defined in the maintenance agreement with the GT vendor.

1.1.81 "Power Purchase Agreements" means this Agreement and those certain similar power purchase agreements between Seller and the other Customers respecting the delivery of Capacity and Energy from Seller's ownership share of the Capacity and Energy of the Facility.

1.1.82 "Prime Rate" means the prime rate of interest as published from time to time in the Wall Street Journal or such other comparable successor publication as the Participants may agree upon. The Prime Rate shall be calculated on the basis of a 365-day year for the actual number of days that a payment, reimbursement or adjustment, as the case may be, has not been made.

1.1.83 "Project" means the Facility, the Facility Site and all other appliances, parts, instruments, appurtenances, accessories and other property that may be incorporated or installed in, or otherwise become part of, any of the foregoing.

1.1.84 "Prudent Utility Practice" means any of the practices, methods and acts engaged in, or approved by, a significant portion of the electric utility industry in the United States [redacted] or any of the practices, methods and acts, which, in the exercise of reasonable judgment in light of the facts known, or that reasonably should have been known, at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with applicable Laws, reliability, safety and expedition. Prudent Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods and acts generally accepted in the United States and having due regard for current editions of the National Electrical Safety Code, the National Electric Code and other applicable electrical, safety and maintenance codes and standards, manufacturers' warranties and applicable Laws.

1.1.85 "Request for Energy" or "Schedule" means a request for the delivery of Energy made by Purchaser and the other Customers in accordance with the process provided in Section 6 and Appendix B for the Customers jointly to Schedule Energy, and any adjustments thereto made in accordance with Appendix B.

1.1.86 "RTO" means a regional transmission organization.

1.1.87 "Scheduled Commencement Date" means the date that is twenty-four (24) months after the receipt of the Site Certification and all other Permits to be obtained by the Customers that are necessary for Seller to commence construction, as such date may be extended under the provisions of Section 5.1, but in no event earlier than October 1, 2003.

1.1.88 "Scheduled Maintenance" means the removal of the Facility or a component thereof from service (which removal reduces the capability of the Facility to operate) to perform maintenance, overhaul, inspection, testing or repair work, as contemplated in Section 6.4.

1.1.89 "SEC Site" means the parcel of land in Orlando, Florida on which the fossil fired generating stations Stanton Unit # 1 and Stanton Unit #2 are located, including the parcel of land on which the Facility is to be located.

1.1.90 "Seller" has the meaning given such term in the first paragraph of this Agreement.

1.1.91 "Senior Lien Resolution" shall mean the OUC resolution duly adopted on June 3, 1993, as supplemented and amended, authorizing the issuance of OUC's Water and Electric Revenue Bonds.

1.1.92 "Site Certification" means (i) the final approval by the applicable Governmental Body of the initial need for power determination and site certification permit applications pursuant to the Florida Electrical Power Plant Siting Act, and (ii) the receipt of the air construction (Prevention of Significant Deterioration) permit by OUC issued by FDEP pursuant to the delegated authority of the United States Environmental Protection Agency under the Clean Air Act Amendments of 1977.

1.1.93 "Technical Limits" means the limits and constraints relating to the operation and maintenance of the Facility, as described in Appendix A.

1.1.94 "Termination Payment" means the payment to be paid by a Defaulting Party to the Non-Defaulting Party under in Section 12.5.1.

1.1.95 "Test Energy" means (i) Energy produced by the Facility during testing of the Facility prior to the Commencement Date; and (ii) Energy produced by the Facility during periodic tests of the Facility's Capacity output capability following the Commencement Date.

1.2 Rules of Construction. In this Agreement, unless the context otherwise requires, the singular shall include the plural, the masculine shall include the feminine and neuter, and vice versa. The terms "include," "includes" and "including" shall be deemed to be followed by the words "without limitation." The term "month" refers to a calendar month, and any period measured by a "month" from a reference date refers to the period beginning on such reference date and ending on the same date of the next succeeding calendar month or, if no such date exists in the next succeeding calendar month, the last day of such next succeeding calendar month. References to a Section, Table or Appendix shall be references to a Section of, Table of or Appendix to this Agreement unless specifically stated otherwise. A reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented and restated through the date as of which such reference is made. The term "or" is not exclusive, the term "shall" is mandatory and the term "may" is permissive. In the event that any index or publication referenced in this Agreement ceases to be published, each such reference shall be deemed to be a reference to a successor or alternate index or publication reasonably agreed by the Parties. Both Parties acknowledge that each was actively involved in the negotiation and drafting of this Agreement and that no law or rule of construction shall be raised or used in which the provisions of this Agreement shall be construed in favor of or against either Party because one is deemed to be the author thereof.

1.3 Consents. Whenever the consent or approval of either Party is required under this Agreement, such consent or approval shall not be unreasonably withheld, unless this Agreement provides that such consent or approval is to be given by such Party at its sole or absolute discretion or is otherwise qualified.

SECTION 2
TERM OF AGREEMENT

2.1 Initial Term.

2.1.1 This Agreement shall become effective as set forth in Section 3.1, and shall remain in full force and effect, subject to the early termination provisions set forth herein, through the later of (i) the last day of the month in which the tenth (10^{th}) anniversary of the Scheduled Commencement Date occurs or (ii) the last day of the month in which the tenth (10^{th}) anniversary of the Commencement Date occurs (the "Initial Term").

2.1.2 Notwithstanding the provisions of Section 2.1.1, the Initial Term shall terminate on (a) November 30, 2013 if Section 2.1.1 yields an end date falling between December 1, 2013 and April 30, 2014, inclusive, or (b) November 30, 2014 if Section 2.1.1 yields an end date that falls on or after May 1, 2014.

2.2 Extension of Initial Term. The Initial Term shall be automatically extended an additional five (5) years from the end of the Initial Term ("Extended Term"); *provided, however*, that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of the Initial Term by providing written notice of such election to Seller no later than the date that is three (3) years prior to the end of the Initial Term.

2.3 Extensions of Extended Term. The Extended Term shall be automatically extended three (3) successive periods of five (5) years each from the end of the Extended Term (the "Further Extensions"); *provided, however*, that the Purchaser shall have the option to elect to terminate this Agreement effective on the last day of any of (i) the Extended Term, (ii) the first Further Extension, or (iii) the second Further Extension, by providing written notice of such election to Seller no later than the date that is, respectively, three (3) years prior to the end of the Extended Term, three (3) years prior to the end of the first Further Extension, or three (3) years prior to the end of the second Further Extension, as the case may be; *provided, further,* that with respect to each Further Extension, Seller shall have the right to establish the Annual Capacity Charge for such Further Extension based on Seller's then-current assessment of market conditions by providing Purchaser written notice of the new proposed Annual Capacity Charge no later than the date that is three and one-half (3 1/2) years prior to the date that such Further Extension period is scheduled to begin, subject to Purchaser's right to request that Seller negotiate in good faith to agree on any other price that Purchaser believes in good faith reflects current market conditions.

2.4 Survival. Applicable provisions of this Agreement shall continue in effect after termination to the extent necessary to satisfy the terms and conditions of this Agreement

and, as applicable, to provide for: final billings and adjustments related to the period prior to termination, repayment of any money due and owing either Party pursuant to this Agreement, repayment of principal and interest associated with security funds, and the indemnifications specified in this Agreement.

SECTION 3
CONDITIONS PRECEDENT

3.1 Condition Precedent to Effectiveness. The Parties agree and acknowledge that this Agreement shall be effective only upon the date on or before which both of the following have occurred (such date, the "Effective Date"): (i) the execution and delivery of the Ownership Agreement and the Operating Agreement and all other Collateral Documents; and (ii) the acknowledgment of the Participants' satisfaction of the foregoing condition and the accuracy of the cross-references to the Collateral Documents contained in this Agreement.

3.2 Conditions Precedent to Obligations. Notwithstanding any provisions of this Agreement to the contrary, the obligations of the Parties to this Agreement shall be subject to the fulfillment of each of the conditions (or the waiver in writing of such conditions by the respective Party or Parties) set forth in Article 8 of the Ownership Agreement.

SECTION 4
SALE AND PURCHASE

4.1 Capacity Delivery and Payment. Subject to the terms and conditions of this Agreement, during the Operating Period, Seller agrees to deliver and sell to Purchaser and Purchaser agrees to receive and purchase from Seller up to [redacted] of the Actual Capability of the Facility in accordance with the following provisions:

4.1.1 The Capacity payment (the "Capacity Payment" or "CP") in respect of each month during the Operating Period shall be an amount equal to: the product of the Annual Purchaser's Capacity Nomination (expressed in kilowatts) multiplied by the Annual Capacity Charge. For any partial month during the Operating Period, the Capacity Payment shall equal the amount determined pursuant to the formula set forth in the preceding sentence multiplied by a fraction, the numerator of which is the number of days of such partial month within the Operating Period, and the denominator of which is the total number of days in such month. If the Annual Purchaser's Capacity Nomination changes during a month, then the Capacity Payment for such month shall be equal to the product of the Annual Capacity Charge multiplied by the sum of the two results obtained: (i) first by multiplying the old Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including

fractional days) prior to the time of the change over the total number of days in the month; and (ii) second by multiplying the new Annual Purchaser's Capacity Nomination by the ratio of the number of days in the month (including fractional days) after the time of the change over the total number of days in the month. The Capacity Payment shall be paid by Purchaser to Seller in accordance with Section 9.1. Notwithstanding the above, if during the first three (3) months of the Operating Period any Governmental Body shall prohibit the Facility from operating because of Seller's failure to obtain, prior to the Commencement Date any Permit required by Law for Seller to operate the Facility, then Purchaser's obligation to make Capacity Payments shall be suspended until the earlier of: (i) the lifting of such prohibition; or (ii) the date that is three (3) months after the Commencement Date.

4.1.2 The initial Demonstrated Capability of the Facility shall be established in accordance with the Capacity testing procedure set forth in Appendix C. Following the first anniversary of the Commencement Date, Seller shall perform Capacity tests [redacted] pursuant to the testing procedures set forth in Appendix C, during the Summer and Winter periods as defined by FRCC; *provided, however*, that Seller shall be entitled to a [redacted] period of maintenance that does not affect calculation of Actual Availability of the Facility (which period shall be prior to any such Capacity test from 9 p.m. Friday to 7 a.m. Monday, unless OUC, in its sole discretion, agrees otherwise). In addition, Seller may retest when a repair or modification of the Facility, or a corrected or improved operational or maintenance activity, results in an increase in the Capacity of the Facility (including adjustments made during initial shakedown), provided that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) is at least one hundred and one percent (101%) of the last Demonstrated Capability test amount. Should any test or retest conducted pursuant this Section 4.1.2 indicate that the actual full load output (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) has changed by an amount equal to or greater than one percent (1%) of the last Demonstrated Capability test amount, the Demonstrated Capability shall be reset at such actual full load output for purposes of determining the Capacity Payment as of the time the test is completed; *provided, however*, that if the test is performed during a Force Majeure event and such Force Majeure event resulted in the reduction of the Demonstrated Capability, the Capacity Payment shall not be reduced

thereby until the end of the [redacted] period described in the last paragraph of Section 4.1 below.

4.1.3 Seller shall conduct additional tests as required by the FRCC or as requested by Purchaser pursuant to Purchaser's legal or contractual obligations with third parties; *provided, however*, such additional tests shall be for informational purposes and shall not be used to reset the Demonstrated Capability or otherwise determine the Capacity Payment under this Agreement.

4.1.4 Beginning with the sixth (6^{th}) Contract Year and ending with the tenth (10^{th}) Contract Year, the Customers shall have the irrevocable right to jointly reduce the total of their combined Annual Purchaser's Capacity Nominations, for the remainder of the Initial Term and any Extended Term or Further Extensions, by either twenty-five (25) MW or fifty (50) MW (as adjusted to seventy degrees Fahrenheit (70°F) and forty-five percent (45%) relative humidity) per year; *provided, however*, that such combined total of the Annual Purchaser's Capacity Nominations may not be reduced by more than 200 MW in the aggregate. Purchaser must give Seller notice of any such reduction elected by Purchaser not later than three (3) years prior to the commencement of the Contract Year in which such reduction shall occur; *provided, however*, that such notice shall be effective if and only if either it is made jointly with the other Customers or the other Customers give Seller a similar notice under their respective Power Purchase Agreements with all such notices together satisfying the above criteria; *provided, further,* that such notices shall specify any changes in the percentage of the Annual Purchaser's Capacity Nomination to be purchased by Purchaser under Section 4.1.1 and by the other Customers under the corresponding provisions of their respective Power Purchase Agreements.

Notwithstanding the foregoing provisions of this Section 4.1, if and to the extent that a Force Majeure event affects Seller's ability to deliver and sell to Purchaser the Capacity of the Facility or any portion thereof, Seller shall be excused from any delay in performing or failure to perform any or all of such obligations (and in this regard, the Parties shall follow the procedures contemplated in Section 11.1); *provided, however*, that notwithstanding such reduction or elimination of the Actual Capability of the Facility, Purchaser shall continue to pay Seller the full Capacity Payment attributable to the [redacted] following the date of Seller's notification to Purchaser of any such Force Majeure effect; *provided, further,* that if the effect of a Force Majeure event lasts for longer than [redacted] then Purchaser shall not be required to make Capacity Payments attributable to any continued period of Force Majeure

declaration after the end of such [redacted] period, but Purchaser must resume making Capacity Payments when Seller declares the Force Majeure period over and resumes its obligation for delivery of Energy under this Agreement; *and provided, further,* that the Capacity Payment relief contemplated in the immediately preceding clause shall not apply if the Force Majeure event affecting Seller resulted from a failure of Purchaser or another Customer to fulfill its obligations under this Agreement or any of the Collateral Documents; *and provided, further,* that a Force Majeure event that affects Purchaser's ability to receive Energy from the Facility shall not excuse Purchaser's obligation to make Capacity Payments, except solely to the extent provided for in Section 5.1.3 if and to the extent such provision is applicable.

4.2 Energy Delivery and Payment. Subject to the terms and conditions of this Agreement and, in particular, subject to the provisions of Section 6 and Appendix B, Seller shall sell and deliver, and Purchaser shall purchase and receive, during the Operating Period, Energy requested by Purchaser in a Request for Energy, as well as Energy generated by associated ramp up and ramp down of the Facility and Test Energy; *provided, however,* that Purchaser shall not be required to make any payments for Test Energy produced prior to the Commencement Date. The Customers shall pay for and supply all fuel associated with the Customers' Request for Energy in accordance with the provisions of Section 3.2 of the Operating Agreement. The Energy payment (the "Energy Payment" or "EP") in respect of each month shall be the sum of four (4) components: a variable O&M component for operation on natural gas, a variable O&M component for operation on fuel oil, a start-up component, and a fuel component for Energy delivered from Alternate Resources. The components of the Energy Payment shall be calculated as follows:

4.2.1 Variable O&M Component—Natural Gas. The variable O&M component for operation on natural gas shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} [(DENG_{ij} \times VOMR) + HVOM_{ij}]$$

Where:

$DENG_{ij}$ is Delivered Energy in MWh (other than Test Energy prior to the Commencement Date) from the Facility produced with natural gas during hour j of day i; *provided, however,* that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with natural gas; and

VOMR is the variable O&M rate (in $/MWh), which shall be [redacted]; and

HVOM is the hourly variable O&M rate (in $ per hour) as determined from Table A and its accompanying Notes applicable for hour j of day i during which the Facility is operating on natural gas and which is applicable only when $DENG_{ij}$ is > 0.

Table A

Hourly Variable O&M Charges for Operation on Natural Gas

Annual On-Line Factor	Combined Hourly Variable O&M Rate (in $ per hour) for all Customers (see Notes below)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table A:

1) The Hourly Variable O&M Rate in Table A represents the rate applicable for the Annual Purchaser's Capacity Nominations of all Customers. The actual Hourly Variable O&M Rate for Purchaser for an hour in a particular Contract Year shall equal the product of the applicable rate from the table for such Contract Year multiplied by the ratio of Purchaser's portion of the Request for Energy for such hour over the total Request for Energy for such hour.

2) The Hourly Variable O&M Rate for a Contract Year shall be interpolated between the values shown in Table A when the Annual

On-Line Factor for the previous Contract Year falls between the specific percentages shown on Table A. For example, with respect to an Annual On-Line Factor of [redacted] the Hourly Variable O&M Rate shall be [redacted]

3) The dollar amounts shown in Table A are expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

4) The dollar amounts in Table A represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Customers under the Power Purchase Agreements. If Purchaser and the other Customers elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table A shall be proportionately reduced commensurate with such Capacity reduction.

5) The Annual On-Line Factor shall be calculated for each Contract Year, as follows:

Annual On-Line Factor = SH/ (PH – OH)

Where:

SH is the number of hours that the Customers Schedule and Seller delivers Energy in a Contract Year; and

PH is the number of hours in a Contract Year; and

OH is the number of hours in a Contract Year during which (i) the Facility is unavailable due to a forced outage or due to a maintenance outage that Seller has scheduled pursuant to Section 6.4 or, if applicable, that is a permitted [redacted] under Section 4.1.2, and (ii) Seller does not deliver from an Alternate Resource.

6) For the first Contract Year, all monthly Energy billings will be made assuming an Annual On-Line Factor of [redacted] The rate shall be determined annually for each Contract Year based on the Annual On-Line Factor for the previous Contract Year. At the end of each Contract Year, the Annual On-Line Factor for such Contract Year shall be calculated and the Hourly Variable O&M charges

for such Contract Year shall be recalculated using such Annual On-Line Factor for such Contract Year. A true-up payment or refund shall be made to adjust the amounts collected by Seller from Purchaser during each Contract Year to the amount computed by Seller using such Annual On-Line Factor for such Contract Year. Any true-up payments shall be included on an invoice as soon as reasonably practicable following the end of the applicable Contract Year.

4.2.2 Variable O&M Component—Fuel Oil. The variable O&M component for operation on fuel oil when firing the gas turbines shall be calculated as follows:

$$\sum_{i=\text{ Days in the Month}} \sum_{j=\text{ Hours in the Day}} [(DEFO_{ij} \times VOMRFO) + HVOMFO_{ij}]$$

Where:

$DEFO_{ij}$ is Delivered Energy (other than Test Energy prior to the Commencement Date) produced with fuel oil during hour j of day i; provided that if the Facility uses both natural gas and fuel oil in a given hour, then fifty percent (50%) of the Delivered Energy in such hour shall be deemed to be produced with fuel oil; and

VOMRFO is the variable O&M rate (in $/MWh) for Energy produced with fuel oil, which shall be [redacted] subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations); and

HVOMFO is the hourly variable O&M rate (in $ per hour) for hour j of day i during which the Facility is Operated on fuel oil, which rate shall be [redacted] subject to adjustment up or down based on the Participants' evaluation of General Electric's reports on the effect of burning fuel oil on variable O&M costs (as mutually agreed by the Participants following good faith negotiations), and which is applicable only when $DEFO_{ij}$ is > 0.

4.2.3 Start-up Component. The start-up component shall be calculated as follows:

GTS x SUR

Where:

GTS is the number of gas turbine starts required to meet a Request for Energy (other than for Test Energy prior to the Commencement Date) where the amount of Energy delivered from any single gas turbine increases from zero to an amount greater than zero; *provided, however*, that the calculation of GTS shall not include: (i) any starts required to resume delivery to Purchaser due to an interruption caused by a forced outage, or (ii) any starts initiated by Seller in order to make third party sales in any given hour where the Facility would otherwise not have been started in such hour to meet a Request for Energy.

SUR is the Start-up Rate (in $ per start) for each gas turbine as determined from Table B below and its accompanying Notes:

TABLE B

Start-Up Rates

Cumulative Number of Start-ups per Gas Turbine per Contract Year	Combined Start-up Rate per Start per Gas Turbine for all Customers (see Notes)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Notes to Table B:

1) The SUR in Table B represents the rate applicable to all Customers for each start-up during a Contract Year. [redacted] and the combined rate among all Customers participating in each subsequent start-

up during such Contract Year shall be as identified in the Table B. The actual SUR for Purchaser (in $ per start) for any such start-up shall equal the quotient of the applicable rate from the Table B divided by the number of Customers participating in the Request for Energy that requires the start-up (and in which Purchaser is one of those Customers); *provided, however,* Purchaser will not have to pay for start-ups in which it does not participate.

2) The SUR is expressed in January 1, 2003 dollars and shall be escalated based upon [redacted]

3) The dollar amounts in Table B represent the charge for sixty-five percent (65%) of the Facility's Capacity being sold to Participants under the Power Purchase Agreements. If the Participants elect to reduce their combined Annual Purchaser's Capacity Nominations pursuant to Section 4.1.4, then the dollar amounts in Table B shall be proportionately reduced commensurate with such Capacity reduction.

4.2.4 O&M Rate Adjustment. The rates in Sections 4.2.1, 4.2.2 and 4.2.3 shall be increased or decreased based on good faith negotiation of the Parties (in accordance with Section 18) to reflect and include any actual increase or decrease in Seller's costs of operating the Facility that is caused by any mutually agreed-upon modification or design change or any actual increase or decrease in Purchaser's or another Customers' charges for providing any services to Seller.

4.2.5 Energy Payment for Delivery from Alternate Resources.

4.2.5.1 If Seller elects to deliver Energy from Alternate Resources pursuant to Section 4.4, then the variable O&M component and the start-up component of the Energy Payment shall be calculated in accordance with Sections 4.2.1 and 4.2.3, respectively, for such Alternate Resource Energy as if it were delivered from the Facility. In addition, the fuel component for the Energy delivered from Alternate Resources shall be calculated as follows:

$$\sum_{i=\text{Days in the month}} \sum_{j=\text{Hours in the Day}} (MDE_{ij} \times HR_{ij} \times FRP_{ij})$$

Where:

MDE_{ij} = Scheduled Energy in MWhs delivered from an Alternate Resource during hour j of day i;

when the Facility is unavailable, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs;

when the Facility is available, then HR_{ij} for an hour = (i) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is [redacted] MWhs or less; or (ii) the heat rate of [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs but less than or equal to [redacted] MWhs; or (iii) [redacted] MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than [redacted] MWhs; and

FRP_{ij} = the fuel rate proxy for an hour calculated in dollars per MMBtus in accordance with the applicable provisions of either Section 4.2.5.2 or 4.2.5.3.

4.2.5.2 If the Fuel Supply Agent has not already scheduled the transportation of gas to the Facility to meet the Customers' Schedules for the hour during which Seller elects to deliver the Scheduled Energy from Alternate Resources, then following notification from Seller of its election to deliver the Scheduled Energy from Alternate Resources, Seller shall be obligated to obtain the necessary quantities of gas and necessary gas transportation capacity to accommodate any portion of the Schedule that Seller has elected to satisfy from Alternate

Resources. During periods that Seller elects to deliver Energy from Alternate Resources, the Fuel Supply Agent shall make available transportation capacity, within constraints of the pipeline tariffs and operational procedures in effect at the time and at no additional cost to the Fuel Supply Agent, in the amount determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtus) shall be equal to the sum of: (i) [redacted] and (ii) the applicable firm gas transportation variable cost associated with deliveries to the Facility under such Participant's firm transportation agreement(s). All risks of gas supply and transportation interruption to accommodate deliveries of Energy from Alternate Resources shall be borne by Seller.

4.2.5.3 If the Fuel Supply Agent has already scheduled the transportation of gas to the Facility to meet the Customers' Schedules by the time Seller notifies Purchaser of Seller's election to deliver the Scheduled Energy from Alternate Resources, then at Seller's election:

(i) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to revise its scheduled transportation of gas to the Facility to provide for the delivery of the gas to Seller at any alternate delivery point designated by Seller that is available under the Customers' firm transportation agreement(s). The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time, and the Fuel Supply Agent shall not be required to incur any additional cost as a result of the revision of the schedule of transportation of gas to the alternate delivery point. The amount of scheduled transportation of gas to be delivered to the alternate delivery point shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining

HR in the formula provided in Section 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has delivered Energy from Alternate Resources under these circumstances, then the FRP (in $ per MMBtu) shall be [redacted] or

(ii) Seller shall direct Fuel Supply Agent to use commercially reasonable efforts to remarket to third parties the gas that has been scheduled for delivery to the Facility on the best terms possible under the circumstances. The efforts of the Fuel Supply Agent shall be subject to the constraints of the pipeline tariffs and operational procedures in effect at the time. The amount of scheduled transportation of gas to be remarketed to third parties shall be determined by the quantity of Energy supplied from Alternate Resources and the applicable heat rate determined by the rules for defining HR in the formula provided in from paragraph 4.2.5.1. An example of the determination of the transportation capacity is included in Appendix D. If Seller has directed the Fuel Supply Agent to remarket the gas under these circumstances, the FRP (in $ per MMBtu) shall be [redacted]

4.3 Availability Guarantee.

4.3.1 Seller guarantees that the Actual Availability of the Facility for [redacted] of each Contract Year will equal or exceed

[redacted] ("Availability Guarantee"); *provided, however,* that (i) the [redacted] of operation following the Commencement Date shall be excluded from the Availability Guarantee, (ii) if and to the extent that a Force Majeure event affects Seller's ability to achieve the Availability Guarantee, other than in the case of Equipment Breakdown, Seller shall be excused from the Availability Guarantee (and in this regard the Parties shall follow the procedures contemplated in Section 11), and (iii) to the extent that the Facility is fired with fuel oil in excess of [redacted] per combustion turbine unit in any Contract Year in order to meet Purchaser's Request for Energy, then for every additional [redacted] that the Facility is fired using fuel oil, the lower end of the Availability Guarantee range, and the factors [redacted] in Sections 4.3.5.1 and 4.3.5.2, shall be reduced by [redacted] each, which reductions shall remain in effect until the next Planned Major Maintenance occurs. If either combustion turbine is not fired on oil during any Contract Year for the same number of hours as the other combustion turbine, then for purposes of calculating the adjustment to the Availability Guarantee, each combustion turbine will be deemed to have been fired on oil during such Contract Year for a number of hours that is equal to one half of the summation of the number of hours that each combustion turbine was actually fired on oil during such Contract Year.

4.3.2 In each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, Seller shall be entitled to an availability incentive payment from Purchaser ("Availability Incentive Payment") equal to (a) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Peak Period, and/or (b) [redacted] during such Contract Year when the Actual Availability of the Facility exceeds [redacted] during the Off-Peak Period.

4.3.3 The Actual Availability for the Peak Period of each Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, shall be calculated as follows and then rounded up or down to the nearest tenth of a percentage point [redacted] *provided, however,* that such Actual Availability shall not exceed one (1.00):

Actual Availability = (PH-OH -EDH+EMH+ARDH)/PH

Where: "PH" (or "Period Hours") shall equal the hours in the Peak Period of such calendar year;

"OH" (or "Outage Hours") in the Peak Period of such Contract Year means all hours the Facility is unavailable for operation; *provided, however*, that OH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day;

"EDH" (or "Equivalent Derated Hours") in the Peak Period of such Contract Year means the summation of EDH for each hour during the Peak Period; *provided, however*, that EDH shall not include hours in any day during which the Purchaser has not Scheduled any Energy from the Facility during the entirety of such day. In each hour for which the EDH of such hour must be calculated, EDH for the hour will equal (Guaranteed Output - Actual Capability)/Guaranteed Output;

"EMH" (or "Excused Maintenance Hours") shall equal hours that Seller has scheduled maintenance on the Facility in the Peak Period of such calendar year pursuant to Section 6.4 and, if applicable, the [redacted] of pre-testing maintenance allowed prior to a Capacity test under Section 4.1.2; *provided, however*, that in any hour EMH must be zero if there is no Outage Hour in such hour; and

"ARDH" (or "Alternate Resource Delivery Hours") shall equal the number of hours that Seller delivers Energy to Purchaser from Alternate Resources in the Peak Period of such Contract Year to fully or partially make up for shortfalls caused by Facility outages or derates. Seller will not receive any credit for ARDH in any entire day unless Seller is able to deliver at least partial Energy in each hour of such day that Purchaser Schedules Energy, in which case Seller will receive ARDH credit for each hour of the day based on the lowest ratio during any hour of such day of Delivered Energy to Scheduled Energy.

4.3.4 The Actual Availability for the Off-Peak Period of each Contract Year shall be calculated in a fashion similar to Section 4.3.3, substituting "Off-Peak Period" for "Peak Period" where it appears in Section 4.3.3.

4.3.5 In the event that the Actual Availability during the Peak Period or Off-Peak Period, or both, of any given Contract Year, or partial Contract Year in the case of the first Contract Year [redacted] or the last Contract Year, is less than the lower end of the Availability Guarantee range, then Purchaser shall be entitled to receive availability damages ("Availability Damages") from Seller as Purchaser's sole and exclusive remedy for Seller's failure to delivery Capacity and Energy from the Facility due to the unavailability of the Facility.

4.3.5.1 The Availability Damages for the Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Peak Period of any Contract Year = [redacted]

4.3.5.2 The Availability Damages for the Off-Peak Period shall be calculated as follows (with any required adjustments as noted in Section 4.3.5.3):

Availability Damages for the Off-Peak Period of any Contract Year = [redacted]

4.3.5.3 In both of Sections 4.3.5.1 and 4.3.5.2, the factors [redacted] and [redacted] shall be adjusted for the use of fuel oil pursuant to Section 4.3.1(iii), if applicable.

4.3.6 As soon as reasonably practicable after the first month following the Commencement Date, and each month thereafter, Seller shall submit to Purchaser a statement setting forth in reasonable detail the actual availability of the Facility during the prior month, including the underlying availability data.

4.3.7 As soon as reasonably practicable following each Contract Year, Seller shall submit to the Purchaser a statement setting forth the Actual Availability for the preceding Contract Year together with a calculation of the net amount of any Availability Incentive Payment due to Seller or Availability Damages due to the Purchaser for the preceding Contract Year based on the foregoing calculations, as applicable, with respect to the Peak Period and Off-Peak Period of such Contract Year. Within ten (10) Business Days of (a) receipt of such statement, Purchaser shall pay any Availability Incentive Payment due to Seller by wire transfer in immediately available funds, or (b) transmittal of such statement, Seller shall pay any Availability Damages due to Purchaser by wire transfer in immediately available funds.

4.4 Alternate Resources. In any hour in which the Facility is unavailable, Seller may continue to make deliveries of Energy in the full amount Scheduled by Purchaser from non-Facility sources (including, but not limited to, generating units on Seller's or its Affiliates' systems and Energy purchases available to Seller) ("Alternate Resources") to replace the Energy that would have been provided by the unavailable Facility. In any hour in which the Facility is available, Seller may choose to make deliveries of Energy in the full amount Scheduled by Purchaser, or any portion thereof, from Alternate Resources to replace the Energy that would have been provided by the available Facility; *provided, however*, that if the Facility is available, Seller must maintain the Facility on-line and committed at least at the Facility's minimum load, and Purchaser may Schedule spinning reserves from the Facility, all in accordance with Appendix B. Seller must deliver Energy from Alternate Resources to Purchaser at an unconstrained point on the Grid, and if Seller is making such delivery at a time when the Facility is unavailable, then Seller will purchase Firm Transmission Service for such delivery to the extent that such Firm Transmission Service is available for the Alternate Resource Energy from the point of its acquisition by Seller to the unconstrained point on the Grid. In utilizing Alternate Resources, Seller shall comply with the notice requirements of Section 3 of Appendix B.

4.5 Purchaser's Right to Capacity and Energy. During the Operating Period, Purchaser shall have the first call to purchase Seller's share of the Capacity and Energy generated by, and Ancillary Services associated with, the Facility (other than the reductions in Capacity elected jointly by the Customers pursuant to Section 4.1.4); *provided, however*, that (i) subject to Purchaser's right to Capacity and Energy under this Agreement and the Operating Agreement, Seller may make sales of any Capacity and Energy generated by, and Ancillary Services associated with, Seller's Equity Capacity when such Capacity and Energy is not Scheduled by Purchaser, and (ii) in the event that Seller determines that the Facility is capable of delivering Energy to the Grid prior to the Scheduled Commencement Date, Seller shall have the option of either (a) utilizing the Capacity and Energy generated by, and Ancillary Services associated with, its percentage ownership share of the Facility prior to the Scheduled Commencement Date for

sales to third parties by delivering written notice of its election of this option thirty (30) days prior to the anticipated Commercial Operation Date, in which event Purchaser shall not make Capacity Payments until the later of the Scheduled Commencement Date or the Commencement Date, or (b) initiating delivery of Capacity and Energy to Purchaser under this Agreement on the Commencement Date. If Seller makes sales of either or both Capacity and Energy to third parties under Section 4.5(ii)(a) at a time when the Scheduled Commencement Date has passed but the Commencement Date has not yet occurred, then Seller will pay to Purchaser the portion, if any, of the proceeds of such sales that Seller actually receives.

SECTION 5
SCHEDULE FOR DELIVERY OF CAPACITY AND ENERGY

5.1 Scheduled Delivery.

5.1.1 Seller anticipates that, the Facility will achieve the Commencement Date by the Scheduled Commencement Date and shall be fully capable of reliably producing the power and Energy to be provided under this Agreement to Purchaser at the Delivery Point; *provided, however*, that if and to the extent that a Force Majeure event affects Seller's ability to timely comply with the foregoing guarantee, the Scheduled Commencement Date shall be extended by the amount of time Seller reasonably needs to remedy the effects of the Force Majeure that prevented Seller's performance (and in this regard, the Parties shall follow the procedures contemplated in Section 11).

5.1.2 In the event that Seller fails to achieve the Commencement Date by the date that is two (2) years after the Scheduled Commencement Date, then either (i) Seller shall have the right to simultaneously terminate all of the Power Purchase Agreements by delivering written notice of such election to Purchaser and the other Customers ("Seller's Termination Notice"), or (ii) Purchaser may terminate this Agreement, if and only if each of the other Customers also terminates contemporaneously its respective Power Purchase Agreement for the same reason, by delivering written notice of such election to Seller (collectively, together with the other Customers' similar notices, "Purchasers' Termination Notices"). Within ten (10) Business Days of the date of Seller's Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Seller's Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2. Within ten (10)

Business Days of the date of Purchasers' Termination Notice, Seller shall pay Purchaser liquidated damages in the amount of [redacted] this Agreement shall terminate effective as of the date of Purchasers' Termination Notice, and Seller shall have no further liability to Purchaser other than the liquidated damages paid under this Section 5.1.2.

5.1.3 In the event that Seller's failure to achieve the Commencement Date by the Scheduled Commencement Date is attributable to, in whole or in part, the failure of any Customer to meet any of their respective obligations under this Agreement or their respective Power Purchase Agreements or the Collateral Documents, then (a) the Scheduled Commencement Date shall be extended for such period of Purchaser's or such other Customer's failure, and (b) Purchaser shall make Capacity Payments (assuming a Demonstrated Capability of [redacted] MW and an Availability Performance of [redacted] for the period affected by the delay) beginning as of the initial Scheduled Commencement Date (without any extension); *provided, however*, that Purchaser shall not be required to make any Capacity Payments under this Section 5.1.3 to the extent the delay in achieving the Scheduled Commencement Date is attributable to the concurrent failure of Purchaser or such other Customers and Seller (where such concurrent failures are not co-extensive, such relief from Capacity Payments shall apply only during the period of time that Seller's failure to meet its obligations contributed to the delay); *provided, further*, that in the event Purchaser's failure to meet its obligation was the result solely of a Force Majeure event that prevented Purchaser's timely completion of such obligation, then Purchaser will be excused from having to make Capacity Payments as contemplated in Section 5.1.3(b) for the [redacted] after the Scheduled Commencement Date (without benefit of any extension thereof allowed under this Agreement), but if the Commencement Date does not occur within such [redacted] then Purchaser shall recommence making Capacity Payments starting at the beginning of the [redacted] day after the Scheduled Commencement Date and thereafter continue making Capacity Payments as contemplated in Section 5.1.3(b).

5.2 Conditions to Commencement. Seller will notify Purchaser of the date when the Facility has achieved the following criteria (the "Commencement Date"), which notice will be accompanied by reasonable documentation evidencing satisfaction or occurrence of each of the following; *provided, however,* that Seller shall not be precluded from making third-party sales, in accordance with Section 4.5, of its percentage ownership share of Capacity and Energy from the

Facility notwithstanding whether any or all of the following criteria have been met in whole or in part:

5.2.1 successful completion of required testing of the Facility has occurred for purposes of financing, project operation, air permitting, Purchaser's planning and reporting, and manufacturers' warranties, including establishment of the initial Demonstrated Capability of the Facility as contemplated in Section 4.1.2;

5.2.2 the Facility has completed [redacted] successful start-ups without experiencing any abnormal operating conditions and has generated continuously for a period of not less than [redacted] while synchronized to the Grid at a net Capacity output of at least [redacted] of the Demonstrated Capability (adjusted for ambient conditions) without experiencing any abnormal operating conditions;

5.2.3 the Facility is in compliance with the Interconnection Agreement, either is capable of operation in the AGC mode or is capable of responding to manual load change instructions, has achieved initial synchronization with the Grid, and has demonstrated the reliability of its communications systems and communications with the Florida Municipal Power Pool Energy Control Center located in the OUC Pershing Operations Building (or the replacement for such control center if the Customers decide to have their generation control performed at a different location); and

5.2.4 certificates of insurance coverages and/or insurance policies required of Seller have been obtained and submitted to Purchaser as required by Section 28.

5.3 Test Energy. Seller shall coordinate the production and delivery of Test Energy with Purchaser. Purchaser shall cooperate with Seller to facilitate Seller's testing of the Facility, provide the fuel necessary to conduct testing, and shall accept Test Energy delivered to Purchaser in accordance with the provisions of Section 4.2.

SECTION 6
REQUESTS FOR ENERGY; OPERATION AND MAINTENANCE

6.1 Communicating Requests for Energy. Purchaser shall have the right to request deliveries of Energy by providing a Request for Energy to Seller in accordance with this Section 6 and Appendix B; *provided, however*, that Purchaser and the other Customers shall coordinate their Scheduling requirements by jointly submitting a single Request for Energy that covers all of their respective requirements on any given day.

6.1.1 The Customer's joint Requests for Energy may request the full output of the Facility, reduced by those amounts, if any, that Customers jointly elect to subtract from the Capacity available to Customers pursuant to the process provided in Section 4.1.4 of this Agreement and the other Power Purchase Agreements. If the Customer's joint Request for Energy is for less than the full output of the facility, then the request shall be deemed to be a Request for Energy first from Purchaser's Equity Capacity and, if such Equity Capacity is not sufficient, then from Purchaser's purchased Energy under this Agreement.

6.1.2 The Parties hereby consent to the recording of all conversations on the telephone lines used for communicating Requests for Energy and related notices and instructions in accordance with customary industry practice. The contents of such recordings shall be definitive.

6.2 Limitations on Requests for Energy. Notwithstanding anything to the contrary in this Agreement, any Request for Energy, operation in the AGC mode or operation in response to a Capacity Emergency that would require the Facility to operate in a manner inconsistent with the Technical Limits, Prudent Utility Practice or applicable Law and Permit requirements shall be deemed not to comply with the requirements and limitations set forth in this Section 6. If and when a Customers' Request for Energy does not comply with the requirements and limitations of this Section 6 by reason of the previous sentence, Seller will notify Customers of such noncompliance promptly after Seller realizes that the Request for Energy is noncompliant and will modify Customer's Request for Energy to make it consistent with the Technical Limits, Prudent Utility Practice and all applicable Laws and Permits to the extent it is reasonably possible to do so consistent with such standards.

6.3 Operation of the Facility. Seller shall operate and maintain the Facility in accordance with this Agreement, Prudent Utility Practice, the Technical Limits and all applicable Laws and Permit requirements. Any emission allowances required for operation of the Facility as contemplated in this Agreement shall be provided in accordance with the applicable provisions of the Operating Agreement.

6.4 Scheduled Maintenance. Seller agrees to schedule Planned Major Maintenance during the Off-Peak Period, or to obtain Purchaser's consent to schedule such maintenance during the Peak Period. Seller will submit to Purchaser an annual maintenance projection and will make reasonable efforts to coordinate the scheduling of such Planned Major Maintenance with Purchaser, including estimated start dates and return to service dates. Seller must seek the consent of OUC, acting for itself and on behalf of the other Customers (which Purchaser hereby authorizes) in scheduling of any Minor Maintenance; *provided, however*, that Purchaser guarantees Seller will be afforded a minimum of [redacted] such Minor Maintenance events distributed approximately evenly over the Off-Peak Period, with a maximum of [redacted] such

Minor Maintenance events during any year; *provided, further,* that requests for Minor Maintenance events during the period from May 15 through September 15 may be granted or withheld in [redacted].

6.5 Transmission Operator. Coordination with an RTO regarding security and reliability of the Grid as it relates to the Facility, or any other entity, having control over the security and reliability of the Grid shall be the responsibility of Seller as the operator of the Facility. Coordination with an RTO, or other entity, having balancing authority or scheduling authority over the Facility should be handled by Purchaser for any schedules to Purchaser from the Facility and by Seller for any other schedules from the Facility. Any orders, directives or operating requirements that Seller is required to follow by Law imposed on Seller by an RTO, or any other entity, having control over the security and reliability of the Grid shall take precedence over this Agreement. To the extent the requirements of such order, directive or operating requirement necessarily prevent Seller from fulfilling its obligations under this Agreement, Seller shall be relieved of its obligations hereunder. To the extent the requirements of such order, directive or operating requirement conflict with Seller's fulfillment of its obligations hereunder, the rights and obligations of the Parties hereunder shall be adjusted as necessary to comply with such orders, directives or operating requirements.

SECTION 7
INTERCONNECTION AND TRANSMISSION

7.1 Interconnection Facilities. The Parties shall execute an Interconnection Agreement pursuant to applicable interconnection policies and procedures of OUC. The Interconnection Agreement shall contain terms and conditions governing the interconnection and parallel operation of the Facility with the Grid.

7.2 Delay in Interconnection. Purchaser shall complete the OUC Interconnection Facilities and ensure that the Grid is capable of providing and receiving Energy by the date that is [redacted] prior to the anticipated Commercial Operation Date, but in no event earlier than [redacted]. By the date that Seller has completed the collector bus and the 230 kv line to the OUC Interconnection Facilities, but no earlier than the date that is [redacted] prior to the anticipated Commercial Operation Date, OUC shall provide service to the Facility for the purposes of engineering and testing the collector bus and other systems by either providing 230 kv service at the 230 kv Interconnection Point or by providing service to the 4160 kv SWGR bus. If for any reason, other than the fault of Seller, OUC fails to complete the OUC Interconnection Facilities and/or if the Grid is not capable of providing and receiving Energy (as determined by OUC and as supported by reasonable documentation) in accordance with the preceding sentence and, as a result, OUC cannot accommodate Seller's start-up and testing of the Facility (such a delay, an "IF/Grid Delay"), then the Scheduled Commencement Date shall be extended by that period of time equal to the IF/Grid Delay; *provided, however*, that Purchaser shall make the Capacity Payments as provided in Section 5.1.3(b); *provided, further*, that if

Seller would not have been capable of delivering Energy from the Facility to the OUC Interconnection Facilities, even in the absence of an IF/Grid Delay, on the original anticipated Commercial Operating Date ("Seller's Delay"), then extension of the Scheduled Commencement Date and the date on which Purchaser is obligated to make Capacity Payments shall be adjusted by the period of time of Seller's Delay.

7.3 Transmission.

7.3.1 Purchaser shall be responsible for all costs associated with and for making all necessary transmission arrangements for Delivered Energy, including tagging and any required Ancillary Services, with the transmission service provider for delivery from and beyond the Delivery Point.

7.3.2 Seller shall bear all costs and losses and shall be responsible for making all arrangements for transmission service, including tagging and any required ancillary services, with respect to delivery of Capacity and Energy from an Alternate Resource to an unconstrained point on the Grid.

SECTION 8
RISK OF LOSS; METERING

8.1 Risk of Loss. Delivered Energy sold pursuant to this Agreement shall be made available to Purchaser at the Delivery Point. Risk of loss with respect to all such Energy shall pass to Purchaser when such Delivered Energy is made available to Purchaser at the Delivery Point. Risk of loss with respect to the natural gas supply utilized to deliver Energy pursuant to this Agreement shall pass to Seller when such natural gas supply is made available to Seller at the Gas Delivery Point. For purposes of this Agreement, and except to the extent expressly limited in this Agreement, Purchaser shall bear all risk of all occurrences of any nature (including Force Majeure or any other event beyond the reasonable control of either Party) affecting any interconnection facilities, substations, transmission lines and other facilities on Purchaser's side of the applicable Delivery Point and the Gas Delivery Point.

8.2 Place of Measurement. All Energy from the Facility shall be measured by the Facility's meters (such meters collectively, the "Interconnection Meters"), and the Energy delivered from the Facility shall be the Interconnection Meters' readings of the quantities of Energy, reduced by an amount equal to the applicable Energy quantity necessary to compensate for the loss, if any, between the Interconnection Meters and the Delivery Point.

8.3 Testing and Calibration of Interconnection Meters. Seller shall inspect and calibrate the Interconnection Meters at least once a year. Seller shall give Purchaser reasonable advance notice of any inspection, testing or calibration of the Interconnection Meters. Purchaser shall have the right to have a representative present at such inspection, testing or calibration of

the Interconnection Meters. Purchaser shall have the right to require, at Purchaser's expense except as set forth in Section 8.4, a test of any of the Interconnection Meters not more often than once every twelve (12) months. If any Interconnection Meter is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such Interconnection Meter shall be deemed accurate, but Seller shall use its reasonable efforts to adjust such Interconnection Meter immediately and accurately. In the event that any Interconnection Meter is found to be inaccurate by more than one half of a percent (0.5%), Energy delivered at the corresponding Delivery Point shall be measured by reference to Customers' check-meters, if installed and registering accurately, or the meter readings at the Delivery Point for the period of inaccuracy shall be adjusted as far as can be reasonably ascertained by Seller from the best available data from both Parties. If the period of the inaccuracy cannot be ascertained reasonably, any such adjustment shall be for a period equal to one half of the time elapsed since the preceding test. Customers' check meters, if installed, shall be subject to Seller's right to require, at Seller's expense except as set forth in Section 8.4, a test of any of the check-meters not more often than once every twelve (12) months. If any of Customers' check meters is found to be inaccurate by one half of a percent (0.5%) or less, then any previous recordings of such check meter shall be deemed accurate, but Customers shall use their reasonable efforts to adjust such check meter immediately and accurately.

8.4 Delivered Energy Adjustments. In the event that, due to correction for inaccurate Interconnection Meters with an inaccuracy in excess of one half of a percent (0.5%) (determined in accordance with Section 8.3), the amount of Delivered Energy is increased or decreased, the revised quantity of Delivered Energy shall be used for purposes of calculating the Energy Payment pursuant to Section 4.2. If any Energy Payment has already been calculated using the previous quantity of Delivered Energy, the Energy Payment shall be recalculated using the revised quantity of Delivered Energy. If the recalculation (i) increases the Energy Payment, Purchaser shall pay to Seller the amount of such increase, or (ii) decreases the Energy Payment, Seller shall refund to Purchaser the amount of such decrease. In any such case, the required payment shall be included on the next invoice to be issued and shall be paid at the time payment of such invoice is required pursuant to Section 9. Any payment required under this Section 8.4 shall bear interest in accordance with Section 9.3 from the original due date (or from the date paid in the case of a refund) until the date paid (or until the date refunded in the case of a refund). In the case of inaccurate Meters with an inaccuracy in excess of one half of a percent (0.5%), the Party which owns such Meters shall promptly cause such Meters to be corrected and, where such inaccuracy was determined pursuant to a test required by the other Party, the Party which owns such Meters shall bear the expense of any such test.

SECTION 9
METHOD OF PAYMENT

9.1 Invoicing and Payment. As soon as reasonably practicable after the first day of each month commencing with the second month or portion thereof during which Test Energy is delivered to Purchaser and continuing for each month until the first month after the end of the Operating Period, Seller shall submit to Purchaser an invoice as described in Section 9.2. If such invoice indicates a net amount payable to Seller, Purchaser shall pay such invoice within ten (10) Business Days of Purchaser's receipt of the invoice. Such payment shall be made in U.S. dollars by wire transfer of immediately available funds prior to 3:00 p.m. Eastern Prevailing Time, on the date of payment in accordance with the invoice instructions. Payments made after 3:00 p.m. Eastern Prevailing Time or on a day that is not a Business Day shall be deemed to be made on the next subsequent Business Day. If such invoice indicates a net amount payable to Purchaser, Seller shall pay such amount within ten (10) Business Days of Purchaser's receipt of the invoice.

9.2 Monthly Invoices. Each monthly invoice shall show the amount and calculation of the following, as applicable: (i) the Capacity Payment and Energy Payment payable by Purchaser to Seller for the preceding month net of any amounts to be credited by Seller to Purchaser for such month; (ii) following each Contract Year, the net amount payable by Purchaser or Seller pursuant to Section 4.3 respecting the Availability Incentive Payment and Availability Damages, as the case may be; and (iii) payments, refunds, credits and reductions, if any, payable by either Party pursuant to Sections 9.3 or 9.4.

9.3 Late Payments. Any amount due from either Party hereunder not paid in full on or before the date such payment is due will incur a delayed payment charge on the unpaid amount from the original due date until the date paid at an annual rate equal to the then current Prime Rate plus six (6) percentage points (or such lesser annual rate as is the maximum rate permitted by applicable Law).

9.4 Billing Disputes. In the event of any dispute as to all or any portion of any monthly invoice, Purchaser shall give notice of the dispute to Seller but shall pay the full amount of the invoiced charges when due (or if applicable, Seller shall give notice to Purchaser of Seller's dispute regarding any information provided by Purchaser that was a factor in any calculation supporting invoiced amounts). Such notice shall state the amount in dispute and set forth a full statement of the grounds on which such dispute is based. Purchaser and Seller shall give all due and prompt consideration to any such dispute. Upon final determination (whether by agreement, dispute resolution pursuant to Section 18 hereof, or otherwise) of the dispute, any amounts due to Purchaser or Seller, together with interest from the date due until the date paid at the rate specified in Section 9.3, shall be paid no later than thirty (30) days following such final determination. Purchaser and Seller shall have until the end of one hundred eighty (180) days after its receipt of any invoice, statement or information supporting invoice calculations to question or contest the correctness of any charge or credit on such invoice or statement.

9.5 Audit Rights. Until the end of one hundred eighty (180) days after Purchaser's receipt of any invoice, Seller and Purchaser will make available to the other upon written request, and the Purchaser or Seller may audit, such books and records of the other (or other information to which Purchaser or Seller has access) as are reasonably necessary for Purchaser or Seller to calculate and determine the amounts shown on such invoice and thereby to verify the accuracy and appropriateness of the amounts billed or credited to Purchaser or Seller hereunder; *provided, however,* that Purchaser shall coordinate its rights under this section with the other Customers in order to conduct joint, rather than individual, audits pursuant to this provision. The Parties shall maintain their respective books and records in accordance with generally accepted accounting principles applicable from time to time.

ARTICLE 10
CHANGE IN LAW; MODIFICATION OF AGREEMENT

10.1 Change in Law.

10.1.1 The Parties acknowledge that a Change in Law may increase or decrease Seller's costs in providing service under this Agreement. In the event of such a Change in Law, Seller may give notice to Purchaser that Seller's costs of providing service under this Agreement have changed (which notice will include reasonably detailed information about such cost changes) and, in the event such notice is given, this Agreement shall be modified to reflect such changes in costs, subject to Section 18, *provided, however*, that in the event Seller provides notice of such an increase, then Purchaser may provide documentation to Seller of other Changes in Law that have decreased the cost of providing service under this Agreement and Seller shall set-off any such decrease in cost against the increase in cost identified in the Seller's notice.

10.1.2 Purchaser shall pay the adjusted amount calculated pursuant to Section 10.1.1 for the period commencing with the notice of changed cost through the date of termination of this Agreement. The Parties shall make such payments as are appropriate to adjust all prior billings or payments to reflect the adjustments described herein.

10.1.3 A "Change in Law" shall mean a change in Law which constitutes a new environmental or tax Law or a new interpretation of such Law (not including a change in tax Laws that assess taxes only on Seller's net income) or a change in the provisions contained in the Site Certification permits and which generally affects the cost of, or restricts, operation of the Facility.

10.2 Modification of Agreement. In the event the FERC modifies this Agreement, the Parties agree to make all changes necessary to preserve as nearly as possible the bargain contained in this Agreement, including but not limited to, the total amounts of Capacity and Energy delivered to Purchaser and the total amount of revenues to be received by Seller hereunder; *provided, however*, that Seller shall have the right to terminate this Agreement without further obligation to Purchaser in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Seller; *provided, further*, that Purchaser shall have the right to terminate this Agreement without further obligation to Seller in the event that modifications to this Agreement by FERC cause a material adverse effect on the economic value of this Agreement to Purchaser; *and provided, further*, that in the event Seller elects to terminate this Agreement pursuant to this Section 10.2, then Purchaser and Seller agree to expeditiously proceed with a sale [redacted] to Purchaser and the other Customers in accordance with the provisions of the Ownership Agreement. Seller agrees to use good faith efforts, consistent with Prudent Utility Practice, to resist any changes to this Agreement proposed by the FERC or any other Governmental Body or their respective staffs, and Purchaser agrees not to seek, request, promote or support any changes to this Agreement before the FERC or any other Governmental Body.

SECTION 11
FORCE MAJEURE

11.1 Force Majeure Notice and Obligations. With respect to those obligations of the Parties set forth in this Agreement that expressly excuse performance in the event of a Force Majeure, the existence of Force Majeure that causes a Party (the "Non-Performing Party") to delay performance or fail to perform such obligations shall excuse the Non-Performing Party's delay in performing, or failure to perform, such obligations, subject to any express limitations on such excuse provided or referenced in the Section invoking the excuse. In the event of Force Majeure that causes the Non-Performing Party to delay performance or fail to perform its obligations under this Agreement and that excuses such delay or failure:

11.1.1 the Non-Performing Party shall give the other Party written notice and full details as soon as practicable after learning of the Force Majeure;

11.1.2 the Non-Performing Party shall use reasonable dispatch to remedy its inability to perform (except that this provision shall not impose a requirement on either Party to deliver or receive Energy at a delivery point other than a Delivery Point), and, if Seller is the Non-Performing Party, Seller shall use reasonable efforts to provide Energy from the Facility at a Delivery Point; and

11.1.3 when the Non-Performing Party is able to resume performance of its obligations under this Agreement, that Party shall give the other Party written notice to that effect.

SECTION 12
EVENTS OF DEFAULT; TERMINATION

12.1 Events of Default of Seller. Except when excused due to a Force Majeure event pursuant to the provisions of Section 11 hereof, an Event of Default shall be deemed to have occurred with respect to Seller upon the occurrence and during the continuance of any of the following events:

12.1.1 The Bankruptcy of Seller;

12.1.2 Seller fails to pay any invoiced amount or undisputed non-invoiced amount when due under this Agreement within five (5) Business Days after receiving notice of such failure;

12.1.3 Seller fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than obligations addressed in Section 12.1.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Purchaser demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot be reasonably accomplished within such 30-day period and Seller diligently commences such cure in such period and continues such cure to completion); or

12.1.4 Any representation or warranty made by Seller herein, in the Ownership Agreement or in any document or certificate furnished by Seller hereunder shall have been false when made and such false representation or warranty has a material and adverse effect on Purchaser and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Purchaser.

12.2 Events of Default of Purchaser. An Event of Default shall be deemed to have occurred with respect to Purchaser upon the occurrence and during the continuance of any of the following events:

12.2.1 The Bankruptcy of Purchaser;

12.2.2 Purchaser fails: (i) to pay any invoiced amount or any undisputed non-invoiced amount when due under this Agreement within ten (10) Business Days after receiving notice of such failure; or (ii) to make any payment of principal or interest under the Bond Legislation or any other bond resolution, indenture or similar secured instrument of the Purchaser when due (at maturity, upon redemption or otherwise), which failure is not cured within ten (10) Business Days;

12.2.3 Purchaser fails to perform or observe any of its material obligations or covenants hereunder or otherwise is in material breach of this Agreement (other than payment obligations, which are addressed in Section 12.2.2) and such failure or breach continues unremedied for a period of thirty (30) days following notice from Seller demanding cure of such failure or breach (or within such longer period of time as is reasonably necessary to accomplish such cure, if it cannot reasonably be accomplished within such 30-day period and Purchaser diligently commences such cure in such period and continues such cure to completion);

12.2.4 Any representation or warranty made by Purchaser herein, in the Ownership Agreement or in any document or certificate furnished by Purchaser shall have been false when made and such false representation or warranty has a material and adverse effect on Seller and, if capable of being cured, such false representation or warranty is not cured within thirty (30) days after notice thereof from Seller; or

12.2.5 Purchaser fails to comply with any of the requirements of Section 15 within thirty (30) days of receipt of Seller's written notice of such failure.

12.3 Remedies; Notice of Intent to Terminate. Subject to the provisions of this Agreement providing for limitations on damages and for exclusive remedies under certain circumstances, upon the occurrence and during the continuation of any Event of Default, the Party not in default (the "Non-Defaulting Party") shall have the right to pursue all remedies available at law or in equity, suspend its performance under this Agreement to the extent of the Event of Default and/or to deliver a notice of intent to terminate ("Notice of Intent to Terminate") this Agreement to the Party in default ("Defaulting Party"). Any Notice of Intent to Terminate shall specify the Event of Default giving rise to such Notice of Intent to Terminate. Following the giving of a Notice of Intent to Terminate, the Parties shall negotiate pursuant to the provisions of Section 18 hereof, following which, unless the Parties shall have otherwise mutually agreed on a remedy or the Defaulting Party or any lender or financing party ("Lender") to the Defaulting Party or its affiliate, or agent on behalf of a Lender, shall have cured such default or is diligently pursuing a remedy to cure the Event of Default, the Non-Defaulting Party having given the Notice of Intent to Terminate may terminate this Agreement by giving written

notice thereof to the Defaulting Party, whereupon this Agreement shall immediately terminate; *provided, however*, that upon a default under Section 12.2.2, the Non-Defaulting Party may serve a notice of termination of this Agreement, without having first to deliver a Notice of Intent to Terminate and to negotiate under Section 18, whereupon this Agreement shall terminate immediately upon delivery of such notice of termination, unless such default shall have been cured prior to the delivery of such notice of termination. Except as provided in Sections 2.2, 2.3, 5.1.2, 10.2, 12.4, and 12.5 or in this Section 12.3, or in Section 4.3 of the Ownership Agreement, neither Party shall have any right to terminate this Agreement.

12.4 Notice to Lenders. Any and all notices given by Purchaser to Seller under this Section 12 shall also be given at the same time by Purchaser to any Lender for which Seller provides written notice to Purchaser of the need to provide such notice and the address to which such notice must be sent. No termination of this Agreement by Purchaser will be effective until and unless Purchaser shall have given Seller's Lenders notice of Seller's Event of Default and an opportunity to cure such Event of Default, which notice and cure period shall be as set forth in any consent executed by Purchaser with Seller's Lenders but in any event such notice and cure period shall be at least concurrent with that provided to Seller under this Agreement.

12.5 Termination Payment.

12.5.1 Except in the case of an Event of Default under Section 12.2.2 under the circumstances that are described in Section 12.5.2 below or an Event of Default under Section 12.1.3 under the circumstances that are described in Section 12.5.3 below, in the event that a Non-Defaulting Party terminates this Agreement pursuant to Section 12.3 and provided an Event of Default shall not have occurred and be continuing as to such Non-Defaulting Party, the Defaulting Party shall pay the Non-Defaulting Party the Termination Payment, as defined below, within thirty (30) days of the effective date of the termination. Except as so otherwise provided in Section 12.5.2 or 12.5.3, the Termination Payment (if applicable) shall be the Defaulting Party's sole liability arising out of a termination of this Agreement pursuant to Section 12.3, and neither Party shall have any other liability or obligation to the other Party arising out of a termination of this Agreement pursuant to Section 12.3. The Defaulting Party's Termination Payment (if applicable) to the Non-Defaulting Party resulting from an Event of Default under this Agreement shall be calculated as follows:

Termination Payment = TPR * APCN

Where:

TPR = a termination payment rate in dollar per kilowatt, which is equal to: (i) [redacted] if the Notice of Intent to Terminate is given between the date of this Agreement's execution and the end of the twelfth (12th) month after the date Purchaser gives notice under Section 2.2 or 2.3 that it has elected to terminate this Agreement; (ii) [redacted] if the Notice of Intent to Terminate is given between the end of such twelfth (12th) month and the end of the twenty-fourth (24th) month after the date Purchaser gives such notice; or (iii) [redacted] if the Notice of Intent to Terminate is given between the end of such twenty-fourth (24th) month and the expected termination of this Agreement twelve (12) months later; and

APCN = the Annual Purchaser's Capacity Nomination, in kilowatts, that is in effect on the date of the Notice of Intent to Terminate.

Delivery of a Notice to Terminate or calculation or payment of the Termination Payment shall not relieve the Defaulting Party of its obligation to pay all other amounts that became or have become due and payable by the Defaulting Party hereunder prior to the effective date of termination.

12.5.2 In the case of an Event of Default under Section 12.2.2 by Purchaser at a time when Purchaser is able to pay its debts generally as they come due, Seller shall be entitled to recover its actual damages, which the Parties recognize may be greater than, or less than, the Termination Payment. In determining actual damages, any amounts actually recovered from Seller's reasonable efforts to mitigate such damages shall be taken into account.

12.5.3 In the case of an Event of Default by Seller under Section 12.1.3 that results from a failure by Seller to deliver Energy from the Facility to Purchaser as required by this Agreement at a time when (i) the Facility was capable of delivering such Energy to Seller as required by this Agreement consistent with Prudent Utility Practice, the Technical Limits and applicable Law and Permit requirements, and (ii) Seller sold such Energy to a third party, then Purchaser shall be entitled to recover the actual damages of Purchaser, which the Parties recognize may be greater than, or less than, the Termination Payment. In determining actual damages, the actual results of Purchaser's reasonable efforts to mitigate such damages shall be taken into account.

12.5.4 In receiving a Termination Payment or recovering actual damages, the Non-Defaulting Party shall also be entitled to recover its reasonable attorney fees in enforcing this provision.

SECTION 13
WAIVER

Failure by either Party to exercise any of its rights under this Agreement shall not constitute a waiver of such rights. Neither Party shall be deemed to have waived any right resulting from any failure to perform by the other Party unless it has made such waiver specifically in writing, and no such waiver shall operate as a waiver of any future failure to perform whether of a like or different character. No single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege hereunder.

SECTION 14
REPRESENTATIONS AND WARRANTIES

14.1 Representations and Warranties of Seller. Seller hereby represents and warrants to Purchaser as follows:

14.1.1 Organization and Existence. Seller is a limited liability company duly organized, validly existing and in good standing under the laws of the State of Delaware, is qualified to transact business in Florida, and has sufficient power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Seller has full power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.1.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Seller has been duly and effectively authorized by all requisite action on the part of Seller. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Seller, enforceable against Seller in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.1.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Seller's knowledge, threatened against Seller or The Southern Company by or before any Governmental Body having

jurisdiction over Seller or The Southern Company which, if adversely determined, would have a material adverse effect upon Seller's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents. Neither Seller nor The Southern Company is subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Seller or The Southern Company which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Purchaser under this Agreement or the Collateral Documents.

14.1.4 No Violation or Conflict. The execution, delivery and performance by Seller of this Agreement and the Collateral Documents do not violate or conflict with Seller's operating agreement, any existing Law applicable to Seller, or any note, bond, indenture, agreement or instrument to which Seller is a party or by which it is bound.

14.1.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment A of the Ownership Agreement, there are no approvals or consents, the absence of which would materially impair Seller's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2 Representations and Warranties of Purchaser. Purchaser hereby represents and warrants to Seller as follows:

14.2.1 Organization and Existence. Purchaser is a statutory utilities commission duly organized, validly existing and in good standing under the laws of the State of Florida and has sufficient statutory power and authority to execute and deliver this Agreement and the Collateral Documents and to perform its obligations hereunder and thereunder. Purchaser has full statutory power and authority to carry on its business as it is now being conducted and as it is contemplated hereunder and under the Collateral Documents to be conducted in the future.

14.2.2 Due Authorization. The execution, delivery and performance of this Agreement and the Collateral Documents by Purchaser has been duly and effectively authorized by all requisite action on the part of Purchaser's governing board. This Agreement and the Collateral Documents constitute the legal, valid and binding obligations of Purchaser,

enforceable against Purchaser in accordance with their terms, except as limited by applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting the rights of creditors generally and by general principles of equity.

14.2.3 Litigation. There is no action, suit, claim, proceeding or investigation pending or, to Purchaser's knowledge, threatened against Purchaser by or before any Governmental Body having jurisdiction over Purchaser which, if adversely determined, would have a material adverse effect upon Purchaser's ability to enter into and perform its obligations and consummate the transactions contemplated by this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents. Purchaser is not subject to any material outstanding judgment, order, writ, injunction or decree of any Governmental Body having jurisdiction over Purchaser which would materially and adversely affect its ability to enter into and perform its obligations under this Agreement and the Collateral Documents or the material rights of Seller under this Agreement or the Collateral Documents.

14.2.4 No Violation or Conflict. The execution, delivery and performance by Purchaser of this Agreement and the Collateral Documents do not violate or conflict with Purchaser's charter or bylaws, any existing Law applicable to Purchaser, or any note, bond, resolution, indenture, agreement or instrument to which Purchaser is a party or by which it is bound.

14.2.5 Approvals. Other than the approvals by the Governmental Bodies described in Attachment A of the Ownership Agreement, there are no approvals or consents, the absence of which would materially impair Purchaser's ability to consummate the transactions described in, or to perform its obligations under, this Agreement and the Collateral Documents.

14.2.6 No Immunity. With respect to its contractual obligations hereunder and performance thereof, Purchaser is not entitled to claim immunity on the grounds of sovereignty or similar grounds with respect to itself or its revenues or assets from: (a) suit; (b) jurisdiction of any Florida court; or (c) relief by way of injunction, order for specific performance or attachment of property that is subject to execution or levy under Florida Law (including the Eligible Collateral).

14.3 Warranties Regarding Energy, Capacity and Ancillary Services. Seller warrants that the Energy, Capacity and Ancillary Services provided under this Agreement (i) shall have been delivered in accordance with applicable Law, and (ii) meets the requirements set forth in this Agreement. **THE FOREGOING IS IN LIEU OF ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, IN FACT OR BY LAW WITH RESPECT TO THE ENERGY, CAPACITY AND ANCILLARY SERVICES PROVIDED HEREUNDER. SELLER HEREBY DISCLAIMS ANY AND ALL OTHER WARRANTIES WHATSOEVER.**

SECTION 15
PERFORMANCE ASSURANCE

15.1 In the event that Purchaser experiences a Material Adverse Change, as defined below, as security for Purchaser's payment obligations under this Agreement, Purchaser shall deliver to Seller within [redacted] of Seller's written request therefor, Eligible Collateral in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period.

15.1.1 As used in this Section 15.1: (i) a "Material Adverse Change" shall occur (A) when Purchaser's credit rating on its senior securities falls below the lower of (x) [redacted] (Standard & Poors) or [redacted] (Moody's) and (y) the lowest credit rating of Southern Guarantor's senior securities under either Moody's or Standard & Poors, (B) upon an Event of Default by Purchaser under Section 12.2.2(i), (C) upon a failure by Purchaser to make any required deposit into any sinking fund under the Bond Legislation or any other bond resolution, indenture or similar secured instrument entered into in connection with the issuance of additional debt (each a "Debt Instrument"), or (D) upon a failure by Purchaser to maintain in any debt service reserve account under the Bond Legislation or any Debt Instrument at least [redacted] of the amount required to be maintained in such account; and (ii) "Eligible Collateral" means cash deposited into an operating account from "Revenues", as that term is defined in the Senior Lien Resolution, or an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller; *provided, however*, that for purposes of Sections 15.1.1(i)(C) and 15.1.1(i)(D), Eligible Collateral shall constitute an unconditional letter of credit from an "A" rated bank, as determined by Standard & Poors or Moody's, in a form reasonably acceptable to Seller. Costs of a letter of credit shall be borne by Purchaser.

15.1.2 If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Purchaser, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when a "Material Adverse Change" has occurred.

15.2 In the event that legislation is enacted in the State of Florida which contains provisions that will cause an Event of Default by Purchaser at any time during the term of this Agreement, Seller will have the right, from and after the date of enactment of such legislation, to provide Purchaser with written notice requesting Eligible Collateral, as defined above, in an amount equal to the lesser of: (i) [redacted] of Capacity Payments, or (ii) [redacted] of the total of Capacity Payments for the remainder of the Operating Period. Upon receipt of such notice, in addition to Purchaser's other payment obligations under this Agreement, Purchaser shall within [redacted] provide such Eligible Collateral.

15.3. To the extent Purchaser delivers Eligible Collateral in the form of cash to be held in an operating reserve account pursuant to Sections 15.5 or 15.6, Purchaser hereby grants to Seller a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, such Eligible Collateral, and any and all proceeds resulting therefrom or from the liquidation thereof, and Purchaser agrees to take such action as Seller reasonably requires in order to perfect Seller's first-priority security interest in, and lien on (and right of setoff against), such Eligible Collateral and any and all proceeds resulting therefrom or from the liquidation thereof. This Agreement is intended to, and does, constitute a security agreement between Seller and Purchaser with regard to any cash which may constitute Eligible Collateral.

15.4. Upon or any time after the occurrence and during the continuation of an Event of Default of Purchaser, Seller may (i) exercise any of the rights and remedies of a secured party with respect to the Eligible Collateral, including any such rights and remedies under Law then in effect, such as but not limited to the Uniform Commercial Code, and (ii) liquidate and/or draw on any outstanding Eligible Collateral issued for its benefit (free from any claim or right of any nature whatsoever of Purchaser including any equity or right of purchase or redemption by Purchaser) with respect to Purchaser's obligations under this Agreement. In the event that Seller liquidates or draws on any of the Eligible Collateral, Purchaser shall within [redacted] of notice from Seller of such liquidation or draw, deliver additional cash or increase the amount of the letter of credit, as the case may be, in order to replenish the amount of the Eligible Collateral to the extent of the liquidation or draw.

15.5. If the trigger of a Material Adverse Change was occurrence of the circumstances in Sections 15.1.1(i)(A) or the circumstances described in Section 15.2 occur, then: (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at

such time as the circumstances described in Sections 15.1.1(i)(A) and 15.2 no longer apply (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire at such time as the circumstances described in Sections 15.1.1 and 15.2 no longer apply and Seller shall return such letter of credit to Purchaser (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.6 If the trigger of a Material Adverse Change was occurrence of the circumstances described in Section 15.1.1(i)(B), then (i) if the Eligible Collateral is in the form of cash, Seller will hold the Eligible Collateral in an interest-bearing operating reserve account, established by Seller, and the agent for which shall act pursuant to Seller's instructions and will return the balance of such account, including interest, at such time as Purchaser shall have (A) cured the Event of Default under Section 12.2.2 that triggered the Material Adverse Change and (B) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to receive any funds in such operating reserve account at any time and to the extent that such funds exceed [redacted] of the total of Capacity Payments for the remainder of the Operating Period); or (ii) if the Eligible Collateral is in the form of a letter of credit, such letter of credit shall expire (and Seller shall return such letter of credit) at such time as Purchaser shall have (C) cured the Events of Default under Section 12.2.2 that triggered the Material Adverse Change and (D) thereafter avoided both any further Events of Default under Section 12.2.2 and a Material Adverse Change as described in Section 15.1.1(i)(A) or 15.2 for a period of [redacted] (provided that Purchaser shall be entitled to reduce the amount available under the letter of credit at any time and to the extent that such amount exceeds [redacted] of the total of Capacity Payments for the remainder of the Operating Period).

15.7 In the event that the Purchaser exercises its right to elect an Extended Term or any Further Extension of this Agreement pursuant to Sections 2.2 and 2.3, and on any day of such Extended Term or Further Extensions the circumstances of either Sections 15.1.1 or 15.2 apply, then, Purchaser shall deliver to Seller within [redacted] of the date of such occurrence, Eligible Collateral, as defined above, in an amount equal to [redacted] of Capacity Payments, and the provisions of Sections 15.3, 15.4, 15.5 and 15.6 shall apply to such Eligible Collateral.

SECTION 16
LIABILITY OF PARTIES

16.1 INDEMNITIES.

16.1.1 **TO THE EXTENT PERMITTED BY LAW, EACH PARTY (THE "INDEMNIFYING PARTY") SHALL FULLY INDEMNIFY AND DEFEND THE OTHER PARTY AND EACH OF THE OTHER PARTY'S SUBSIDIARIES AND AFFILIATES, AND THE PARTNERS, MEMBERS, PARTICIPANTS, PRINCIPALS, REPRESENTATIVES, SHAREHOLDERS, DIRECTORS, OFFICERS, AGENTS, EMPLOYEES, SUCCESSORS AND ASSIGNS OF EACH OF THEM (THE "INDEMNIFIED PARTIES") FROM AND AGAINST ANY AND ALL LOSSES, COSTS, DAMAGES, INJURIES, LIABILITIES, CLAIMS, DEMANDS, PENALTIES AND INTEREST, INCLUDING REASONABLE ATTORNEYS' FEES, RESULTING FROM THIRD PARTY CLAIMS DIRECTLY OR INDIRECTLY RELATED TO THIS AGREEMENT, TO THE EXTENT CAUSED OR CONTRIBUTED TO BY THE FAULT, INTENTIONAL ACT, NEGLIGENCE OR STRICT LIABILITY OF THE INDEMNIFYING PARTY OR ITS SUBSIDIARIES, AFFILIATES, CONTRACTORS OR SUBCONTRACTORS OR ANY OF THE OFFICERS, PARTNERS, MEMBERS, PARTICIPANTS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, EMPLOYEES, AGENTS, REPRESENTATIVES, SUCCESSORS OR ASSIGNS OF ANY OF THEM OR BY BREACH BY THE INDEMNIFYING PARTY OF THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT ANY LIABILITY TO THIRD PARTIES INCURRED BY SELLER IN PERFORMANCE OF ITS AGENCY FUNCTIONS PURSUANT TO THE OWNERSHIP AGREEMENT OR THE OPERATING AGREEMENT SHALL BE APPORTIONED IN ACCORDANCE WITH ARTICLE 9 OF THE OWNERSHIP AGREEMENT OR ARTICLE 7 OF THE OPERATING AGREEMENT.**

16.1.2 **IF ANY INDEMNIFIED PARTY INTENDS TO SEEK INDEMNIFICATION UNDER THIS SECTION 16.1 FROM AN INDEMNIFYING PARTY WITH RESPECT TO ANY ACTION OR CLAIM, THE INDEMNIFIED PARTY SHALL GIVE THE INDEMNIFYING PARTY WRITTEN NOTICE OF SUCH CLAIM OR ACTION PROMPTLY FOLLOWING THE RECEIPT OF**

ACTUAL KNOWLEDGE OR INFORMATION BY THE INDEMNIFIED PARTY OF A POSSIBLE CLAIM OR OF THE COMMENCEMENT OF A CLAIM OR ACTION, WHICH WRITTEN NOTICE SHALL IN NO EVENT BE DELIVERED LATER THAN THE FIRST TO OCCUR OF (A) FIFTEEN (15) DAYS PRIOR TO THE LAST DAY FOR RESPONDING TO SUCH CLAIM OR ACTION OR (B) THE EXPIRATION OF THE FIRST HALF OF THE PERIOD ALLOWED FOR RESPONDING TO SUCH CLAIM OR ACTION. THE INDEMNIFYING PARTY SHALL HAVE NO LIABILITY UNDER THIS SECTION FOR ANY CLAIM OR ACTION FOR WHICH SUCH NOTICE IS NOT PROVIDED TO THE EXTENT THAT THE FAILURE TO GIVE SUCH WRITTEN NOTICE MATERIALLY PREJUDICES THE INDEMNIFYING PARTY. UPON ACKNOWLEDGMENT OF ITS OBLIGATIONS UNDER THIS SECTION 16.1, THE INDEMNIFYING PARTY SHALL HAVE THE RIGHT TO ASSUME THE DEFENSE OF ANY CLAIM OR ACTION, AT ITS SOLE COST AND EXPENSE, WITH COUNSEL DESIGNATED BY THE INDEMNIFYING PARTY AND REASONABLY SATISFACTORY TO THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE DEFENDANTS IN ANY SUCH ACTION INCLUDE BOTH THE INDEMNIFIED PARTY AND THE INDEMNIFYING PARTY, AND THE INDEMNIFIED PARTY SHALL HAVE REASONABLY CONCLUDED THAT THERE MAY BE LEGAL DEFENSES AVAILABLE TO IT WHICH ARE DIFFERENT FROM OR ADDITIONAL TO THOSE AVAILABLE TO THE INDEMNIFYING PARTY, THE INDEMNIFIED PARTY SHALL HAVE THE RIGHT TO SELECT SEPARATE COUNSEL, AT THE INDEMNIFYING PARTY'S EXPENSE, TO ASSERT SUCH LEGAL DEFENSES AND TO OTHERWISE PARTICIPATE IN THE DEFENSE OF SUCH ACTION ON BEHALF OF SUCH INDEMNIFIED PARTY.

16.1.3 EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFIED PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT HAS SOUGHT OR INTENDS TO SEEK INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFYING PARTY. SHOULD ANY INDEMNIFIED PARTY BE ENTITLED TO INDEMNIFICATION UNDER THIS SECTION 16.1 AS A RESULT OF A CLAIM OR ACTION BY A

THIRD PARTY, AND SHOULD THE INDEMNIFYING PARTY FAIL TO ASSUME THE DEFENSE OF SUCH CLAIM OR ACTION, THE INDEMNIFIED PARTY MAY, AT THE EXPENSE OF THE INDEMNIFYING PARTY, CONTEST (OR, WITH OR WITHOUT THE PRIOR CONSENT OF THE INDEMNIFYING PARTY, SETTLE) SUCH CLAIM OR ACTION. EXCEPT TO THE EXTENT EXPRESSLY PROVIDED HEREIN, NO INDEMNIFYING PARTY SHALL SETTLE ANY CLAIM OR ACTION WITH RESPECT TO WHICH IT MAY BE LIABLE TO PROVIDE INDEMNIFICATION PURSUANT TO THIS AGREEMENT WITHOUT THE PRIOR WRITTEN CONSENT OF THE INDEMNIFIED PARTY; *PROVIDED, HOWEVER*, THAT IF THE INDEMNIFYING PARTY HAS REACHED A BONA FIDE SETTLEMENT AGREEMENT WITH THE PLAINTIFF(S) IN ANY SUCH ACTION AND THE INDEMNIFIED PARTY DOES NOT CONSENT TO SUCH SETTLEMENT AGREEMENT, THEN THE AMOUNT SPECIFIED IN THE SETTLEMENT AGREEMENT, PLUS THE INDEMNIFIED PARTY'S REASONABLE ATTORNEY FEES INCURRED PRIOR TO THE DATE OF SUCH SETTLEMENT AGREEMENT, SHALL ACT AS AN ABSOLUTE MAXIMUM LIMIT ON THE INDEMNIFICATION OBLIGATION OF THE INDEMNIFYING PARTY WITH RESPECT TO THE CLAIM, OR PORTION THEREOF, THAT IS THE SUBJECT OF SUCH SETTLEMENT AGREEMENT TO THE EXTENT SUCH SETTLEMENT AGREEMENT FULLY RELEASES THE INDEMNIFIED PARTY AND DOES NOT REQUIRE ANY PAYMENT FROM, OR IMPOSE ANY RESTRICTION ON, THE INDEMNIFIED PARTY.

16.2 LIMITATION ON DAMAGES. **NEITHER PARTY NOR ITS SUBSIDIARIES OR AFFILIATES NOR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS, DIRECTORS, SUCCESSORS OR ASSIGNS OF ANY OF THEM SHALL IN ANY EVENT BE LIABLE TO THE OTHER PARTY OR ITS SUBSIDIARIES OR AFFILIATES OR THE OFFICERS, AGENTS, EMPLOYEES, REPRESENTATIVES, PARTICIPANTS, PARTNERS, MEMBERS, SHAREHOLDERS, PRINCIPALS OR DIRECTORS OF ANY OF THEM FOR CLAIMS FOR INCIDENTAL, PUNITIVE, CONSEQUENTIAL, EXEMPLARY OR INDIRECT DAMAGES OF ANY NATURE, ARISING AT ANY TIME, FROM ANY CAUSE WHATSOEVER, WHETHER ARISING IN TORT, CONTRACT, WARRANTY, STRICT LIABILITY, BY OPERATION OF LAW OR OTHERWISE, CONNECTED WITH OR RESULTING FROM**

PERFORMANCE OR NON-PERFORMANCE UNDER THIS AGREEMENT; *PROVIDED, HOWEVER*, THAT THIS SECTION 16.2 IS NOT INTENDED, NOR SHALL IT BE CONSTRUED, TO LIMIT OR ELIMINATE A PARTY'S OBLIGATION TO PAY LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR MAKE ANY OTHER PAYMENTS EXPRESSLY CONTEMPLATED HEREIN, OR IN ANY COLLATERAL DOCUMENT, EVEN IF IT MAY BE POSSIBLE TO CHARACTERIZE SUCH LIQUIDATED DAMAGES OR TERMINATION PAYMENTS OR OTHER PAYMENTS AS INCIDENTAL, PUNITIVE, CONSEQUENTIAL OR INDIRECT DAMAGES.

16.3 Seller Affiliate Guarantee. Seller shall at all times following the Effective Date of this Agreement cause an Affiliate of Seller to maintain in place a payment guarantee in the form attached to this Agreement as Appendix E. For purposes of the previous sentence, an "Affiliate" of Seller shall be any entity controlling, under common control with or controlled by Seller, which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's). If at any time during the term of this Agreement neither Standard & Poors nor Moody's is in the business of providing credit ratings or willing to rate Seller's affiliates, then Purchaser and Seller will negotiate in good faith to choose and implement an alternative mechanism for determining if and when an entity controlling, under common control with or controlled by Seller has sufficient credit-worthiness to qualify as an "Affiliate."

16.4 No Penalty. The Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by Purchaser due to Seller's failure to meet the Availability Guarantee or achieve the schedule provided under Section 5.1.1, that the Availability Damages set forth in Section 4.3 and the liquidated damages set forth in Section 5.1.2 are fair and reasonable determinations of the amount of actual damages which would be suffered by Purchaser or Seller, as the case may be, by reason of such failure, and that the Availability Damages and other liquidated damages do not constitute a penalty. Similarly, the Parties agree that it would be extremely difficult to precisely determine the amount of actual damages that would be suffered by either Party in case of an Event of Default and a termination of this Agreement by the Non-defaulting Party, that the Termination Payment set forth in Section 12.5.1 is a fair and reasonable determination of the amount of actual damages which would be suffered by the Non-defaulting Party in such event, and that the Termination Payment does not constitute a penalty.

SECTION 17
ASSIGNMENT

17.1 Agreement Binding. This Agreement shall be binding upon, and shall inure to the benefit of, the Parties and their successors and permitted assigns.

17.2 Permitted Assignment. This Agreement shall not be assignable by Seller without the prior written consent of Purchaser, except that this Agreement (a) may be assigned by Seller

without the requirement for such consent (but with notice to Purchaser) (i) to any Lender from time to time providing financing to Seller or its affiliate with respect to all or any portion of the Project or (ii) to any Lender or its designee in connection with a foreclosure or other exercise of remedies, and (b) unless otherwise waived by Purchaser, shall be assigned in whole or in part by Seller without the requirement for such consent (but with notice to Purchaser) in the event of a sale by Seller of all or a portion of Seller's interest in the Facility, with the purchaser of Seller's interest in the Facility assuming Seller's obligations under this Agreement in the same percentage as the portion of Seller's interest being transferred bears to Seller's entire interest in the Facility. This Agreement shall not be assignable by Purchaser without the prior written consent of Seller, *provided, however*, that Purchaser may assign this Agreement to another Customer without the requirement for such consent (but with notice to Seller) so long as such Customer has not experienced a Material Adverse Change under its PPA. Any such transferee, assignee or purchaser (other than a Lender through assignment in connection with a lease or other financing transaction permitted under Section 6.2.8 of the Ownership Agreement) shall confirm its willingness to accept all of the assigning Party's obligations under this Agreement by writing reasonably acceptable to the non-assigning Party. Any such assignee, transferee or purchaser (other than a Lender through assignment in connection with a lease or other financing transaction permitted under Section 6.2.8 of the Ownership Agreement) must be sufficiently creditworthy and otherwise capable of performing all of the assigning Party's obligations under this Agreement. No assignment or transfer of this Agreement by a Party shall be permitted during any period in which an Event of Default of such Party shall have occurred and be continuing and not cured, unless the other Party shall agree. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement, except that the assignor shall be released from its obligations under this Agreement at such time as all future obligations of the assignor hereunder shall have been assumed by the assignee in a written agreement delivered to the other Party. Any assignment that does not comply with the provisions of this Section 17 shall be null and void.

SECTION 18
DISPUTE RESOLUTION

18.1 Good-Faith Negotiations. The Parties shall first negotiate in good faith to attempt to resolve any dispute, controversy or claim arising out of, under, or relating to this Agreement (a "Dispute"), unless otherwise mutually agreed to by the Parties. In the event that the Parties are unsuccessful in resolving a Dispute through such negotiations, either Party may proceed immediately to litigation concerning the Dispute.

18.1.1 The process of "good-faith negotiations" requires that each Party set out in writing to the other its reason(s) for adopting a specific conclusion or for selecting a particular course of action, together with the sequence of subordinate facts leading to the conclusion or course of action. The

Parties shall attempt to agree on a mutually agreeable resolution of the Dispute. A Party shall not be required as part of these negotiations to provide any information which is confidential or proprietary in nature unless it is satisfied in its discretion that the other Party will maintain the confidentiality of and will not misuse such information or any information subject to attorney-client or other privilege under applicable Law regarding discovery and production of documents.

18.1.2 The negotiation process shall include at least two (2) meetings to discuss any Dispute. Unless otherwise mutually agreed, the first meeting shall take place within ten days after either Party has received notice from the other of the desire to commence formal negotiations concerning the Dispute. Unless otherwise mutually agreed, the second meeting shall take place no more than ten days later. In the event a Party refuses to attend a negotiation meeting, either Party may proceed immediately to litigation concerning the Dispute.

18.2 Confidentiality and Non-Admissibility of Statements Made in, and Evidence Specifically Prepared for, Good Faith Negotiations. Each Party hereby agrees that all statements made in the course of good faith negotiations, as contemplated in Section 18.1, shall be confidential and shall not be disclosed to or shared with any third parties (other than any person whose presence is necessary to facilitate the negotiation process). Each Party agrees and acknowledges that no statements made in or evidence specifically prepared for good faith negotiations under Section 18.1 shall be admissible for any purpose in any subsequent litigation.

SECTION 19
AMENDMENT

This Agreement cannot be amended, modified or supplemented except by written agreement making specific reference hereto executed by both Parties.

SECTION 20
NOTICES

Other than telephonic notices required or permitted under Section 6.1 or Appendix B, any notice required or permitted to be given hereunder shall be in writing and shall be: (i) personally delivered; (ii) transmitted by postage prepaid registered mail; (iii) transmitted by a recognized overnight courier service; or (iv) transmitted by facsimile to the receiving Party as follows, as elected by the Party giving such notice:

20.1 In the case of Purchaser:

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Attention: Vice-President of Power Resources
Telephone: 407-244-8372
Facsimile: 407-275-4120

With a copy to:

Orlando Utilities Commission
500 South Orange Avenue
Orlando, Florida 32801
Attention: Legal Department
Telephone: 407-423-9100
Facsimile: 407-423-9198

20.2 In the case of Seller:

Southern Company Services, Inc.
270 Peachtree Street, Bin 935
Atlanta, Georgia 30303
Attention: Director of Contract Administration
Telephone: 404-506-5100
Facsimile: 404-506-0304

With a copy to:

Troutman Sanders LLP
Bank of America Plaza
600 Peachtree Street N.E.
Atlanta, Georgia 30308
Attention: Robert H. Forry, Esq.
Telephone: 404-885-3142
Facsimile: 404-962-6559

All notices and other communications shall be deemed to have been duly given on (i) the date of receipt if delivered personally, (ii) five (5) days after the date of posting if transmitted by mail, (iii) the Business Day following delivery to the courier if transmitted by overnight delivery service, or (iv) the date of transmission with confirmation if transmitted by facsimile, whichever

shall first occur. Any Party may change its address for purposes hereof by notice to the other Party.

SECTION 21
APPLICABLE LAW

This Agreement shall be governed by, and construed in accordance with, the laws of the State of Florida, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction. The Parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Middle District of Florida, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Circuit Court of the State of Florida sitting in Orange County, Florida, and the Parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

SECTION 22
SEVERABILITY

The invalidity or unenforceability of any provision or portion of this Agreement will not affect the validity of the remainder of this Agreement. If any provision of this Agreement is determined to be invalid or unenforceable, the Parties will negotiate in good faith to agree upon substitute provisions to carry out the purpose and intent of the invalid or unenforceable provision. If the economic or legal substance of the transactions contemplated hereby is affected in any manner adverse to any Party as a result thereof, the Parties shall negotiate in good faith in an effort to agree upon a suitable and equitable substitute provision to effect the original intent of the Parties.

SECTION 23
ENTIRE AGREEMENT

This Agreement and the Collateral Documents contain the complete agreement of the Parties hereto with respect to the matters contained herein and supersede all other agreements, understandings and negotiations, whether written or oral, with respect to the matters contained herein.

SECTION 24
NO THIRD PARTY BENEFICIARIES

This Agreement is intended to be solely for the benefit of Purchaser and Seller and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any Person not a signatory hereto.

SECTION 25
COUNTERPARTS

This Agreement may be executed in one or more counterparts, each of which shall constitute an original but all of which, when taken together, shall constitute only one legal instrument.

SECTION 26
INFORMATION AND CONFIDENTIALITY

Where a Party makes any calculation of costs or damages under this Agreement, such Party shall provide, upon the reasonable request of the other Party, documentation supporting such calculation. Neither Party shall disclose or otherwise make available to any other party any information of a technical, commercial or business nature regarding the Project or this Agreement that has been marked or identified as confidential or proprietary ("Confidential Information") without the prior written consent of the other Party, except that (a) Seller or its affiliate may provide Confidential Information to its or any such affiliate's prospective Lenders, underwriters, investors, affiliates, advisors, employees, officers and directors to the extent reasonably required in connection with the administration of this Agreement, the issuance of debt or equity or other financing activities of Seller or its affiliate, or the performance of any duties relating to this Agreement; (b) Purchaser may provide Confidential Information to its advisors, employees, officers, directors and Lenders to the extent reasonably required in connection with the administration of this Agreement or the performance of any such Person's duties relating to this Agreement; (c) any Party may disclose any such Confidential Information in any litigation or proceeding to enforce or recover damages under this Agreement; (d) any Party (or its affiliate) may disclose any such Confidential Information as may be required by any applicable Law, regulation or governmental order; and (e) any Party (or its affiliate) may disclose such Confidential Information to any person or entity succeeding to all or substantially all the assets of such Party (or its affiliate) or all or a substantial portion of its interest in the Facility; *provided*, that in the case of (e), any such successor shall agree to be bound by the provisions of this Section 26. Confidential Information shall not include information that: (i) the receiving Party can demonstrate was known to it prior to its disclosure by the other Party; (ii) is, or later becomes, public knowledge without breach of this Agreement by the receiving Party; (iii) was received by the receiving Party from a third party without obligation of confidentiality; or (iv) is developed by the receiving Party independently from Confidential Information received from the other Party, as evidenced by appropriate documentation. In the event that disclosure is required by a valid order of a court or Governmental Body, the Party subject to such requirement may disclose Confidential Information to the extent so required, but shall promptly notify the other Party and shall cooperate with the other Party's efforts to obtain protective orders or similar restraints with respect to such disclosure. The provisions of this Section 26 shall continue in effect until three years after the end of the Operating Period.

The Parties understand that under the Florida Public Records Law (Section 119.10, Florida Statutes), any Party or all of them may be subject to statutory fines and penalties, including but not limited to a requesting Party's costs and attorney's fees for failure to make public records available for public inspection upon request (Chapter 119, Florida Statutes). In addition, each Party may be subject to its own costs and expenses of litigation. With this understanding in mind, the Parties agree that in the event Purchaser in an attempt to comply with this Agreement, refuses to honor a public records request under Chapter 119, Florida Statutes, for examination or inspection of a confidential document of Seller or any affiliate of Seller and is forced to defend its actions in a court of competent jurisdiction, Seller shall indemnify, defend, and hold Purchaser harmless from and against any fines, penalties, costs, attorney's fees and expenses, including, but not by way of limitation, attorney's fees, expert fees, court costs and other costs arising from or related to defending any lawsuit bought pursuant to Chapter 119, Florida Statutes; *provided, however,* Seller's consent with such refusal shall be obtained before Seller can be liable under this Section *26*. In addition, the Parties shall cooperate to provide witnesses to support the Parties' declarations and certification that the Confidential Information is a valid trade secret under the above cited Florida law and meets all definitional requirements therein or is exempt from disclosure under other applicable Florida law.

SECTION 27
PUBLIC STATEMENTS

Seller and Purchaser shall consult with each other and neither of them shall issue a press release or make a statement intended for release to the general public with respect to the transactions contemplated hereby without the consent of the other Party, which consent shall not be unreasonably withheld, unless the Party desiring to make such statement or press release is advised by legal counsel that a statement or press release is required by applicable Law (including information provided pursuant to a request for public information under the Florida Public Records Law, Section 119.10, Florida Statutes); *provided, however,* that in this event the Party making the public statement or press release shall notify the other Party in advance of such statement or press release and allow the other Party reasonable time to comment on such statement or press release. Notwithstanding the immediately preceding sentence, the Parties acknowledge that certain meetings of the Orlando Utilities Commission and the City of Orlando are open to the public, and nothing in this Agreement shall be deemed to require that the proceedings of such meetings not be made public or to restrict the reporting by the media of such proceedings.

SECTION 28
INSURANCE

Seller and Purchaser, and all contractors and subcontractors performing any services in connection with the operation or maintenance of the Facility, shall obtain and maintain in force comprehensive general liability insurance, and property insurance for injury to persons and

property, automobile liability insurance and workman's compensation insurance, all in amounts and under terms as required by the Operating Agreement.

SECTION 29
TAXES

Purchaser shall reimburse Seller for, or pay to Seller, all sales, use, personal property and other taxes of every kind paid or collected by Seller, if any, that are not currently levied and are hereafter levied on the purchase, sale or use of fuel consumed by the Facility to provide Energy or Ancillary Services in accordance with this Agreement or the purchase, sale or use of Capacity, Energy or Ancillary Services under this Agreement, but excluding any taxes levied on Seller's net income. Purchaser shall pay directly for all such sales, use, personal property and other taxes which it is legally obligated and empowered to pay. In the event Seller, on behalf of Purchaser, pays any taxes that are the responsibility of Purchaser to reimburse or pay, under the first two sentences of this Section 29, the amount so paid by Seller shall be added to a monthly invoice submitted by Seller to Purchaser under Section 9, and Purchaser shall pay such amount in accordance with Section 9. Upon the reasonable request of Purchaser, Seller agrees to (i) provide documents related to taxes or assessments to be reimbursed or paid by Purchaser under this Agreement and (ii) cooperate with Purchaser at Purchaser's expense should Purchaser seek to obtain from the entity to which taxes were paid a refund of any taxes paid by Seller and/or reimbursed or paid by Purchaser.

IN WITNESS WHEREOF, the Parties, intending to be legally bound, have caused this Agreement to be executed by their duly authorized representatives as of the day and year first written above.

Signed, sealed and delivered in the presence of:

Betty J. Perrow
MY COMMISSION # CC964113 EXPIRES
December 4, 2004
BONDED THRU TROY FAIN INSURANCE, INC.

Betty J. Perrow
Notary Public

ORLANDO UTILITIES COMMISSION

By: _____
H. A. Tico Perez, President

FOR THE USE AND RELIANCE OF OUC ONLY - APPROVED AS TO FORM AND LEGALITY

Wayne Mann
Attorney for OUC

Date: 3-19-01

Attest: _____
Robert C. Haven, CEO and General Manager

Signed, sealed and delivered in the presence of:

Sandra L. Hight
Commission expires 10/28/01
Notary Public

SOUTHERN COMPANY - FLORIDA LLC

By: Southern Power Company, its sole member

By: _____
Douglas E. Jones, Vice President

Attest: _____
Anthony J. Topazi, Vice President

APPENDIX A

TECHNICAL LIMITS

Unit Operating Modes

1. **Definition of Operating Modes**.

The Facility will have several different operating modes.

- Mode 1: Normal Operation—both gas turbines (CTs) operating with no supplemental firing of the Heat Recovery Steam Generator (HRSG) and no gas turbine power augmentation.

- Mode 2: Supplemental Firing Operation—both gas turbines operating at full load with supplemental firing of the HRSG.

- Mode 3: Power Augmentation Operation—both gas turbines operating at full load with supplemental firing of the HRSG's (Mode 2 Supplemental Firing Operation) to produce both steam for full steam turbine-generator output with the maximum allowed continuous throttle flow at the maximum allowed continuous throttle pressure and steam for full gas turbine power augmentation (steam injection.)

- Mode 4: Part-load Operation—one or both gas turbines operating at less than full load.

2. **Natural Gas Requirements**.

The Facility will require "pipeline quality gas" meeting the requirements of GE fuel specification "GEI 41040E - Process Specification Fuel Gases for Combustion in Heavy Duty Gas Turbines".

Natural gas is to be delivered to the Facility by pipeline and the pipeline and gas must meet the following equipment characteristics and requirements:

- Nominal Maximum N.G. Flow (HHV) per Block (2x1) [redacted] MMBtu/hr*
- Nominal N.G. Higher Heating Value [redacted] Btu/lb
- Minimum Fuel Supply Temperature (after PRV) [redacted] °F
- Fuel Pressure at Gas Control Valve** [redacted] PSIG (nominal)

[redacted]PSIG maximum

* Based on Winter Peaking [redacted] Power during Full Pressure Operation.

** Reference GE Pub. GEI 41040E.

3. **Fuel Oil Requirements**.

The Facility will require fuel oil that is in compliance with ASTM Standard Specification D-2880 (as revised) and "GE Gas Turbine Liquid Fuel Specifications" (document number GEI 41047H). This No. 2 GT Grade Gas Turbine Fuel Oil must be in compliance with the specifications and procedures for No. 2 Fuel Oil as defined in ASTM D396.

Note that environmental permitting may create conditions for sulfur, fuel bound nitrogen and other specifications which could affect or add minimum specifications, such as, but not limited to, those identified in the following table:

	SPECIFICATIONS	**ASTM TEST METHOD**
Sulfur, % Wt., Max.	0.05	D – 1266
Fuel Bound Nitrogen	0.050% Max.	

4. **Dispatch and Operational Requirements**.

- The Facility will be capable of operating with fuel oil. The Facility may fire oil in the gas turbines only and not in the HRSG duct burners. During these periods, the Facility shall operate in Mode 1 (Normal Operation) only.

- The Facility will require shutdown for a minimum of one hour prior to switching from natural gas to oil firing. The fuel oil forwarding system will not be operated during normal gas firing, but operation of the fuel forwarding system will be initiated upon proper notice of a requirement for fuel switching. The Facility will be capable of switching from oil to natural gas without shutdown; however, the Facility may be required to decrease to a minimum load and stabilize prior to ramping to full load.

- The Facility will be capable of being controlled via Automatic Generation Control (AGC) in Mode 1 (Normal Operation). The AGC load range and ramp rate will be set by the Facility's operator based on the actual capability of the CTs as determined through testing. With the duct burners firing (Mode 2 – Supplemental Firing Operation), the load range and ramp rate

will be set and manually controlled by the Facility's operator based on the capabilities of the duct burners. No load following capability is available in Mode 3 (Power Augmentation Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) only at ambient temperatures of [redacted] and higher.

- The Facility will require [redacted] of de-mineralized water for Mode 1 (Normal Operation).

- The expected maximum allowable rate of load increase for the Facility will be [redacted] Actual maximum load increase rate will be determined by actual testing and in light of final permit restrictions and emissions tests.

- The Facility will be expected to be capable of operating minimum load with one CT at [redacted] load or two CTs each at part of [redacted] load. Actual minimum load will be determined in light of final NOx emissions and permit restrictions and testing.

- Required startup times for the Facility shall be as follows:

  Mode 1 (Normal Operation): refer to Attachment 1 – Time to Dispatch Curve. Note: Actual Curve to be determined by testing.

  Mode 2 (Supplemental Firing Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation).

  Mode 3 (Power Augmentation Operation): [redacted] from one hundred percent (100%) Mode 1 (Normal Operation) or [redacted] from one hundred percent (100%) Mode 2 (Supplemental Firing Operation).

- The Facility will be allowed to operate in Mode 3 (Power Augmentation Operation) a maximum of [redacted] based on the LTSA contract with GE.

- The Facility will not be allowed to operate in a traditional CT only mode (no simple cycle operation, *i.e.*, no bypass stack). However, the CTs will be capable of operating independently of the steam turbine utilizing the steam bypass systems for a limited time. Most major plant equipment (such as HRSG BFP's, condenser, cooling tower and circulating water pumps) will be required during operation in this mode. The HRSG duct burners will not be available in this mode. The maximum generation capability of the Facility operating in this mode will be [redacted] CT load.

- The Facility's CT evaporative coolers should not be operated at ambient temperatures less than [redacted] to prevent freezing at the CT compressor inlet.

APPENDIX B

REQUESTS FOR ENERGY

1.1 Schedules for Requested Quantities of Energy. Purchaser and each other Customer shall provide Seller with a single Request for Energy in order to schedule requested quantities of each category of unit output as follows:

1.1.1 Day Ahead Daily Schedule. Customers shall communicate the day ahead Request for Energy for each day to Seller at or before [redacted] Eastern Prevailing Time of the immediately preceding day before delivery is to be made, or such other earlier time that may be required by an RTO.

1.1.1.1 When AGC mode is available, during each hour the unit is scheduled to be in AGC mode, the Request for Energy shall specify the maximum amount of Energy desired for each of the twenty-four (24) hours. During each hour the unit is in AGC mode, the Customers shall not be permitted to reduce the Request for Energy to an amount less than [redacted] MW of the maximum Energy scheduled during that hour in the Request for Energy from the Customers' aggregate Equity Capacity and the Customers' aggregate capacity available under the Power Purchase Agreements (Customers' "PPA Capacity"). If in any hour, should the Customers reduce the Request for Energy amount by more than [redacted] MW, the Customers shall pay Seller [redacted] for the difference between the amount of the Delivered Energy and the amount that is [redacted] MW below the Request for Energy amount.

1.1.1.2 During each hour the Facility is not scheduled to be in AGC mode or the AGC mode is unavailable, the Request for Energy shall specify the amount of Energy from the Customers' aggregate PPA Capacity and aggregate Equity Capacity for each of the twenty-four (24) hours. Requests for Energy shall be submitted in [redacted] MW increments in a total amount that falls between the Facility's minimum capability and its maximum capability as described in the Technical Limits.

1.2. Hourly Changes to the Daily Schedule. The Customers jointly shall be entitled to make changes to a Request for Energy by communicating such changes to Seller no later than [redacted] prior to the beginning of the hour in which such changes are to become effective. The Customers shall

be responsible for any costs associated with OASIS notifications and NERC tagging requirements.

1.3. Capacity Emergency. During any periods in which the Customers experience a Capacity Emergency, the Customers shall be entitled to increase the Request for Energy on shorter notice than that provided in paragraph 1.2 above by an amount not to exceed the Customers' unavailable resources that were the cause of the Capacity Emergency and Seller shall endeavor to comply with the request consistent with the Technical Limits, Prudent Utility Practice, applicable Law and Permit requirements.

1.4. Minimum Start-up Time. If the Customers have scheduled a zero amount of Capacity in any hour and the Facility is not on-line, the Customers shall provide notice consistent with the Technical Limits prior to scheduling any Request for Energy.

1.5. Load Following Service. The Customers shall have the ability to control the output of the Facility using the AGC mode, if available, only to the extent that the Facility has the ability to operate in the AGC mode consistent with the Technical Limits, Prudent Utility Practice, and applicable Law and Permit requirements.

1.6 Electronic Scheduling. The Customers shall use electronic scheduling for Requests for Energy under this Agreement, if and to the extent that Seller's electronic scheduling capability is operational. To the extent it is not, the Parties will use other mutually agreed-upon communication procedures (such as fax).

2.1 Shortfall Conditions; Oversupply Conditions.

2.1.1 If the Facility is in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the Facility is not within [redacted] MW of the Request for Energy, OUC shall communicate to Seller the amount of error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the Request for Energy within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.1.1 If the actual output of the Facility is greater than the Request for Energy (an "Oversupply Condition"), the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the Facility equals the Request for Energy. OUC, acting for itself and on behalf of the other Customers, shall coordinate with Seller during the period that the actual output of the Facility exceeds the Request for Energy. The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition. Seller shall compensate OUC, on its own behalf and as agent for KUA and FMPA, for any such Oversupply Condition.

2.1.1.2 If the actual output of the unit is less than the Request for Energy (an "Undersupply Condition"), the provisions of Section 4.3 will apply if applicable.

2.1.2 If the Facility is not in load following service and OUC, acting for itself and on behalf of the other Customers, determines that the actual output of the unit is not within [redacted] MW of the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy pursuant to Section 4.5 of this Agreement), then OUC shall communicate to Seller the amount of the error. Seller shall endeavor to adjust the actual output of the Facility to be equal to the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of receipt of the notification. If the actual output of the Facility does not equal the schedule included in the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy) within [redacted] of the notification, the Customers shall be entitled to reimbursement of their costs from Seller as follows:

2.1.2.1 If an Oversupply Condition exists, the decremental cost associated with over-generation shall be documented by the Customers until the actual output of the unit equals the Request for Energy (plus any other scheduled output pursuant to Seller's right to schedule Energy). The Customers shall advise Seller of the total decremental costs associated with each instance of an Oversupply Condition.

2.1.2.2 If an Undersupply Condition exists, the provisions of Section 4.3 will apply if applicable.

3.1 Notification Requirements for Delivery of Energy from Alternate Resources.

3.1.1 When the Facility is available and running at minimum load and spinning reserves are available, Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of Customers' Schedule at least [redacted] (or the amount of time in which an RTO has determined that the Physical Transmission Rights ("PTRs") may be recalled) prior to the scheduled commencement of delivery of such Energy. For purposes of paragraph 3.1, the phrase "has scheduled delivery" means that Seller has scheduled and arranged the OASIS, tagging, and any transmission rights required by an RTO. If an RTO is established in Florida, and under such condition the RTO determines that Physical Transmission Rights (PTRs) may be recalled if not utilized, then Seller will notify OUC if Seller has so scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.2 When the Facility is unavailable and is not scheduled to return to service in time for Seller to serve the Customers' Schedule, Seller will notify OUC within [redacted] after Seller's receipt of Customers' Schedule if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customers' Schedule. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.3 When the Facility becomes unavailable while Seller is serving Customers' Schedule, Seller will notify OUC within [redacted] after the Facility is deemed unavailable if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of the remainder of Customers' Schedule. If Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than the top of the next full hour following the hour that Seller notified OUC of Seller's election. (Example: The Facility becomes unavailable at [redacted] Seller gives notice no later than [redacted] if Seller will arrange to deliver Energy from

Alternate Resources. Delivery from Alternate Resources should begin no later than [redacted]) At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

3.1.4 When the Facility is expected to return from an outage, but does not, Seller will notify OUC within [redacted] of Seller's realization that the Facility will not be available as expected to meet the start of a Customer's Schedule. If the start of such Customer's Schedule is to begin within [redacted] or less from the time of such notice, Seller will notify OUC at the same time if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule. Otherwise Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources to meet all or a portion of such Customer's Schedule at least [redacted] prior to the start of such Schedule and preferably at least [redacted]. If Seller notifies OUC that Seller has scheduled delivery of Energy from Alternate Resources, then Seller will schedule delivery of such Energy to begin no later than [redacted] that Seller notified OUC of Seller's election (but not earlier than the original start of such Customers' Schedule). If an RTO develops in Florida, and under such condition the RTO determines that PTRs may be recalled if not utilized, then Seller will notify OUC if Seller has scheduled delivery of Energy from Alternate Resources at least [redacted] (or the amount of time in which an RTO has determined that the PTRs may be recalled) and [redacted] prior to the scheduled commencement of delivery of such Energy. At the time Seller notifies OUC that Seller has so scheduled delivery of Energy from Alternate Resources, Seller will identify the source and quantity of such Energy and the path of its transmission to OUC.

APPENDIX C

CAPACITY TESTING PROCEDURE

The capability of the Facility will be required to be demonstrated prior to the Commencement Date. The demonstration of the capability of the Facility following the Commencement Date shall be scheduled in accordance with the provisions of Section 4.1.2. As provided in Section 4.1.3, Participants may also request additional tests of the Facility which shall not be used as the basis for determining the Demonstrated Capability of the Facility. Purchaser shall have the right to monitor (either on-Site or otherwise) all performance tests.

All Capacity testing will be adjusted to the Rated Conditions using correction curves supplied by Seller. "Rated Conditions" means seventy (70) degrees Fahrenheit (°F) and forty five percent (45%) relative humidity. The demonstrated net output of the Facility will be as measured by the Meters.

On the date of the Capacity test, Seller shall bring the Facility to maximum full load capability within the Technical Limits of the Facility for the ambient conditions for that day. The test shall be scheduled between the weekday hours of [redacted] (prevailing Eastern Time) and will be conducted over [redacted] period (or a lesser period if mutually agreed upon). Seller must notify Customers when the Facility is at maximum full load capability, at which time the Capacity test shall begin. The Demonstrated Capability will be the average net hourly output over the test period corrected to Rated Conditions.

APPENDIX D

Example Calculations of Quantities of Gas Transportation and/or Commodity Required for Delivery from Alternate Resources

Listed below are examples of the determination of the amount of gas transportation and/or commodity that the Fuel Supply Agent shall provide to Seller pursuant to Section 4.2.5.2 or 4.2.5.3 when Seller elects to deliver Energy from Alternate Resources.

Example 1

The facility is unavailable. The Customers have Scheduled 400 MWh of Energy in an hour. Seller notifies OUC that Seller will supply the 400 MWh of Energy for the subject hour from Alternate Resources.

In Example 1, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 2

The facility is unavailable. The Customers have Scheduled 610 MWh of Energy in an hour. Seller notifies OUC that Seller will supply 550 MWh of Energy for the subject hour from Alternate Resources.

In Example 2, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 3

The facility is available. The Customers have Scheduled 450 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 100 MWh of Energy for the subject hour from Alternate Resources and 350 MWh from the Facility.

In Example 3, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

Example 4

The facility is available. The Customers have Scheduled 600 MWh of Energy in an hour. Seller notifies OUC that Seller will deliver 200 MWh of Energy for the subject hour from Alternate Resources and 400 MWh from the Facility.

In Example 4, the Fuel Supply Agent will provide [redacted] MMBtus of gas transportation and/or commodity determined as follows:

[redacted]

APPENDIX E

AFFILIATE GUARANTEE

[FORM OF] PAYMENT GUARANTY

This Guaranty Agreement (the "Guaranty") is made by The Southern Company ("Guarantor"), a Delaware corporation, in favor of Orlando Utilities Commission ("OUC"), a Florida statutory chartered public utility commission.

WHEREAS, Southern Company - Florida LLC ("Principal Obligor"), a Delaware limited liability company, and OUC entered into that certain Power Purchase Agreement, dated as of March 19, 2001 (the "PPA");

WHEREAS, Guarantor has agreed to provide assurance for the payment of Principal Obligor's obligations in connection with the PPA as provided in this Guaranty; and

WHEREAS, the execution and delivery of this Guaranty by Guarantor is pursuant to the terms of the PPA in order to satisfy the requirement that Principal Obligor cause an Affiliate to maintain in place a guaranty of Principal Obligor's obligations under the PPA.

NOW, THEREFORE, in consideration of the premises and other good and valuable consideration, the adequacy, receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. **Guaranty.** Guarantor hereby irrevocably, unconditionally and absolutely guarantees the punctual payment when due of Principal Obligor's payment obligations arising under the PPA, as amended or modified from time to time, together with any interest thereon, including, without limitation, any interest amounts accruing under the PPA during the pendency of insolvency, bankruptcy, reorganization or other similar proceedings affecting Principal Obligor or its assets; provided, however, that the maximum liability of Guarantor under this Guaranty with respect to Principal Obligor's obligations under the PPA shall be limited to the amount that is equal to the then-current Termination Payment (as defined in the PPA), which shall not exceed in any event [redacted] (collectively, the "Guaranteed Obligations"); provided, further, that the cap on Guarantor's liability under this Guaranty established in the immediately preceding clause creates an absolute cap on Guarantor's liability to OUC in relation to the PPA and, if and when Guarantor's liability under this Guaranty has reached such cap, then from and after such time, Guarantor shall have no further liability under this Guaranty whatsoever to OUC and this Guaranty shall thereupon terminate; provided, further, that costs incurred by Guarantor under Section 4

hereof shall not be counted for purposes of determining whether Guarantor has reached such cap, unless and to the extent that Guarantor's costs under such Section 4, together with costs incurred by Guarantor under the corresponding provisions of Guarantor's other three Payment Guarantees of contemporaneous date to one or more of OUC, FMPA and KUA, exceed [redacted]

2. **Guaranty Absolute.** The liability of Guarantor under this Guaranty shall be irrevocable, absolute and unconditional irrespective of:

(a) any lack of validity or enforceability of or defect or deficiency in the PPA or any other documents executed in connection with the PPA;

(b) any assignment, transfer, modification, extension or waiver of any of the terms of the PPA;

(c) any change in the time, manner, terms of payment of or in any other term of, all or any of the Guaranteed Obligations, or any other amendment or waiver of or any consent to departure from any agreement or instrument executed in connection therewith;

(d) any sale, exchange, release or non-perfection of any property standing as security for the liabilities hereby guaranteed or any liabilities incurred directly or indirectly hereunder or any set off against any of said liabilities, or any release or amendment or waiver of or consent to departure from any other guaranty, for all or any of the Guaranteed Obligations;

(e) applicable statutes of limitation, failure, omission, delay, waiver or refusal by OUC to exercise, in whole or in part, any right or remedy held by OUC with respect to the PPA or any transaction under the PPA; or

(f) any change in the existence, structure or ownership of Guarantor or Principal Obligor, or any insolvency, bankruptcy, reorganization or other similar proceeding affecting Principal Obligor or its assets.

The obligations of the Guarantor hereunder are several from the Principal Obligor or any other person, and are primary obligations concerning which the Guarantor is the principal obligor. There are no conditions precedent to the enforcement of this Guaranty, except as expressly contained herein.

This Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations are annulled, set aside, invalidated, declared to be fraudulent or preferential, rescinded or must otherwise be returned, refunded or

repaid by OUC upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of Principal Obligor or any other guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, Principal Obligor or any other guarantor or any substantial part of its property or otherwise, all as though such payment or payments had not been made.

3. **Waiver.** This is a guaranty of payment and not of collection. Guarantor hereby waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of any of the Guaranteed Obligations and of any action by OUC in reliance hereon or in connection herewith;

(b) except as expressly set forth herein, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest with respect to the Guaranteed Obligations; and

(c) any requirement that suit be brought against Principal Obligor or any other person as a condition to Guarantor's liability for the Guaranteed Obligations under this Guaranty or as a condition to the enforcement of this Guaranty against Guarantor.

Notwithstanding anything to the contrary set forth herein, Guarantor shall have the same defenses available to it as Principal Obligor may have with respect to any payment obligations arising under the PPA.

4. **Expenses.** Guarantor agrees to pay on demand any and all costs, including reasonable legal fees, and other expenses incurred by OUC in enforcing Guarantor's payment obligations under this Guaranty; provided that the Guarantor shall not be liable for any expenses of OUC if no payment under this Guaranty is due.

5. **Subrogation.** Guarantor shall be subrogated to all rights of OUC against Principal Obligor in respect of any amounts paid by Guarantor pursuant to the Guaranty, provided that Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise, until all of the Guaranteed Obligations shall have been irrevocably paid to OUC in full. If any amount shall be paid to the Guarantor on account of such subrogation rights at any time when all the Guaranteed Obligations shall not have been paid in full, such amount shall be held in trust for the benefit of OUC and shall forthwith be paid to OUC to be applied to the Guaranteed Obligations. If (a) the Guarantor shall perform and shall make payment to OUC of all or any part of the Guaranteed Obligations and (b) all the Guaranteed Obligations shall have been paid in full, OUC shall, at the Guarantor's request, execute and deliver to the Guarantor appropriate documents necessary to evidence the transfer by

subrogation to the Guarantor of any interest in the Guaranteed Obligations resulting from such payment by Guarantor.

6. **Notices.** All demands, notices and other communications provided for hereunder shall, unless otherwise specifically provided herein, (a) be in writing addressed to the party receiving the notice at the address set forth below or at such other address as may be designated by written notice, from time to time, to the other party, and (b) be effective upon delivery, when mailed by U.S. mail, registered or certified, return receipt requested, postage prepaid, or personally delivered. Notices shall be sent to the following addresses:

If to OUC:

Orlando Utilities Commission

500 South Orange Avenue

Orlando, FL 32801

Attention: Vice-President of Power Resources

Tel: 407-244-8372

Fax: 407-275-4120

With a copy to:

Orlando Utilities Commission

500 South Orange Avenue

Orlando, FL 32801

Attention: Legal Department

Telephone: 407-423-9100

Facsimile: 407-423-9198

If to Guarantor:

The Southern Company

c/o Southern Company Services, Inc.

270 Peachtree Street NW

Suite 2000

Atlanta, GA 30303

Attention: Allen L. Leverett, Vice President and Treasurer

Tel: 404-506-0710

Fax: 404-506-0712

With a copy to:

Robert H. Forry, Esq.

Troutman Sanders LLP

Bank of America Plaza

600 Peachtree Street, N.E.

Suite 5200

Atlanta, Georgia 30308-2216

Tel: 404-885-3142

Fax: 404-962-6559

If to Principal Obligor:

Southern Company - Florida LLC

c/o Southern Company Services, Inc.

270 Peachtree Street NW

Suite 2000

Atlanta, GA 30303

Attention: Allen L. Leverett, Vice President and Treasurer

Tel: 404-506-0710

Fax: 404-506-0712

With a copy to:

Robert H. Forry, Esq.

Troutman Sanders LLP

Bank of America Plaza

600 Peachtree Street, N.E.

Suite 5200

Atlanta, Georgia 30308-2216

Tel: 404-885-3142

Fax: 404-962-6559

7. **Demand and Payment.** Any demand by OUC for payment hereunder shall be in writing, signed by a duly authorized officer of OUC and delivered to the Guarantor pursuant to Section 6 hereof, and shall (a) reference this Guaranty, (b) specifically identify the Principal Obligor, the Guaranteed Obligations to be paid and the amount of such Guaranteed Obligations and (c) set forth payment instructions. There are no other requirements of notice, presentment or demand. Guarantor shall pay, or cause to be paid, such Guaranteed Obligations within three (3) business days of receipt of such demand.

8. **No Waiver; Remedies.** Except as to applicable statutes of limitation, no failure on the part of OUC to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The remedies herein provided are cumulative and not exclusive of any remedies provided by law.

9. **Replacement of Guarantor and Termination.**

(a) Guarantor may assign and delegate its rights and obligations under this Guarantee, in whole or in part, as follows: (i) without the consent of OUC, to Southern Power Company, a Delaware corporation and parent company of Principal Obligor, or

other Affiliate of Principal Obligor, if Southern Power Company or such other Affiliate has achieved the following three characteristics: (1) a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's), (2) Net Equity (as hereinafter defined) of at least [redacted], as reflected on its most recent audited balance sheet, and (3) Gross Equity (as hereinafter defined) of at least [redacted], provided, however, that the date on which Guarantor causes such a replacement of this Guaranty under this Section 9(a)(i) may not be earlier than the Commercial Operation Date (as defined in the Ownership Agreement); or (ii) with the consent of OUC, which consent may not be unreasonably withheld, to an assignee which has a credit rating on its senior securities at or above [redacted] (Standard & Poors) and [redacted] (Moody's) and which meets other reasonable financial criteria similar to those identified in Section 9(a)(i), provided, however, that if Guarantor requests OUC's consent to such an assignment and delegation in connection with a permitted transfer or assignment of the PPA, then OUC may not withhold such consent if the assignee meets the financial criteria in Section 9(a)(ii). An assignment and delegation of Guarantor's rights and obligations under this Section 9 shall become effective when the replacement guarantor executes and delivers to OUC a replacement guaranty on terms and conditions substantially similar to this Guaranty.

(b) For purposes of this Guaranty, the following terms shall have the following meanings:

"Net Equity" shall mean the aggregate of the capital stock and other equity accounts (including retained earnings and paid-in capital) of Southern Power Company or other Affiliate of Principal Obligor, as the case may be.

"Gross Equity" shall mean Net Equity plus Guaranteed Debt plus loans to Southern Power Company from its parent corporation.

"Guaranteed Debt" shall mean any obligations of Southern Power Company or other Affiliate of Principal Obligor, as the case may be, for or in respect of (a) moneys borrowed or raised (whether or not for cash) by whatever means (including acceptances, deposits, discounting, letters of credit, factoring (other than on a non-recourse basis), finance leases, and any other form of financing which is recognized in Southern Power Company's or other Affiliate of Principal Obligor's, as the case may be, financial statements as being in the nature of a borrowing (excluding for the avoidance of doubt, share capital, share premium account and any capital prepayment reserve), which has been guaranteed by Guarantor, and (b) the deferred purchase price of assets or services (other than goods and services obtained on normal commercial terms in the ordinary course of business or operations), which has been guaranteed by Guarantor.

"Affiliate" of an Entity shall mean any other entity controlled by, controlling or under common control with such entity, where control of an entity means the ability to direct the policies of such entity through election of a majority of such entity's board of directors or other governing body or by contract or otherwise.

(c) This Guaranty shall terminate, and upon the effective date of such termination Guarantor shall have no further liability hereunder, on the earliest to occur of: (i) the satisfaction of all of the Guaranteed Obligations, (ii) the termination or expiration of the PPA, (iii) the date on which the liability cap is reached, as provided in Section 1 hereof, or (iv) the date on which an assignment and delegation by Guarantor of its rights and obligations hereunder becomes effective under Section 9(a) hereof.

10. **Assignment by OUC; Successors and Assigns.** OUC may, upon notice to Guarantor, assign its rights hereunder only to a subsequent owner of all of OUC's interest in the Facility and the Interconnection Facilities (as defined in the PPA) without the consent of Guarantor. Subject to the foregoing, this Guaranty shall be binding upon and inure to the benefit of the parties hereto and their respective successors, permitted assigns, and legal representatives.

11. **Amendments, Etc.** No amendment of this Guaranty shall be effective unless in writing and signed by Guarantor and OUC. No waiver of any provisions of this Guaranty or consent to any departure by Guarantor therefrom shall in any event be effective unless such waiver shall be in writing and signed by OUC. Any such waiver shall be effective only in the specific instance and for the specific purpose for which it was given.

12. **Captions.** The captions in this Guaranty have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Guaranty.

13. **Representations and Warranties.**

The Guarantor represents and warrants as follows:

(a) The Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty.

(b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets.

(c) This Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting OUC's rights and to general equity principles.

(d) The financial statements of Guarantor for the year ended December 31, 2000 (the "Financial Statements"), heretofore delivered to OUC or filed with the United States Securities Exchange Commission by Guarantor present fairly the financial condition and results of operations of Guarantor and its consolidated subsidiaries as of the dates and for the period specified therein in conformity with generally accepted accounting principles, and, except as otherwise expressly stated therein, consistently applied.

14. **Limitation by Law.** All rights, remedies and powers provided in this Guaranty may be exercised only to the extent that the exercise thereof does not violate any applicable provision of law, and all the provisions of this Guaranty are intended to be subject to all applicable mandatory provisions of law that may be controlling and to be limited to the extent necessary so that they will not render this Guaranty invalid, unenforceable, in whole or in part, or not entitled to be recorded, registered or filed under the provisions of any applicable law.

15. **Governing Law; Submission to Jurisdiction.** This Guaranty shall be governed by, and construed in accordance with, the laws of the State of Georgia, exclusive of any conflict of laws provisions thereof that would apply the laws of another jurisdiction. The parties hereby submit to the jurisdiction of, and agree that venue for actions hereunder shall be, the U.S. District Court for the Northern District of Georgia, if the U.S. District Court has jurisdiction, or, if the U.S. District Court does not have jurisdiction, the Superior Court of the State of Georgia sitting in Fulton County, Georgia and the parties hereby waive any objection to venue in such courts and any objection to any action or proceeding on the basis of forum non conveniens.

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized officer effective as of this ___ day of _____, 2001.

"Guarantor"

THE SOUTHERN COMPANY

By:_____

Name:_____

Title:_____

YOUNG, VAN ASSENDERP, VARNADOE & ANDERSON, P.A.

ATTORNEYS AT LAW

REPLY TO:

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CLAY C. BROOKER
TASHA O. BUFORD
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C. LAURENCE KEESEY
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TELECOPIER (941) 597-1060

MEMORANDUM

TO: Blanca Bayo
Records and Recording
Florida Public Service Commission

FROM: Roy C. Young RCY/swp

DATE: April 18, 2001

SUBJECT: Docket #010142-EM

RECEIVED-FPSC
01 APR 18 PM 3:30
RECORDS AND REPORTING

Enclosed find original and seven (7) copies of the following affidavits regarding the above-referenced docket:

1. Frederick F. Haddad, Jr.
2. John E. Hearn
3. Eric Fox
4. William Herrington
5. Abani Kumar Sharma
6. Jonathan Schaefer
7. Paul A. Arsuaga
8. Richard L. Casey
9. Stephen L. Thumb
10. Thomas O. Anderson
11. Myron Rollins
12. Jill Schuepbach
13. Douglas Jones

Thank you for your assistance.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010142-EM EXHIBIT NO. 11
COMPANY/ WITNESS: FPSC Staff
DATE: 4-23-01

RCY:swp
Enclosures

cc: Cochran Keating (with enclosures)

sparrett\ouc\blanca bayo re affidavits.Apr. 18

DOCUMENT NUMBER-DATE
04816 APR 18 01
FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Frederick F. Haddad, have prefiled testimony in this case consisting of thirteen (13) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Frederick F. Haddad, Jr.

STATE OF FLORIDA
COUNTY OF Orange

I, the undersigned authority, certify that Frederick F. Haddad personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Orlando, County of Orange, State of Florida, this 16th day of April, 2001.

Notary Public
My Commission

Ruth P Whittaker
My Commission CC843229
Expires June 3, 2003

Expires:

Personally known X
Produced Identification
Type of Identification produced

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, John E. Hearn, have prefiled testimony in this case consisting of five (5) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

John E. Hearn

STATE OF FLORIDA
COUNTY OF Orange

I, the undersigned authority, certify that John E. Hearn personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Orlando, County of Orange, State of Florida, this 16th day of April, 2001.

Sharon L. Knudsen
Notary Public
My Commission

Expires: 3-14-03

Personally known ✓
~~Produced Identification~~
~~Type of Identification produced~~

Sharon L. Knudsen
MY COMMISSION # CC792042 EXPIRES
March 14, 2003
BONDED THRU TROY FAIN INSURANCE, INC

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Eric Fox, have prefiled testimony in this case consisting of seven (7) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Eric Fox

STATE OF MASSACHUSETTS
COUNTY OF Suffolk

I, the undersigned authority, certify that Eric Fox personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Boston, County of Suffolk, State of MA, this 16 day of April, 2001.

KATHLEEN McDONOUGH
Notary Public
My Commission Expires:
June 2 2006

Notary Public
My Commission

Expires: 6/2/06

Personally known ____
Produced Identification MA. License
Type of Identification produced ____

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, William Herrington, have prefiled testimony in this case consisting of four (4) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

William Herrington

STATE OF FLORIDA
COUNTY OF ORANGE

I, the undersigned authority, certify that William Herrington personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Orlando, County of Orange, State of Florida, this 17 day of April, 2001.

Ruth E. Brown
Notary Public
My Commission

Expires: 11/11/04

Personally known ✓
Produced Identification
Type of Identification produced

Ruth E. Brown
MY COMMISSION EXPIRES November 11, 2004
#CC979001
Bonded thru Troy Fain-Insurance
NOTARY PUBLIC, STATE OF FLORIDA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Abani Kumar Sharma, have prefiled testimony in this case consisting of ten (10) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Ak Sharma
Abani Kumar Sharma

STATE OF FLORIDA
COUNTY OF Osceola

I, the undersigned authority, certify that Abani Kumar Sharma personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Kissimmee County of Osceola, State of Florida, this 16 day of April, 2001.

M Hauser
Notary Public
My Commission

Expires: 4-8-02

Personally known ✓
Produced Identification
Type of Identification produced

MARTHA HAUSER
Notary Public, State of Florida
My comm. expires April 08, 2002
No. CC944825
Bonded thru Ashton Agency, Inc. (800)451-4854

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Jonathan Schaefer, have prefiled testimony in this case consisting of six (6) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Jonathan Schaefer

STATE OF FLORIDA
COUNTY OF Osceola

I, the undersigned authority, certify that Jonathan Schaefer personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Kissimmee, County of Osceola, State of Florida, this 16 day of April, 2001.

Notary Public
My Commission

Expires: 4-8-02

Personally known ✓
Produced Identification
Type of Identification produced

MARTHA HAUSER
Notary Public, State of Florida
My comm. expires April 08, 2002
No. CC944825
Bonded thru Ashton Agency, Inc. (800)451-4854

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of) Need for Proposed Stanton Energy Center) Combined Cycle Unit A by Orlando Utilities) Commission, Kissimmee Utility Authority,) Florida Municipal PowerAgency,) and Southern Company – Florida LLC.)	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Paul A. Arsuaga, have prefiled testimony in this case consisting of thirteen (13) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Paul A. Arsuaga

STATE OF FLORIDA
COUNTY OF ORANGE

I, the undersigned authority, certify that Paul A. Arsuaga personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of ORLANDO, County of ORANGE, State of FLORIDA, this 16th day of April, 2001.

Notary Public
My Commission

Expires: 5/2/2002

Personally known ✓
Produced Identification
Type of Identification produced

NOTARY PUBLIC - STATE OF FLORIDA
THADDEUS SZYMANKIEWICZ
COMMISSION # CC734075
EXPIRES 5/2/2002
BONDED THRU ASA 1-888-NOTARY1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Richard L. Casey, have prefiled testimony in this case consisting of eleven (11) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Richard L. Casey

STATE OF FLORIDA
COUNTY OF Orange

I, the undersigned authority, certify that Richard L. Casey personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Orlando, County of Orange, State of Florida, this 16 day of April, 2001.

Notary Public
My Commission

Expires: 10/17/04

Dana L Schult
My Commission CC975843
Expires October 17 2004

Personally known ✓
Produced Identification _____
Type of Identification produced _____

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal Power Agency, and Southern Company - Florida LLC.	))))))	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Stephen L. Thumb, have prefiled testimony in this case consisting of nineteen (19) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Stephen L. Thumb

COMMONWEALTH OF VIRGINIA)
) ss.
COUNTY OF ARLINGTON)

I, the undersigned authority, certify that Stephen L. Thumb personnally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the County of Arlington, Commonwealth of Virginia, this 16th date of April , 2001.

Notary Public: Donna M. Wilson

My commission expires: May 31, 2003.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Thomas O. Anderson, have prefiled testimony in this case consisting of ten (10) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Thomas O. Anderson

STATE OF ~~GEORGIA~~ Alabama
COUNTY OF Jefferson

I, the undersigned authority, certify that Thomas O. Anderson personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Birmingham County of Jefferson, State of Alabama this 16 day of April, 2001.

Geraldine B. Lofton
Notary Public
My Commission

Expires: 7/5/2004

Personally known ✓
Produced Identification _____
Type of Identification produced _____

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of Need for Proposed Stanton Energy Center Combined Cycle Unit A by Orlando Utilities Commission, Kissimmee Utility Authority, Florida Municipal PowerAgency, and Southern Company – Florida LLC.	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Myron Rollins, have prefiled testimony in this case consisting of twenty-three (23) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Myron Rollins

STATE OF KANSAS
COUNTY OF Johnson

I, the undersigned authority, certify that Myron Rollins personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Overland Park County of Johnson, State of Kansas, this 17th day of April, 2001.

Deborah A Fendorf
Notary Public
My Commission

Expires: March 10, 2005

Personally known ✓
Produced Identification
Type of Identification produced

DEBORAH A. FENDORF
Notary Public - State of Kansas
My Appt. Expires 03/10/05

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Joint Petition for Determination of) Need for Proposed Stanton Energy Center) Combined Cycle Unit A by Orlando Utilities) Commission, Kissimmee Utility Authority,) Florida Municipal PowerAgency,) and Southern Company – Florida LLC.)	DOCKET NO. 010142-EM FILED: April 23, 2001

AFFIDAVIT

I, Douglas E. Jones, have prefiled testimony in this case consisting of eight (8) pages dated March 5, 2001 and associated exhibits identified in Paragraph IX Exhibit List of the Prehearing Order.

I file this Affidavit to affirm the correctness of my testimony and associated exhibits.

Douglas E. Jones

STATE OF ALABAMA
COUNTY OF Jefferson

I, the undersigned authority, certify that Douglas E. Jones personally appeared before me and was duly sworn by me to tell the truth.

WITNESS my hand and official seal in the City of Birmingham County of Jefferson, State of Alabama, this 17th day of April, 2001.

Christina A. Ulmer
Notary Public
My Commission

Expires: June 4, 2001

Personally known	X
Produced Identification	X
Type of Identification produced	X

Stanton Energy Center Combined Cycle Unit A

Need for Power Application

Kissimmee Utility Authority – Volume 1C

January 29, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010142-EM EXHIBIT NO. 1 (Rpt 3 of 4)
COMPANY/WITNESS: Orlando Utilities Commission
DATE: 4-23-01

BLACK & VEATCH

11401 Lamar, Overland Park, Kansas, 66211, USA (913) 458-2000

Table of Contents

1C.1.0 Overview and Summary 1-1
1C.1.1 Overview 1-1
1C.1.2 Summary 1-2

1C.2.0 Description of System 2-1
1C.2.1 KUA Structure 2-1
1C.2.2 Generation System 2-2
1C.2.3 Purchase Power Resources 2-4
1C.2.4 Transmission Systems 2-5
1C.2.5 Service Area 2-5

1C.3.0 Evaluation Criteria 3-1

1C.4.0 Forecast of Power Demand and Energy Consumption 4-1
1C.4.1 Introduction 4-1
1C.4.2 Forecast Modeling Approach 4-1
1C.4.3 Econometric Data and Projections 4-2
1C.4.3.1 Historical Data 4-2
1C.4.3.2 Econometric Projections 4-3
1C.4.3.3 Forecasting Assumptions 4-3
1C.4.4 Sales Forecast 4-4
1C.4.4.1 Residential Sales 4-4
1C.4.4.2 General Service Nondemand Forecast 4-6
1C.4.4.3 General Service Demand Forecast 4-6
1C.4.4.4 Outdoor Lighting Forecast 4-7
1C.4.5 Net Energy for Load and Peak Demand Forecast 4-8
1C.4.5.1 Net Energy for Load 4-8
1C.4.5.2 Peak Demand Forecast 4-8
1C.4.6 High and Low Sensitivities 4-8
1C.4.7 Major Additional Loads 4-12

1C.5.0 Demand-Side Programs 5-1
1C.5.1 Existing Conservation Programs 5-1
1C.5.1.1 Residential Load Management (SAVE) 5-2
1C.5.1.2 Residential Appliance Efficiency 5-4

Table of Contents (Continued)

1C.5.1.3 Commercial Cooling 5-4
1C.5.1.4 Residential Fix Up 5-5
1C.5.2 Analysis of Demand-Side Management Alternatives 5-5
1C.5.2.1 FIRE Model Output Analysis 5-5

1C.6.0 Reliability Criteria 6-1
1C.6.1 Development of Reliability Criteria 6-1
1C.6.1.1 Traditional Reserve Margin 6-1
1C.6.1.2 Loss of Load Probability 6-1
1C.6.2 Reliability Need 6-2

1C.7.0 Economic Analysis 7-1
1C.7.1 Methodology 7-1
1C.7.2 Expansion Candidates 7-1
1C.7.3 Results of Economic Analysis 7-3

1C.8.0 Sensitivity Analysis 8-1
1C.8.1 High Fuel Price Escalation 8-1
1C.8.2 Low Fuel Price Escalation 8-1
1C.8.3 AEO Fuel Price Projections 8-1
1C.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation 8-2
1C.8.5 Constant 2000 Fuel Price Projections 8-2
1C.8.6 High Load and Energy Growth 8-2
1C.8.7 Low Load and Energy Growth 8-3
1C.8.8 Sensitivity Analysis Summary 8-3

1C.9.0 Financial Analysis 9-1

Appendix 1C.A Economic Evaluation Spreadsheets

Tables

Table 1C.2-1 Kissimmee Utility Authority Existing Generating Facilities 2-3
Table 1C.2-2 KUA's Purchase Power 2-6
Table 1C.4-1 Scheduled Rate Increases 4-4

Table of Contents (Continued)
Tables (Continued)

Table 1C.4-2	Sales Forecast Equations and Statistics	4-5
Table 1C.4-3	Base Case Load Forecast (Includes World Expo Center)	4-9
Table 1C.4-4	High Load Forecast (Includes World Expo Center)	4-10
Table 1C.4-5	Low Load Forecast (Includes World Expo Center)	4-11
Table 1C.4-6	Summary of Gross Peak Demand	4-12
Table 1C.4-7	World Exposition Center Load Forecast Annual Peak Demand and Energy	4-14
Table 1C.5-1	KUA Load Management Impact	5-3
Table 1C.5-2	SAVE Program, Load Management Credits	5-4
Table 1C.5-3	FIRE Model Results	5-6
Table 1C.6-1	Projected Reserve Margins – Summer / Base Case	6-3
Table 1C.7-1	Summary of KUA Generation Alternatives (2000 $, unless otherwise noted)	7-2
Table 1C.7-2	KUA Least-Cost Base Case Expansion Plan	7-5
Table 1C.7-3	KUA Least-Cost Runner-Up Base Case Expansion Plan	7-6
Table 1C.7-4	KUA Least-Cost Second Runner-Up Base Case Expansion Plan	7-7
Table 1C.7-5	KUA Joint Development Without PPA Extension Option Base Case Expansion Plan	7-8
Table 1C.7-6	KUA Summer Capacity Balance (After Expansion Plan Outlined in Table 1C.7-2)	7-9
Table 1C.7-7	KUA Summer Capacity Balance (After Expansion Plan Outlined in Table 1C.7-3)	7-10
Table 1C.7-8	Excess KUA Entitlement Sold to OUC	7-11
Table 1C.8-1	KUA High Fuel Price Escalation Expansion Plan	8-4
Table 1C.8-2	KUA High Fuel Price Escalation Runner Up Expansion Plan	8-5
Table 1C.8-3	KUA Low Fuel Price Escalation Expansion Plan	8-6
Table 1C.8-4	KUA Low Fuel Price Escalation Runner-Up Expansion Plan	8-7
Table 1C.8-5	AEO Fuel Price Projection Expansion Plan	8-8
Table 1C.8-6	KUA AEO Fuel Price Projection Runner-Up Expansion Plan	8-9
Table 1C.8-7	OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan	8-10
Table 1C.8-8	OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan	8-11
Table 1C.8-9	OUC Constant 2000 Fuel Price Projection Expansion Plan	8-12

Table of Contents (Continued)

Tables (Continued)

Table 1C.8-10 OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan 8-13
Table 1C.8-11 KUA Summer Reserve Requirements - High Load and Energy Growth Scenario 8-14
Table 1C.8-12 KUA High Load and Energy Growth Expansion Plan 8-15
Table 1C.8-13 KUA High Load and Energy Growth Runner-Up Expansion Plan 8-16
Table 1C.8-14 KUA Summer Reserve Requirements - Low Load and Energy Growth Scenario 8-17
Table 1C.8-15 KUA Low Load and Energy Growth Expansion Plan 8-18
Table 1C.8-16 KUA Low Load and Energy Growth Runner-Up Expansion Plan 8-19

Figures

Figure 1C.2-1 Service Area Map 2-7

1C.1.0 Overview and Summary

1C.1.1 Overview

Stanton A is planned as a new combined cycle addition to the existing Stanton Energy Center site, located 12 miles southeast of Orlando, Florida. The Stanton Energy Center site was originally certified for an ultimate capacity of approximately 2,000 MW based on four coal fired units. The existing Stanton Unit 1 is a 444 MW net coal fired facility and Stanton 2 is a 446 MW net coal fired generating facility. Stanton 1 was placed in operation on July 1, 1987 followed by Stanton 2 which was placed in operation on June 1, 1996. Stanton A will provide very economical power for the Kissimmee Utility Authority (KUA) with a minimal environmental impact. Stanton A will be a 2 x 1 GE 7FA combined cycle unit. The net output of the unit is estimated to be 633 MW at 70° F under new and clean conditions and will be jointly owned by KUA, Orlando Utilities Commission (OUC), Florida Municipal Power Agency (FMPA) and Southern-Florida. KUA will be a 10 percent joint owner of the 35 percent (221.6 MW) capacity to be owned by the utility applicants. KUA's ownership portion of generation from Stanton A will be approximately 22 MW. KUA will also receive 10 percent of the 65 percent capacity owned by Southern-Florida and supplied under a power purchase agreement (PPA). Details specific to the project are presented in Volume 1A. This volume, Volume 1C, contains information specific to KUA's need for the project.

KUA strives to meet its responsibility to supply its customer's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. KUA is committed to meet its customer's needs and identify projects that will provide economical power through the combination of demand-side and supply-side resources. KUA has been a strong supporter of conservation and demand-side programs where cost-effective. With KUA's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

KUA achieves savings through economy interchange and central dispatch which are obtained through participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, KUA, and the FMPA All-Requirements Project.

KUA's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with Stanton A. Stanton A will burn natural gas as the primary fuel with Selective Catalytic Reduction providing a very clean burning, highly efficient unit.

As discussed in the remainder of this application, KUA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements.

KUA believes that Stanton 2 represents the minimal cost and performance risk to its customers due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be KUA's most cost-effective alternative through exhaustive evaluations as well as a thorough test of the marketplace.

1C.1.2 Summary

KUA historically has been one of the fastest growing utilities in the United States with a 5.7 percent annual growth rate in peak demand over the last 10 years. Rapid growth is projected to continue with a 3.7 percent annual growth rate in peak demand projected through the end of the 20 year planning period. The development of the proposed World Exposition Center (Expo Center) in KUA's service territory is projected to contribute significantly to KUA's load growth. KUA has incorporated estimates of the direct loads from the Expo Center into KUA's forecast. Indirect loads from the Expo Center are likely to be significant and currently are only considered in sensitivity projections.

KUA is currently using a 15 percent reserve margin for planning purposes. KUA has a supplemental resale contract with Florida Power Corporation which allows KUA to purchase the capacity necessary to maintain a 15 percent reserve margin with the Expo Center's loads. While this purchase has not been explicitly included in KUA's expansion plans, KUA can implement it, if necessary, as the Expo Center loads develop. In 2004, KUA's reserve margin is projected to be negative with and without the Expo Center requiring the addition of capacity.

KUA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under both base and sensitivity conditions.

1C.2.0 Description of System

1C.2.1 KUA Structure

The first recorded mention of electric lights, in what was at the time called Kissimmee City, was made during a City Council meeting held December 17, 1891. An Electric Light Committee was formed and notified the Council that a plan had been prepared showing the location of proposed lights for the town. However, in order for the plan to be a success, requests for 300 lights would be required to secure the first electric light plant in the area. During the years to follow, discussions about electric lighting persisted. By April 9, 1892, a proposal was made that a bond issue for $23,000 be implemented to provide for a public works department and electric lights. On April 18, 1893, a ballot was taken and the bonding request was approved by a vote of 41 to 5.

On December 4, 1900, Kissimmee City entered into a contract with W. C. Maynard, a citizen of the town, doing business as Kissimmee Light Co. The contract with Mr. Maynard gave him the exclusive right and franchise to erect and maintain an electric light plant in Kissimmee City for a period of 20 years. Initially, Kissimmee Light Co. agreed to supply consumers with electricity at a cost of 3¢ per night for each sixteen candle power incandescent light and $7.50 per month for arc lights of standard power.

During a City Council meeting held June 28, 1901, a resolution was passed and Kissimmee City purchased Kissimmee Light Co. from Mr. Maynard for $4,293.59. A committee was appointed by the City Council to manage the company.

The decades that span the 1900s to the 1980s were spent laying the operational groundwork and infrastructure KUA relies upon so heavily today. The utility's initial purchase, in 1901, was a 16 kilowatt generator. In the 1920s, three diesel engines were added to the system, providing electricity to approximately 200 customers. The 1930s marked the pioneer interconnection between St. Cloud and Kissimmee, and during the 1940s and 1950s the utility worked diligently to increase its distribution capacity. The 1970s proved monumental when Kissimmee and St. Cloud interconnected with the rest of the continental United States through Florida Power Corporation at Lake Bryan.

From 1972 to 1982, the utility experienced multiple management changes, including five different Utility Directors. In 1982, James C. Welsh, the current President and General Manager, replaced Don Hornak as Utility Director. As KUA settled in with a new Director, many accomplishments were realized. One such accomplishment occurred when KUA became joint owners in the St. Lucie nuclear power plant with Florida Power & Light. Additionally, KUA marked its first entry into combustion turbine technology. KUA also reentered the steam electric generation business with the

installation of a 50 MW combined cycle unit after many years of sole dependence on diesel type units.

The year 1983 marked the turning point in the making of what KUA is today. During 1983, the City Commission established an Ad-Hoc Committee to explore the concept of making the electric utility department of the City into a separate authority. The Committee also investigated the best way to manage the utility. The conclusion was that an independent board consisting of individuals with strong business backgrounds would best run the authority. In 1984, the Ad-Hoc Committee presented its recommendation of making the electric utility department of the City into a separate authority. Subsequently, the City Commission reappointed the Ad-Hoc Committee members to a Charter Committee. This latter committee had the difficult task of developing a charter for the utility. In 1985, voters approved the Charter for Kissimmee Utility Authority.

KUA now operates as an independent utility authority owned by the City of Kissimmee and operated by a five-member Board of Directors plus the mayor of the City of Kissimmee who serves as a nonvoting member. In addition, KUA acts as a billing and customer service agent for the Water and Sewer and Refuse Departments of the City of Kissimmee. Its service area covers the City of Kissimmee and some unincorporated areas, totaling approximately 85 square miles. The primary goal of KUA is to provide reliable electric service to its customers at the lowest possible cost in the best environmentally acceptable method. In order to accomplish this, KUA has diversified its power supply resources, which are based on KUA's own generation, offsite generation through joint participation projects, and through long- and short-term purchase power contracts. Since becoming an independent utility authority, KUA has enjoyed stable management and has been operated by the Board of Directors in a very business like environment.

1C.2.2 Generation System

KUA owns and operates or has ownership interest in generating units comprised of several technologies, including nuclear, coal fired, diesel, simple cycle combustion turbine, and combined cycle. Table 1C.2-1 provides a summary of KUA's existing generating resources. The following paragraphs describe KUA's generating assets and ownership interests in detail.

KUA owns and operates eight diesel generating units ranging in age from 18 to 42 years. All of these diesel units are located at the Roy B. Hansel Generating Station in Kissimmee. Six of these diesel units are fueled by natural gas with No. 2 oil as pilot oil while the remaining two burn No. 2 oil only. The total nameplate capacity of the eight

Table 1C.2-1
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel		Fuel Transportation		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability	
				Primary	Alternate	Primary	Alternate				Summer (MW)	Winter (MW)
Hansel	8	Osceola	IC	NG	FO2	PL	TK	02/59	-/98	3.00	3	3
	14		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	15		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	16		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	17		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	18		IC	NG	FO2	PL	TK	02/72	01/02	2.07	2	2
	19		IC	FO2	---	TK	---	02/83	01/13	2.50	3	3
	20		IC	FO2	---	TK	---	02/83	01/13	2.50	3	3
	21		CT	NG	---	PL	TK	02/83	01/13	35.00	28	32
	22		ST	WH	---	---	---	02/83	01/13	10.00	10	10
	23		ST	WH	---	---	---	02/83	01/13	10.00	10	10
Plant Total										**73.35**	**67**	**71**
Crystal River	3	Citrus	N	UR	---	TK	---	03/77	Unknown	890.46	6[1]	6[1]
Plant Total										**890.46**	**6**	**6**
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.58	21[2]	21[2]
Plant Total										**464.58**	**21**	**21**
Indian River	A	Brevard	CT	NG	FO2	PL	TK	07/89	Unknown	41.40	4.5[3]	5.5[3]
	B		CT	NG	FO2	PL	TK	07/89	Unknown	41.40	4.5[3]	5.5[3]
Plant Total										**82.80**	**9**	**11**
Cane Island	1	Osceola	CT	NG	F02	PL	TK	01/95	Unknown	40.00	15[4]	20[4]
	2		CC	NG	F02	PL	TK	06/95	Unknown	122.00	54[4]	60[4]
Plant Total										**162**	**69**	**80**
System Total as of January 1, 2000											**172**	**189**

Notes:
(1)KUA's 0.6754 percent portion of joint ownership.
(2)KUA's 4.8193 percent ownership portion.
(3)KUA's 12.2 percent portion of joint ownership.
(4)KUA's 50 percent ownership portion.

diesels is 18.35 MW. In addition, KUA owns and operates a natural gas fired (with No. 2 oil as backup) combined cycle plant, which is also located at the Hansel site. This plant consists of a 35 MW (nameplate) combustion turbine which provides waste heat for two 10 MW (nameplate) steam turbine generators. The total nameplate generating capability at the Hansel site is approximately 73.35 MW.

KUA and FMPA are both 50 percent joint owners of Cane Island Units 1 and 2. Unit 1 is a simple cycle General Electric LM6000 aeroderivative combustion turbine with a nameplate rating of 42 MW. Unit 2 is a 1 x 1 General Electric Frame 7EA combined cycle with a nameplate rating of 120 MW. KUA and FMPA have also committed to build Cane Island Unit 3, which is a nominal 250 MW combined cycle unit. This unit is currently under construction with an expected commercial operation date of June 28, 2001. KUA's 50 percent ownership share of the Cane Island Units is 206 MW (nameplate).

KUA owns a 0.6754 percent interest, or 6 MW (nameplate), in the Florida Power Corporation's (FPC) Crystal River Nuclear Unit 3, located in Citrus County, Florida. KUA also has a 4.8193 percent ownership interest, or 22.3 MW (nameplate), in the Orlando Utilities Commission's (OUC) Stanton Energy Center Unit 1 and a 12.2 percent, or 10 MW (Nameplate), of OUC's Indian River Combustion Turbine Project Units A and B.

1C.2.3 Purchase Power Resources

KUA is a member of the Florida Municipal Power Agency (FMPA), a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 15 other members of the FMPA. KUA's entitlement share of this unit, based on a power purchase contract and adjusted for transmission losses, is 6.9 MW. FMPA has also entered into a Reliability Exchange Agreement with FPL under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit No. 1 and half from Unit No. 2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has a contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases up to an additional 50 MW if the capacity is available from OUC. KUA also has a contract with OUC to purchase up to 40 MW from the Stanton 2 plant. The contract ends in December 2000. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton 1 Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton 2 Project. The Stanton 2 percentage includes entitlement acquired from

Homestead and Lake Worth totaling 3.8314 percent. Table 1C.2-2 presents KUA's purchase power resources.

KUA is a member of the Florida Reliability Coordinating Council (FRCC). The FRCC has established an energy broker system which provides economic interchange of electric energy between member utilities, including KUA. KUA has purchased and sold energy through this broker system, and intends to continue such transactions whenever conditions are favorable. Currently, these economy transactions are conducted through the Florida Municipal Power Pool (FMPP).

1C.2.4 Transmission Systems

KUA has direct transmission interconnections with: (i) FPC, delivered at 69 kV from the FPC Lake Bryan substation and at 230 kV at OUC's Taft substation; (ii) OUC delivered from two 230 kV lines from Cane Island, one 230 kV line from the Taft substation, and a 230/69 kV autotransformer at Taft substation serving KUA's 69 kV line; (iii) the City of St. Cloud, Florida now being operated by OUC, at KUA's 69 kV interconnection with St. Cloud's transmission facilities; and (iv) TECO, one 230 kV circuit through the interconnection with the Osceola and Lake Jewell circuits.

Electric power and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to eight distribution substations. KUA provides electric service to retail customers primarily by 13.2 kV feeder circuits from the distribution substations.

1C.2.5 Service Area

KUA serves a total area of approximately 85 square miles, which includes the City of Kissimmee and surrounding areas of Osceola County. As of January 1, 2001, KUA served approximately 48,115 electric customers. Of these, 40,172 were residential, 7,272 were general service nondemand, and the remaining 671 were general service demand customers. KUA's electric service area, shown on Figure 1C.2-1, is entirely located in Osceola County.

Table 1C.2-2
KUA's Purchase Power[1]

CY	Utility/Unit (MW)				Annual Total
	St. Lucie 1 & 2	Stanton 1[2]	Stanton 2[3]	OUC[4]	
2000	6.9	7.9	33.3	60	108.1
2001	6.9	7.9	33.3	20	68.1
2002	6.9	7.9	33.3	20	68.1
2003	6.9	7.9	33.3	20	68.1
2004	6.9	7.9	33.3	0	48.1
2005	6.9	7.9	33.3	0	48.1
2006	6.9	7.9	33.3	0	48.1
2007	6.9	7.9	33.3	0	48.1
2008	6.9	7.9	33.3	0	48.1
2009	6.9	7.9	33.3	0	48.1
2010	6.9	7.9	33.3	0	48.1
2011	6.9	7.9	33.3	0	48.1
2012	6.9	7.9	33.3	0	48.1
2013	6.9	7.9	33.3	0	48.1
2014	6.9	7.9	33.3	0	48.1
2015	6.9	7.9	33.3	0	48.1
2016	6.9	7.9	33.3	0	48.1
2017	6.9	7.9	33.3	0	48.1
2018	6.9	7.9	33.3	0	48.1
2019	6.9	7.9	33.3	0	48.1

Notes:

[1]No reserves are supplied by the selling utility. KUA provides for 15 percent reserves.
[2]KUA share of Stanton 1 through FMPA Stanton 1 Project is 1.80725 percent.
[3]KUA share of Stanton 2 through FMPA Stanton 2 Project is 7.6628 percent. Total percentage represents KUA's original purchase percentage plus the sum of recently acquired Homestead and Lake Worth purchase percentages equal to 3.8314 percent.
[4]20 MW Schedule D and 40 MW short-term purchase in 2000.

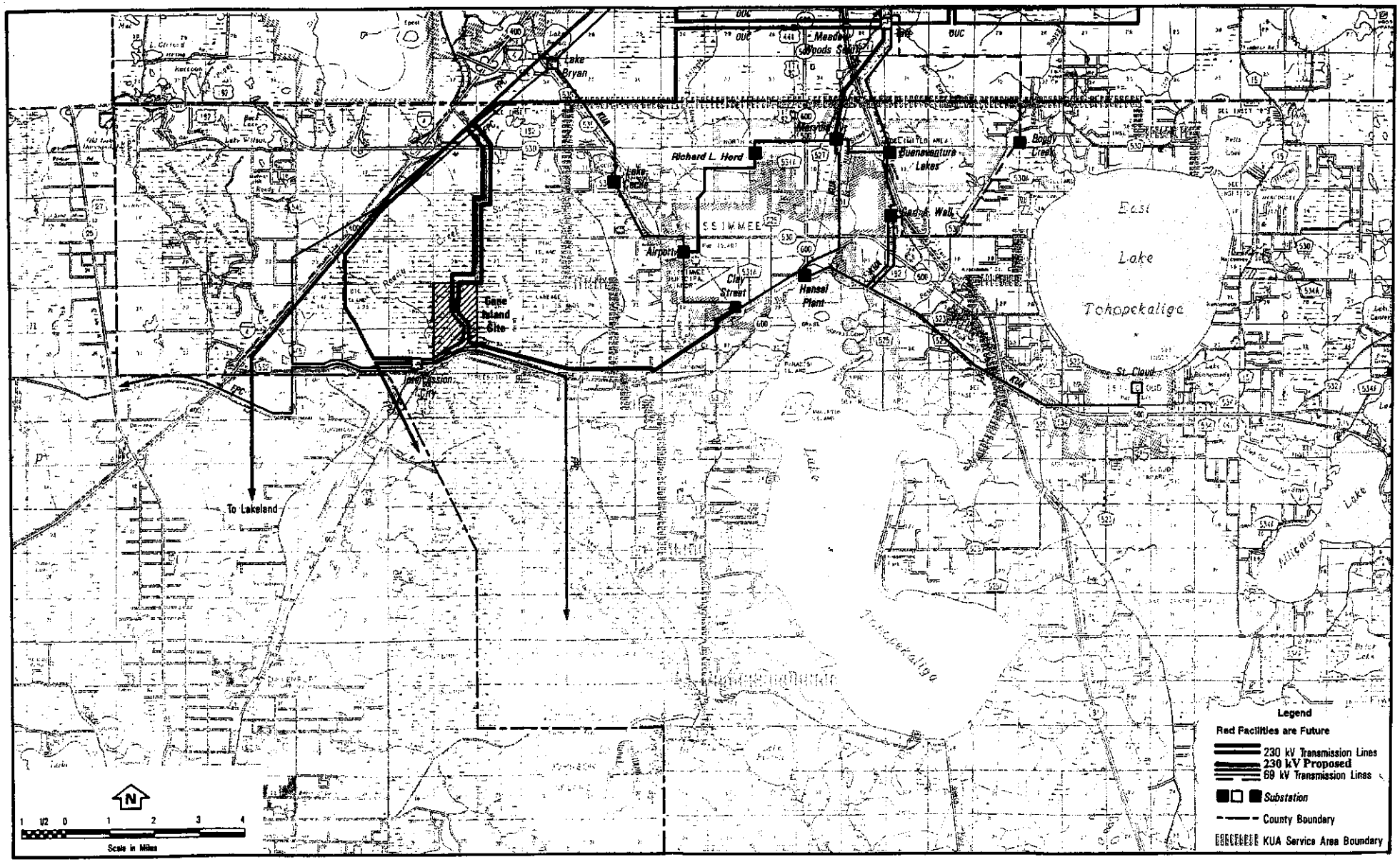


Figure 2-1
Service Area Map

1C.3.0 Evaluation Criteria

KUA as a municipal utility is structured similarly to OUC. For evaluation purposes, the economic criteria for OUC are used for KUA. These evaluation and economic criteria are presented in Section 1A.5.0.

1C.4.0 Forecast of Power Demand and Energy Consumption

1C.4.1 Introduction

Annually, KUA prepares a detailed long-term electric load and energy forecast using econometric techniques. This detailed forecast is developed on a fiscal year basis (October through September), and serves as a primary driver in annual planning activities. The information presented has been summarized in calendar year format in accordance with FRCC guidelines.

The following sections describe KUA's general forecasting approach. Each of the forecasting models is explained, and the summary results of the forecasts are presented.

1C.4.2 Forecast Modeling Approach

Econometric forecast models have been used to project monthly sales by customer class. The econometric models and associated statistical relationships were developed to forecast annual changes in electricity consumption by rate classification as a function of demographic, weather and economic factors such as income, temperature and real price of electricity. The models were developed using statistical relationships between historical, economic, weather, and electric system data.

The statistical estimating technique used in the development of the models was ordinary least squares multiple regression. This method is used to determine the linear relationship between a dependent variable, such as energy usage, and multiple independent econometric variables based on changes in the values of the variables through time. Implicit in the model development is the assumption that customer class energy usage will be affected by the same key factors in the future as in the past. The following equation represents this linear relationship:

$$Y = a + \sum_{i-1}^{n} [b_i * X_i] + e$$

where:

Y = dependent variable (predicted)
a = constant term
b_i = coefficient terms
X_i = independent variables
e = error term

The calculated equation minimizes the sum of the squared errors between the actual and predicted values of the dependent variable.

An important consideration in regression analysis is the selection of variables. Independent variables explain changes in the dependent variable. Therefore, sufficient historical data for both dependent and independent variables must be available to produce a reliable regression equation. Also, to forecast values of the dependent variable, the independent variables must have the potential to be projected into the future.

All regression equations were tested using five primary statistical measures. The first measure is the adjusted R^2, the coefficient of determination corrected for reduced degrees of freedom due to inclusion of additional independent variables in the regression equation. The coefficient of determination (perfect = 1.0) is the proportion of variability in the dependent variable that is explained by the independent variables. The second measure is the F statistic, which is a test of whether there is a significant linear relationship between the dependent variable and the entire set of independent variables. The F-test is performed by determining the calculated F statistic (F_{CALC}) and comparing this value with the corresponding value of the F distribution (F_{DIST}). The third measure is the T statistic, which is a test for multi-collinearity of the independent variables. This test is performed by determining the calculated T statistic (T_{CALC}) and comparing this value with the corresponding value of the T distribution (T_{DIST}). The fourth measure is the Durbin-Watson (DW) statistic, which is a test for serial correlation of adjacent error terms. The fifth, and final, measure is the Bayesian Information Criterion (BIC). The BIC serves as a guide to the selection of the number of terms in an equation by placing a penalty on additional coefficients.

1C.4.3 Econometric Data and Projections

This section describes the data sources used in the development of the econometric variable projections for the forecast period. As in previous forecasts, economic and population forecasts from the Bureau of Economic and Business Research (BEBR) were included in the analysis as econometric variables.

1C.4.3.1 Historical Data

A careful compilation of historical data was developed to formulate a reliable econometric model for forecasting electricity sales. Monthly historical sales data were compiled for each major customer classification for the period of January 1985 through September 1999. Additional data including temperature, population, employment, households, real personal income, and total housing starts was also compiled. The econometric data used was obtained from BEBR data applicable to the Metropolitan Statistical Area (MSA) in which Kissimmee is located.

MSAs are defined by the census bureau for various regions within each state. Kissimmee is located within the Orlando MSA. The Orlando MSA also includes Lake, Orange, Osceola and Seminole Counties. Although some variance in general MSA versus Kissimmee data can be expected, the homogeneous nature of the surrounding region provided well-aligned trend relationships between historical electricity use and the econometric variables selected for the forecast.

1C.4.3.2 Econometric Projections

The BEBR has estimated that during the next 15 years employment will grow at an average annual rate of 2.2 percent, down from 3.5 percent from 1980 through 1995. Real personal income is estimated to grow at an average annual rate of 3.0 percent, down from 4.1 percent from 1980 through 1995. In general, the slower percentage growth rates of employment and income for Florida are related to a slowing annual population growth rate. Florida's average annual population growth rate is forecast to be 1.6 percent from 1995 through 2010, down from 2.5 percent from 1980 through 1995. Although Osceola County economic and population forecasts show slower growth, Osceola County's annual growth rate continues to exceed the surrounding counties.

Due to publication delays, KUA was forced to use 1998's Long-Term Economic Forecast for economic data. However, the 1999 population forecast was available and was used in the projection of economic data beyond 2010.

1C.4.3.3 Forecasting Assumptions

The first key assumption included in the load forecast analysis is related to regional weather patterns. Because predicting future weather patterns is not possible, normal weather conditions were assumed for the load forecast model. Monthly average temperatures for the last 10 years were used as a representation of normal weather. For weather projections, the weather for every month of the forecast period was set equal to that month's 10 year average of monthly temperatures for the historical period. The same methodology was applied uniformly to all other weather-related variables used in the analysis.

The second key assumption of significance to the 2000 sales forecast is the inclusion of estimated annual rate increases scheduled for implementation beginning in October 2000. Currently, rate increases are scheduled as shown in Table 1C.4-1.

Table 1C.4-1 Scheduled Rate Increases	
Effective Date	Average Across-the-Board Rate Increase
10/2000	1.6505%
10/2001	1.6508%

1C.4.4 Sales Forecast

1C.4.4.1 Residential Sales

To forecast residential electricity sales, annual forecasts of residential electricity use per customer and number of customers were developed using ordinary least-squares multiple regression models. The product of residential service customers and electricity use per customer forecasts yielded total annual residential electricity sales.

1C.4.4.1.1 Residential Customers. In the development of the 1999 econometric model for residential customers, Osceola County population (POPA) estimates were used as a potential explanatory variable. Based on KUA's statistical evaluation, POPA outperformed Osceola County total housing starts (TS) in representing the fluctuations in residential customers. Auto-regressive (AR) factors were introduced to minimize the effects of serial correlation. In effect, the AR variable incorporates the residual from previous observations into the regression model for the current observation. The resulting equation and statistics are shown in Table 1C.4-2.

1C.4.4.1.2 Residential Energy Use Per Customer. Residential electricity use per customer was based on the relationship between historical income per household, the previous year's real price of electricity and weather impacts. The resulting equation and statistics are shown in Table 1C.4-2.

1C.4.4.1.3 Weather Impacts. Temperature and billing data were adjusted to compensate for different reporting periods. The degree days were shifted from calendar month to billing month to more accurately reflect the relationship between temperature and energy consumption. An example of this shifting is described as follows:

> *A customer has his electric meter read on billing cycle 2. In February, billing cycle 2 corresponds with a meter reading date of February 2nd. Sales to this customer are billed in February, but primarily occur in January. If the remainder of February is bitterly cold, the corresponding degree days are not reflected in the customer's February bill. As a result, error is introduced.*

Table 1C.4-2
Sales Forecast Equations and Statistics

RSCUSTT = 246.750*POPA + 0.487*_AUTO[-1] + 0.441*AUTO[-2] RSCUSTT :Total Residential Customers POPA :Total Population in Osceola County _AUTO[-1] :First Order Auto-Regressive Term _AUTO[-2] :Second Order Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9982 Durbin-Watson: 2.0970 Bayesian Information Criterion: 270
RSUPC = - 8.562*PRICERES[-12] + 21.805*INCPERHH + 1.367*BM_CDD + 2.295*BM_HDD + 0.534*BM_CDD[-1] + 0.806*BM_HDD[-1] + 0.431*_AUTO[-1] RSUPC :Residential Use Per Customer PRICERES :Residential Real Price of Electricity INCPERHH :Real Personal Income Per Household BM_CDD :Billing Month Adjusted Cooling Degree Days BM_HDD :Billing Month Adjusted Heating Degree Days _AUTO[-1] :First Order Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9201 Durbin-Watson: 2.078 Bayesian Information Criterion: 68.19
GSNCUSTT = 146.836*POPA + 0.994*_AUTO[-1] GSNCUSTT :Total General Service Nondemand Customers POPA :Total Population in Osceola County _AUTO[-1] :First Order Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9981 Durbin-Watson: 1.936 Bayesian Information Criterion: 94.86
GSNKWHT = - 69023.372*PRICEGSN(-12) + 5956.965*RYTOT + 9159.405*BM_CDD + 6367.537*BM_HDD + 5359.291*BM_CDD(-1) + 4364.508*BM_HDD(-1) + 0.324*_AUTO[-1] GSNKWHT :Total General Service Nondemand Energy Sales PRICEGSN :General Service Nondemand Real Price of Electricity RYTOT :Real Personal Income Osceola County BM_CDD :Billing Month Adjusted Cooling Degree Days BM_HDD :Billing Month Adjusted Heating Degree Days _AUTO[-1] :First Order Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9539 Durbin-Watson: 1.934 Bayesian Information Criterion: 6.905e+005

By aligning the sales and degree days, the model became more responsive to changes in temperature.

1C.4.4.2 General Service Nondemand Forecast

The model for the general service nondemand rate classification comprises forecasts for a number of customers and energy sales and includes temporary service and KUA rate classifications.

1C.4.4.2.1 General Service Nondemand Customers. Osceola County population was used as the basis for forecasting the number of general service nondemand customers. The resulting equation and statistics that were developed to forecast the number of general service nondemand customers are shown in Table 1C.4-2.

1C.4.4.2.2 General Service Nondemand Electricity Sales. The general service nondemand model for annual electricity sales is primarily driven by the real price of electricity and real personal income. Weather is also a strong influence on general service nondemand sales. Last year, the model included a variable to reflect the impact of a rate reclassification in October 1990 on customers and sales. This year the model was developed by excluding data prior to October 1991, thereby bypassing the rate reclassification completely. The resulting equation, used to forecast the energy sales in kilowatt-hours for the general service nondemand customer class, is shown in Table 1C.4-2.

1C.4.4.3 General Service Demand Forecast

For the purposes of this load forecast, general service demand comprises GSD, GSDT, GSLD, Interruptible, and Contract Rate classifications. General service demand represents approximately 30 percent of total energy sales with approximately 760 customers. Because general service demand represents such a large percentage of total energy consumption, assumptions, and models used to forecast have a significant impact on the overall energy forecast.

The number of customers in the general service demand rate classification (GSD) has continued to decline over the course of the last several years. The initial, and most abrupt, decrease occurred as a result of a shift in rate classification (October 1990) which encouraged the migration of smaller GSD customers to the nondemand classification (GSND). However, the decline did not stop there. In fact, since the beginning of 1992, the net gain in customers is two.

Generally, the general service demand class is a more diversified mix of customers, and are typically fewer in number. Because of class diversity, the general service demand rate classification is also less amenable to statistical methods.

The general service demand customer forecast was evaluated using Box-Jenkins and exponential smoothing models. The historical series for GSD customers does not increase linearly and uniformly or vary with seasons or regularity. The exponential smoothing model forecasts the number of customers to be level at 763 with no projected increase over the forecast horizon.

The forecast of no growth is reasonable given the unexplained variation in GSD customers. Though the net gain in customers since the beginning of 1992 is two, the fluctuations in customers have been as great as 9 percent in 3 months. This size of a drop in general service demand is certainly suspicious. Without understanding the reasons behind data volatility, it is difficult to forecast. Meetings with key personnel have brought no additional insight to this situation, and until it is better understood, forecasting no customer growth for general service demand customers is recommended.

Using OLS, a model was prepared for general service demand energy sales. The final model fit the historical data well, but when used to forecast, it produced unreasonable results. Because a model for general service demand customers had already been determined, the OLS model for general service demand energy sales was theoretically indicating that the use per customer would double over the forecast horizon. This conclusion is unreasonable.

KUA's Manager of Distribution and planners from the City of Kissimmee were subsequently consulted regarding future large customer expansions. In addition to the information provided by City planners and KUA staff, a review of the energy sales growth rates in GSD shows the smallest increase in energy sales to be approximately 1 percent. Based on conversations with KUA staff and City planners and review of past performance, an annual energy sales increase of 1 percent is recommended for the forecast horizon. It is important to note that the World Expo Center energy sales are in addition to this projected annual growth of 1 percent.

1C.4.4.4 Outdoor Lighting Forecast

Street lighting, vapor lighting, and outdoor lighting were combined into one class for forecasting purposes. This year, the best prediction of future outdoor lighting is simply a linear trend. Because outdoor lighting's contribution to total energy sales is stable and represents less than 0.8 percent, this method of forecasting is both acceptable and relatively accurate.

1C.4.5 Net Energy for Load and Peak Demand Forecast

1C.4.5.1 Net Energy for Load

During the past several years, net energy for load (NEL) was projected by applying an efficiency factor of 95 percent to the projection of total sales. During 1997, an attempt was made to develop an econometric model for NEL using the relationship of NEL to total sales and certain monthly variables. After further review, it was decided that the econometric model did not provide significant accuracy to the projection of NEL and KUA returned to the 95 percent efficiency factor methodology. Tables 1C.4-3 through 1C.4-5 present KUA's base, high and low case NEL forecasts. Net energy for load is projected to grow at an average annual rate of 3.5 percent from 1999 through 2019 compared to 5.4 percent from 1989 through 1998.

1C.4.5.2 Peak Demand Forecast

The forecast of peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. Previous attempts to model peak load have been unsuccessful due to a lack of data. The estimate of peak load conditions is very dependent on weather and customer equipment. Although relatively reliable temperature data is available, peak load is also sensitive to other variables such as cloud cover, humidity, and barometric pressure.

Table 1C.4-6 presents KUA's winter and summer base-, high-, and low-case peak demand forecasts. A 3.7 percent annual summer peak demand growth rate is projected for 2000 through 2019. This growth rate is lower than KUA's historical annual growth rate of 5.7 percent during the last 10 years.

1C.4.6 High and Low Sensitivities

In addition to the base-case load forecast, projections were developed for high- and low-load growth scenarios based on high and low population estimates published by the Bureau of Economic and Business Research (BEBR).

The high and low load forecast sensitivities were developed based on changes in the independent economic variables, specifically, the BEBR's high and low population forecast. The economic forecast provided by BEBR is projected to 2010, and BEBR's long-term population forecast is projected to 2020. The BEBR economic forecast was used through 2010. To develop economic data beyond 2010, the economic data were adjusted by using their rate of change with respect to population in the base case, and maintaining that ratio in the high and low cases.

Table 1C.4-3
Base Case Load Forecast (Includes World Expo Center)

Year	Residential		GS Nondemand		GS Demand		Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)					
2000	39,766	525,936	8,818	164,977	763	358,262	8,899	49,347	1,058,073	55,688	1,113,762
2001	41,082	554,147	9,146	174,282	763	375,902	9,367	50,991	1,113,699	58,616	1,172,314
2002	42,357	579,853	9,474	183,376	763	402,493	9,853	52,954	1,175,575	61,872	1,237,448
2003	43,642	607,124	9,808	193,098	763	426,550	10,354	54,213	1,237,126	65,112	1,302,238
2004	44,949	637,861	10,148	203,911	763	452,011	10,870	55,861	1,304,653	68,666	1,373,319
2005	46,255	668,996	10,488	214,877	763	467,880	11,388	57,506	1,363,141	71,744	1,434,885
2006	47,427	697,487	10,795	224,938	763	472,438	11,855	58,985	1,406,717	74,038	1,480,755
2007	48,064	726,408	11,102	235,132	763	475,954	12,324	60,468	1,449,818	76,306	1,526,124
2008	49,808	756,254	11,413	245,641	763	479,505	12,805	61,984	1,494,204	78,642	1,572,847
2009	51,041	787,063	11,730	256,479	763	483,092	13,298	63,535	1,539,931	81,049	1,620,980
2010	52,293	818,629	12,050	267,570	763	486,715	13,798	65,107	1,586,712	83,511	1,670,223
2011	53,518	849,962	12,362	278,548	763	490,374	14,287	66,643	1,633,172	85,956	1,719,128
2012	54,763	882,095	12,678	289,794	763	494,069	14,785	68,204	1,680,744	88,460	1,769,204
2013	56,036	915,207	12,999	301,382	763	497,802	15,295	69,799	1,729,686	91,036	1,820,722
2014	57,340	949,329	13,326	313,326	763	501,571	15,816	71,429	1,780,043	93,686	1,873,729
2015	58,662	984,218	13,656	325,540	763	505,379	16,345	73,081	1,831,482	96,394	1,927,876
2016	59,953	1,018,762	13,978	337,610	763	509,225	16,861	74,694	1,882,458	99,077	1,981,534
2017	61,264	1,054,117	14,304	349,964	763	513,109	17,385	76,331	1,934,575	101,820	2,036,395
2018	62,603	1,090,481	14,635	632,684	763	517,032	17,921	78,002	1,988,118	104,638	2,092,756
2019	63,972	1,127,884	14,973	375,784	763	520,994	18,469	79,708	2,043,131	107,533	2,150,664

Table 1C.4-4
High Load Forecast (Includes World Expo Center)

Year	Residential		GS Nondemand		GS Demand		Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)					
2000	40,220	536,419	8,990	187,849	763	361,869	9,652	49,973	1,095,789	57,673	1,153,462
2001	41,934	574,115	9,487	204,252	763	385,493	10,599	52,184	1,174,458	61,814	1,236,272
2002	43,675	611,205	9,990	222,597	763	424,631	11,435	54,428	1,269,868	66,835	1,336,703
2003	45,500	651,672	10,514	242,726	763	459,300	12,278	56,777	1,365,975	71,893	1,437,869
2004	47,413	697,465	11,061	265,066	763	476,681	13,155	59,237	1,452,367	76,440	1,528,807
2005	49,385	745,391	11,623	288,592	763	500,758	14,056	61,771	1,548,797	81,516	1,630,312
2006	51,274	791,700	12,160	311,561	763	516,098	14,918	64,197	1,634,277	86,015	1,720,292
2007	53,221	840,111	12,711	335,707	763	523,288	15,807	66,696	1,714,914	90,259	1,805,172
2008	55,252	891,327	13,285	361,403	763	530,622	16,735	69,301	1,800,087	94,741	1,894,828
2009	57,370	945,514	13,883	388,759	763	538,103	17,704	72,016	1,890,079	99,478	1,989,557
2010	59,551	1,002,178	14,497	417,525	763	454,733	18,702	74,812	1,984,137	104,428	2,088,566
2011	61,682	1,058,666	15,097	446,254	763	553,516	19,677	77,542	2,078,112	109,374	2,187,487
2012	63,878	1,117,744	15,713	476,545	763	561,454	20,682	80,355	2,176,334	114,544	2,290,878
2013	66,161	1,179,968	16,354	508,467	763	569,551	21,728	83,278	2,279,714	119,985	2,399,699
2014	68,533	1,245,511	17,019	542,410	763	577,810	22,816	86,316	2,388,547	125,713	2,514,260
2015	70,971	1,313,816	17,703	577,995	763	586,235	23,934	89,437	2,501,980	131,683	2,633,663
2016	73,361	1,381,967	18,371	613,591	763	594,828	25,030	92,495	2,615,415	137,653	2,753,069
2017	75,818	1,453,018	19,059	650,907	763	603,592	26,157	95,640	2,733,674	143,878	2,877,552
2018	78,365	1,527,576	19,772	690,322	763	612,532	27,326	98,900	2,857,756	150,408	3,008,165
2019	81,005	1,605,821	20,510	731,960	763	621,651	28,539	102,278	2,987,972	157,262	3,145,233

Table 1C.4-5
Low Load Forecast (Includes World Expo Center)

Year	Residential		GS Nondemand		GS Demand		Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)					
2000	38,633	506,234	8,590	153,483	763	351,048	8,003	47,986	1,018,768	53,619	1,072,387
2001	38,724	513,320	8,686	147,813	763	359,689	7,718	48,174	1,028,541	54,134	1,082,675
2002	38,840	517,859	8,785	148,818	763	372,497	7,653	48,387	1,046,828	55,096	1,101,924
2003	38,968	523,321	8,882	151,368	763	384,662	7,682	48,612	1,067,033	56,160	1,123,192
2004	39,107	531,152	8,978	155,002	763	396,225	7,754	48,848	1,090,133	57,375	1,147,509
2005	39,213	538,190	9,061	158,289	763	401,027	7,824	49,037	1,105,330	58,175	1,163,505
2006	39,100	540,843	9,085	159,728	763	403,708	7,796	48,948	1,112,075	58,530	1,170,605
2007	38,963	542,910	9,099	160,874	763	403,708	7,757	48,825	1,115,249	58,697	1,173,946
2008	38,833	544,940	9,112	161,982	763	403,708	7,719	48,708	1,118,349	58,860	1,177,209
2009	38,709	546,931	9,124	163,050	763	403,708	7,682	48,596	1,121,371	59,020	1,180,391
2010	38,550	548,091	9,125	163,766	763	403,708	7,627	48,438	1,123,192	59,115	1,182,307
2011	39,192	545,194	9,071	162,823	763	403,708	7,476	48,027	1,119,202	58,905	1,178,107
2012	37,813	541,765	9,010	161,653	763	403,708	7,314	47,586	1,114,439	58,655	1,173,094
2013	37,440	538,315	8,949	160,483	763	403,708	7,152	47,152	1,109,658	58,403	1,168,061
2014	37,074	534,845	8,887	159,315	763	403,708	6,992	46,724	1,104,859	58,150	1,163,010
2015	36,668	530,444	8,814	157,795	763	403,708	6,812	46,245	1,098,759	57,829	1,156,589
2016	36,034	521,410	8,680	154,474	763	403,708	6,524	45,477	1,086,116	57,164	1,143,280
2017	35,380	511,920	8,539	150,993	763	403,708	6,225	44,682	1,072,846	56,466	1,129,312
2018	34,740	502,578	8,400	147,613	763	403,708	5,932	43,903	1,059,830	55,781	1,115,611
2019	34,113	493,382	8,263	144,331	763	403,708	5,644	43,139	1,047,064	55,109	1,102,172

Table 1C.4-6
Summary of Gross Peak Demand

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
2000	243	250	237	252	260	246
2001	254	266	237	264	277	246
2002	272	293	243	282	304	253
2003	290	321	250	301	333	260
2004	307	345	257	319	358	267
2005	321	367	261	333	380	271
2006	334	389	264	346	403	274
2007	344	407	264	356	422	275
2008	354	427	265	367	443	275
2009	364	447	266	378	464	276
2010	375	469	266	389	486	277
2011	386	491	266	400	509	276
2012	397	513	265	412	532	275
2013	408	537	264	423	557	274
2014	419	562	262	435	583	272
2015	431	588	261	448	610	271
2016	443	614	259	460	637	268
2017	455	641	256	472	665	265
2018	467	669	253	485	694	262
2019	480	699	250	498	725	259

1C.4.7 Major Additional Loads

The developers of the World Exposition Center (Expo Center) are planning a major commercial development on an 800 acre site in the northwest quarter of KUA's service territory in Osceola County. The construction of this world-class, mixed-used facility is currently in the planning stages and was, at one point, expected to be operational in 2000.

Phase I of the current plan, slated to be completed by the first part of 2000, includes a 2.4 million square foot exposition hall, 1.3 million square foot outside parking area, and 8.6 million square foot parking garage. Phase 1A, scheduled to be completed by the first part of 2001, includes a 1.0 million square foot hotel, 1.3 million square foot county convention center, and 79,000 square feet of commercial office space.

Phase II of construction is projected to be completed during 2002-2004 in stages after Phase I and Phase IA are operational. Phase II facilities include three resort hotels totaling 1.6 million square feet, two office buildings totaling 0.5 million square feet, a 1.0 million square foot retail and entertainment complex, a public safety facility, and 2.0 million square feet of additional parking.

Complete build-out of this facility may require an estimated $1.1 billion. The total employment projection for the project and supporting industries is nearly 30,000 jobs with an estimated annual payroll of $700 million.

At this time, the World Expo Center team is still engaged in planning and negotiating, and plans to build are not yet certain. However, if completed in accordance with current plans, the peak demand and energy requirements of the Expo Center will significantly impact KUA's current system demand and least-cost planning methodology. Accordingly, KUA has conducted a detailed consumption analysis to determine the potential peak demand and energy use of this facility. Due to the lack of data on facilities of this magnitude, demand and energy consumption per square foot from similar-use facilities were used as planning-level estimates.

Table 1C.4-7 shows the base, high and low case annual peak demand and energy forecasts for the World Expo Center. For the current forecast, this project has been delayed 1 year from the original construction plans. This assumption is based on delays which have already taken place, and seem likely to continue.

Table 1C.4-7
World Exposition Center Load Forecast
Annual Peak Demand and Energy

Year	Low Forecast		Base Forecast		High Forecast	
	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)
2002	4.0	5,710	6.6	12,850	10.0	22,355
2003	7.6	10,956	12.9	22,952	19.8	39,703
2004	9.9	15,019	17.5	31,160	27.6	54,195
2005	11.0	20,229	19.6	47,245	30.8	73,398
2006	12.4	23,804	22.3	48,680	35.4	84,453
2007-2019	12.4	23,804	22.3	48,680	35.4	84,453

Source: 1998 Cane Island 3 Need for Power Application Table 1B.5-3, delayed 2 years, and reduced by 50 percent based on revised projections shown in the Journal of Osceola County Business (7/99).

1C.5.0 Demand-Side Programs

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (FPSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, Kissimmee Utility Authority (KUA) has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the FPSC approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

1C.5.1 Existing Conservation Programs

KUA is committed to conservation and load management programs and will continue to evaluate both old and new DSM programs on a frequent and regular basis in an attempt to identify cost-effective programs for the electric system that add value for the customers. KUA's energy conservation specialist performs approximately 600 free audits annually, advising customers on the appropriate conservation programs to implement.

KUA's conservation programs were originally established for the City of Kissimmee under the Florida Energy Efficiency and Conservation Act (FEECA) program. KUA is no longer classified as a FEECA utility. The following is a list of conservation programs outlined in KUA's submission to the FPSC when KUA was subject to FEECA:

- Residential energy audit.
- Commercial and industrial energy analysis.
- Fix up program - KUA will assist or arrange to have installed in residences:
  - Electrical outlet gaskets.
  - Solar screen/reflective film.
  - Water heater jackets.
  - Water flow restrictors.
  - Weatherstripping.
  - Caulking.
  - Energy conserving lamps.

  - Duct tape.
  - Pool timers.
  - Clock thermostats.
  - Water heater thermostat set-back.
  - Hot water pipe insulation.
  - Water heater timers.
  - Ceiling insulation.
- High-pressure sodium street lighting/private area lighting conversion (from mercury vapor and incandescent).
- Water heater conversion from resistance heating to:
  - Dedicated heat pump water heaters.
  - Natural gas.
  - Solar.
  - Air conditioning/heat pump.
- Elimination of electric strip heating.
- Public awareness programs.
- Natural gas.
- Cogeneration plans.

The following sections discuss the DSM programs KUA now has in place.

1C.5.1.1 Residential Load Management (SAVE)

KUA currently offers a residential direct load control program which has been in place since 1992. This program is called Shifting Adds Value to Energy (SAVE). SAVE is designed to cycle residential air conditions, electric water heaters, and electric space heaters to reduce KUA's system peak demand. The SAVE program was administered to over 4,891 customers as of September 30, 2000. The program is voluntary for all residential customers. For participating in the program, customers receive a monthly credit on their bills. KUA installs load control receivers on eligible equipment, and transmits radio signals to cycle equipment for peak demand reduction. The SAVE program provides a utility controlled process that ensures direct capacity value to KUA while minimizing impacts to the customer's lifestyle.

There are no significant reductions in energy consumption from this program. Table 1C.5-1 shows KUA's historical and forecasted estimate of peak demand reductions resulting from this load management program.

Table 1C.5-1
KUA Load Management Impact

Year	Average Active Customers	Low Case Load Management Impact (MW)	Base Case Load Management Impact (MW)	High Case Load Management Impact (MW)
1993	1,914	-	3.16	-
1994	5,040	-	8.32	-
1995	7,213	-	11.90	-
1996	7,648	-	12.62	-
1997	6,870	-	11.98	-
1998	6,201	-	12.15	-
1999	5,532	-	12.00	-
2000	-	8.9	11.00	13.1
2001	-	7.9	10.00	12.1
2002	-	7.9	10.00	12.1
2003	-	7.9	10.00	12.1
2004	-	7.9	10.00	12.1
2005	-	7.9	10.00	12.1
2006	-	7.9	10.00	12.1
2007	-	7.9	10.00	12.1
2008	-	7.9	10.00	12.1
2009	-	7.9	10.00	12.01

1C.5.1.1.1 Delivery Strategy. The approach for delivering the program is based on two design components: (i) promoting the program to existing customers through bill inserts and general media; and (ii) granting bill credits for participants based on the number and type of appliances being controlled. A schedule reflecting bill credits is presented in Table 1C.5-2.

Table 1C.5-2
SAVE Program, Load Management Credits

Appliance	Control Period	Monthly Credit	With Water Heater Control
Water Heater	Year Round	$2.50	--
Central AC (15 minutes per 1/2 hour)	April-October	$4.50	$7.00
Central heating (15 minutes per 1/2 hour)	November-March	$4.50	$7.00

1C.5.1.1.2 Implementation Activities. Because KUA has operated the program since 1992, current implementation activities focus on ongoing installation and maintenance of load switches, and updating and maintaining tracking systems to monitor participation.

1C.5.1.2 Residential Appliance Efficiency

The Residential Appliance Efficiency Program is designed to encourage the specification and installation of energy efficient appliances such as high efficiency central air conditioners, heat pumps, and pool pumps.

Promotion of these high efficiency residential appliances helps to reduce residential cooling loads, which contribute to KUA's system peak. Additionally, since the useful lifetime estimates of these appliances are relatively long (15 years or greater), this program serves to address "lost opportunities," particularly in the new construction market.

The program is targeted to residential homeowners in the replacement and new construction market. Customers include those who currently have standard air conditioners, heat pumps, and/or pool pumps. When applicable equipment requires replacement, customers become candidates for an upgrade to high efficiency systems.

1C.5.1.3 Commercial Cooling

The Commercial Cooling Program is designed to use customer and trade ally information and education to encourage the specification and installation of energy efficient cooling systems in the commercial markets.

The promotion of these high efficiency commercial systems helps to reduce commercial cooling loads which contribute to KUA's system peak. Additionally, since

the useful lifetime estimates of these systems are relatively long (15 years or greater), this program serves to address "lost opportunities," particularly in the new construction market.

Although difficult to estimate, KUA's energy and summer demand are reduced with this program.

1C.5.1.4 Residential Fix Up

This program is designed to make residential dwellings more efficient, focusing on the thermal envelope. This includes the following measures for existing residential buildings:

- Ceiling insulation.
- Duct leak repair (also for new homes).
- Hot water saving measures.

Duct leak repair is recommended for new homes because inspections often reveal installation problems that cause significant inefficiencies. Although difficult to estimate, this program achieves energy savings and some peak reduction in both the summer and winter.

1C.5.2 Analysis of Demand-Side Management Alternatives

KUA used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8.0. For the residential sector, KUA is already implementing the following three DSM measures which were found to be the most cost-effective based on the Rate Impact Test in FPL's 2000 Demand-Side Management Plan:

- Residential Load Control--Existing Construction.
- Residential Load Control--New Construction.
- Ceiling Insulation R0 - R19--Existing Construction.

Therefore, KUA analyzed the next most cost-effective residential DSM measure in FPL's 2000 Demand-Side Management Plan which is the BuildSmart EPI less than 90 for new construction. The results of that analysis follow along with the analysis of the commcial off-peak battery charging measure.

1C.5.2.1 FIRE Model Output Analysis

KUA requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, KUA has concluded that there are no cost-effective DSM measures available that

would avoid or defer the need for Stanton A. Table 1C.5-3 presents the FIRE model results of the DSM analysis.

Table 1C.5-3
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
BuildSmart - EPI Less Than 90 - New Construction	0.44	0.71	0.07
Commercial			
Off-Peak Battery Charging	0.37	0.04	0.48

The results of the DSM analysis are not surprising due to the previously performed analyses for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for KUA and FMPA for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand-Side Management Ten Year Plans for OUC (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1C.6.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand plus maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development of the reliability criteria used by KUA.

1C.6.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. The methods are discussed below.

1C.6.1.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand}}$$

From the equation, it is seen that should the net capacity or net peak demand deviate from the predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. A weakness with the formula is that it does not indicate what the appropriate reserve margin is for a given system; the appropriate reserve level must be determined elsewhere.

In establishing the appropriate reserve margin levels, KUA considers the Florida Reliability Coordinating Council (FRCC) minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has also established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Fla. Admin. Code, for the purposes of sharing responsibility for grid reliability. Consequently, KUA has established a 15 percent minimum planned reserve margin criteria for both the summer and winter periods

1C.6.1.2 Loss of Load Probability

The second commonly used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP) method. This method has the advantage in that it can result in a measure of how much capacity and reserves are needed to meet a target level of reliability (most utilities adopt a LOLP of one day in 10 years). Given the

nature of KUA's relatively small, high interconnected system, LOLP for KUA's system is driven almost entirely by the interconnections. Since the reliability of the interconnections is driven by the capacity from other systems available to the interconnection, the reliability of interconnections is difficult to predict and is generally out of the control of KUA. For these reasons, KUA does not use LOLP as the reliability criterion and instead uses the reserve margin criterion. LOLP is much better suited for measuring reliability of large systems such as FRCC.

1C.6.2 Reliability Need

KUA's need for capacity is driven by the summer peak demand which exceeds the winter peak demand as shown in Table 1C.4-6. KUA's available capacity is also less in the summer than the winter as shown in Table 1C.2-1.

Table 1C.6-1 compares KUA's net system capacity with summer peak demand during the forecasting period. The reserve margins displayed in the table assume no capacity additions beyond Cane Island 3, from which KUA will receive 120 MW. The capacity required in order for KUA to achieve its summer reserve margin requirements is also shown.

Table 1C.6-1
Projected Reserve Margins – Summer / Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand (MW)		Reserve Margin (%)		Excess / (Deficit) to Maintain 15 % Reserve Margin (MW)	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
2000	176	108.1	0	284	252	241	12.7	17.8	(6)	7
2001	297	68.1	0	365	264	254	38.8	43.7	61	73
2002	297	68.1	0	365	282	272	29.4	34.2	41	52
2003	297	68.1	0	365	301	291	21.3	25.4	19	30
2004	297	48.1	0	345	319	309	8.2	11.7	(22)	(11)
2005	297	48.1	0	345	333	323	3.6	6.8	(38)	(27)
2006	297	48.1	0	345	346	336	(0.3)	2.7	(53)	(42)
2007	297	48.1	0	345	356	346	(3.1)	(0.3)	(65)	(53)
2008	297	48.1	0	345	367	357	(6.0)	(3.4)	(77)	(66)
2009	297	48.1	0	345	378	368	(8.7)	(6.3)	(90)	(78)
2010	297	48.1	0	345	389	379	(11.3)	(9.0)	(103)	(91)
2011	297	48.1	0	345	400	390	(13.8)	(11.5)	(115)	(104)
2012	297	48.1	0	345	412	402	(16.3	(14.2)	(129)	(118)
2013	297	48.1	0	345	423	413	(18.4)	(16.5)	(142)	(130)
2014	297	48.1	0	345	435	425	(20.7)	(18.8)	(155)	(144)
2015	297	48.1	0	345	448	438	(23.0)	(21.2)	(170)	(159)
2016	297	48.1	0	345	460	450	(25.0)	(23.3)	(184)	(173)
2017	297	48.1	0	345	472	462	(26.9)	(25.3)	(198)	(187)
2018	297	48.1	0	345	485	475	(28.9)	(27.4)	(213)	(201)
2019	297	48.1	0	345	498	488	(30.7)	(29.3)	(228)	(216)

Note: ( ) indicates a negative value.

1C.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of KUA's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine KUA's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluation analyses are presented in Section 1C.5.0. The proposal evaluations are presented in Section 1A.6. The sensitivity analyses are discussed in Section 1C.8.0.

1C.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a twenty-year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan.

1C.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation represent the conventional alternatives presented in Section 1A.7.0. Table 1C.7-1 summarizes the expansion alternatives considered for KUA in the optimization study for supply-side alternatives.

Table 1C.7-1
Summary of KUA Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal (25%)[3]	128,291	111.5	3.73	14.17	Coal	9,979	3.0	30	2006
LM 6000 SC	36,778	35.7	2.53	13.92	Nat. Gas	9,621	5.0	14	2003
7FA SC	73,877	156	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
7FA SC (50 %)	36,939	78	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
WH 501 F 1x1 (50%)[3]	74,736	125	2.49	4.66	Nat. Gas	7,128	2.86	15	2005
7FA 2x1 CC (self-build)[3]	29,021[4]	61	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[3]	[redacted]	21	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	[redacted]	2003[5]

1. At 70 – 72 °F, depending on the generation alternative (after degradation).
2. (2003 $)
3. Reflects KUA's portion of total generation alternative capacity.
4. Mixed year dollars to reflect commercial operation date of October 1, 2003.
5. October 1, 2003.

1C.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7.0 and summarized in Table 1C.7-1. Production costs were modeled at temperatures which closely approximate (within 2 degrees) the average annual temperature for KUA. Winter and summer unit ratings were used to determine capacity requirements. KUA has not made a final decision regarding joining GridFlorida, the proposed regional transmission organization (RTO). For evaluation purposes, it is assumed that KUA joins GridFlorida and as a result transmission wheeling costs and losses are not included in the economic evaluations because they are assumed to be the same in all plans.

The expansion plan outlined in Table 1C.7-2 shows that the joint development project with Southern-Florida is the least-cost capacity addition plan for KUA under the base case scenario. For comparison purposes, Table 1C.7-3 displays the least-cost expansion capacity addition plan for KUA that does not include the joint-development project with Southern-Florida, while Table 1C.7-4 displays the least-cost expansion capacity addition plan if KUA decides not to participate in the Stanton A project as either a joint development project with Southern-Florida or as a self build project. Table 1C.7-5 displays the least cost expansion plan if the extension of the Southern-Florida PPA for an additional five years is not an option. The units and power purchases comprising the expansion plans are listed in the tables according to their year of commercial operation. Tables 1C.7-6 and 1C.7-7 present the summer capacity balances for the expansion plans presented in Tables 1C.7-2 and 1C.7-3, respectively. For both capacity expansion plans in Tables 1C.7-2 and 1C.7-3, KUA is assumed to sell the excess capacity presented in Table 1C.7-8 to OUC. For the joint development expansion plan in Table 1C.7-2, the excess capacity is sold to OUC at the rates contained in the PPA and for the self build expansion plan the excess capacity is sold at KUA's carrying costs. In essence, KUA's entitlement is merely reduced and transferred to OUC in the 3 years in which Stanton A would provide excess capacity to KUA. Appendix 1C.B presents tables showing the fuel, O&M, and capital costs for expansion plans on an annual basis.

It is clear from a comparison of Tables 1C.7-2, 1C.7-3, and 1C.7-4 that the joint development project with Southern-Florida provides the most cost-effective solution to satisfy KUA's forecast capacity requirements. The joint development project with Southern-Florida results in a projected $1.621 million in cumulative present worth savings over the self build alternative and over $20 million in cumulative present worth savings if Stanton A were not available as a self build alternative. Since participation in

Stanton A as a self build option would not be an alternative for KUA if the Southern-Florida joint development project is implemented, the realistic savings for KUA for participation in the Southern-Florida joint development project are $20 million. Finally, since decisions to extend the Southern-Florida PPA for the additional five year options must be made collectively by OUC, KUA, and FMPA, Table 1C7-5 indicates that not extending the PPA increases KUA's cost $6.4 million which is still $13.6 million less thant if Stanton A were not available. In addition, involvement in the joint development project provides KUA with the flexibility and strategic advantages discussed in Section 1A.6.4.

Table 1C.7-2
KUA Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,923	232,128
2004	21 MW Joint Development with Southern – Florida (10/03)	47,478	267,026
	40 MW Southern – Florida Power Purchase (10/03)		
2005		49,187	300,501
2006		53,765	334,382
2007		58,157	368,316
2008	78 MW (50%) GE 7FA Simple Cycle (06/08)	63,915	402,848
2009		70,042	437,886
2010		73,457	471,911
2011		81,044	506,669
2012		82,915	539,596
2013	Terminate 40 MW Southern – Florida Power Purchase (11/13)	87,942	571,932
	Extend 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW GE LM6000 Simple Cycle (06/14)	95,845	604,564
2015		103,434	637,170
2016	36 MW GE LM6000 Simple Cycle (06/16)	111,101	669,600
2017		119,133	701,798
2018	36 MW GE LM6000 Simple Cycle (06/18)		
	Terminate 40 MW Southern-Florida Purchase (11/18)	127,578	733,724
2019	36 MW GE LM6000 Simple Cycle (06/19)	136,554	765,365

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.7-3
KUA Least-Cost Runner-Up Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,791	232,023
2004	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	48,982	268,026
2005		49,618	301,795
2006		53,228	335,338
2007		57,854	369,095
2008	78 MW (50%) GE 7FA Simple Cycle (06/08)	63,802	403,565
2009		69,769	438,467
2010		73,306	472,422
2011		80,840	507,093
2012		82,790	539,971
2013		87,789	572,250
2014	36 MW GE LM6000 Simple Cycle (06/14)	95,468	604,754
2015		102,931	637,202
2016	36 MW GE LM6000 Simple Cycle (06/16)	110,566	669,475
2017		118,723	701,562
2018	78 MW (50%) GE 7FA Simple Cycle (06/18)	130,679	734,265
2019		141,217	766,986

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.7-4
KUA Least-Cost Second Runner-Up Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,040	231,427
2004	36 MW GE LM6000 Simple Cycle (06/04)	50,305	268,403
2005		52,632	304,223
2006	36 MW GE LM6000 Simple Cycle (06/06)	57,444	340,423
2007		62,528	376,907
2008		65,805	412,459
2009	36 MW GE LM6000 Simple Cycle (06/09)	71,300	448,127
2010		76,488	483,556
2011	36 MW GE LM6000 Simple Cycle (06/11)	82,262	518,836
2012		88,774	554,090
2013		92,902	588,250
2014	78 MW (50%) GE 7FA Simple Cycle (06/14)	100,914	622,607
2015		108,481	656,805
2016	36 MW GE LM6000 Simple Cycle (06/16)	114,498	690,226
2017		119,751	722,591
2018		126,780	754,317
2019	36 MW GE LM6000 Simple Cycle (06/16)	134,025	785,373

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.7-5
KUA Joint Development Without PPA Extension Option Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,105	141,705
2002		56,466	190,116
2003		52,923	232,128
2004	21 MW Joint Development with Southern – Florida (10/03)	47,478	267,026
	40 MW Southern – Florida Power Purchase (10/03)		
2005		49,187	300,501
2006		53,765	334,382
2007		58,157	368,316
2008	78 MW (50%) GE 7FA Simple Cycle (06/14)	63,915	402,848
2009		70,042	437,886
2010		73,457	471,911
2011		81,044	506,669
2012		82,915	539,596
2013	Terminate 40 MW Southern – Florida Power Purchase (11/13)	88,116	571,996
2014	257 MW (50%) WH 501F 2x1 Combined Cycle (06/14)	98,457	605,517
2015		110,184	640,252
2016		116,082	674,135
2017		121,780	707,048
2018		129,520	739,460
2019	36 MW LM 6000 Simple Cycle (06/19)	139,208	771,717

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.7-6
KUA Summer Capacity Balance (After Expansion Plan Outlined in Table 1C.7-2)

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	241	0	241	176	108.1	284	43	36.2	7
2001	254	0	254	297	68.1	365	111	38.1	73
2002	272	0	272	297	68.1	365	93	40.8	52
2003	291	0	291	297	68.1	365	74	43.7	30
2004	309	40	349	318	86.8	364	55	52.4	3
2005	323	24	347	318	86.8	380	57	52.1	5
2006	336	10	346	318	86.8	394	58	51.9	6
2007	346	0	346	318	86.8	404	58	51.9	6
2008	357	0	357	388	86.8	474	117	53.6	64
2009	368	0	368	388	86.8	474	106	55.2	51
2010	379	0	379	388	86.8	474	95	56.9	38
2011	390	0	390	388	86.8	474	84	58.5	26
2012	402	0	402	388	86.8	474	72	60.3	12
2013	413	0	413	388	86.8	474	61	62.0	(1)
2014	425	0	425	421	86.8	507	82	63.8	19
2015	438	0	438	421	86.8	507	69	65.7	4
2016	450	0	450	454	86.8	540	90	67.5	23
2017	462	0	462	454	86.8	540	78	69.3	9
2018	475	0	475	487	86.8	573	98	71.3	27
2019	488	0	488	520	48.1	568	80	73.2	6

Table 1C.7-7
KUA Summer Capacity Balance (After Expansion Plan Outlined in Table 1C.7-3)

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	241	0	241	176	108.1	284	43	36.2	7
2001	254	0	254	297	68.1	365	111	38.1	73
2002	272	0	272	297	68.1	365	93	40.8	52
2003	291	0	291	297	68.1	365	74	43.7	30
2004	309	40	349	356	48.1	364	55	52.4	3
2005	323	24	347	356	48.1	380	57	52.1	5
2006	336	10	346	356	48.1	394	58	51.9	6
2007	346	0	346	356	48.1	404	58	51.9	6
2008	357	0	357	426	48.1	474	117	53.6	64
2009	368	0	368	426	48.1	474	106	55.2	51
2010	379	0	379	426	48.1	474	95	56.9	38
2011	390	0	390	426	48.1	474	84	58.5	26
2012	402	0	402	426	48.1	474	72	60.3	12
2013	413	0	413	426	48.1	474	61	62.0	(1)
2014	425	0	425	459	48.1	507	82	63.8	19
2015	438	0	438	459	48.1	507	69	65.7	4
2016	450	0	450	492	48.1	540	90	67.5	23
2017	462	0	462	492	48.1	540	78	69.3	9
2018	475	0	475	562	48.1	610	135	71.3	64
2019	488	0	488	562	48.1	610	122	73.2	49

Table 1C.7-8
Excess KUA Entitlement Sold to OUC

Period	MW[1]
10/01/03-09/30/04	40
10/01/04-09/30/05	24
10/01/05-09/30/06	10

1. Based on 633 MW rating at 70° F.

1C.8.0 Sensitivity Analysis

KUA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1C.8.1 through 1C.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1C.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1C.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1C.8-2 presents the runner-up expansion plan. The plan including the self build alternative on a cumulative present worth basis over a 20 year planning horizon is only $200,000 lower than the plan with the joint development project.

1C.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1C.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1C.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $0.8 million cumulative present worth savings over the self build plan.

1C.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1C.8-5 and Table 1C.8-6 presents

the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $2.1 million lower in cumulative present worth cost.

1C.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1C.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1C.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $0.4 million savings over the plan with the self build project.

1C.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1C.8-9 and Table 1C.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $2.9 million.

1C.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1C.4. Table 1C.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1C.8-11, the high load and energy growth scenario results in a minimal 4 MW capacity shortfall in the summer of 2003 growing to a 53 MW shortfall in 2004. It has been assumed that KUA will purchase power on the spot market to make up the resultant deficit in 2003.

Table 1C.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1C.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is $5.4 million lower in cost than the plan including self build alternative.

1C.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1C.4.0. Table 1C.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast, however, for evaluations the effect of adding the joint development project and the self build project are presented in Tables 1C.8-15 and 1C.8-16, respectively.

Table 1C.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1C.8-16 presents the runner-up expansion plan. Again, the plan with the joint development project is least cost by $6.0 million in cumulative present worth cost over the 20 year period.

1C.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but one of the sensitivity analyses. In several of these analyses, the extension of the PPA for an additional five years is part of the expansion plan. Since extension of the PPA must be done collectively, it may not be possible for KUA to obtain the five year extension. Costs would then increase for the plans with the joint development project. However, a more realistic comparison would be to compare a plan that does not include participation in any project at Stanton Energy Center. For that comparison there would be substantial savings associated with the Southern-Florida joint development project.

Table 1C.8-1
KUA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	55,134	236,258
2004		52,393	274,769
2005		53,463	311,155
2006		58,080	347,755
2007		64,441	385,356
2008	36 MW LM6000 Simple Cycle (06/08)	70,300	423,337
2009		77,383	462,047
2010		82,516	500,268
2011	36 MW LM6000 Simple Cycle (06/11)	92,858	540,093
2012		99,036	579,422
2013	36 MW LM6000 Simple Cycle (06/13)	107,486	618,944
2014		117,083	658,807
2015		125,664	698,421
2016	36 MW LM6000 Simple Cycle (06/16)	135,677	738,024
2017		147,901	777,997
2018	36 MW LM6000 Simple Cycle (06/18)	161,858	818,502
2019		174,712	858,985

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-2
KUA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	21 MW Joint Development with Southern–Florida (10/03)	55,251	236,351
	40 MW Southern-Florida Power Purchase (10/03)		
2004		50,776	273,673
2005		52,967	309,721
2006		58,544	346,614
2007		64,405	384,194
2008	78 MW 7FA Simple Cycle (06/08)	71,372	422,754
2009		78,956	462,252
2010		84,118	501,215
2011		94,251	541,637
2012		97,760	580,459
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	105,300	619,177
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	115,693	658,566
2015		126,525	698,452
2016	36 MW LM6000 Simple Cycle (06/16)	136,912	738,415
2017			
2018	36 MW LM6000 Simple Cycle (06/18)	148,923	778,665
	Terminate 40 MW Southern–Florida Power Purchase (11/18)	160,795	818,904
2019	36 MW LM6000 Simple Cycle (06/19)	173,713	859,155

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-3
KUA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	21 MW Joint Development with Southern–Florida (10/03)	50,186	227,576
	40 MW Southern-Florida Power Purchase (10/03)		
2004		44,908	260,585
2005		45,684	291,677
2006		49,457	322,843
2007		52,975	353,753
2008	78 MW 7FA Simple Cycle (06/08)	57,608	384,877
2009		62,455	416,120
2010		64,847	446,157
2011		70,494	476,391
2012		71,114	504,631
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	74,479	532,017
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	80,276	559,348
2015		86,031	586,468
2016	36 MW LM6000 Simple Cycle (06/16)	91,895	613,291
2017		97,631	639,678
2018	36 MW LM6000 Simple Cycle (06/18)	104,038	665,713
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	111,040	691,443

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-4
KUA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	50,050	227,467
2004		46,423	261,590
2005		46,092	292,960
2006		48,902	323,776
2007		52,675	354,512
2008	78 MW 7FA Simple Cycle (06/08)	57,488	385,571
2009		62,157	416,665
2010		64,692	446,630
2011		70,273	476,768
2012		70,967	504,950
2013		74,322	532,278
2014	36 MW LM6000 Simple Cycle (06/14)	79,835	559,459
2015		85,500	586,412
2016	36 MW LM6000 Simple Cycle (06/16)	91,341	613,074
2017		97,153	639,331
2018	78 MW 7FA Simple Cycle (06/18)	106,187	665,905
2019		113,472	692,198

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		54,063	54,063
2001		46,179	96,821
2002		42,078	132,896
2003	21 MW Joint Development with Southern–Florida (10/03)	48,077	171,061
	40 MW Southern-Florida Power Purchase (10/03)		
2004		49,471	207,424
2005		53,768	244,018
2006		58,427	280,837
2007		63,154	317,687
2008	78 MW 7FA Simple Cycle (06/08)	68,896	354,909
2009		75,314	392,585
2010		79,130	429,237
2011		87,394	466,719
2012		89,126	502,112
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	94,343	536,802
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	102,349	571,648
2015		110,563	606,502
2016	36 MW LM6000 Simple Cycle (06/16)	118,357	641,050
2017		126,967	675,365
2018	36 MW LM6000 Simple Cycle (06/18)	136,061	709,414
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	146,296	743,312

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-6
KUA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		54,063	54,063
2001		46,179	96,821
2002		42,078	132,896
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	48,013	171,010
2004		50,841	208,380
2005		54,241	245,296
2006		57,723	281,671
2007		62,981	318,420
2008	78 MW 7FA Simple Cycle (06/08)	69,004	355,701
2009		75,156	393,297
2010		79,042	429,909
2011		87,185	467,301
2012		89,086	502,679
2013		94,265	537,340
2014	36 MW LM6000 Simple Cycle (06/14)	101,954	572,051
2015		110,154	606,776
2016	36 MW LM6000 Simple Cycle (06/16)	117,890	641,187
2017		126,771	675,449
2018	78 MW 7FA Simple Cycle (06/18)	139,838	710,444
2019		150,942	745,419

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,958	72,958
2001		64,161	132,366
2002		59,619	183,480
2003	21 MW Joint Development with Southern–Florida (10/03)	67,899	237,380
	40 MW Southern-Florida Power Purchase (10/03)		
2004		70,271	289,032
2005		76,250	340,926
2006		82,215	392,736
2007		88,883	444,598
2008	112 MW Pulverized Coal (06/08)	96,814	496,903
2009		106,897	550,378
2010		110,984	601,785
2011		119,186	652,902
2012		121,684	701,224
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	128,605	748,512
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014		136,325	794,925
2015		144,060	840,339
2016		152,392	884,821
2017	36 MW LM6000 Simple Cycle (06/17)	164,319	929,231
2018	Terminate 40 MW Southern–Florida Power Purchase (11/18)	176,803	973,476
2019	78 MW 7FA Simple Cycle (06/19)	191,457	1,017,839

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,958	72,958
2001		64,161	132,366
2002		59,619	183,480
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	67,775	237,282
2004		71,709	289,990
2005		76,700	342,191
2006		81,646	393,642
2007		88,614	445,348
2008	112 MW Pulverized Coal (06/08)	96,479	497,472
2009		106,833	550,915
2010		110,787	602,231
2011		119,032	653,282
2012		121,558	701,554
2013		128,304	748,731
2014		135,902	795,000
2015		143,464	840,226
2016	36 MW LM6000 Simple Cycle (06/16)	154,494	885,322
2017		166,477	930,315
2018		176,409	974,461
2019	36 MW LM6000 Simple Cycle (06/19)	189,113	1,018,281

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,899	131,197
2002		57,961	180,889
2003	21 MW Joint Development with Southern–Florida (10/03)	64,881	232,394
	40 MW Southern-Florida Power Purchase (10/03)		
2004		65,887	280,822
2005		71,296	329,345
2006		76,525	377,569
2007		82,100	425,474
2008	78 MW 7FA Simple Cycle (06/08)	88,299	473,179
2009		95,686	521,046
2010		99,875	567,307
2011		109,396	614,225
2012		110,759	658,209
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	116,444	701,025
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	124,728	743,490
2015		132,312	785,200
2016	36 MW LM6000 Simple Cycle (06/16)	139,525	825,927
2017		147,465	865,782
2018	36 MW LM6000 Simple Cycle (06/18)	154,721	904,501
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	163,339	942,348

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,898	131,196
2002		57,961	180,889
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	64,735	232,277
2004		67,382	281,805
2005		71,828	330,690
2006		76,052	378,616
2007		81,875	426,389
2008	78 MW 7FA Simple Cycle (06/08)	88,273	474,080
2009		95,446	521,827
2010		99,797	568,053
2011		109,258	614,911
2012		110,758	658,895
2013		116,399	701,695
2014	36 MW LM6000 Simple Cycle (06/14)	124,528	744,091
2015		131,855	785,658
2016	36 MW LM6000 Simple Cycle (06/16)	139,069	826,251
2017		147,135	866,017
2018	78 MW 7FA Simple Cycle (06/18)	159,363	905,897
2019		169,780	945,237

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-11
KUA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	247	0	0	176	108.1	284	37	37	0\
2001	265	0	0	297	68.1	365	100	40	60
2002	292	0	0	297	68.1	365	73	44	29
2003	321	0	0	297	68.1	365	44	48	(4)
2004	346	0	0	297	48.1	345	0	53	(53)
2005	368	0	0	297	48.1	345	0	78	(78)
2006	391	0	0	297	48.1	345	0	105	(105)
2007	410	0	0	297	48.1	345	0	127	(127)
2008	431	0	0	297	48.1	345	0	151	(151)
2009	452	0	0	297	48.1	345	0	175	(175)
2010	474	0	0	297	48.1	345	0	200	(200)
2011	497	0	0	297	48.1	345	0	227	(227)
2012	520	0	0	297	48.1	345	0	253	(253)
2013	545	0	0	297	48.1	345	0	282	(282)
2014	571	0	0	297	48.1	345	0	312	(312)
2015	598	0	0	297	48.1	345	0	343	(343)
2016	625	0	0	297	48.1	345	0	374	(374)
2017	653	0	0	297	48.1	345	0	406	(406)
2018	682	0	0	297	48.1	345	0	439	(439)
2019	713	0	0	297	48.1	345	0	475	(475)

Table 1C.8-12
KUA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	21 MW Joint Development with Southern–Florida (10/03)	59,209	251,028
	40 MW Southern-Florida Power Purchase (10/03)	54,817	291,320
2004	36 MW LM6000 Simple Cycle (06/04)	62,223	333,668
2005	78 MW 7FA Simple Cycle (06/05)	70,369	378,012
2006		76,554	422,680
2007		81,721	466,832
2008		89,568	511,638
2009	36 MW LM6000 Simple Cycle (06/09)	98,818	557,410
2010	36 MW LM6000 Simple Cycle (06/10)	109,719	604,467
2011		116,344	650,668
2012	36 MW LM6000 Simple Cycle (06/12)	126,625	697,228
2013	36 MW LM6000 Simple Cycle (06/13)	137,302	743,974
	Terminate 40 MW Southern–Florida Power Purchase (11/13)	149,361	791,059
2014	78 MW 7FA Simple Cycle (06/14)	160,972	838,045
2015	36 MW LM6000 Simple Cycle (06/15)	172,454	884,654
2016	36 MW LM6000 Simple Cycle (06/16)	185,799	931,150
2017	36 MW LM6000 Simple Cycle (06/17)	203,166	978,226
2018	36 MW LM6000 Simple Cycle (06/18)		
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	78 MW 7FA Simple Cycle (06/19)		

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-13
KUA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	59,114	250,953
2004	36 MW LM6000 Simple Cycle (06/04)	56,249	292,298
2005	78 MW 7FA Simple Cycle (06/05)	62,535	334,858
2006		69,686	378,772
2007		76,349	423,321
2008		81,604	467,409
2009	36 MW LM6000 Simple Cycle (06/09)	89,408	512,135
2010	36 MW LM6000 Simple Cycle (06/10)	98,585	557,799
2011		109,371	604,707
2012	36 MW LM6000 Simple Cycle (06/12)	115,988	650,767
2013	36 MW LM6000 Simple Cycle (06/13)	127,355	697,595
2014	78 MW 7FA Simple Cycle (06/14)	140,771	745,522
2015		152,841	793,704
2016	36 MW LM6000 Simple Cycle (06/16)	163,127	841,319
2017	36 MW LM6000 Simple Cycle (06/17)	175,725	888,812
2018	36 MW LM6000 Simple Cycle (06/18)	189,140	936,145
2019	36 MW LM6000 Simple Cycle (06/19)	204,936	983,631

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-14
KUA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	237	0	0	176	108.1	284	47	36	11
2001	238	0	0	297	68.1	365	127	36	91
2002	245	0	0	297	68.1	365	120	37	83
2003	252	0	0	297	68.1	365	113	38	75
2004	259	0	0	297	48.1	345	86	39	47
2005	263	0	0	297	48.1	345	82	39	42
2006	266	0	0	297	48.1	345	79	40	39
2007	267	0	0	297	48.1	345	78	40	38
2008	267	0	0	297	48.1	345	78	40	38
2009	268	0	0	297	48.1	345	77	40	36
2010	269	0	0	297	48.1	345	76	40	35
2011	268	0	0	297	48.1	345	77	40	36
2012	267	0	0	297	48.1	345	78	40	38
2013	266	0	0	297	48.1	345	79	40	39
2014	264	0	0	297	48.1	345	81	40	41
2015	263	0	0	297	48.1	345	82	39	42
2016	260	0	0	297	48.1	345	85	39	46
2017	257	0	0	297	48.1	345	88	39	49
2018	254	0	0	297	48.1	345	91	38	53
2019	251	0	0	297	48.1	345	94	38	56

Table 1C.8-15
KUA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	21 MW Joint Development with Southern–Florida (10/03)	45,187	209,895
	40 MW Southern-Florida Power Purchase (10/03)		
2004		41,431	240,348
2005		42,026	268,950
2006		44,718	297,130
2007		46,696	324,377
2008		48,112	350,370
2009		49,486	375,125
2010		50,945	398,723
2011		53,364	421,610
2012		54,278	443,164
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	54,739	463,292
2014		53,210	481,408
2015		54,930	498,724
2016		56,028	515,078
2017		57,482	530,613
2018		59,263	545,444
2019		60,249	559,404

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-16
KUA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	45,017	209,760
2004		42,677	241,129
2005		42,243	269,878
2006		43,900	297,542
2007		46,321	324,570
2008		47,659	350,319
2009		49,017	374,840
2010		50,479	398,221
2011		52,909	420,913
2012		53,934	442,331
2013		55,067	462,579
2014		56,657	481,868
2015		58,612	500,345
2016		60,030	517,867
2017		61,718	534,548
2018		63,238	550,373
2019		64,947	565,422

Note: Capacity is stated at average annual temperature for KUA.

1C.9.0 Financial Analysis

KUA has not made a final decision regarding financing KUA's 3.5 percent equity share of Stanton A. The relatively small amount of equity required may come from a number of sources including retained earnings, tax exempt bond proceeds from either existing or future issues, short term commercial paper or similar instruments, or even the FMPA Pooled Loan Project. For evaluation purposes, a weighted average cost of capital of approximately 8 percent was used.

KUA's strong financial position will support any of the above methods of finance. In Fiscal 1999, KUA operating revenues were $79.7 million with an operating income of $12.0 million. KUA's debt service coverage was 1.81 for Fiscal 1999.

Appendix 1C.A
Economic Evaluation Spreadsheets

Kissimmee Utility Authority

Case

Scenario: Southern-Florida Base Case

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.417	53,095	5,941
LM 6001	36	36,778	8	2016.417	55,783	6,242
LM 6002	36	36,778	8	2018.417	58,607	6,558
LM 6003	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,624	4,214	807	(9)	52,635	288	52,923	232,128
2004	41,706	4,567	89	(35)	46,327	1,151	47,478	267,026
2005	41,846	4,918	1,306	(35)	48,035	1,151	49,187	300,501
2006	44,969	5,226	2,453	(35)	52,614	1,151	53,765	334,382
2007	48,305	5,524	3,212	(35)	57,006	1,151	58,157	368,316
2008	50,583	5,780	3,417	(34)	59,745	4,170	63,915	402,848
2009	54,101	6,078	3,572	(34)	63,716	6,326	70,042	437,886
2010	57,163	6,419	3,584	(34)	67,131	6,326	73,457	471,911
2011	64,409	6,747	3,596	(34)	74,718	6,326	81,044	506,669
2012	65,852	7,162	3,609	(34)	76,589	6,326	82,915	539,596
2013	70,412	7,554	3,684	(34)	81,616	6,326	87,942	571,932
2014	73,833	7,839	4,415	(34)	86,053	9,792	95,845	604,564
2015	78,153	8,311	4,736	(34)	91,167	12,267	103,434	637,170
2016	81,433	8,593	5,201	(34)	95,193	15,908	111,101	669,600
2017	86,048	9,051	5,557	(33)	100,624	18,509	119,133	701,798
2018	90,458	9,331	5,487	(33)	105,243	22,335	127,578	733,724
2019	94,870	9,258	3,471	(33)	107,566	28,989	136,554	765,365

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case
Scenario: Self Build KUA Base

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,606	4,211	82	13	51,911	880	52,791	232,023
2004	41,884	4,564	(1,037)	51	45,462	3,520	48,982	268,026
2005	42,069	4,923	(947)	53	46,098	3,520	49,618	301,795
2006	45,290	5,222	(857)	54	49,708	3,520	53,228	335,338
2007	48,397	5,523	358	55	54,334	3,520	57,854	369,095
2008	50,861	5,777	570	57	57,264	6,539	63,802	403,565
2009	54,211	6,075	730	58	61,075	8,695	69,769	438,467
2010	57,387	6,416	749	59	64,611	8,695	73,306	472,422
2011	64,570	6,748	767	61	72,146	8,695	80,840	507,093
2012	66,085	7,162	786	62	74,096	8,695	82,790	539,971
2013	70,669	7,556	806	64	79,094	8,695	87,789	572,250
2014	74,166	7,839	1,238	66	83,308	12,160	95,468	604,754
2015	78,354	8,308	1,567	67	88,296	14,635	102,931	637,202
2016	81,599	8,583	2,038	69	92,290	18,276	110,566	669,475
2017	86,331	9,043	2,402	71	97,847	20,877	118,723	701,562
2018	93,641	9,504	2,721	72	105,939	24,740	130,679	734,265
2019	100,702	9,964	2,977	74	113,717	27,500	141,217	766,986

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case	Economic	
Scenario: Base Case Second Runner Up	CPW Discount Rate:	8.0%
	Capital Escalation Rate:	2.5%
	Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM 6000	36	36,778	8	2004.417	41,478	4,641
LM 6000	36	36,778	8	2006.417	43,578	4,876
LM 6000	36	36,778	8	2009.417	46,928	5,251
LM 6000	36	36,778	8	2011.417	49,304	5,517
Joint 7FA SC	78	36,939	12	2014.417	53,627	6,001
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,871	4,169	0	0	52,040	0	52,040	231,427
2004	42,857	4,420	322	0	47,598	2,707	50,305	268,403
2005	42,666	4,763	562	0	47,991	4,641	52,632	304,223
2006	44,100	4,944	914	0	49,958	7,486	57,444	340,423
2007	46,652	5,177	1,181	0	53,010	9,518	62,528	376,907
2008	49,598	5,478	1,211	0	56,287	9,518	65,805	412,459
2009	51,454	5,660	1,605	0	58,719	12,581	71,300	448,127
2010	53,872	5,938	1,908	0	61,719	14,769	76,488	483,556
2011	55,799	6,137	2,338	0	64,275	17,987	82,262	518,836
2012	59,377	6,437	2,673	0	68,488	20,286	88,774	554,090
2013	63,112	6,764	2,740	0	72,616	20,286	92,902	588,250
2014	67,101	6,983	3,043	0	77,127	23,787	100,914	622,607
2015	71,544	7,361	3,289	0	82,194	26,287	108,481	656,805
2016	77,096	7,744	3,372	0	88,211	26,287	114,498	690,226
2017	81,889	8,119	3,456	0	93,464	26,287	119,751	722,591
2018	88,413	8,538	3,542	0	100,493	26,287	126,780	754,317
2019	90,996	8,725	4,097	0	103,817	30,208	134,025	785,373

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

4

Kissimmee Utility Authority

Case

Scenario: KUA Joint Development without PPA extension Option

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
Joint WH 501F 1x1	125	74,736	23	2014.417	110,182	12,329
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,138	3,968	0	0	75,105	0	75,105	141,705
2002	52,644	3,823	0	0	56,466	0	56,466	190,116
2003	47,624	4,214	807	(9)	52,635	288	52,923	232,128
2004	41,706	4,567	89	(35)	46,327	1,151	47,478	267,026
2005	41,846	4,918	1,306	(35)	48,035	1,151	49,187	300,501
2006	44,969	5,226	2,453	(35)	52,614	1,151	53,765	334,382
2007	48,305	5,524	3,212	(35)	57,006	1,151	58,157	368,316
2008	50,583	5,780	3,417	(34)	59,745	4,170	63,915	402,848
2009	54,101	6,078	3,572	(34)	63,716	6,326	70,042	437,886
2010	57,163	6,419	3,584	(34)	67,131	6,326	73,457	471,911
2011	64,409	6,747	3,596	(34)	74,718	6,326	81,044	506,669
2012	65,852	7,162	3,609	(34)	76,589	6,326	82,915	539,596
2013	71,171	7,547	3,106	(34)	81,790	6,326	88,116	571,996
2014	76,450	7,490	1,033	(34)	84,939	13,518	98,457	605,517
2015	82,412	7,743	1,408	(34)	91,529	18,655	110,184	640,252
2016	87,858	8,159	1,443	(34)	97,427	18,655	116,082	674,135
2017	93,084	8,595	1,479	(33)	103,125	18,655	121,780	707,048
2018	100,304	9,077	1,516	(33)	110,865	18,655	129,520	739,460
2019	105,169	9,476	2,020	(33)	116,632	22,576	139,208	771,717

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Self Build KUA High Fuel

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	3,520
LM 6000	36	36,778	8	2008.417	45,784	5,123
LM 6000	36	36,778	8	2011.417	49,304	5,517
LM 6000	36	36,778	8	2013.417	51,800	5,796
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,976	3,969	0	0	75,945	0	75,945	142,482
2002	54,507	3,823	0	0	58,330	0	58,330	192,491
2003	49,942	4,217	82	13	54,254	880	55,134	236,258
2004	45,268	4,591	(1,037)	51	48,873	3,520	52,393	274,769
2005	45,921	4,916	(947)	53	49,943	3,520	53,463	311,155
2006	50,143	5,220	(857)	54	54,560	3,520	58,080	347,755
2007	54,966	5,542	358	55	60,921	3,520	64,441	385,356
2008	57,241	5,771	722	57	63,791	6,509	70,300	423,337
2009	61,615	6,069	997	58	68,740	8,643	77,383	462,047
2010	66,372	6,420	1,022	59	73,873	8,643	82,516	500,268
2011	72,851	6,654	1,430	61	80,996	11,862	92,858	540,093
2012	76,031	7,040	1,742	62	84,875	14,160	99,036	579,422
2013	80,385	7,308	2,187	64	89,945	17,542	107,486	618,944
2014	86,909	7,619	2,532	66	97,126	19,957	117,083	658,807
2015	94,913	8,131	2,596	67	105,707	19,957	125,664	698,421
2016	100,546	8,371	3,093	69	112,079	23,598	135,677	738,024
2017	109,305	8,844	3,483	71	121,702	26,199	147,901	777,997
2018	118,512	9,224	4,025	72	131,833	30,025	161,858	818,502
2019	127,773	9,653	4,454	74	141,955	32,757	174,712	858,985

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Southern-Florida High Fuel

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.417	53,095	5,941
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	71,976	3,969	0	0	75,945	0	75,945	142,482
2002	54,507	3,823	0	0	58,330	0	58,330	192,491
2003	49,946	4,219	807	(9)	54,963	288	55,251	236,351
2004	44,972	4,599	89	(35)	49,625	1,151	50,776	273,673
2005	45,627	4,917	1,306	(35)	51,816	1,151	52,967	309,721
2006	49,750	5,224	2,453	(35)	57,393	1,151	58,544	346,614
2007	54,530	5,546	3,212	(35)	63,253	1,151	64,405	384,194
2008	58,039	5,780	3,417	(34)	67,202	4,170	71,372	422,754
2009	63,009	6,084	3,572	(34)	72,630	6,326	78,956	462,252
2010	67,815	6,427	3,584	(34)	77,792	6,326	84,118	501,215
2011	77,608	6,755	3,596	(34)	87,925	6,326	94,251	541,637
2012	80,695	7,165	3,609	(34)	91,434	6,326	97,760	580,459
2013	87,764	7,560	3,684	(34)	98,974	6,326	105,300	619,177
2014	93,665	7,855	4,415	(34)	105,901	9,792	115,693	658,566
2015	101,194	8,362	4,736	(34)	114,258	12,267	126,525	698,452
2016	107,160	8,676	5,201	(34)	121,004	15,908	136,912	738,415
2017	115,750	9,140	5,557	(33)	130,414	18,509	148,923	778,665
2018	123,605	9,402	5,487	(33)	138,461	22,335	160,795	818,904
2019	131,912	9,374	3,471	(33)	144,724	28,989	173,713	859,155

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Southern-Florida Low Fuel

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.417	53,095	5,941
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	70,404	3,965	0	0	74,370	0	74,370	141,024
2002	50,657	3,828	0	0	54,486	0	54,486	187,737
2003	44,884	4,217	807	(9)	49,899	288	50,186	227,576
2004	39,104	4,599	89	(35)	43,757	1,151	44,908	260,585
2005	38,342	4,920	1,306	(35)	44,533	1,151	45,684	291,677
2006	40,659	5,228	2,453	(35)	48,306	1,151	49,457	322,843
2007	43,103	5,543	3,212	(35)	51,823	1,151	52,975	353,753
2008	44,281	5,774	3,417	(34)	53,438	4,170	57,608	384,877
2009	46,518	6,074	3,572	(34)	56,130	6,326	62,455	416,120
2010	48,538	6,433	3,584	(34)	58,521	6,326	64,847	446,157
2011	53,875	6,731	3,596	(34)	64,168	6,326	70,494	476,391
2012	54,066	7,147	3,609	(34)	64,789	6,326	71,114	504,631
2013	56,957	7,547	3,684	(34)	68,154	6,326	74,479	532,017
2014	58,278	7,825	4,415	(34)	70,484	9,792	80,276	559,348
2015	60,756	8,304	4,736	(34)	73,764	12,267	86,031	586,468
2016	62,217	8,602	5,201	(34)	75,986	15,908	91,895	613,291
2017	64,546	9,052	5,557	(33)	79,122	18,509	97,631	639,678
2018	66,916	9,333	5,487	(33)	81,703	22,335	104,038	665,713
2019	69,336	9,278	3,471	(33)	82,051	28,989	111,040	691,443

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case	
Scenario: Self Build KUA Low Fuel	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost [1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	67,945	4,218	0	0	72,163	0	72,163	72,163
2001	70,404	3,965	0	0	74,370	0	74,370	141,024
2002	50,657	3,828	0	0	54,486	0	54,486	187,737
2003	44,861	4,214	82	13	49,170	880	50,050	227,467
2004	39,293	4,596	(1,037)	51	42,903	3,520	46,423	261,590
2005	38,542	4,924	(947)	53	42,572	3,520	46,092	292,960
2006	40,963	5,223	(857)	54	45,382	3,520	48,902	323,776
2007	43,198	5,543	358	55	49,155	3,520	52,675	354,512
2008	44,552	5,770	570	57	50,949	6,539	57,488	385,571
2009	46,603	6,071	730	58	53,463	8,695	62,157	416,665
2010	48,758	6,431	749	59	55,997	8,695	64,692	446,630
2011	54,017	6,733	767	61	61,578	8,695	70,273	476,768
2012	54,277	7,147	786	62	62,272	8,695	70,967	504,950
2013	57,211	7,547	806	64	65,628	8,695	74,322	532,278
2014	58,547	7,824	1,238	66	67,675	12,160	79,835	559,459
2015	60,929	8,302	1,567	67	70,865	14,635	85,500	586,412
2016	62,365	8,592	2,038	69	73,065	18,276	91,341	613,074
2017	64,761	9,043	2,402	71	76,277	20,877	97,153	639,331
2018	69,170	9,483	2,721	72	81,447	24,740	106,187	665,905
2019	72,977	9,945	2,977	74	85,973	27,500	113,472	692,198

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Southern-Florida AEO

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)		Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21				2003.833		
Joint 7FA SC	70	36,939		12	2008.417	46,242	5,175
LM 6000	36	36,778		8	2014.417	53,095	5,941
LM 6000	36	36,778		8	2016.417	55,783	6,242
LM 6000	36	36,778		8	2018.417	58,607	6,558
LM 6000	36	36,778		8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)		O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	49,846	4,217		0	0	54,063	0	54,063	54,063
2001	42,158	4,021		0	0	46,179	0	46,179	96,821
2002	38,243	3,835		0	0	42,078	0	42,078	132,896
2003	42,769	4,222		807	(9)	47,789	288	48,077	171,061
2004	43,664	4,602		89	(35)	48,320	1,151	49,471	207,424
2005	46,419	4,926		1,306	(35)	52,617	1,151	53,768	244,018
2006	49,620	5,237		2,453	(35)	57,276	1,151	58,427	280,837
2007	53,269	5,557		3,212	(35)	62,003	1,151	63,154	317,687
2008	55,556	5,787		3,417	(34)	64,726	4,170	68,896	354,909
2009	59,360	6,091		3,572	(34)	68,988	6,326	75,314	392,585
2010	62,822	6,433		3,584	(34)	72,805	6,326	79,130	429,237
2011	70,737	6,769		3,596	(34)	81,068	6,326	87,394	466,719
2012	72,045	7,180		3,609	(34)	82,800	6,326	89,126	502,112
2013	76,791	7,577		3,684	(34)	88,018	6,326	94,343	536,802
2014	80,298	7,879		4,415	(34)	92,557	9,792	102,349	571,648
2015	85,229	8,365		4,736	(34)	98,296	12,267	110,563	606,502
2016	88,639	8,642		5,201	(34)	102,448	15,908	118,357	641,050
2017	93,835	9,099		5,557	(33)	108,458	18,509	126,967	675,365
2018	98,873	9,399		5,487	(33)	113,726	22,335	136,061	709,414
2019	104,493	9,376		3,471	(33)	117,307	28,989	146,296	743,312

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Self Build KUA AEO

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	49,846	4,217	0	0	54,063	0	54,063	54,063
2001	42,158	4,021	0	0	46,179	0	46,179	96,821
2002	38,243	3,835	0	0	42,078	0	42,078	132,896
2003	42,818	4,220	82	13	47,133	880	48,013	171,010
2004	43,706	4,601	(1,037)	51	47,321	3,520	50,841	208,380
2005	46,687	4,928	(947)	53	50,721	3,520	54,241	245,296
2006	49,768	5,238	(857)	54	54,203	3,520	57,723	281,671
2007	53,488	5,559	358	55	59,461	3,520	62,981	318,420
2008	56,054	5,785	570	57	62,465	6,539	69,004	355,701
2009	59,585	6,088	730	58	66,461	8,695	75,156	393,297
2010	63,108	6,432	749	59	70,348	8,695	79,042	429,909
2011	70,895	6,767	767	61	78,490	8,695	87,185	467,301
2012	72,362	7,181	786	62	80,392	8,695	89,086	502,679
2013	77,121	7,579	806	64	85,570	8,695	94,265	537,340
2014	80,614	7,876	1,238	66	89,794	12,160	101,954	572,051
2015	85,522	8,363	1,567	67	95,519	14,635	110,154	606,776
2016	88,875	8,631	2,038	69	99,614	18,276	117,890	641,187
2017	94,329	9,092	2,402	71	105,894	20,877	126,771	675,449
2018	102,742	9,562	2,721	72	115,098	24,740	139,838	710,444
2019	110,345	10,047	2,977	74	123,442	27,500	150,942	745,419

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case
Scenario: Southern-Florida 2000 - AEO

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Coal	112	128,291	42	2008.417	167,486	18,742
LM 6000	36	36,778	8	2017.417	57,178	6,398
Joint 7FA SC	70	36,939	12	2019.417	60,674	6,789

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost [1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,741	4,217	0	0	72,958	0	72,958	72,958
2001	60,154	4,007	0	0	64,161	0	64,161	132,366
2002	55,784	3,836	0	0	59,619	0	59,619	183,480
2003	62,586	4,227	807	(9)	67,611	288	67,899	237,380
2004	64,463	4,603	89	(35)	69,119	1,151	70,271	289,032
2005	68,896	4,931	1,306	(35)	75,099	1,151	76,250	340,926
2006	73,407	5,238	2,453	(35)	81,064	1,151	82,215	392,736
2007	78,996	5,558	3,212	(35)	87,731	1,151	88,883	444,598
2008	74,221	6,200	4,343	(34)	84,730	12,084	96,814	496,903
2009	75,113	6,735	5,191	(34)	87,004	19,893	106,897	550,378
2010	78,743	7,138	5,244	(34)	91,091	19,893	110,984	601,785
2011	86,566	7,464	5,298	(34)	99,293	19,893	119,186	652,902
2012	88,577	7,895	5,353	(34)	101,791	19,893	121,684	701,224
2013	94,958	8,317	5,471	(34)	108,712	19,893	128,605	748,512
2014	101,926	8,705	5,835	(34)	116,432	19,893	136,325	794,925
2015	109,103	9,203	5,894	(34)	124,167	19,893	144,060	840,339
2016	116,879	9,698	5,956	(34)	132,499	19,893	152,392	884,821
2017	124,153	10,113	6,461	(33)	140,694	23,625	164,319	929,231
2018	133,637	10,628	6,280	(33)	150,512	26,291	176,803	973,476
2019	146,413	11,071	3,754	(33)	161,205	30,252	191,457	1,017,839

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Self Build KUA 2000 + AEO

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,741	4,217	0	0	72,958	0	72,958	72,958
2001	60,154	4,007	0	0	64,161	0	64,161	132,366
2002	55,784	3,836	0	0	59,619	0	59,619	183,480
2003	62,574	4,226	82	13	66,895	880	67,775	237,282
2004	64,572	4,602	(1,037)	51	68,189	3,520	71,709	289,990
2005	69,146	4,928	(947)	53	73,180	3,520	76,700	342,191
2006	73,689	5,240	(857)	54	78,126	3,520	81,646	393,642
2007	79,125	5,556	358	55	85,094	3,520	88,614	445,348
2008	74,276	6,197	1,496	57	82,026	14,453	96,479	497,472
2009	75,436	6,728	2,350	58	84,571	22,262	106,833	550,915
2010	78,920	7,137	2,408	59	88,525	22,262	110,787	602,231
2011	86,783	7,458	2,469	61	96,770	22,262	119,032	653,282
2012	88,816	7,888	2,530	62	99,296	22,262	121,558	701,554
2013	95,070	8,315	2,593	64	106,042	22,262	128,304	748,731
2014	102,214	8,702	2,658	66	113,640	22,262	135,902	795,000
2015	109,208	9,202	2,725	67	121,202	22,262	143,464	840,226
2016	115,650	9,647	3,225	69	128,591	25,903	154,494	885,322
2017	124,192	10,091	3,619	71	137,973	28,504	166,477	930,315
2018	133,488	10,635	3,709	72	147,905	28,504	176,409	974,461
2019	141,229	11,117	4,268	74	156,688	32,425	189,113	1,018,281

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case

Scenario: Southern-Florida No Real

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.417	53,095	5,941
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	58,924	3,974	0	0	62,899	0	62,899	131,197
2002	54,123	3,838	0	0	57,961	0	57,961	180,889
2003	59,577	4,218	807	(9)	64,593	288	64,881	232,394
2004	60,114	4,567	89	(35)	64,735	1,151	65,887	280,822
2005	63,944	4,929	1,306	(35)	70,145	1,151	71,296	329,345
2006	67,720	5,235	2,453	(35)	75,374	1,151	76,525	377,569
2007	72,218	5,554	3,212	(35)	80,949	1,151	82,100	425,474
2008	74,933	5,813	3,417	(34)	84,129	4,170	88,299	473,179
2009	79,681	6,142	3,572	(34)	89,360	6,326	95,686	521,046
2010	83,499	6,500	3,584	(34)	93,549	6,326	99,875	567,307
2011	92,684	6,824	3,596	(34)	103,070	6,326	109,396	614,225
2012	93,614	7,244	3,609	(34)	104,433	6,326	110,759	658,209
2013	98,826	7,642	3,684	(34)	110,118	6,326	116,444	701,025
2014	102,592	7,963	4,415	(34)	114,936	9,792	124,728	743,490
2015	106,911	8,432	4,736	(34)	120,045	12,267	132,312	785,200
2016	109,733	8,716	5,201	(34)	123,617	15,908	139,525	825,927
2017	114,267	9,164	5,557	(33)	128,955	18,509	147,465	865,782
2018	117,509	9,423	5,487	(33)	132,387	22,335	154,721	904,501
2019	121,515	9,398	3,471	(33)	134,350	28,989	163,339	942,348

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case
Scenario: Self Build KUA No Real

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	58,924	3,974	0	0	62,898	0	62,898	131,196
2002	54,123	3,838	0	0	57,961	0	57,961	180,889
2003	59,546	4,215	82	13	63,855	880	64,735	232,277
2004	60,283	4,565	(1,037)	51	63,862	3,520	67,382	281,805
2005	64,268	4,934	(947)	53	68,308	3,520	71,828	330,690
2006	68,105	5,231	(857)	54	72,532	3,520	76,052	378,616
2007	72,387	5,554	358	55	78,354	3,520	81,875	426,389
2008	75,296	5,812	570	57	81,734	6,539	88,273	474,080
2009	79,822	6,141	730	58	86,752	8,695	95,446	521,827
2010	83,796	6,499	749	59	91,103	8,695	99,797	568,053
2011	92,910	6,825	767	61	100,563	8,695	109,258	614,911
2012	93,968	7,246	786	62	102,063	8,695	110,758	658,895
2013	99,188	7,646	806	64	107,704	8,695	116,399	701,695
2014	103,101	7,963	1,238	66	112,368	12,160	124,528	744,091
2015	107,156	8,430	1,567	67	117,220	14,635	131,855	785,658
2016	109,975	8,710	2,038	69	120,793	18,276	139,069	826,251
2017	114,629	9,157	2,402	71	126,259	20,877	147,135	866,017
2018	122,177	9,652	2,721	72	134,623	24,740	159,363	905,897
2019	129,093	10,136	2,977	74	142,280	27,500	169,780	945,237

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case
Scenario Southern-Florida High Load

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003 833	[redacted]	
LM 6000	36	36,778	8	2004 417	41,478	4,641
Joint 7FA SC	78	36,939	12	2005 417	42,941	4,805
LM 6000	36	36,778	8	2009 417	46,928	5,251
LM 6000	36	36,778	8	2010 417	48,102	5,383
LM 6000	36	36,778	8	2012 417	50,537	5,655
LM 6000	36	36,778	8	2013 417	51,800	5,796
Joint 7FA SC	78	36,939	12	2014 417	53,627	6,001
LM 6000	36	36,778	8	2015 417	54,423	6,090
LM 6000	36	36,778	8	2016 417	55,783	6,242
LM 6000	36	36,778	8	2017 417	57,178	6,398
LM 6000	36	36,778	8	2018 417	58,607	6,558
Joint 7FA SC	78	36939	12	2019 417	60,674	6,789

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs)	20
Plant Life	30

Year	Fuel and Energy Cost [1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	71,674	4,339	0	0	76,013	0	76,013	76,013
2001	76,691	4,184	0	0	80,875	0	80,875	150,897
2002	57,795	4,175	0	0	61,970	0	61,970	204,026
2003	53,429	4,694	807	(9)	58,921	288	59,209	251,028
2004	45,519	5,063	410	(35)	50,958	3,859	54,817	291,320
2005	46,100	5,506	2,056	(35)	53,627	8,596	62,223	333,668
2006	50,490	5,958	3,358	(35)	59,772	10,598	70,369	378,012
2007	55,473	6,378	4,139	(35)	65,956	10,598	76,554	422,680
2008	60,132	6,861	4,165	(34)	71,124	10,598	81,721	466,832
2009	64,099	7,286	4,556	(34)	75,907	13,661	89,568	511,638
2010	66,907	7,727	5,229	(34)	79,829	18,989	98,818	557,410
2011	74,882	8,087	5,552	(34)	88,487	21,232	109,719	604,467
2012	77,155	8,686	6,006	(34)	91,813	24,530	116,344	650,668
2013	81,121	9,021	6,248	(34)	96,357	30,268	126,625	697,228
2014	87,880	8,977	4,295	(34)	101,119	36,184	137,302	743,974
2015	92,773	9,391	4,994	(34)	107,125	42,236	149,361	791,059
2016	97,051	9,683	5,857	(34)	112,557	48,415	160,972	838,045
2017	100,919	10,061	6,759	(33)	117,705	54,748	172,454	884,654
2018	106,503	10,386	7,703	(33)	124,560	61,240	185,799	931,150
2019	115,834	10,942	8,490	(33)	135,233	67,933	203,166	978,226

Notes

(1) Includes start-up costs

(2) Fixed costs are included only for new units

(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case
Scenario: Self Build KUA High Load

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	21			2003.833	31,458	3,520
LM 6000	36	36,778	8	2004.417	41,478	4,641
Joint 7FA SC	78	36,939	12	2005.417	42,941	4,805
LM 6000	36	36,778	8	2009.417	46,928	5,251
LM 6000	36	36,778	8	2010.417	48,102	5,383
LM 6000	36	36,778	8	2012.417	50,537	5,655
LM 6000	36	36,778	8	2013.417	51,800	5,796
Joint 7FA SC	78	36,939	12	2014.417	53,627	6,001
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2017.417	57,178	6,398
LM 6000	36	36,778	8	2018.417	58,607	6,558
LM 6000	36	36778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	71,674	4,339	0	0	76,013	0	76,013	76,013
2001	76,691	4,184	0	0	80,875	0	80,875	150,897
2002	57,795	4,175	0	0	61,970	0	61,970	204,026
2003	53,445	4,694	82	13	58,234	880	59,114	250,953
2004	45,623	5,063	(715)	51	50,022	6,228	56,249	292,298
2005	46,212	5,502	(197)	53	51,570	10,964	62,535	334,858
2006	50,663	5,955	48	54	56,719	12,967	69,686	378,772
2007	55,670	6,371	1,286	55	63,383	12,967	76,349	423,321
2008	60,408	6,856	1,318	57	68,638	12,967	81,604	467,409
2009	64,328	7,278	1,715	58	73,378	16,030	89,408	512,135
2010	67,067	7,708	2,394	59	77,228	21,358	98,585	557,799
2011	74,914	8,072	2,723	61	85,771	23,600	109,371	604,707
2012	77,184	8,658	3,183	62	89,088	26,899	115,988	650,767
2013	81,606	9,100	3,948	64	94,718	32,637	127,355	697,595
2014	88,057	9,524	4,572	66	102,218	38,552	140,771	745,522
2015	96,615	10,251	4,856	67	111,789	41,053	152,841	793,704
2016	102,321	10,633	5,410	69	118,433	44,694	163,127	841,319
2017	107,176	11,150	6,301	71	124,698	51,027	175,725	888,812
2018	112,877	11,438	7,234	72	131,621	57,519	189,140	936,145
2019	120,418	12,062	8,209	74	140,764	64,172	204,936	983,631

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units
(3) Includes fees for site lease as well as credit for services and cooling water

Kissimmee Utility Authority

Case

Scenario: Southern-Florida Low Load

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	64,345	4,079	0	0	68,424	0	68,424	68,424
2001	64,062	3,650	0	0	67,713	0	67,713	131,121
2002	46,675	3,367	0	0	50,042	0	50,042	174,024
2003	40,487	3,615	807	(9)	44,899	288	45,187	209,895
2004	36,383	3,842	89	(35)	40,280	1,151	41,431	240,348
2005	35,577	4,026	1,306	(35)	40,874	1,151	42,026	268,950
2006	36,982	4,166	2,453	(35)	43,567	1,151	44,718	297,130
2007	38,122	4,246	3,212	(35)	45,545	1,151	46,696	324,377
2008	39,402	4,378	3,215	(34)	46,960	1,151	48,112	350,370
2009	40,684	4,467	3,218	(34)	48,335	1,151	49,486	375,125
2010	41,998	4,609	3,221	(34)	49,794	1,151	50,945	398,723
2011	44,333	4,690	3,225	(34)	52,213	1,151	53,364	421,610
2012	45,089	4,844	3,228	(34)	53,127	1,151	54,278	443,164
2013	46,030	4,876	2,716	(34)	53,588	1,151	54,739	463,292
2014	47,104	4,839	149	(34)	52,058	1,151	53,210	481,408
2015	48,710	4,949	153	(34)	53,778	1,151	54,930	498,724
2016	49,764	4,990	157	(34)	54,877	1,151	56,028	515,078
2017	51,136	5,068	161	(33)	56,331	1,151	57,482	530,613
2018	52,841	5,139	165	(33)	58,112	1,151	59,263	545,444
2019	53,824	5,138	169	(33)	59,098	1,151	60,249	559,404

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority

Case
Scenario: Self Build KUA Low Load

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	3,520

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	64,345	4,079	0	0	68,424	0	68,424	68,424
2001	64,062	3,650	0	0	67,713	0	67,713	131,121
2002	46,675	3,367	0	0	50,042	0	50,042	174,024
2003	40,432	3,610	82	13	44,137	880	45,017	209,760
2004	36,308	3,834	(1,037)	51	39,156	3,520	42,677	241,129
2005	35,601	4,015	(947)	53	38,722	3,520	42,243	269,878
2006	37,025	4,158	(857)	54	40,380	3,520	43,900	297,542
2007	38,146	4,242	358	55	42,801	3,520	46,321	324,570
2008	39,346	4,369	367	57	44,138	3,520	47,659	350,319
2009	40,604	4,458	376	58	45,497	3,520	49,017	374,840
2010	41,916	4,598	386	59	46,959	3,520	50,479	398,221
2011	44,251	4,681	395	61	49,389	3,520	52,909	420,913
2012	45,112	4,833	405	62	50,413	3,520	53,934	442,331
2013	46,163	4,904	415	64	51,547	3,520	55,067	462,579
2014	47,663	4,983	426	66	53,137	3,520	56,657	481,868
2015	49,469	5,119	437	67	55,092	3,520	58,612	500,345
2016	50,830	5,164	447	69	56,510	3,520	60,030	517,867
2017	52,401	5,267	459	71	58,198	3,520	61,718	534,548
2018	53,864	5,312	470	72	59,718	3,520	63,238	550,373
2019	55,496	5,375	482	74	61,427	3,520	64,947	565,422

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Stanton Energy Center Combined Cycle Unit A

Need for Power Application

Florida Municipal Power Agency – Volume 1D

January 29, 2001

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO. 1 (Part 4 of 4)
COMPANY/
WITNESS: Orlando Utilities Com.
DATE: 4-23-01

BLACK & VEATCH

11401 Lamar, Overland Park, Kansas, 66211, USA (913) 458-2000

Table of Contents

1D.1.0 Overview and Summary 1-1
1D.1.1 Overview 1-1
1D.1.2 Summary 1-2

1D.2.0 Description of System 2-1
1D.2.1 Generation System 2-1
1D.2.1.1 St. Lucie Project 2-4
1D.2.1.2 Stanton Project 2-4
1D.2.1.3 Tri-City Project 2-4
1D.2.1.4 Stanton II Project 2-4
1D.2.1.5 All-Requirements Project 2-6
1D.2.1.6 All-Requirements Project Participants 2-9
1D.2.2 Purchased Power 2-16
1D.2.2.1 Firm Power Purchases from All-Requirements Project Members 2-16
1D.2.2.2 Firm Power Purchases from Other Utilities 2-16
1D.2.2.3 Partial Requirements Purchases 2-19
1D.2.3 Committed Units 2-19
1D.2.4 Transmission System 2-22

1D.3.0 Evaluation Criteria 3-1
1D.3.1 Economic Parameters 3-1
1D.3.1.1 Escalation Rates 3-1
1D.3.1.2 Bond Interest Rates 3-1
1D.3.1.3 Present Worth Discount Rate 3-1
1D.3.1.4 Interest During Construction 3-1
1D.3.1.5 Levelized Fixed Charge Rate 3-1

1D.4.0 Forecast of Demand and Energy 4-1
1D.4.1 Introduction 4-1
1D.4.2 Forecast Methodology 4-1
1D.4.3 Base Case Load Forecast 4-2
1D.4.3.1 Net Energy for Load Forecast 4-2
1D.4.3.2 Summer Peak Demand Forecast 4-2
1D.4.3.3 Winter Peak Demand Forecast 4-6
1D.4.4 Sensitivities 4-6

Table of Contents (Continued)

1D.5.0 Demand-Side Programs 5-1
1D.5.1 Existing Conservation Programs 5-1
1D.5.1.1 Residential Energy Audits Program 5-2
1D.5.1.2 High Pressure Sodium Outdoor Lighting Conversion 5-2
1D.5.1.3 Assistance for Commercial/ Industrial Audits 5-2
1D.5.1.4 Commercial Time-of-Use Program 5-2
1D.5.1.5 Natural Gas Promotion 5-2
1D.5.1.6 Fix-Up Program for the Elderly and Handicapped 5-2
1D.5.1.7 Residential Load Management Program 5-3
1D.5.2 Analysis of Demand-Side Management Alternatives 5-3
1D.5.2.1 FIRE Model Output 5-3
1D.5.2.2 FIRE Model Output Analysis 5-4

1D.6.0 Reliability Criteria 6-1
1D.6.1 Development of Reliability Criteria 6-1
1D.6.1.1 Traditional Reserve Margin 6-1
1D.6.1.2 Loss of Load Probability 6-2
1D.6.2 Reliability Need 6-2

1D.7.0 Economic Analysis 7-1
1D.7.1 Methodology 7-1
1D.7.2 Expansion Candidates 7-1
1D.7.3 Results of Economic Analysis 7-3

1D.8.0 Sensitivity Analysis 8-1
1D.8.1 High Fuel Price Escalation 8-1
1D.8.2 Low Fuel Price Escalation 8-1
1D.8.3 AEO Fuel Price Projections 8-1
1D.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation 8-2
1D.8.5 Constant 2000 Fuel Price Projections 8-2
1D.8.6 High Load and Energy Growth 8-2
1D.8.7 Low Load and Energy Growth 8-3
1D.8.8 Sensitivity Analysis Summary 8-3

1D.9.0 Financial Analysis 9-1

Table of Contents (Continued)

Appendix 1D.A Economic Evaluation Spreadsheets

Tables

Table 1D.2-1	Summary of Project Participants	2-2
Table 1D.2-2	Florida Municipal Power Agency Existing and Planned Generating Facilities	2-5
Table 1D.2-3	Date ARP Member Joined	2-6
Table 1D.2-4	FMPA All-Requirements Project Existing and Planned Generating Facilities	2-7
Table 1D.2-5	FMPA All Requirements Project Existing Member Generating Facilities	2-8
Table 1D.2-6	FMPA Power Purchase Capacity	2-17
Table 1D.2-7	All-Requirements Total Capacity - Summer (MW)	2-20
Table 1D.2-8	All-Requirements Total Capacity - Winter (MW)	2-21
Table 1D.4-1	All-Requirements Project Member Net Electric Load	4-3
Table 1D.4-2	ARP Member Summer Peak Demand (Noncoincident Demand Peak)	4-4
Table 1D.4-3	Forecast of Summer Peak Demand – Base Case	4-5
Table 1D.4-4	ARP Member Winter Peak Demand (Noncoincident Demand Peak)	4-7
Table 1D.4-5	Forecast of Winter Peak Demand – Base Case	4-8
Table 1D.4-6	Forecast of Summer and Winter Peak Demand with NEL– High Case	4-9
Table 1D.4-7	Forecast of Summer and Winter Peak Demand with NEL– Low Case	4-10
Table 1D.5-1	FIRE Model Results	5-4
Table 1D.6-1	Projected Reliability Levels - Winter/Base Case	6-3
Table 1D.6-2	Projected Reliability Levels - Summer/Base Case	6-4
Table 1D.7-1	Summary of FMPA Generation Alternatives (2000 $, unless otherwise noted)	7-2
Table 1D.7-2	FMPA Base Case Expansion Plan	7-4
Table 1D.7-3	Projected Reliability Levels – Summer/Base Case with Expansion Plan Identified in Table 1D.7-2	7-5
Table 1D.7-4	FMPA Base Case Runner Up Expansion Plan	7-6
Table 1D.8-1	FMPA High Fuel Price Escalation Expansion Plan	8-4
Table 1D.8-2	FMPA High Fuel Price Escalation Runner Up Expansion Plan	8-5
Table 1D.8-3	FMPA Low Fuel Price Escalation Expansion Plan	8-6

Table of Contents (Continued)
Tables (Continued)

Table 1D.8-4 FMPA Low Fuel Price Escalation Runner-Up Expansion Plan 8-7
Table 1D.8-5 AEO Fuel Price Projection Expansion Plan 8-8
Table 1D.8-6 FMPA AEO Fuel Price Projection Runner-Up Expansion Plan 8-9
Table 1D.8-7 OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan 8-10
Table 1D.8-8 OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan 8-11
Table 1D.8-9 OUC Constant 2000 Fuel Price Projection Expansion Plan 8-12
Table 1D.8-10 OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan 8-13
Table 1D.8-11 FMPA Summer Reserve Requirements - High Load and Energy Growth Scenario 8-15
Table 1D.8-12 FMPA High Load and Energy Growth Expansion Plan 8-16
Table 1D.8-13 FMPA High Load and Energy Growth Runner-Up Expansion Plan 8-17
Table 1D.8-14 FMPA Summer Reserve Requirements - Low Load and Energy Growth Scenario 8-19
Table 1D.8-15 FMPA Low Load and Energy Growth Expansion Plan 8-20
Table 1D.8-16 FMPA Low Load and Energy Growth Runner-Up Expansion Plan 8-21

Figures

Figure 1D.2-1 Member Cities 2-3

1D.1.0 Overview and Summary

1D.1.1 Overview

Stanton A is planned as a new combined cycle addition to the existing Stanton Energy Center site, located 12 miles southeast of Orlando, Florida. The Stanton Energy Center site was originally certified for an ultimate capacity of approximately 2,000 MW based on four coal-fired units. The existing Stanton Unit 1 is a 444 MW net coal-fired facility and Stanton 2 is a 446 MW net coal-fired generating facility. Stanton 1 was placed in operation on July 1, 1987 followed by Stanton 2 which was placed in operation on June 1, 1996. Stanton A will provide very economical power for the Florida Municipal Power Agency (FMPA or Agency) All-Requirements Project members with a minimal environmental impact. Stanton A will be a 2 x 1 GE 7FA combined cycle unit. The net output of the unit is estimated to be 633 MW at 70 F under new and clean conditions and will be jointly owned by Kissimmee Utility Authority (KUA), Orlando Utility Commission (OUC), FMPA and Southern Company – Florida LLC (Southern-Florida). FMPA will be a 10 percent joint owner of the 35 percent (221.6 MW) capacity to be owned by the utility applicants. FMPA's portion of generation from Stanton A will be approximately 22 MW. FMPA will also receive 10 percent of the 65 percent capacity owned by Southern-Florida and supplied under the power purchase agreement (PPA). Details specific to the project are presented in Volume 1A. This volume, Volume 1D, contains information specific to FMPA's need for the project.

FMPA strives to meet their responsibility to supply their member's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. FMPA is committed to meet its All-Requirements customers' needs and identify projects that will provide economical power to its members through the combination of demand-side and supply-side resources. Through the member cities, FMPA has been a strong supporter of conservation and demand-side programs where cost-effective. With FMPA's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

FMPA achieves savings through economy interchange and central dispatch which are obtained through participation in the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland, Kissimmee, and the FMPA All-Requirements Project.

FMPA's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with Stanton A. Stanton A will burn natural gas as the primary fuel with Selective Catalytic Reduction providing a very clean burning, highly efficient unit.

As discussed in the remainder of this application, FMPA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements.

FMPA believes that Stanton A represents the minimal cost and performance risk to its members due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be FMPA's most cost-effective through exhaustive evaluations as well as a thorough test of the marketplace.

1D.1.2 Summary

FMPA's All-Requirements has been growing rapidly through the addition of new members, with Lake Worth projected to join in 2002. FMPA's peak demand is projected to grow at a 1.8 percent average annual rate from 2000 through the end of the planning period in 2019. The projected load growth assumes no new members will join after Lake Worth in 2002.

FMPA uses an 18 percent summer reserve margin and a 15 percent winter reserve margin as reliability criterion. FMPA's reserve margin is projected to drop to 14.1 percent during the summer of 2003, dictating the need to add capacity.

FMPA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under both base and all but one sensitivity analysis.

1D.2.0 Description of System

The Florida Municipal Power Agency (FMPA) was created on February 24, 1978, by signing of the Interlocal Agreement among its 29 members, which specified the purposes and authority of FMPA. FMPA was formed under the provisions of Article VII, Section 10 of the Florida Constitution, Joint Power Act, which constitutes Chapter 361, Part II, as amended; and the Florida Interlocal Cooperation Act of 1969, which begins at Section 163.01 of the Florida Statutes, as amended. The Florida Constitution and the Joint Power Act provide the authority for municipal electric utilities to join together for the joint financing, construction, acquiring, managing, operating, utilizing, and owning of electric power plants. The Interlocal Cooperation Act authorizes municipal electric utilities to cooperate with each other on a basis of mutual advantage to provide services and facilities in a manner and in a form of governmental organization that will accord best with geographic, economic, population, and other factors influencing the needs and development of local communities.

Each city commission or authority which is a signatory to the Interlocal Agreement has the right to appoint one member to FMPA's Board of Directors, the governing body of the Agency. The Board has the responsibility for developing and approving the Agency's budget, hiring a General Manager, and establishing both bylaws which govern how the Agency operates and policies which implement such bylaws. At its annual meeting, the Board elects a Chairman, Vice Chairman, Secretary-Treasurer, Assistant Secretary-Treasurer, and Executive Committee. The Executive Committee consists of nine representatives elected by the Board plus the then current Chairman and Vice Chairman of the Board.

The Executive Committee meets regularly to control the Agency's day-to-day operations and approve expenditures and contracts. The Executive Committee is also responsible for assuring that budgeted expenditure levels are not exceeded and that authorized work is completed in a timely manner.

1D.2.1 Generation System

FMPA is a project-oriented, joint action agency where each project stands on its own. FMPA currently has five power supply projects in operation: (i) the St. Lucie Project, (ii) the Stanton I Project, (iii) the Tri-City Project, (iv) the All-Requirements Project (ARP), and (v) the Stanton II Project. Each of the projects is summarized in Subsections 1D.2.1.1 through 1D.2.1.5. Table 1D.2-1 provides a summary of the member participation for each project. Figure 1D.2-1 illustrates the location of the

Table 1D.2-1
Summary of Project Participants

Agency Member	St. Lucie Project	Stanton Project	Tri-City Project	All-Requirements Project	Stanton II Project
City of Alachua	X				
City of Bartow					
City of Bushnell				X	
City of Chattahoochee					
City of Clewiston	X			X	
City of Ft. Meade	X			X	
Ft. Pierce Utilities Authority	X	X	X	X	X
Gainesville Regional Utilities					
City of Green Cove Springs	X			X	
Town of Havana				X	
City of Homestead	X	X	X		X
City of Jacksonville Beach	X			X	
Key West City Electric System			X	X	X
Kissimmee Utility Authority	X	X			X
City of Lakeland					
City of Lake Worth	X	X		P (2002)	
City of Leesburg	X			X	
City of Moore Haven	X				
City of Mt. Dora					
City of Newberry	X			X	
City of New Smyrna Beach	X				
City of Ocala				X	
Orlando Utilities Commission					
City of Quincy					
City of St. Cloud					X
City of Starke	X	X		X	X
City of Vero Beach	X	X		X	X
City of Wauchula					
City of Williston					

P - Planned addition of new member.

FLORIDA MUNICIPAL POWER AGENCY

** All-Requirements Project Members*

FMPA member cities within Peninsular Florida. Table 1D.2-2 provides a summary of the existing FMPA generating facilities with project capacities combined where appropriate.

1D.2.1.1 St. Lucie Project

On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie 2 was declared in commercial operation August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the Agency's members are participants in the St. Lucie Project and eight of the fifteen (ten of the fifteen including the City of Lake Worth which is projected to become a member in 2002) are also members of the All-Requirements Project.

1D.2.1.2 Stanton Project

On August 13, 1984, the Agency purchased from Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton 1. Stanton 1 is a pulverized coal unit that went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project and three of the six are also members of the All-Requirements Project.

1D.2.1.3 Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton 1. Three of the Agency's members are participants in the Tri-City Project and two of the three are also members of the All-Requirements Project.

1D.2.1.4 Stanton II Project

On June 6, 1991, the Agency, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of the Agency's members are participants in the Stanton II Project and four of the seven are also members of the All-Requirements Project.

Table 1D.2-2
Florida Municipal Power Agency
Existing and Planned Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	FMPA Net Capability[1]		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Existing Generating Facilities												
St. Lucie	2	St. Lucie	N	N	None	08/83	Unknown	839.00	74.0	75.0	TK	None
Stanton Energy Center (SEC)	1	Orange	FS	C	None	07/87	Unknown	464.58	115.0	115.0	RR	None
	2		FS	C	None	06/96		464.58	122.0	122.0	RR	None
Indian River	CT A	Brevard	CT	NG	LO	06/89	Unknown	41.40	14.6	18.6	PL	TK
	CT B		CT	NG	LO	07/89	Unknown	41.40	14.6	18.6	PL	TK
	CT C		CT	NG	LO	08/92	Unknown	122.04	21.7	27.0	PL	TK
	CT D		CT	NG	LO	10/92	Unknown	122.04	21.7	27.0	PL	TK
Cane Island	1	Osceola	CT	NG	LO	01/95	Unknown	40.00	15.2	15.2	PL	TK
	2		CCT	NG	LO	06/95	Unknown	122.00	54.2	60.2	PL	TK
Stock Island	CT 2	Monroe	CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
	CT 3		CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
Planned Generating Facilities												
Cane Island	3	Osceola	CC	NG	LO	06/01 (planned)	Unknown	250.00	120	120	PL	TK
SEC[2]	1	Orange	FS	C	None	01/02	Unknown	464.58	10.1	10.1	RR	None
St. Lucie[2]	1	St. Lucie	N	N	None	01/02	Unknown	850.00	9.17	9.17	TK	None
	2					01/02	Unknown	839.00	9.17	9.17	TK	None
SEC	3	Orange	CC	NG	LO	10/03 (planned)	Unknown	633	20.8	22.6	PL	TK
McIntosh	4	Polk	FS	PET	C	06/05 (planned)	Unknown	288.00	100	100	TR	TR

[1] FMPA's ownership share. Does not include City of Newberry's capacity in St. Lucie 2.
[2] Result of addition of Lake Worth to ARP in January of 2002.
Source: FMPA Ten Year Site Plan April 2000.

1D.2.1.5 All-Requirements Project

The All-Requirements Project was formed on May 1, 1986, with five members; other members have joined through the years, and the total will be 14 members when the City of Lake Worth joins in 2001. The All-Requirements Project participants now consist of City of Bushnell, City of Clewiston, City of Fort Meade, Fort Pierce Utilities Authority, City of Green Cove Springs, Town of Havana, City of Jacksonville Beach, City of Key West, City of Leesburg, City of Newberry, Ocala Electric Utility, City of Starke, and City of Vero Beach. Table 1D.2-3 shows the date that each member joined the All-Requirements Project. Under the All-Requirements Project, the Agency currently serves all the power requirements (above certain excluded resources) for the members Table 1D.2-4 provides a summary of the existing and planned generating resources of the All-Requirements Project. This table does not include member generating resources. The member generating resources are shown in Table 1D.2-5. Table 1D.2-4 indicates approximately 18 MW of generating capacity from Crystal River 3 for the All-Requirements Project. This capacity in Crystal

Table 1D.2-3
Date ARP Member Joined

Agency Member	Date Member Joined
City of Bushnell	May 1, 1986
City of Clewiston	May 8, 1991
City of Fort Pierce Utilities Authority	January 1, 1998
City of Fort Meade	February 1, 2000
City of Green Cove Springs	May 1, 1986
City of Jacksonville Beach	May 1, 1986
Key West City Electric System	April 1, 1998
City of Vero Beach	June , 1997
City of Leesburg	May 1, 1986
City of Ocala	May 1, 1986
City of Starke	October 1, 1997
Town of Havana	July 1, 2000
City of Lake Worth	January 1,2002
City of Newberry	December 2000

Table 1D.2-4
FMPA All-Requirements Project Existing and Planned Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability[1]		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
St. Lucie	1	St. Lucie	N	N	None	05/76	Unknown	850.00	16.7	16.7	TK	None
	2		N	N	None	08/83	Unknown	839.00	18.3	18.3	TK	None
Crystal River	3	Citrus	N	N		03/77	Unknown	890.46	17.8	17.8		
Stanton Energy Center (SEC)	1	Orange	FS	C	None	07/87	Unknown	464.58	82.3	82.3	RR	None
	2		FS	C	None	06/96	Unknown	464.58	66.0	66.0	RR	None
Indian River	CT A	Brevard	CT	NG	LO	06/89	Unknown	41.40	14.6	18.6	PL	TK
	CT B		CT	NG	LO	07/89	Unknown	41.40	14.6	18.6	PL	TK
	CT C		CT	NG	LO	08/92	Unknown	122.04	21.7	27.0	PL	TK
	CT D		CT	NG	LO	10/92	Unknown	122.04	21.7	27.0	PL	TK
Cane Island	1	Osceola	CT	NG	LO	01/95	Unknown	40.00	15.2	15.2	PL	TK
	2		CCT	NG	LO	06/95	Unknown	122.00	54.2	60.2	PL	TK
Stock Island	CT 2	Monroe	CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
	CT 3		CT	LO	LO	06/99	Unknown	21.00	17.0	17.0	TK	TK
FMPA ARP Total Generation Capacity for 2000									377.0	401.6		
Cane Island	3	Osceola	CC	NG	LO	06/01 (planned)	Unknown	250.00	120	120	PL	TK
FMPA ARP Total Generation Capacity for 2001									497.0	401.6		
SEC[2]	1	Orange	FS	C	None	01/02	Unknown	464.58	10.1	10.1	RR	None
St. Lucie[2]	1	St. Lucie	N	N	None	01/02	Unknown	850.00	9.2	9.2	TK	None
	2					01/02	Unknown	839.00	9.2	9.2	TK	None
FMPA ARP Total Generation Capacity for 2002									525.5	550.1		
SEC[3]	A	Orange	CC	NG	LO	10/03 (planned)	Unknown	633	20.8	22.6	PL	TK
FMPA ARP Total Generation Capacity for 2003									525.5	550.1		
FMPA ARP Total Generation Capacity for 2004									525.5	550.1		
McIntosh	4	Polk	FS	PET	C	06/05 (planned)	Unknown	288.00	100	100	TR	TR
FMPA ARP Total Generation Capacity for 2005									625.5	650.1		
FMPA ARP Total Generation Capacity for 2006									625.5	650.1		

[1] FMPA All-Requirements Project members' ownership share.
[2] Result of addition of Lake Worth to ARP in January of 2002.
[3] SEC A's capacity has not been included in the total capacity available to FMPA.

Table 1D.2-5
FMPA All Requirements Project Existing Member Generating Facilities

Plant	Unit No.	Location (County)	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
H.D. King	7	St. Lucie	FS	NG	HO	01/64	Unknown	33.00	32.0	32.0	PL	TK
	8		FS	NG	HO	05/76	Unknown	56.116	50.0	50.0	PL	TK
	9		CCT	NG	LO	05/90	Unknown	30.895	31.0	31.0	PL	TK
	D1		D	LO	None	04/70	Unknown	2.75	2.5	2.5	TK	
	D2		D	LO	None	04/70	Unknown	2.75	2.5	2.5	TK	
Big Pine	1	Monroe	D	LO	None	02/69	Unknown	2.75	2.5	2.5	TK	
Cudjoe	2	Monroe	D	LO	None	08/68	Unknown	2.75	2.25	2.25	TK	
	3		D	LO		08/68	Unknown	2.30	2.25	2.25	TK	
Stock Island	CT1	Monroe	CT	LO	None	11/78	Unknown	23.45	20.0	23.0	WA	
	IC1		D	LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
	IC2		D	LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
	IC3		D	LO	None	01/65	Unknown	2.50	2.0	2.0	WA	
Medium Speed Diesel	IC4	Monroe	D	LO	None	06/91	Unknown	9.60	8.7	8.7	WA	
	IC5		D	LO	None	06/91	Unknown	9.60	8.7	8.7	WA	
Vero Beach	1	Indian River	FS	NG	HO	11/61	Unknown	12.50	12.0	13.0	PL	TK
	3		FS	NG	HO	09/71	Unknown	33.00	34.0	34.0	PL	TK
	4		FS	NG	HO	08/76	Unknown	55.00	56.0	56.0	PL	TK
	5		CCW	NG	LO	12/92	Unknown	57.90	47.5	54.5	PL	TK
FMPA ARP Total Generation Capacity for 2000									317.9	328.9		
FMPA ARP Total Generation Capacity for 2001									317.9	328.9		
Lake Worth* Tom G Smith	S-1	Palm Beach	FS	NG	HO	01/61	Unknown	7.50	7.0	8.0	PL	TK
	S-3		FS	NG	HO	11/67	Unknown	26.50	24.8	27.0	PL	TK
	MU1		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU2		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU3		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU4		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	MU5		D	LO	None	12/65	Unknown	2.00	1.8	2.0	TK	
	CT-1		CT	LO	None	12/76	Unknown	30.80	26.0	32.0	TK	
	S-5		CCW	NG	LO	03/78	Unknown	31.41	28.0	33.0	PL	TK
FMPA ARP Total Generation Capacity for 2002									412.8	438.9		

*Lake Worth anticipates joining ARP January of 2002.
Source: FMPA

River 3 is actually owned by several of the individual All-Requirements Project members, but FMPA is responsible for dispatching its capacity along with all other FMPA All-Requirement Project resources. Table 1D.2-5 indicates St. Lucie 2 generating capacity that is also actually owned by several of the individual All-Requirements Project members and is also dispatched by FMPA. Table 1D.2-5 also indicates capacity from St. Lucie 1. Certain All-Requirements Project members actually have ownership in St. Lucie 2, but power is supplied equally from St. Lucie 1 and 2 through a reliability exchange agreement. The Stanton 1 and 2 capacity shown in Table 1D.2-5 includes the capacity owned by individual members as well as the capacity owned directly by the All-Requirements Project itself.

The All-Requirements Project provides its members with all of their capacity and energy requirements above excluded resources that are the members' ownership in Crystal River 3 and St. Lucie 2. All-Requirements Project members which have joint ownership in other FMPA projects make available their joint ownership interests to the All-Requirements Project and the All-Requirements Project incorporates the capacity into the total project power supply. For All-Requirements Project members that own on-system generation, the All-Requirements Project purchases the capacity and energy from the on-system generation for use by the All-Requirements Project and then, in turn, supplies the members their full capacity and energy requirements. The All-Requirements Project members are responsible for maintenance and operation of their on-system generating units. The All-Requirements Project schedules the commitment and dispatch of the units. As a member of the Florida Municipal Power Pool (FMPP), the actual commitment and dispatch of units is conducted by FMPP for the All-Requirements Project.

1D.2.1.6 All-Requirements Project Participants

A brief description of each of the participants is provided in the following subsections. Table 1D.2-5 provides a summary of each member's existing generation sources.

1D.2.1.6.1 City of Bushnell. Bushnell, "Seat of Sumter County," is located in west central Florida, 55 miles from Orlando and 50 miles north of Tampa. The City operates under a Council-Manager form of government. Bushnell owns and operates its own electric and water system, the revenues from which are combined for financial purposes; thus, these utility services are integrated for purposes of the All-Requirements Power Supply Project Contract.

The City of Bushnell entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Energy is delivered through a delivery point in the City at 12 kV. Excluded Power Supply Resources for the City of Bushnell include only its partial ownership in FPC's

Crystal River 3 nuclear unit, which equals 0.0388 percent of that unit (or 306 kW based on current net summer rating).

The City of Bushnell's electric utility service area covers approximately 3 square miles and has a territorial agreement with a neighboring cooperative. Ninety-two percent of the customers served reside within the city limits.

1D.2.1.6.2 City of Clewiston. The City of Clewiston is located in Hendry County on the southwest tip of Lake Okeechobee, mid-way between West Palm Beach on the east and Fort Myers on the west. Clewiston is the headquarters of the United States Sugar Corporation. The City operates and maintains electric, water, and wastewater utilities.

The City of Clewiston purchased its electric system in May 1942, from U.S. Sugar Corporation. On May 8, 1991, Clewiston became an All-Requirements Project Participant. Excluded Power Supply Resources for the City of Clewiston include only its entitlement share in the Agency's St. Lucie Project (approximately 1,624 kW). The City's 138 kV transmission system interconnects with FPL. One substation supplies voltage at 12 kV to a predominantly overhead distribution system.

The City's electric utility service area encompasses approximately 8.5 square miles with 70 percent of the customers served residing within city limits. Clewiston has a territorial agreement with Glades Electric Cooperative and has a franchise from Hendry County to serve its current service area.

1D.2.1.6.3 City of Fort Pierce Utilities Authority. The City of Fort Pierce is located in St. Lucie County on the East Coast of Florida approximately 125 miles north of Miami. The Fort Pierce Utilities Authority was established in 1972 for the purpose of governing and operating the City's electric, water, wastewater, and natural gas distribution utilities as a separate unit of City government. The City Commission appoints Utility Authority Members to overlapping 4 year terms, and each Authority Member is limited to two consecutive terms of office. The Authority employs the Director of Utilities.

The Fort Pierce Utilities Authority owns and operates electric generating facilities capable of supplying a portion of its system requirements. The existing on-system capacity, which amounts to 119 MW (excluding units on extended cold standby), is primarily fueled by natural gas (99.85 percent) pursuant to a contract with Florida Gas Transmission Company (FGT). On January 1, 1998, Fort Pierce became an All-Requirements Project participant. Additionally, the Authority has the right to receive up to 11.217 MW from FMPA's St. Lucie Project. The Fort Pierce Utilities Authority is also a participant in FMPA's Stanton Project and Tri-City Project with a total interest of approximately 20 MW from Stanton 1 for both projects. Fort Pierce's electric utility service area encompasses approximately 40 square miles with 78 percent of electric utility

customers residing within the City limits. Fort Pierce's transmission system includes a 138 kV interconnection with FPL, a 138 kV line connecting Fort Pierce with the City of Vero Beach, and a 69 kV line completely looping the Fort Pierce service area. Six major substations supply voltage at 13 kV to a predominantly overhead distribution system.

1D.2.1.6.4 City of Fort Meade. The City of Fort Meade is located in Polk County along the Peace River and is the oldest town in that particular region of Florida, established in 1851. Its 5,600 citizens reside within an area of 4.5 square miles. The City operates under a commission/manager form of government that controls the delivery of essential services. The City became an All-Requirements Project member in February of 2000.

1D.2.1.6.5 City of Green Cove Springs. The City of Green Cove Springs is located on the St. John's River in Clay County, 26 miles south of Jacksonville. The City operates and maintains the electric, water, and wastewater utilities. The City operates under the City Council/Manager form of government. The five member City Council is elected at large and appoints the City Manager, who serves as the City's chief administrative officer and directs the operation of the City's utility service.

Green Cove Springs became an All-Requirements Project Participant when the project was originally implemented on May 1, 1986. The City's electric utility service area encompasses approximately 10 square miles with 85 percent of customers residing within city limits and 15 percent residing outside of city limits. The City has a territorial agreement with a neighboring cooperative utility.

1D.2.1.6.6 City of Jacksonville Beach. The City of Jacksonville Beach is located in Duval County approximately 18 miles east of Jacksonville. The City operates under the City Council/City Manager form of government. The City operates and maintains electric, water, and wastewater utility operations. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities.

Jacksonville Beach is predominantly a residential community whose citizens, for the most part, work in the metropolitan Jacksonville area. Additionally, the City is a major recreation area for the people of Duval County, Florida.

The City of Jacksonville Beach entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Jacksonville Beach include only its entitlement share in the Agency's St. Lucie Project (approximately 5,406 kW). Jacksonville Beach owns one 230 kV transmission substation that ties to Florida Power & Light and has available a transmission tie to Jacksonville Electric Authority. They also have 12 distribution substations, which deliver energy at 26 kV,

12 kV, and 4 kV levels. Approximately 50 percent of the distribution circuits are underground installations.

The City of Jacksonville Beach electric utility service area encompasses approximately 45 square miles including the neighboring town of Neptune Beach, and the unincorporated areas of Ponte Vedra and Palm Valley located in St. Johns County. Portions of this territory have been assigned to the City by the Florida PSC. Forty-four percent of the customers served reside within City limits.

1D.2.1.6.7 City of Key West Utilities Board. The City of Key West was first incorporated in 1828 and is the county seat of Monroe County, Florida. It is located near the southern extreme of the Florida keys, a string of coral islands extending in a southwesterly arc from Biscayne Bay to the Dry Tortugas, and lies further south than any other point in the continental United States. The Utility Board of the City of Key West operates the municipally owned electric generating and distribution system of the City. The Utility Board is composed of a chairman who is elected for a term of two years and four members who are elected for a term of four years by the voters of the City of Key West. The Utility Board employs the Manager of the Electric System.

The Utility Board operates and maintains the on-system electric generating facilities of the electric system which consist of diesel generating units and one combustion turbine generating unit, with a total capacity of 50.4 MW. On April 1, 1998, the Utility Board became a member of the All-Requirements Project. The Utility Board is also a participant in FMPA's Tri-City Project and Stanton II Project with entitlements of approximately 12 MW from Stanton Unit No. 1 and 10 MW from Stanton Unit No. 2.

The electric system currently uses No. 2 and No. 6 fuel oil for all of its on-system generation facilities. The generating units of the system are not capable of using alternative fuels.

Key West obtains a major portion of its power via a 138 kV transmission line that extends up the causeway through Florida Keys Electric Cooperative Association, Inc. (FKEC) service territory and ties in with FPL on the mainland. Key West's portion of this main transmission line consists of 46.11 miles of 138 kV overhead line from Key West's Stock Island Substation to FKEC's Marathon Key Substation. Subtransmission is provided in Key West through various 69 kV overhead transmission lines with an aggregate total of 15.2 miles. Transformation between the 138 kV and 69 kV transmission lines is obtained by a 105 MVA autotransformer at the Stock Island Substation.

Key West's distribution system is comprised of approximately 202 miles of 13.8 kV and 19 miles of three-phase equivalent 4.16 kV feeder lines from Key West's power generation units and substation power transformers. In order to reduce system

losses, Key West has an ongoing program to convert all of its 4.16 kV distribution lines to 13.8 kV.

Key West's service area consists of the lower Florida Keys, extending approximately 44 miles in an east-west direction from Pigeon Key, adjacent to the service area of FKEC to the City of Key West. Within its area, the electric system currently services the area between Ohio Key and the City. The FKEC and Key West have a Florida Public Service Commission approved territorial agreement.

Two additional 17.7 MW combustion turbines went into service at Key West's Stock Island Plant, and are owned by FMPA's All-Requirements Project.

1D.2.1.6.8 City of Leesburg. The City of Leesburg is located in Lake County, 41 miles north of Orlando and 36 miles south of Ocala. The City operates under a Commission/ Manager form of government. The five member City Commission is elected at large and employs the City Manager, who serves as the City's chief administrative officer. The City operates and maintains electric, water, sewer, and natural gas distribution utilities. Each of the City's utility operations is supervised by a Director.

The City of Leesburg entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Leesburg include its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 0.8244 percent of that unit (or 6,496 kW based on current net summer rating), and its entitlement in the Agency's St. Lucie Project (approximately 1,716 kW). The City owns four substations which convert the 69 kV voltage delivered by Florida Power Commission (FPC) down to the system distribution voltage of 13 kV. These substations and their attendant transmission systems completely loop the service area and assure dependable system operation. The city-owned distribution system has a 190 MVA capacity and delivers all the system energy at the 13 kV level. Approximately 15 percent of electric service is provided in underground circuits. A load management and SCADA system was installed during 1985.

The City's electric utility service area includes the incorporated cities of Leesburg and Fruitland Park and encompasses approximately 59 square miles with 40 percent of the customers served residing within the 23.5 square mile city limits of Leesburg. The City has received Florida PSC approval of a territorial agreement with FPC and the local electric cooperative.

1D.2.1.6.9 Ocala Electric Utility. The City of Ocala is located in Marion County near the geographic center of the State of Florida, approximately 35 miles south of Gainesville and 75 miles north of Orlando. The City operates under the City Council/City Manager form of government. The City operates and maintains electric,

water, and wastewater utility operations which are not integrated for purposes of the All-Requirements Power Supply Project Contract. As the Chief Administrative Officer, the City Manager appoints the Directors of Electric and Water Utilities.

The economy of Ocala and Marion County is diversified. The three major payroll classifications in the private sector are: services (tourism), manufacturing, and retail trade, in that order. Next are wholesale trade and construction. Agriculture and the thoroughbred horse industry are also major contributors to the area economy. As the center of retail trade for a four county area, the City of Ocala and Marion County have each experienced significant growth in both retail sales and in the number of establishments catering to the retail sector.

The City of Ocala entered into an All-Requirements Power Supply Project Contract with FMPA and became a full requirements customer of the Agency on May 1, 1986. Excluded Power Supply Resources for the City of Ocala include only its partial ownership in FPC's Crystal River 3 nuclear unit, which equals 1.3333 percent of that unit (or 10,504 kW based on current net summer rating). The City owns and operates its bulk power supply system which consists of 70 miles of 230 kV transmission line, three 230 kV to 69 kV substations, an 80 mile 69 kV transmission loop, and 15 distribution substations delivering power at 12 kV. The distribution system consists of approximately 800 miles of overhead lines and 100 miles of underground.

The City's service area encompasses approximately 171 square miles. The service area is generally rectangular in shape, extending approximately 21 miles east and west and 17 miles north and south. The City of Ocala has received Florida PSC approval of territorial agreements with Clay Electric Cooperative and Sumter Electric Cooperative. Sixty-one percent of the customers served reside within the City limits.

1D.2.1.6.10 City of Starke. The City of Starke, in Bradford County, is located in northeast Florida, approximately 50 miles southwest of the City of Jacksonville. The City, established in 1875, operates under the Mayor/Commissioner form of government. The City operates and maintains electric, water, sewer, and gas distribution utilities. An elected city clerk serves as the City's chief administrative officer, and utility operations are under the supervision of an appointed Electric System Director.

The City of Starke owns and operates electric distribution facilities. The City receives up to 1.634 MW from FMPA's St. Lucie Project and up to approximately 1.5 MW from FMPA's Stanton Project. In order to meet its total electric system requirements, the City is a member of the All-Requirements Project. The City has one 13 kV interconnection with FPL and one substation reduces this voltage to 4 kV for predominantly overhead delivery to electric system customers.

1D.2.1.6.11 City of Vero Beach. The City of Vero Beach, the county seat of Indian River County, is located on the East Coast of Florida midway between Miami and Jacksonville. The City was incorporated in 1919 and established a City Council/City Manager organization in 1951. The City Manager also serves as the Director of Utilities. The City owns and operates electric, water, and sewer utilities.

The City of Vero Beach owns and operates on-system electric generating facilities. The existing on-system capacity amounts to 150 MW (excluding units on extended cold standby) of oil and gas fired units predominantly fueled by natural gas. The City paid FGT to expand the fuel gas pipeline to allow the City's existing capacity to be totally gas fired. Natural gas is currently supplied pursuant to a contract with FGT. In addition to its existing on-system generating capacity, the City has entitlements of 11.214 MW of nuclear power and 20 MW of coal fired power from Stanton 1 from FMPA's St. Lucie and Stanton Projects, respectively. The City's 69 kV transmission system includes interconnections with FPL and the Fort Pierce Utilities Authority. The transmission system completely loops the service area, enhancing service reliability. Eight substations supply voltage at 13 kV to a predominantly overhead distribution system.

1D.2.1.6.12 Town of Havana. Located in Gadsden County, the Town of Havana is a small town approximately 12 miles north of Tallahassee with a population near 1,800. The Town of Havana has no generating capacity.

1D.2.1.6.13 City of Newberry. Located in Alchua County, the City of Newberry has nearly 1,700 residents. The City of Newberry has no generating capacity.

1D.2.1.6.14 City of Lake Worth. The City of Lake Worth is located in Palm Beach County on the East Coast of Florida, 7 miles south of West Palm Beach and 61 miles north of Miami. The City was incorporated in 1913 and has been supplying electric power to the area since 1916. The City of Lake Worth assumed the operation of, and all obligations for, the electric, water, and wastewater utilities in 1985 through state of Florida legislative action.

Lake Worth owns on-system electric generating facilities. The existing on-system winter capacity amounts to 13.8 MW (excluding units on extended cold standby), primarily fueled by natural gas (71 percent). Lake Worth purchases gas pursuant to a contract for interruptible gas service with Florida Public Utilities Company. Lake Worth has entitlements of 18.35 MW of nuclear power and approximately 10 MW of coal fired power from FMPA's St. Lucie and Stanton Projects, respectively. Lake Worth is interconnected with the transmission facilities of FPL and, through them, to the State transmission grid. Five 26 kV transmission lines presently serve nine 26/4 kV distribution substations; however, the distribution system in the western portion of the service area has been upgraded to 26 kV concurrent with the transmission system improvement

program and is served by a 138/26 kV substation. While the distribution system is predominantly overhead, new installations, serving platted developments, are installed underground. FMPA is planning for Lake Worth to join the All-Requirements Project in January of 2002.

1D.2.2 Purchased Power

FMPA currently has several power purchase contracts. These contracts exist with members as firm power purchases, from other utilities as firm power purchases, and from other utilities as partial requirements contracts. Subsections 1D.2.2.1 through 1D.2.2.3 outline the purchase power contracts in detail.

1D.2.2.1 Firm Power Purchases from All-Requirements Project Members

Generating members of the All-Requirements Project have firm purchase power contracts with FMPA for the purchase of capacity and energy from the members' generating units. Generating members of the All-Requirements Project consist of City of Vero Beach, City of Fort Pierce, and Key West City Utility Board. Table 1D.2-5 displays the generating units each of the member cities owns and operates. The total capacity of the firm power purchases from the generating members is 413 MW in summer and 439 MW in the winter after the addition of Lake Worth. FMPA is currently planning to add the City of Lake Worth as a member to the All-Requirements Project in 2002. Lake Worth will be a generating member at the time of addition. The generation capacity of Lake Worth's units is also shown in Table 1D.2-5.

1D.2.2.2 Firm Power Purchases from Other Utilities

The All-Requirements Project has ten firm purchase power contracts with other utilities. The contracts exist with Lake Worth, Gainesville Regional Utilities, Orlando Utility Commission, Tampa Electric Company, Lakeland Electric, and Florida Power and Light. Each of the firm purchase power contracts is discussed in detail below and displayed in Table 1D.2-6.

1D.2.2.2.1 Lake Worth. The All-Requirements Project currently has a firm power purchase for capacity and energy through 2001. The capacity is for 15 MW for the years 1998 through 2000 and for 10 MW in 2001. The contract falls under Schedule D of the interchange agreements.

Table 1D.2-6
FMPA Power Purchase Capacity

	2000		2001		2002		2003		2004		2005		2006		2007		2008		2009	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
FIRM POWER PURCHASE																				
TECO	150	150	150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC – Ind. River	93	93	93	93	71	71	50	50	28	28	6	6	0	0	0	0	0	0	0	0
OUC – Ind. River	37	37	37	37	37	37	37	37	37	37	37	37	22	22	0	0	0	0	0	0
OUC	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0	0	0	0	0	0
GRU	10	40	40	40	40	40	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stark	3	3	3	3	3	3	3	3	0	0	0	0	0	0	0	0	0	0	0	0
FPL	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Lakeland	0	0	50	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
FPL	0	0	0	0	0	75	75	75	75	75	75	75	75	75	75	75	0	0	0	0
Lake Worth[1]	15	15	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	373	403	448	348	316	391	330	330	285	285	263	263	242	242	220	220	145	145	145	145
PARTIAL REQUIREMENTS PURCHASE																				
FPC[2]	80	80	40	40	27	27	15	15	15	15	40	40	0	0	0	0	0	0	0	0
Total	80	80	40	40	27	27	15	15	15	15	40	40	0	0	0	0	0	0	0	0
TOTAL PURCHASE POWER																				
Total	453	483	488	388	343	418	345	345	300	300	303	303	242	242	220	220	145	145	145	145

[1]Lake Worth assumed to join FMPA January of 2002.
[2]Capacity varies based on the time of day. Maximum capacity available is listed.

Table 1D.2-6 (Continued)
FMPA Power Purchase Capacity

	2010		2011		2012		2013		2014		2015		2016		2017		2018		2019	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
FIRM POWER PURCHASE																				
TECO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC – Ind. River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC – Ind. River	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OUC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRU	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stark	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lakeland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FPL	45	45	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lake Worth	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	145	145	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PARTIAL REQUIREMENTS PURCHASE																				
FPC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
TOTAL PURCHASE POWER																				
Total	**145**	**145**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

1D.2.2.2.2 Gainesville Regional Utilities Contracts. The All-Requirements Project currently has two contracts with GRU for firm power purchase capacity and energy that total 43 MW for the summer period of 2000. The first contract for 3 MW is a firm power purchase contract that the All-Requirements Project took over with the addition of the City of Starke to the Project. This contract is for 3 MW annually until the year 2004, after which time FMPA does not plan on extending the contract. The second contract is for 40 MW through the year 2001.

1D.2.2.2.3 Orlando Utilities Commission Contracts. FMPA currently has three contracts with OUC for firm capacity and energy. The contracts extend through the year 2006 and total 150 MW for the summer period of 2000. The first contract is for 20 MW and extends through 2003. The second contract is for 93 MW through 2001. Thereafter, the capacity is decreased by 21.667 MW annually through 2005. The third contract is for 37 MW through 2005, decreasing to 22 MW in 2006. Table 1D.2-6 displays the contract capacities for these two purchases.

1D.2.2.2.4 Tampa Electric Company Contract. The All-Requirements Project currently has one contract with TECO for firm capacity and energy. The contract is through the month of March 2001. The contract specifies that 150 MW of capacity is available for 2000 until the contract is terminated.

1D.2.2.2.5 Lakeland Electric Contract. The All-Requirements Project currently has one contract with Lakeland for capacity and energy. The contract is for 50 MW through June 14, 2001, then 100 MW through December 15, 2010.

1D.2.2.2.6 Florida Power and Light Contracts. The All-Requirements Project currently has two contracts with FPL. The first existing contract is for 45 MW terminating end of 2010. The second contract is effective beginning June 2002 and terminates October 2009. Reserves are included with the capacity in both contracts.

1D.2.2.3 Partial Requirements Purchases

The All-Requirements Project has one partial requirements purchase from Florida Power Corporation (FPC), which varies from 80 MW in 2000 to 40 MW in 2005 after which it terminates. Tables 1D.2-7 and 1D.2-8 display the values for the partial requirements purchases.

1D.2.3 Committed Units

Currently, FMPA and Lakeland are planning to submit a Need for Power Application for the construction of McIntosh Unit 4. The McIntosh Unit 4 unit type has not yet been decided. Lakeland and FMPA are currently evaluating proposals received

Table 1D.2-7
All-Requirements Total Capacity - Summer (MW)

Year	All-Requirements Member Capacity	Generating Member Firm Purchases	Existing Firm Power Purchases	Partial Requirements Purchase	Total Capacity
2000	377.0	317.9	403.0	80.0	1,177.9
2001	497.0	317.9	348.0	40.0	1,202.9
2002	525.5	412.8	391.0	27.0	1,356.3
2003	525.5	412.8	330.0	15.0	1,283.3
2004	525.5	412.8	285.0	15.0	1,238.3
2005	625.5	412.8	263.0	40.0	1,341.3
2006	625.5	412.8	242.0	0.0	1,280.3
2007	625.5	412.8	220.0	0.0	1,258.3
2008	625.5	412.8	145.0	0.0	1,183.3
2009	625.5	412.8	145.0	0.0	1,183.3
2010	625.5	412.8	145.0	0.0	1,183.3
2011	625.5	412.8	0.0	0.0	1,038.3
2012	625.5	412.8	0.0	0.0	1,038.3
2013	625.5	412.8	0.0	0.0	1,038.3
2014	625.5	412.8	0.0	0.0	1,038.3
2015	625.5	412.8	0.0	0.0	1,038.3
2016	625.5	412.8	0.0	0.0	1,038.3
2017	625.5	412.8	0.0	0.0	1,038.3
2018	625.5	412.8	0.0	0.0	1,038.3
2019	625.5	412.8	0.0	0.0	1,038.3

Lake Worth Capacity included beginning 2002.
Proposed Stanton A not included.

Table 1D.2-8
All-Requirements Total Capacity - Winter (MW)

Year	All-Requirements Member Capacity	Generating Member Firm Purchases	Existing Firm Power Purchases	Partial Requirements Purchase	Total Capacity
1999/00	401.6	328.9	373.0	80.0	1,183.5
2000/01	401.6	328.9	448.0	40.0	1,218.5
2001/02	550.1	438.9	316.0	27.0	1,332.0
2002/03	550.1	438.9	330.0	15.0	1,334.0
2003/04	550.1	438.9	285.0	15.0	1,289.0
2004/05	550.1	438.9	263.0	40.0	1,292.0
2005/06	650.1	438.9	242.0	0.0	1,331.0
2006/07	650.1	438.9	220.0	0.0	1,309.0
2007/08	650.1	438.9	145.0	0.0	1,234.0
2008/09	650.1	438.9	145.0	0.0	1,234.0
2009/10	650.1	438.9	145.0	0.0	1,234.0
2010/11	650.1	438.9	0.0	0.0	1,089.0
2011/12	650.1	438.9	0.0	0.0	1,089.0
2012/13	650.1	438.9	0.0	0.0	1,089.0
2013/14	650.1	438.9	0.0	0.0	1,089.0
2014/15	650.1	438.9	0.0	0.0	1,089.0
2015/16	650.1	438.9	0.0	0.0	1,089.0
2016/17	650.1	438.9	0.0	0.0	1,089.0
2017/18	650.1	438.9	0.0	0.0	1,089.0
2018/19	650.1	438.9	0.0	0.0	1,089.0

Lake Worth Capacity included beginning 2002.
Proposed Stanton A not included.

from their Request for Proposal issued last summer. The nameplate capacity of the unit is currently unknown. Therefore, for modeling purposes, FMPA has assumed a 288 MW unit, in which Lakeland owns 188 MW and FMPA owns 100 MW. Field construction of McIntosh 4 is planned to start in June of 2002 with a commercial operation date of June 2005. For modeling purposes, FMPA has assumed the Pressurized Fluidized Bed Combined Cycle, as shown in Lakeland's 2000 Ten Year Site Plan. Petroleum coke was assumed as the primary fuel.

1D.2.4 Transmission System

Electric capacity and energy for the All-Requirements Project will be transmitted to the All-Requirements members utilizing the transmission systems of FPL, FPC, and OUC. FMPA divides the All-Requirements members into two categories: members east of Orlando that are served off of FPL's transmission system and members west of Orlando that are served off of FPC's transmission system. Members east of Orlando include: Jacksonville Beach, Green Cove Springs, Clewiston, Vero Beach, Starke, Fort Pierce, Key West, and Lake Worth. Members west of Orlando include Ocala, Leesburg, Bushnell, Ft. Meade, Havana, and Newberry.

Network transmission service for east members is provided under an existing agreement FMPA currently has in place with FPL. FMPA began purchasing network transmission service from FPL effective April 1, 1996, culminating a 6 year battle in the courts and regulatory forums. FMPA strived to obtain network service in order to integrate the operations of several members.

Network transmission for the west members is provided under an agreement with FPC. Network transmission service is also purchased under an agreement with OUC.

1D.3.0 Evaluation Criteria

1D.3.1 Economic Parameters

1D.3.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital cost and Operations and Maintenance (O&M) expenses is also assumed to be 2.5 percent.

1D.3.1.2 Bond Interest Rates

The long-term tax-exempt bond interest rate is assumed to be 6.0 percent. For smaller financing requirements, such as the Stanton A joint development project, FMPA can utilize the FMPA Pooled Loan Project, which has a 5.0 percent interest rate.

1D.3.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the 6.0 percent long-term bond interest rate.

1D.3.1.4 Interest During Construction

The interest during construction interest rate is assumed to be 6.0 percent.

1D.3.1.5 Levelized Fixed Charge Rate

FMPA plans to use the FMPA Pooled Loan Project for small financing requirements such as the equity portion of Stanton A. The fixed charge rate for the equity portion of Stanton A is merely the capital recovery factor over a 20 year period at the FMPA Pooled Loan Project interest rate of 5.0 percent or 8.02 percent.

For larger financing requirements, FMPA issues tax-exempt bonds. The fixed charge rate for these larger requirements is 8.602 percent based on a bond term of 30 years with a 6.0 percent bond interest rate, 2.9 percent bond issuance fee, a 1 year debt service reserve fund earning interest at the 6.0 percent bond interest rate, and one percent for insurance.

1D.4.0 Forecast of Demand and Energy

1D.4.1 Introduction

Under the All-Requirements Project structure, FMPA agrees to meet all of its members' power requirements. To secure sufficient capacity and energy, FMPA forecasts each of its members' loads on an individual basis and integrates the results into a FMPA forecast of electrical power demand and energy consumption. The forecast of electrical power demand and energy consumption includes current member cities plus cities that are planning to become members of the All-Requirements Project.

1D.4.2 Forecast Methodology

The load forecast attempts to predict peak capacity and total energy requirements of member cities over time. The forecast considers a number of variables including changes in population, historical trends, weather patterns, conservation programs, account types, economic conditions, and customer growth. Several techniques are utilized to develop certain portions of the load forecast including:

- Econometric modeling of member customer class requirements.
- Aggregate econometric modeling of system requirements.
- Statistical Analysis Techniques (time series, multiple regression, auto-regression, Box Jenkins).
- Incremental Load Analysis.
- Informed Judgement.

The FMPA forecasting process involves applying some or all of these methods to develop individual peak demand and energy requirement forecasts for each All-Requirements Project member. The forecast methodology varies from member to member to provide the most reliable forecast possible consistent with available data. Generally, FMPA uses Forecast Pro to forecast peak demand and energy requirement loads for its member cities. Forecast Pro is a commercially available software package that conducts econometric and other statistical analyses considering moving averages, exponential smoothing, Box-Jenkins, event models, and multiple level models. The model considers the statistical relevance of input variables and forecasts based on the highest correlation. The forecasts are then compared and checked for reasonableness by FMPA and any known unusual incremental load additions or reductions are integrated into the forecast.

1D.4.3 Base Case Load Forecast

The Town of Havana joined the All-Requirements Project on July 1, 2000. The City of Newberry joined the All-Requirements Project in December 2000. Both cities joined the All-Requirements Project after the load forecast was conducted and, therefore, are not included in FMPA's forecast. The Town of Havana's peak demand for 2000 was 6.0 MW, and the peak demand for the City of Newberry for 2000 was 7.0 MW. The high load forecast case, however, more than covers the addition of the Town of Havana and the City of Newberry with a 57 MW increase in peak demand for 2000.

1D.4.3.1 Net Energy for Load Forecast

FMPA forecasts net energy for load for each member taking into account all conservation programs that were active over the historical period. Once the net energy for load forecasts are compiled for all the member cities, the loads are integrated into an FMPA net energy for load forecast.

Table 1D.4-1 displays each member's net energy for load forecast for the planning horizon. The projected average annual growth rate (AAGR) for the base case including the addition of the City of Lake Worth in January of 2002 and Fort Meade in 2009 is 1.84 percent. The growth rate includes not only growth in the All-Requirements Project, but also the increased participation in the All-Requirements Project. For forecasts using regression analysis, the minimum coefficient of determination was 93 percent, implying a strong correlation of historical information.

1D.4.3.2 Summer Peak Demand Forecast

To forecast the summer peak demand for each member city, average annual summer load factors are determined from the historical information and applied to the forecasted net energy for load to arrive at the forecasted summer peak demand. The summer peak demands are for noncoincidental peak demand. For the forecast of summer peak demand for FMPA's All-Requirements Project, to consider diversity among the individual members, FMPA applies seasonal factors to the All-Requirement Project net energy for load forecast to arrive at the forecast.

Table 1D.4-2 shows the projected summer peak demand for the individual All-Requirements Project members. Table 1D.4-3 displays the FMPA forecasted summer peak demand for the base case and presents the projected demand reduction due to residential load management. The projected average annual growth rate (AAGR) for the base case including the addition of the City of Lake Worth in January of 2002 and Fort Meade in 2009 is 1.84 percent. The growth rate includes not only the projected growth in

Table 1D.4-1
All-Requirements Project Member Net Electric Load

Calendar Year	City of Bushnell (GWh)	City of Clewiston (GWh)	City of Fort Meade (GWh)	City of Fort Pierce (GWh)	City of Green Cove Springs (GWh)	City of Jacksonville Beach (GWh)	City of Key West (GWh)	City of Leesburg (GWh)	City of Ocala (GWh)	City of Starke (GWh)	City of Vero Beach (GWh)	City of Lake Worth (GWh)	Total[1, 2] (GWh)	Total With Transmission Losses[1, 2] (GWh)
Projected														
2000	24	126	43	585	119	735	702	476	1,256	75	733	418	4,831	4,903
2001	24	127	44	593	115	759	715	484	1,295	76	750	424	4,939	5,013
2002	25	129	44	601	118	783	728	492	1,322	77	766	430	5,470	5,552
2003	26	130	44	609	121	806	741	499	1,353	78	781	436	5,579	5,663
2004	26	132	44	617	124	828	753	507	1,382	79	796	441	5,684	5,769
2005	27	133	44	625	127	848	765	515	1,410	80	810	447	5,786	5,873
2006	27	135	44	631	130	868	775	523	1,436	81	823	452	5,880	5,968
2007	27	136	44	638	132	887	786	530	1,461	82	835	457	5,971	6,061
2008	28	138	44	644	134	906	795	538	1,484	83	847	463	6,059	6,150
2009	28	139	45	650	137	923	805	545	1,506	84	858	468	6,188	6,281
2010	29	140	45	656	139	940	814	553	1,527	85	868	473	6,269	6,363
2011	29	142	45	661	141	957	822	560	1,546	87	878	478	6,346	6,441
2012	29	143	45	666	142	973	830	568	1,564	88	887	483	6,418	6,514
2013	30	144	45	671	144	988	838	576	1,581	89	895	488	6,489	6,586
2014	30	146	45	676	146	1,003	845	583	1,596	90	903	493	6,556	6,654
2015	30	147	45	680	147	1,017	852	591	1,610	91	910	497	6,617	6,716
2016	30	149	45	684	149	1,031	858	598	1,623	92	916	502	6,677	6,777
2017	31	150	45	688	150	1,044	864	606	1,634	93	921	507	6,733	6,834
2018	31	151	46	691	151	1,056	869	613	1,644	94	926	512	6,784	6,886
2019	31	153	46	694	153	1,068	874	621	1,653	95	930	516	6,834	6,937

[1]Fort Meade's load included beginning 2009.
[2] Lake Worth's load included beginning January of 2002.
The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-2
ARP Member Summer Peak Demand (Noncoincident Demand Peak)

Calendar Year	City of Bushnell (MW)	City of Clewiston (MW)	City of Fort Meade[1] (MW)	City of Fort Pierce (MW)	City of Green Cove Springs (MW)	City of Jacksonville Beach (MW)	City of Key West (MW)	City of Leesburg (MW)	City of Ocala (MW)	City of Starke (MW)	City of Vero Beach (MW)	City of Lake Worth[2] (MW)
Historical												
1999	5.0	25.8	8.8	114.0	27.5	169.3	126.0	102.2	273.0	16.5	147.0	80.0
Projected												
2000	5.3	26.2	9.0	114.1	23.9	173.1	126.4	105.5	280.4	16.6	151.5	83.5
2001	5.4	26.5	9.1	115.7	24.1	178.8	128.8	107.2	289.0	16.9	155.0	84.7
2002	5.5	26.8	9.1	117.2	24.7	184.4	131.2	109.0	295.1	17.1	158.3	85.9
2003	5.6	27.1	9.1	118.8	25.4	189.8	133.4	110.7	301.9	17.4	161.5	87.0
2004	5.7	27.4	9.2	120.3	26.0	195.0	135.6	112.5	308.4	17.6	164.5	88.1
2005	5.8	27.7	9.2	121.7	26.6	199.8	137.7	114.3	314.7	17.9	167.4	89.2
2006	5.9	28.0	9.2	123.1	27.1	204.4	139.6	115.9	320.5	18.1	170.1	90.3
2007	6.0	28.3	9.2	124.3	27.6	208.8	141.5	117.6	326.0	18.3	172.7	91.4
2008	6.1	28.6	9.3	125.5	28.1	213.3	143.3	119.3	331.3	18.6	175.1	92.4
2009	6.2	28.9	9.3	126.7	28.5	217.4	144.9	120.9	336.2	18.8	177.4	93.4
2010	6.3	29.2	9.3	127.8	29.0	221.4	146.6	122.6	340.8	19.0	179.5	94.5
2011	6.4	29.5	9.3	128.9	29.4	225.4	148.1	124.3	345.1	19.3	181.5	95.5
2012	6.4	29.8	9.4	129.9	29.8	229.1	149.5	125.9	349.2	19.5	183.3	96.5
2013	6.5	30.1	9.4	130.8	30.1	232.7	150.9	127.6	352.9	19.8	185.0	97.5
2014	6.6	30.3	9.4	131.7	30.5	236.2	152.2	129.3	356.3	20.0	186.6	98.4
2015	6.6	30.6	9.4	132.5	30.8	239.5	153.4	130.9	359.4	20.2	188.0	99.4
2016	6.7	30.9	9.4	133.3	31.1	242.8	154.5	132.6	362.3	20.5	189.3	100.3
2017	6.7	31.2	9.5	134.0	31.4	245.8	155.6	134.3	364.8	20.7	190.4	101.3
2018	6.8	31.5	9.5	134.7	31.7	248.6	156.5	136.0	367.0	20.9	191.4	102.2
2019	6.8	31.8	9.5	135.3	31.9	251.4	157.4	137.6	369.0	21.2	192.3	103.1

[1]Fort Meade's load included beginning 2009.
[2] Lake Worth's load included beginning January of 2002.
The Town of Havana and the City of Newberry are not included in the forecast.

Table 1D.4-3
Forecast of Summer Peak Demand – Base Case

Year	Total Demand (MW)	Residential Load Management (MW)	Net Firm Demand (MW)
2000	996	4.0	992
2001	1,024	4.2	1,020
2002	1,123	4.5	1,119
2003	1,146	4.7	1,141
2004	1,168	4.8	1,163
2005	1,189	5.0	1,184
2006	1,209	5.1	1,204
2007	1,228	5.2	1,223
2008	1,246	5.3	1,241
2009	1,273	5.3	1,268
2010	1,290	5.0	1,285
2011	1,306	5.0	1,301
2012	1,322	5.0	1,317
2013	1,336	5.0	1,331
2014	1,350	5.0	1,345
2015	1,363	5.0	1,358
2016	1,376	5.0	1,371
2017	1,387	5.0	1,382
2018	1,398	5.0	1,393
2019	1,408	5.0	1,403

Forecast includes addition of Lake Worth beginning January of 2002 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

the current All-Requirements Project membership, but also includes the expected increased member city participation in the All-Requirements Project.

1D.4.3.3 Winter Peak Demand Forecast

Winter peak demand forecasts are conducted in a similar fashion to the summer peak demand forecast. To forecast the winter peak demand for each member city, average annual winter load factors are determined from the historical information and applied to the forecasted net energy for load to arrive at the forecasted winter peak demand. The winter peak demands are for non-coincidental peak demand. For the forecast of winter peak demand for FMPA's All-Requirements Project, considering diversity among the individual members, FMPA applies seasonal factors to the All-Requirements Project net energy for load forecast to arrive at the forecast. Because the City of Lake Worth is expected to join the All-Requirements Project in January of 2002, the demand for Lake Worth is not included in the forecast until the winter of 2002.

Table 1D.4-4 shows the projected winter peak demand for the individual All-Requirements Project members. Table 1D.4-5 displays the FMPA forecasted winter peak demand for the base case and presents the projected demand reduction due to residential load management. The projected average annual growth rate (AAGR) for the base case including the addition of the City of Lake Worth in January of 2002 and Fort Meade in 2009 is 1.85 percent. The growth rate includes not only the projected growth in the current All-Requirements Project membership, but also includes the expected increased member city participation in the All-Requirements Project.

1D.4.4 Sensitivities

Uncertainties in the assumptions for future conditions dictate the development of high and low band forecasts to ensure that the addition of Stanton A is the least cost option under alternative but reasonable conditions that might be encountered in the future.

The high load growth sensitivity assumes an initial value that is 2.9 percent higher than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is an increase in nominal projected growth of 100 percent of the base case increase for that year.

The low load growth sensitivity assumes an initial value that is 2.9 percent lower than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is a decrease in nominal projected growth of 50 percent of the base case increase for that year. The high and low forecasts are presented in Tables 1D.4-6 and 1D.4-7.

Table 1D.4-4
ARP Member Winter Peak Demand (Noncoincident Demand Peak)

Calendar Year	City of Bushnell (MW)	City of Clewiston (MW)	City of Fort Meade (MW)	City of Fort Pierce (MW)	City of Green Cove Springs (MW)	City of Jacksonville Beach (MW)	City of Key West (MW)	City of Leesburg (MW)	City of Ocala (MW)	City of Starke (MW)	City of Vero Beach (MW)	City of Lake Worth (MW)
Historical												
1999	5.8	22.2	11.7	121.0	27.2	172.5	97.0	95.1	247.7	14.6	151.0	74.0
Projected												
2000	5.8	22.2	11.8	128.5	26.9	180.2	101.9	94.9	235.6	13.4	169.1	78.9
2001	5.9	22.5	11.9	130.3	25.2	186.2	103.8	96.5	242.8	13.6	173.0	80.0
2002	6.0	22.7	11.9	132.0	25.9	192.0	105.7	98.1	247.9	13.8	176.7	81.1
2003	6.1	23.0	11.9	133.7	26.6	197.6	107.5	99.7	253.6	14.0	180.2	82.1
2004	6.3	23.3	11.9	135.4	27.2	203.1	109.3	101.3	259.1	14.2	183.6	83.2
2005	6.4	23.5	12.0	137.1	27.8	208.0	111.0	102.9	264.4	14.3	186.8	84.2
2006	6.5	23.8	12.0	138.6	28.4	212.8	112.6	104.4	269.3	14.5	189.8	85.3
2007	6.6	24.0	12.0	140.0	28.9	217.4	114.0	105.9	273.9	14.7	192.7	86.3
2008	6.7	24.3	12.0	141.4	29.4	222.0	115.5	107.4	278.3	14.9	195.4	87.2
2009	6.8	24.5	12.1	142.7	29.9	226.4	116.8	108.9	282.4	15.1	197.9	88.2
2010	6.9	24.8	12.1	143.9	30.3	230.5	118.1	110.4	286.3	15.3	200.3	89.2
2011	7.0	25.0	12.1	145.1	30.8	234.7	119.4	111.9	290.0	15.5	202.6	90.1
2012	7.0	25.2	12.2	146.2	31.2	238.6	120.5	113.4	293.4	15.7	204.6	91.1
2013	7.1	25.5	12.2	147.3	31.5	242.3	121.6	114.9	296.5	15.9	206.5	92.0
2014	7.2	25.7	12.2	148.3	31.9	246.0	122.7	116.4	299.4	16.1	208.3	92.9
2015	7.2	26.0	12.3	149.2	32.2	249.4	123.6	117.9	302.0	16.2	209.8	93.8
2016	7.3	26.2	12.3	150.1	32.6	252.7	124.5	119.4	304.4	16.4	211.3	94.7
2017	7.3	26.5	12.3	150.9	32.9	255.9	125.4	120.9	306.5	16.6	212.5	95.6
2018	7.4	26.7	12.4	151.7	33.1	258.9	126.2	122.4	308.4	16.8	213.7	96.5
2019	7.4	27.0	12.4	152.3	33.4	261.8	126.9	123.9	310.0	17.0	214.6	97.4

The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-5
Forecast of Winter Peak Demand – Base Case

Year	Total Demand (MW)	Residential Load Management (MW)	Net Firm Demand (MW)
2000	936	6.8	929
2001	1,026	7.2	1,019
2002	1,047	7.6	1,039
2003	1,068	7.9	1,060
2004	1,089	8.2	1,081
2005	1,109	8.5	1,101
2006	1,127	8.7	1,118
2007	1,145	8.9	1,136
2008	1,162	9.0	1,153
2009	1,191	9.0	1,182
2010	1,215	9.0	1,206
2011	1,230	9.0	1,221
2012	1,245	9.0	1,236
2013	1,258	9.0	1,249
2014	1,271	9.0	1,262
2015	1,284	9.0	1,275
2016	1,295	9.0	1,286
2017	1,306	9.0	1,297
2018	1,317	9.0	1,308
2019	1,326	9.0	1,317

Forecast includes addition of Lake Worth beginning January of 2002 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-6
Forecast of Summer and Winter Peak Demand with NEL– High Case

Year	Net Firm Summer Demand (MW)	Net Firm Winter Demand (MW)	Net Energy for Load (GWh)
2000	1,049	1,048	5,144
2001	1,098	1,089	5,298
2002	1,226	1,213	5,964
2003	1,271	1,256	6,182
2004	1,316	1,298	6,394
2005	1,357	1,337	6,596
2006	1,397	1,374	6,784
2007	1,435	1,409	6,968
2008	1,471	1,444	7,144
2009	1,515	1,489	7,365
2010	1,548	1,521	7,526
2011	1,581	1,551	7,680
2012	1,611	1,580	7,827
2013	1,640	1,608	7,967
2014	1,668	1,634	8,102
2015	1,694	1,659	8,226
2016	1,719	1,682	8,344
2017	1,742	1,704	8,456
2018	1,764	1,824	8,561
2019	1,784	1,743	8,657

Forecast includes addition of Lake Worth beginning January of 2001 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

Table 1D.4-7
Forecast of Summer and Winter Peak Demand with NEL– Low Case

Year	Net Firm Summer Demand (MW)	Net Firm Winter Demand (MW)	Net Energy for Load (GWh)
2000	943	816	4,622
2001	956	826	4,707
2002	1,043	905	5,166
2003	1,055	915	5,221
2004	1,066	926	5,274
2005	1,076	935	5,325
2006	1,086	944	5,372
2007	1,095	953	5,418
2008	1,104	962	5,462
2009	1,122	982	5,544
2010	1,131	990	5,584
2011	1,139	997	5,623
2012	1,146	1,005	5,660
2013	1,154	1,011	5,695
2014	1,160	1,048	5,729
2015	1,167	1,024	5,760
2016	1,173	1,030	5,790
2017	1,179	1,038	5,818
2018	1,184	1,041	5,844
2019	1,189	1,045	5,868

Forecast includes addition of Lake Worth beginning January of 2002 and Fort Meade beginning 2009.

The Town of Havana and City of Newberry are not included in the forecast.

The high demand growth sensitivity assumes a 1999 value that is 11.7 percent higher than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is an increase in nominal projected growth by 100 percent.

The low demand growth sensitivity assumes a 1999 value that is 11.7 percent lower than the base case value, as this has been the historical standard deviation from predicted values. For following years, there is a decrease in nominal projected growth by 50 percent. The high and low forecasts are also presented in Tables 1D.4-6 and 1D.4-7.

1D.5.0 Demand-Side Programs

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (PSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, FMPA has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the PSC approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

1D.5.1 Existing Conservation Programs

FMPA is a strong supporter of the conservation of electricity where cost-effective, and promotes such programs to its members. FMPA will continue to assist members in increasing the promotion and use of such conservation programs to retail customers and will assist its members in the evaluation of any new programs to ensure their cost-effectiveness. FMPA staff and member cities promote conservation programs through a number of methods including providing speakers on energy conservation matters to radio talk shows, civic clubs, churches, schools, and so forth. Additionally, bill inserts are utilized to keep customers aware of available conservation programs.

FMPA is also assisting in the development of renewable energy resources by participating in the Utility Photovoltaic Group (UPG). UPG is a non-profit organization formed to accelerate the commercialization of photovoltaic systems for the benefit of electric utilities and their customers.

The following is a combined list of conservation programs offered by FMPA members:

- Residential Energy Audits Program
- High-Pressure Sodium Outdoor Lighting Conservation
- Assistance for Commercial/ Industrial Audits
- Commercial Time-of-Use Program
- Natural Gas Promotion
- Fix-Up Program for the Elderly and Handicapped
- Residential Load Management Program

A brief description of each of the conservation programs is provided in the following subsections.

1D.5.1.1 Residential Energy Audits Program

Residential energy audits are offered to residential customers. The program offers walk-through audits to identify energy savings opportunities. Audits are conducted in accordance with FPSC rules. The audits consist of a walk-through Home Energy Survey with the following materials available upon customer request.

- Electric outlet gaskets
- Socket protectors
- Water flow restrictors
- Electric water heater jacket
- Low flow shower heads

Home Energy Surveys also include water heater temperature reduction and the installation of the water heater insulating blanket upon customer request. The Energy Star program has been incorporated and offered since October 1999.

1D.5.1.2 High Pressure Sodium Outdoor Lighting Conversion

This program involves eliminating mercury vapor street and yard lighting. The mercury vapor fixtures are converted whenever maintenance is required.

1D.5.1.3 Assistance for Commercial/ Industrial Audits

Free on-site audits are available to industrial and commercial customers with the intention of shifting demand from peak to off-peak periods. ESCO referral is also provided upon request.

1D.5.1.4 Commercial Time-of-Use Program

Time-of-Use rates are offered to commercial and industrial customers with the intention of shifting demand from peak to off-peak periods.

1D.5.1.5 Natural Gas Promotion

This program was established to replace older electric heat and water heaters with natural gas when the conversion would benefit the customers.

1D.5.1.6 Fix-Up Program for the Elderly and Handicapped

The program seeks and receives grants for the Community Block Development Program and Weatherization Program. This is a low-income program with participants as directed by the grants. Energy auditors recommend homes for the weatherization program.

1D.5.1.7 Residential Load Management Program

Residential Load Management Program is intended for customers that have electric water heaters, central air conditioning units, and central heating units. This program allows the city to regulate the usage of the appliances as a way to reduce weather sensitive peak demands. Two of the All-Requirements members currently have direct load control programs in place. The members are City of Ocala and City of Leesburg. The City of Leesburg's load management program was analyzed and started under the direction of the City. The City of Ocala's load management program was analyzed and started under the direction of FMPA. Savings from the two programs are shared among all All-Requirements members when activated.

1D.5.2 Analysis of Demand-Side Management Alternatives

The FIRE model evaluates the economic impact of conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

1D.5.2.1 FIRE Model Output

FIRE model results are presented in the form of three cost-effectiveness tests. All the DSM cost-effectiveness tests are based on the comparison of discounted present worth benefits to costs for a specific DSM measure. Each test is designed to measure costs and benefits from a different perspective.

The Total Resource Cost Test measures the benefit to cost ratio by comparing the total program benefits (both the participant's and the utility's) to the total program costs (equipment costs, supply costs, and participant costs).

The Participant's Test measures the impact of the DSM program on the participating customer. Benefits to the participant may include bill reductions, incentives paid, and tax credits. Participant's costs may include equipment costs, operation and maintenance expenses, equipment removal, etc. The Participant's Test is important because customers will not participate in a program unless it is beneficial to them.

The Rate Impact Test is a measure of the expected impact on customer rates resulting from a DSM program. The test statistic is the ratio of the utility's benefits (avoided supply costs and increased revenues) compared to the utility's costs (program costs, incentives paid, increased supply costs, and revenue losses). A value of less than one indicates an upward pressure an electricity rates as a result of the DSM program. FMPA views the Rate Impact Test as the primary test for determining the cost-effectiveness of a DSM measure on its system.

OUC used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8. The results of that analysis are as follows.

1D.5.2.2 FIRE Model Output Analysis

FMPA requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, FMPA has concluded that there are no cost-effective DSM measures reasonable available that would avoid or defer the need for Stanton A. Table 1D.5-1 presents the FIRE model results of the DSM analysis.

Table 1D.5-1
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.4	1.0	1.81
Commercial			
Off-Peak Battery Charging	0.53	0.02	0.49

The results of the DSM analysis are not surprising due to the previously performed analysis for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and FMPA for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand-Side Management Ten Year Plans for Orlando Utilities Commission (OUC) (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1D.6.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand plus maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development of the reliability criteria used by FMPA.

1D.6.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. FMPA utilizes an adjusted traditional reserve margin for planning purposes, which accounts for partial requirement and other purchases that include reserves. The methods are discussed below.

1D.6.1.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand}}$$

From the equation, it is seen that should the net capacity or net peak demand deviate from the predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. A weakness with the formula is that it does not indicate what the appropriate reserve margin is for a given system; the appropriate reserve level must be determined elsewhere. Nevertheless, given the nature of the FMPA All Requirements Project members (numerous members geographically dispersed) a modified version of this formula is used.

In establishing the appropriate reserve margin levels, FMPA considers the Florida Reliability Coordinating Council (FRCC) minimum planned reserve margin criteria of 15 percent. The Florida Public Service Commission (FPSC) has also established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Fla. Admin. Code, for the purposes of sharing responsibility for grid reliability. Consequently, FMPA has established a 15 percent minimum planned reserve margin criteria for the winter period, and has adopted a reserve margin of 18 percent in the summer. The formula used

by FMPA to calculate its reserve margin is based on the following formula which considers that the partial requirements purchases include their own reserves.

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand} - \text{Partial Requirements}}$$

1D.6.1.2 Loss of Load Probability

The second commonly-used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP) method. This method has the advantage in that it can result in a measure of how much capacity (and reserves) are needed to meet a target level of reliability (most utilities adopt a LOLP of one day in ten years). Given the unique nature of FMPA's geographically dispersed membership, it is not practical to use this method for its member cities and the adjusted traditional reserve margin method is used.

1D.6.2 Reliability Need

Table 1D.6-1 (winter) and 1D.6-2 (summer) compare FMPA's net system capacity with the peak demand during the forecast period. The tables display the reserve margin for both winter and summer assuming no capacity additions other than Cane Island 3 and the proposed McIntosh Unit 4, of which FMPA is assumed to receive 100 MW. The capacity required in order for FMPA to achieve its reserve margin requirements is also shown.

For the winter peak, the reserve margin is projected to fall below the required 15 percent in the winter of 2007/08. The reserve margin falls to 7.3 percent, creating an 85 MW deficit in that year. This deficit increases the next winter, with the system falling 119 MW below the level needed to maintain adequate reserves. By 2009/1010, the capacity deficit increases to 146 MW.

Summer reserve margins are expected to fall below the required 18 percent level by the summer of 2003. In 2003 the reserve margin would fall to an estimated 14.1 percent, which is equivalent to a 39 MW capacity shortfall. The deficit would increase to 325 MW by the summer of 2010 if no additional capacity is added.

Table 1D.6-1
Projected Reliability Levels - Winter/Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases That Contain Reserve Margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/(Deficit) to Maintain 15%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	401.6	656.9	125.0	0.0	1,183.5	935.8	929.0	30.6	31.7	126.1	133.9
2001	401.6	731.9	85.0	0.0	1,218.5	1,026.2	1,019.0	20.4	21.4	51.1	59.4
2002	550.1	709.9	72.0	0.0	1,332.0	1,046.6	1,039.0	29.3	30.3	139.2	148.0
2003	550.1	648.9	135.0	0.0	1,334.0	1,067.9	1,060.0	28.5	29.6	126.2	135.3
2004	550.1	603.9	135.0	0.0	1,289.0	1,089.2	1,081.0	20.9	22.0	56.7	66.1
2005	550.1	581.9	160.0	0.0	1,292.0	1,109.5	1,101.0	19.2	20.3	40.1	49.9
2006	650.1	560.9	120.0	0.0	1,331.0	1,126.7	1,118.0	20.3	21.3	53.3	63.3
2007	650.1	538.9	120.0	0.0	1,309.0	1,144.9	1,136.0	16.0	17.0	10.4	20.6
2008	650.1	538.9	45.0	0.0	1,234.0	1,162.0	1,153.0	6.4	7.3	-95.6	-85.2
2009	650.1	538.9	45.0	0.0	1,234.0	1,191.0	1,182.0	3.8	4.6	-128.9	-118.6
2010	650.1	538.9	45.0	0.0	1,234.0	1,215.0	1,206.0	1.6	2.4	-156.5	-146.2
2011	650.1	438.9	0.0	0.0	1,089.0	1,230.0	1,221.0	-11.5	-10.8	-325.5	-315.2
2012	650.1	438.9	0.0	0.0	1,089.0	1,245.0	1,236.0	-12.5	-11.9	-342.8	-332.4
2013	650.1	438.9	0.0	0.0	1,089.0	1,258.0	1,249.0	-13.4	-12.8	-357.7	-347.4
2014	650.1	438.9	0.0	0.0	1,089.0	1,271.0	1,262.0	-14.3	-13.7	-372.7	-362.3
2015	650.1	438.9	0.0	0.0	1,089.0	1,284.0	1,275.0	-15.2	-14.6	-387.6	-377.3
2016	650.1	438.9	0.0	0.0	1,089.0	1,295.0	1,286.0	-15.9	-15.3	-400.3	-389.9
2017	650.1	438.9	0.0	0.0	1,089.0	1,306.0	1,297.0	-16.6	-16.0	-412.9	-402.6
2018	650.1	438.9	0.0	0.0	1,089.0	1,317.0	1,308.0	-17.3	-16.7	-425.6	-415.2
2019	650.1	438.9	0.0	0.0	1,089.0	1,326.0	1,317.0	-17.9	-17.3	-435.9	-425.6

Table 1D.6-2
Projected Reliability Levels - Summer/Base Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Purchases That Contain Reserve Margin	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/(Deficit) to Maintain 18%	
						Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	377.0	675.9	125.0	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	85.0	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	147.0	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	135.0	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8
2004	525.5	577.8	135.0	0.0	1,238.3	1,167.8	1,163.0	6.8	7.3	-115.4	-109.7
2005	625.5	555.8	160.0	0.0	1,341.3	1,189.0	1,184.0	14.8	15.4	-32.9	-27.0
2006	625.5	534.8	120.0	0.0	1,280.3	1,209.1	1,204.0	6.5	7.0	-124.8	-118.8
2007	625.5	512.8	120.0	0.0	1,258.3	1,228.2	1,223.0	2.7	3.2	-169.4	-163.2
2008	625.5	512.8	45.0	0.0	1,183.3	1,246.3	1,241.0	-5.2	-4.8	-279.2	-273.0
2009	625.5	512.8	45.0	0.0	1,183.3	1,273.3	1,268.0	-7.3	-6.9	-311.1	-304.8
2010	625.5	512.8	45.0	0.0	1,183.3	1,290.0	1,285.0	-8.6	-8.2	-330.8	-324.9
2011	625.5	412.8	0.0	0.0	1,038.3	1,306.0	1,301.0	-20.5	-20.2	-502.8	-496.9
2012	625.5	412.8	0.0	0.0	1,038.3	1,322.0	1,317.0	-21.5	-21.2	-521.7	-515.8
2013	625.5	412.8	0.0	0.0	1,038.3	1,336.0	1,331.0	-22.3	-22.0	-538.2	-532.3
2014	625.5	412.8	0.0	0.0	1,038.3	1,350.0	1,345.0	-23.1	-22.8	-554.7	-548.8
2015	625.5	412.8	0.0	0.0	1,038.3	1,363.0	1,358.0	-23.8	-23.5	-570.0	-564.1
2016	625.5	412.8	0.0	0.0	1,038.3	1,376.0	1,371.0	-24.5	-24.3	-585.4	-579.5
2017	625.5	412.8	0.0	0.0	1,038.3	1,387.0	1,382.0	-25.1	-24.9	-598.4	-592.5
2018	625.5	412.8	0.0	0.0	1,038.3	1,398.0	1,393.0	-25.7	-25.5	-611.3	-605.4
2019	625.5	412.8	0.0	0.0	1,038.3	1,408.0	1,403.0	-26.3	-26.0	-623.1	-617.2

1D.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of FMPA's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine FMPA's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluations were discussed in 1D.5.0. The sensitivity analyses are discussed in Section 1D.8.0. The proposal evaluations were discussed in Section 1A.5.0.

1D.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. The program operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options while maintaining user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 18 percent. All capacity expansion plans were analyzed over a twenty-year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO was used to obtain the annual production cost for the expansion plan.

1D.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation were discussed in Section 1A.7.0. Table 1D.7-1 Summarizes the expansion alternatives considered for FMPA in the optimization study for supply-side alternatives.

Table 1D.7-1
Summary of FMPA Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal (50%)	256,581	212.5	3.73	14.17	Coal	9,979	3.0	30	2005
501F 2x1 CC (50%) (standard)	129,594[2]	257	3.68[3]	6.32[3]	Nat. Gas	7,074	1.0	14	2005
501F 1x1 CC (50%)	73,984	125	2.49	4.66	Nat. Gas	10,841	2.86	15	2005
7FA SC	76,681	156	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[4]	29,021[2]	61	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[4]	[redacted]	21	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	14	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. Mixed year dollars to reflect commercial operation date of October 1, 2003.
3. (2003 $)
4. Reflects FMPA's portion of total generation alternative capacity.
5. October 1, 2003.

1D.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7.0 and summarized in Table 1D.7-1. The expansion plan outlined in Table 1D.7-2 represents the least-cost capacity addition plan for FMPA under the base case scenario. The units comprising the least-cost capacity addition plan are listed in the table according to their year of commercial operation. Table 1D.7-3 displays the reserve margins for the base case after the construction of the generating resources identified.

Table 1D.7-4 provides the runner up to the least-cost expansion plan identified in Table 1D.7-2. Comparing the two plans indicates that the plan with the Southern-Florida joint development project is $33.9 million lower in cumulative present worth costs over the 20 year evaluation period.

Table 1D.7-2
FMPA Base Case Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,757	259,207
2002		156,804	398,762
2003	21 MW Joint Development with Southern-Florida (10/03)		
	40 MW Southern-Florida Power Purchase (10/03)	162,496	535,197
2004		162,960	664,276
2005		163,919	786,766
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	176,530	911,213
2007		186,719	1,035,392
2008		201,339	1,161,715
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	214,359	1,288,594
2010		227,656	1,415,716
2011		236,388	1,540,242
2012		249,955	1,664,462
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	258,513	1,785,663
2014	156 MW GE 7FA Simple Cycle (06/14)	273,844	1,906,784
2015		286,895	2,026,495
2016		300,114	2,144,634
2017		312,764	2,260,783
2018		327,658	2,375,576
2019		343,844	2,489,221

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.7-3
Projected Reliability Levels – Summer/Base Case with Expansion Plan Identified in Table 1D.7-2

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand (MW)		Reserve Margin (MW)		Excess / (Deficit) to Maintain 18 % Reserve Margin (MW)	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
2000	377.0	675.9	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	-44.3	-38.8
2004	546.3	616.5	0.0	1,297.8	1,167.8	1,163.0	12.6	13.1	-55.9	-50.3
2005	646.3	594.5	0.0	1,400.8	1,189.0	1,184.0	20.6	21.2	26.5	32.4
2006	887.3	573.5	0.0	1,580.8	1,209.1	1,204.0	34.1	34.8	175.6	181.6
2007	887.3	551.5	0.0	1,558.8	1,228.2	1,223.0	29.8	30.4	131.1	137.2
2008	887.3	551.5	0.0	1,483.8	1,246.3	1,241.0	19.8	20.3	21.2	27.5
2009	1,128.3	551.5	0.0	1,724.8	1,273.3	1,268.0	36.8	37.3	230.4	236.6
2010	1,128.3	551.5	0.0	1,724.8	1,290.0	1,285.0	34.9	35.5	210.7	216.6
2011	1,128.3	451.5	0.0	1,579.8	1,306.0	1,301.0	21.0	21.4	38.7	44.6
2012	1,128.3	451.5	0.0	1,579.8	1,322.0	1,317.0	19.5	20.0	19.8	25.7
2013	1,128.3	451.5	0.0	1,579.8	1,336.0	1,331.0	18.2	18.7	3.3	9.2
2014	1,268.3	412.8	0.0	1,681.1	1,350.0	1,345.0	24.5	25.0	88.1	94.0
2015	1,268.3	412.8	0.0	1,681.1	1,363.0	1,358.0	23.3	23.8	72.8	78.7
2016	1,268.3	412.8	0.0	1,681.1	1,376.0	1,371.0	22.2	22.6	57.4	63.3
2017	1,268.3	412.8	0.0	1,681.1	1,387.0	1,382.0	21.2	21.6	44.5	50.4
2018	1,268.3	412.8	0.0	1,681.1	1,398.0	1,393.0	20.3	20.7	31.5	37.4
2019	1,268.3	412.8	0.0	1,681.1	1,408.0	1,403.0	19.4	19.8	19.7	25.6

Table 1D.7-4
FMPA Base Case Runner Up Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,757	259,207
2002		156,804	398,762
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (61 MW)	162,560	535,250
2004		162,262	663,777
2005		163,268	785,780
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	175,957	909,823
2007		186,119	1,033,603
2008		200,800	1,159,587
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	214,044	1,286,279
2010		227,069	1,413,073
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	242,784	1,540,969
2012		263,715	1,672,027
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	272,567	1,799,817
2014		288,022	1,927,209
2015		296,887	2,051,090
2016		309,859	2,173,065
2017		320,074	2,291,929
2018		333,276	2,408,690
2019		346,421	2,523,187

Note: Capacity is stated at average annual temperature for FMPA.

1D.8.0 Sensitivity Analysis

FMPA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1D.8.1 through 1D.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1D.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1D.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1D.8-2 presents the runner-up expansion plan. The plan including joint development is $42.5 million lower than the plan with the self build alternative.

1D.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1D.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1D.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $2.9 million cumulative present worth savings over the self build plan.

1D.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1D.8-5 and Table 1D.8-6 presents the runner-up expansion plan. Under this scenario, the expansion plan with the joint development project is $49.8 million lower in cumulative present worth cost.

1D.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1D.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1D.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $73.4 million savings over the plan with the self build project.

1D.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1D.8-9 and Table 1D.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $61.6 million.

1D.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1D.8-11, the high load and energy growth scenario results in capacity shortfall beginning the summer of 2000. Since there are no capacity alternatives identified which can be placed in operation until Stanton A, it has been assumed that FMPA will purchase power on the spot market to make up the resultant deficits.

Table 1D.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1D.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is slightly higher in cost ($1.192 million) than the plan including self build alternative.

1D.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast until 2006. Nevertheless, for evaluation purposes, Table 1D.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1D.8-16 presents the runner-up expansion plan with the joint development and self build projects installed for October 1, 2003 commercial operation. The plan with the joint development project is slightly lower in cumulative present worth cost ($257,000) over the 20 year period.

1D.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but one of the sensitivity analyses. However, it should be noted that for the sensitivity scenario in which the self build alternative shows as the more cost-effective approach the margin is only slightly higher than $1 million. This cumulative present worth savings does not even compare to those provided by participation in the joint development project with Southern-Florida for the remaining five sensitivity cases.

Table 1D.8-1
FMPA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,641	260,040
2002		158,828	401,396
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	163,063	538,307
2004		168,952	672,133
2005		179,579	806,325
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,608	939,286
2007		202,252	1,073,795
2008		220,377	1,212,063
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	239,142	1,353,610
2010		257,178	1,497,217
2011		273,653	1,641,374
2012		290,694	1,785,840
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	309,331	1,930,867
2014	223 MW Pulverized Coal (06/14)	329,953	2,076,805
2015		352,569	2,223,920
2016		370,678	2,369,836
2017		386,208	2,513,260
2018		407,930	2,656,176
2019		440,095	2,801,633

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-2
FMPA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,641	260,040
2002		158,828	401,396
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	163,160	538,389
2004		168,268	671,673
2005		178,974	805,412
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,031	937,967
2007		201,683	1,072,097
2008		219,855	1,210,037
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	239,001	1,351,501
2010		256,449	1,494,701
2011	156 MW GE 7FA Simple Cycle (06/11)	284,316	1,644,475
2012		306,776	1,796,934
2013		323,703	1,948,699
2014		344,269	2,100,969
2015	223 MW Pulverized Coal (06/15)	359,749	2,251,080
2016		382,926	2,401,817
2017		399,545	2,550,194
2018		421,743	2,697,949
2019		442,193	2,844,100

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-3
FMPA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,933	258,429
2002		154,364	395,813
2003	21 MW Joint Development with Southern-Florida (10/03)	157,595	528,132
	40 MW Southern-Florida Power Purchase (10/03)		
2004		157,038	652,521
2005		160,704	772,609
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	165,021	888,942
2007		172,318	1,003,543
2008		181,148	1,117,198
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	192,538	1,231,160
2010		202,721	1,344,359
2011		206,273	1,453,021
2012		216,426	1,560,578
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	219,249	1,663,370
2014	125 MW WH 501F 1x1 Combined Cycle (06/14)	228,885	1,764,606
2015		237,544	1,863,725
2016		244,297	1,959,892
2017		249,001	2,052,362
2018		256,587	2,142,256
2019	125 MW WH 501F 1x1 Combined Cycle	273,177	2,232,545

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-4
FMPA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,933	258,429
2002		154,364	395,813
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	157,662	528,189
2004		156,355	652,037
2005		160,114	771,683
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	164,438	887,605
2007		171,721	1,001,809
2008		180,594	1,115,116
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	191,889	1,228,695
2010		201,108	1,340,992
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	211,245	1,452,273
2012		225,600	1,564,390
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	226,707	1,670,679
2014		233,198	1,773,822
2015		237,246	1,872,817
2016		243,417	1,968,637
2017		247,535	2,060,562
2018		254,250	2,149,637
2019		259,483	2,235,400

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		107,973	107,973
2001		122,212	223,267
2002		137,446	345,594
2003	21 MW Joint Development with Southern-Florida (10/03)	147,902	469,776
	40 MW Southern-Florida Power Purchase (10/03)		
2004		160,235	596,697
2005		171,057	724,521
2006	223 MW Pulverized Coal (06/06)	173,553	846,869
2007		181,503	967,579
2008		197,190	1,091,298
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	210,190	1,215,709
2010		221,539	1,339,416
2011		231,872	1,461,563
2012		241,643	1,581,652
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	250,179	1,698,946
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	265,093	1,816,196
2015		279,691	1,932,902
2016		290,045	2,047,077
2017		297,852	2,157,688
2018		310,437	2,266,448
2019		322,374	2,372,997

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-6
FMPA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		107,973	107,973
2001		122,212	223,267
2002		137,446	345,594
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	147,976	469,837
2004		159,558	596,223
2005		170,470	723,608
2006	223 MW Pulverized Coal (06/06)	172,990	845,558
2007		180,932	965,889
2008		196,751	1,089,332
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	211,155	1,214,315
2010		222,459	1,338,535
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	243,935	1,467,037
2012		264,948	1,598,708
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	266,618	1,723,709
2014		279,615	1,847,383
2015		287,928	1,967,525
2016		299,916	2,085,586
2017		308,507	2,200,154
2018		320,895	2,312,578
2019		333,329	2,422,748

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,008	251,814
2002		157,339	391,845
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	171,336	535,702
2004		188,702	685,172
2005		208,258	840,794
2006	223 MW Pulverized Coal (06/06)	208,995	988,127
2007		216,544	1,132,141
2008		242,358	1,284,199
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	258,258	1,437,061
2010		272,588	1,589,273
2011		300,453	1,747,548
2012		314,914	1,904,051
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	327,584	2,057,635
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	346,065	2,210,700
2015		363,253	2,362,273
2016		378,885	2,511,420
2017		390,292	2,656,360
2018		408,460	2,799,461
2019		426,851	2,940,541

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,008	251,814
2002		157,339	391,845
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	171,427	535,778
2004		188,233	684,876
2005		207,772	840,135
2006	223 MW Pulverized Coal (06/06)	208,696	987,258
2007		216,186	1,131,034
2008		242,136	1,282,953
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	260,925	1,437,395
2010		276,077	1,591,555
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	320,749	1,760,521
2012		350,327	1,934,623
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	347,233	2,097,419
2014		362,985	2,257,968
2015		374,974	2,414,432
2016		392,229	2,568,831
2017		405,094	2,719,268
2018		423,688	2,867,705
2019		442,536	3,013,969

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	*Generation Addition (month/year)*	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	170,076	533,988
2004		185,519	680,936
2005		203,173	832,758
2006	223 MW Pulverized Coal (06/06)	206,483	978,320
2007		216,679	1,122,424
2008		239,428	1,272,644
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	255,212	1,423,704
2010		268,656	1,573,720
2011		287,937	1,725,402
2012		299,714	1,874,350
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	309,454	2,019,435
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	325,133	2,163,241
2015		338,864	2,304,637
2016		349,809	2,442,339
2017		356,799	2,574,841
2018		369,030	2,704,128
2019		380,471	2,829,879

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	170,213	534,102
2004		185,052	680,680
2005		202,682	832,136
2006	223 MW Pulverized Coal (06/06)	206,152	977,465
2007		216,288	1,121,309
2008		239,135	1,271,345
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	257,042	1,423,488
2010		270,816	1,574,710
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	304,360	1,735,043
2012		328,714	1,898,404
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	327,786	2,052,083
2014		341,125	2,202,963
2015		348,776	2,348,495
2016		361,007	2,490,604
2017		369,657	2,627,881
2018		381,413	2,761,507
2019		393,338	2,891,510

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-11
FMPA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2000	1,049.0	0	0	377.0	800.9	1,177.9	151	189	(37.4)
2001	1,098.1	0	0	497.0	705.9	1,202.9	120	198	(77.6)
2002	1,226.0	0	0	525.5	830.8	1,356.3	157	221	(63.9)
2003	1,271.0	0	0	525.5	757.8	1,283.3	37	229	(192.2)
2004	1,316.0	0	0	525.5	712.8	1,238.3	0	237	(290.3)
2005	1,357.0	0	0	625.5	715.8	1,341.3	13	244	(231.2)
2006	1,397.0	0	0	625.5	654.8	1,280.3	0	251	(346.6)
2007	1,435.0	0	0	625.5	632.8	1,258.3	0	258	(413.4)
2008	1,471.0	0	0	625.5	557.8	1,183.3	0	265	(544.4)
2009	1,515.0	0	0	625.5	557.8	1,183.3	0	273	(596.3)
2010	1,548.0	0	0	625.5	557.8	1,183.3	0	279	(635.2)
2011	1,581.0	0	0	625.5	412.8	1,038.3	0	285	(827.3)
2012	1,611.0	0	0	625.5	412.8	1,038.3	0	290	(862.7)
2013	1,640.0	0	0	625.5	412.8	1,038.3	0	295	(896.9)
2014	1,668.0	0	0	625.5	412.8	1,038.3	0	300	(929.9)
2015	1,694.0	0	0	625.5	412.8	1,038.3	0	305	(960.6)
2016	1,719.0	0	0	625.5	412.8	1,038.3	0	309	(990.1)
2017	1,742.0	0	0	625.5	412.8	1,038.3	0	314	(1,017.3)
2018	1,764.0	0	0	625.5	412.8	1,038.3	0	318	(1,043.2)
2019	1,784.0	0	0	625.5	412.8	1,038.3	0	321	(1,066.8)

Table 1D.8-12
FMPA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		130,844	130,844
2001		163,286	284,887
2002		176,044	441,566
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	184,501	596,477
2004		190,479	747,354
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	191,154	890,195
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	209,917	1,038,178
2007		226,458	1,188,786
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	248,249	1,344,540
2009		268,488	1,503,458
2010		281,841	1,660,837
2011	223 MW Pulverized Coal (06/11)	305,528	1,821,785
2012		331,994	1,986,776
2013		342,014	2,147,125
2014		358,015	2,305,475
2015		370,177	2,459,937
2016		385,367	2,611,635
2017	125 MW WH 501F 1x1 Combined Cycle (06/17)	405,013	2,762,043
2018		427,567	2,911,838
2019		441,760	3,057,846

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-13
FMPA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		130,844	130,844
2001		163,286	284,887
2002		176,044	441,566
2003	21 MW Joint Development with Southern-Florida (10/03)	184,416	596,405
	40 MW Southern-Florida Power Purchase (10/03)		
2004		191,016	747,707
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	191,782	891,017
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	210,421	1,039,356
2007		227,087	1,190,382
2008	156 MW GE 7FA Simple Cycle (06/08)	247,424	1,345,619
2009		266,026	1,503,079
2010		279,648	1,659,232
2011	223 MW Pulverized Coal (06/11)	301,732	1,818,181
2012		325,800	1,980,094
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	336,885	2,138,039
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	358,012	2,296,388
2015		377,844	2,454,049
2016		394,292	2,609,260
2017		406,124	2,760,080
2018		435,508	2,912,658
2019		442,888	3,059,038

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-14
FMPA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 18% Reserve Margin (MW)
2000	943.0	0	0	377.0	800.9	1,177.9	257.4	170	87.7
2001	959.6	0	0	497.0	705.9	1,202.9	258.6	173	85.9
2002	1,043.0	0	0	525.5	830.8	1,356.3	339.8	188	152.0
2003	1,055.0	0	0	525.5	757.8	1,283.3	252.6	190	62.7
2004	1,066.0	0	0	525.5	712.8	1,238.3	196.6	192	4.7
2005	1,076.0	0	0	625.5	715.8	1,341.3	294.1	194	100.4
2006	1,086.0	0	0	625.5	654.8	1,280.3	215.9	195	20.4
2007	1,095.0	0	0	625.5	632.8	1,258.3	184.9	197	(12.2)
2008	1,104.0	0	0	625.5	557.8	1,183.3	87.4	199	(111.3)
2009	1,122.0	0	0	625.5	557.8	1,183.3	69.4	202	(132.6)
2010	1,131.0	0	0	625.5	557.8	1,183.3	60.4	204	(143.2)
2011	1,139.0	0	0	625.5	412.8	1,038.3	0	205	(305.7)
2012	1,146.0	0	0	625.5	412.8	1,038.3	0	206	(314.0)
2013	1,154.0	0	0	625.5	412.8	1,038.3	0	208	(323.4)
2014	1,160.0	0	0	625.5	412.8	1,038.3	0	209	(330.5)
2015	1,167.0	0	0	625.5	412.8	1,038.3	0	210	(338.8)
2016	1,173.0	0	0	625.5	412.8	1,038.3	0	211	(345.8)
2017	1,179.0	0	0	625.5	412.8	1,038.3	0	212	(352.9)
2018	1,184.0	0	0	625.5	412.8	1,038.3	0	213	(358.8)
2019	1,189.0	0	0	625.5	412.8	1,038.3	0	214	(364.7)

Table 1D.8-15
FMPA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,241	234,135
2002		140,565	359,238
2003	21 MW Joint Development with Southern-Florida (10/03)	141,789	478,287
	40 MW Southern-Florida Power Purchase (10/03)		
2004		144,551	592,785
2005		143,507	700,021
2006		152,672	807,649
2007		161,203	914,858
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	172,282	1,022,950
2009		181,922	1,130,630
2010		188,597	1,235,941
2011	223 MW Pulverized Coal (06/11)	205,143	1,344,008
2012		221,344	1,454,009
2013		225,881	1,559,911
2014		231,453	1,662,283
2015		237,165	1,761,244
2016		245,615	1,857,929
2017		250,954	1,951,125
2018		260,216	2,042,290
2019		267,895	2,130,833

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-16
FMPA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,241	234,135
2002		140,565	359,238
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	141,891	478,373
2004		143,852	592,317
2005		142,864	699,073
2006		152,068	806,275
2007		160,596	913,080
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	171,711	1,020,814
2009		181,352	1,128,156
2010		188,069	1,233,173
2011	223 MW Pulverized Coal (06/11)	204,675	1,340,994
2012		220,962	1,450,805
2013		225,931	1,556,730
2014		233,238	1,659,891
2015		238,714	1,759,498
2016		247,087	1,856,763
2017		252,383	1,950,489
2018		261,532	2,042,115
2019		269,201	2,131,090

Note: Capacity is stated at average annual temperature for FMPA.

1D.9.0 Financial Analysis

FMPA is a project oriented, joint-action agency and, therefore, relies on debt financing to fund capital additions to its system. The All-Requirements Project is planning to use the FMPA Pooled Loan Project to obtain the financing for FMPA's 3.5 percent equity share of Stanton A. The FMPA Pooled Loan Project is a financing pool in which participating members can obtain loans for electric system projects. The All-Requirements Project can borrow up to $10 million at an interest rate of approximately
5 percent for a period of 20 years.

The All-Requirements Project is financially sound and could obtain traditional tax-exempt bond financing if it chose to do so for Stanton A. FMPA's bonds are Ambac insured with an AAA rating. For fiscal 2000, the All-Requirements Project had operating revenues of $226.2 million with a net operating income of $8.6 million.

Appendix 1D.A
Economic Evaluation Spreadsheets

Florida Municipal Power Agency

Case

Scenario: Southern-Florida FMPA Base

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
GE 7FA SC	156	76,681	12	2014.417	111,323	9,576

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,695	10,062	0	0	147,757	0	147,757	259,207
2002	144,902	11,902	0	0	156,804	0	156,804	398,762
2003	148,867	12,646	807	(30)	162,290	206	162,496	535,197
2004	145,360	13,691	3,203	(119)	162,135	825	162,960	664,276
2005	145,203	14,805	3,205	(119)	163,094	825	163,919	786,766
2006	146,361	17,372	4,234	(120)	167,847	8,683	176,530	911,213
2007	148,601	18,940	5,004	(120)	172,423	14,296	186,719	1,035,392
2008	160,600	21,513	5,052	(121)	187,043	14,296	201,339	1,161,715
2009	162,750	22,768	6,205	(122)	191,601	22,758	214,359	1,288,594
2010	168,033	23,861	7,081	(122)	198,853	28,803	227,656	1,415,716
2011	175,053	25,474	7,181	(123)	207,585	28,803	236,388	1,540,242
2012	187,575	26,417	7,284	(123)	221,152	28,803	249,955	1,664,462
2013	195,599	27,363	6,873	(124)	229,710	28,803	258,513	1,785,663
2014	206,390	28,310	4,879	(124)	239,455	34,389	273,844	1,906,784
2015	214,100	29,200	5,341	(125)	248,516	38,379	286,895	2,026,495
2016	225,888	30,498	5,474	(126)	261,735	38,379	300,114	2,144,634
2017	237,751	31,149	5,611	(126)	274,385	38,379	312,764	2,260,783
2018	251,430	32,225	5,752	(127)	289,279	38,379	327,658	2,375,576
2019	266,570	33,128	5,895	(128)	305,465	38,379	343,844	2,489,221

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA Base

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,695	10,062	0	0	147,757	0	147,757	259,207
2002	144,902	11,902	0	0	156,804	0	156,804	398,762
2003	148,900	12,646	325	13	161,884	677	162,560	535,250
2004	145,503	13,669	333	51	159,556	2,706	162,262	663,777
2005	145,386	14,783	341	53	160,562	2,706	163,268	785,780
2006	146,599	17,365	1,375	54	165,393	10,564	175,957	909,823
2007	148,798	18,938	2,151	55	169,942	16,177	186,119	1,033,603
2008	160,852	21,510	2,204	57	184,623	16,177	200,800	1,159,587
2009	168,106	22,179	2,687	58	193,030	21,014	214,044	1,286,279
2010	176,356	23,121	3,063	59	202,599	24,470	227,069	1,413,073
2011	185,631	23,951	3,588	61	213,232	29,552	242,784	1,540,969
2012	201,664	24,804	4,003	62	230,533	33,182	263,715	1,672,027
2013	197,724	26,935	5,321	64	230,044	42,523	272,567	1,799,817
2014	204,330	28,096	6,336	66	238,827	49,195	288,022	1,927,209
2015	212,092	29,040	6,494	67	247,693	49,195	296,887	2,051,090
2016	223,656	30,283	6,656	69	260,665	49,195	309,859	2,173,065
2017	232,788	31,198	6,823	71	270,880	49,195	320,074	2,291,929
2018	244,680	32,336	6,993	72	284,082	49,195	333,276	2,408,690
2019	256,832	33,152	7,168	74	297,226	49,195	346,421	2,523,187

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Southern-Florida FMPA High Fuel

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
Pulverized Coal	223	256,581	42	2014.417	388,463	33,416

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,579	10,062	0	0	148,641	0	148,641	260,040
2002	146,935	11,892	0	0	158,828	0	158,828	401,396
2003	149,567	12,513	807	(30)	162,857	206	163,063	538,307
2004	151,495	13,548	3,203	(119)	168,127	825	168,952	672,133
2005	159,368	16,300	3,205	(119)	178,753	825	179,579	806,325
2006	158,569	17,243	4,234	(120)	179,925	8,683	188,608	939,286
2007	164,255	18,818	5,004	(120)	187,956	14,296	202,252	1,073,795
2008	179,396	21,755	5,052	(121)	206,081	14,296	220,377	1,212,063
2009	187,372	22,928	6,205	(122)	216,383	22,758	239,142	1,353,610
2010	197,445	23,971	7,081	(122)	228,375	28,803	257,178	1,497,217
2011	211,809	25,982	7,181	(123)	244,850	28,803	273,653	1,641,374
2012	227,721	27,010	7,284	(123)	261,891	28,803	290,694	1,785,840
2013	245,878	27,902	6,873	(124)	280,529	28,803	309,331	1,930,867
2014	244,903	29,734	7,145	(124)	281,658	48,295	329,953	2,076,805
2015	250,030	31,144	9,302	(125)	290,351	62,218	352,569	2,223,920
2016	266,659	32,393	9,534	(126)	308,460	62,218	370,678	2,369,836
2017	281,039	33,304	9,773	(126)	323,989	62,218	386,208	2,513,260
2018	301,283	34,538	10,017	(127)	345,712	62,218	407,930	2,656,176
2019	332,457	35,280	10,268	(128)	377,877	62,218	440,095	2,801,633

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA High Fuel

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
GE 7FA SC	156	76,681	12	2011.417	103,374	8,892
Pulverized Coal	223	256,581	42	2015.417	398,174	34,251

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,579	10,062	0	0	148,641	0	148,641	260,040
2002	146,935	11,892	0	0	158,828	0	158,828	401,396
2003	149,636	12,513	807	13	162,484	677	163,160	538,389
2004	151,635	13,548	3,203	51	165,562	2,706	168,268	671,673
2005	159,588	16,300	3,205	53	176,268	2,706	178,974	805,412
2006	158,780	17,243	4,234	54	177,467	10,564	188,031	937,967
2007	164,474	18,818	5,004	55	185,506	16,177	201,683	1,072,097
2008	179,662	21,755	5,052	57	203,678	16,177	219,855	1,210,037
2009	192,940	22,928	6,205	58	217,987	21,014	239,001	1,351,501
2010	205,419	23,971	7,081	59	231,980	24,470	256,449	1,494,701
2011	226,607	25,982	7,181	61	254,659	29,657	284,316	1,644,475
2012	244,068	27,010	7,284	62	273,415	33,362	306,776	1,796,934
2013	259,826	27,902	6,873	64	290,342	33,362	323,703	1,948,699
2014	279,412	29,734	7,145	66	310,907	33,362	344,269	2,100,969
2015	269,717	31,144	9,302	67	306,407	53,342	359,749	2,251,080
2016	274,441	32,393	9,534	69	315,313	67,613	382,926	2,401,817
2017	289,975	33,304	9,773	71	331,932	67,613	399,545	2,550,194
2018	310,762	34,538	10,017	72	354,130	67,613	421,743	2,697,949
2019	329,909	35,280	10,268	74	374,580	67,613	442,193	2,844,100

Notes

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Southern-Florida FMPA Low Fuel

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 1x1	125	73,984	23	2014.417	109,072	9,382
WH 501F 1x1	125	73,984	23	2019.417	123,406	10,615

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,867	10,066	0	0	146,933	0	146,933	258,429
2002	142,073	12,291	0	0	154,364	0	154,364	395,813
2003	143,859	12,753	807	(30)	157,389	206	157,595	528,132
2004	139,125	14,004	3,203	(119)	156,213	825	157,038	652,521
2005	140,441	16,352	3,205	(119)	159,879	825	160,704	772,609
2006	134,440	17,785	4,234	(120)	156,338	8,683	165,021	888,942
2007	133,658	19,481	5,004	(120)	158,022	14,296	172,318	1,003,543
2008	140,544	21,377	5,052	(121)	166,852	14,296	181,148	1,117,198
2009	141,179	22,517	6,205	(122)	169,779	22,758	192,538	1,231,160
2010	143,237	23,722	7,081	(122)	173,918	28,803	202,721	1,344,359
2011	144,983	25,428	7,181	(123)	177,470	28,803	206,273	1,453,021
2012	154,206	26,257	7,284	(123)	187,623	28,803	216,426	1,560,578
2013	156,427	27,271	6,873	(124)	190,446	28,803	219,249	1,663,370
2014	161,889	27,951	4,893	(124)	194,609	34,276	228,885	1,764,606
2015	165,226	28,893	5,365	(125)	199,359	38,185	237,544	1,863,725
2016	170,666	30,072	5,499	(126)	206,112	38,185	244,297	1,959,892
2017	174,498	30,808	5,637	(126)	210,816	38,185	249,001	2,052,362
2018	180,774	31,977	5,778	(127)	218,402	38,185	256,587	2,142,256
2019	190,098	32,361	6,469	(128)	228,800	44,377	273,177	2,232,545

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA Low Fuel

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,867	10,066	0	0	146,933	0	146,933	258,429
2002	142,073	12,291	0	0	154,364	0	154,364	395,813
2003	143,913	12,736	325	13	156,985	677	157,662	528,189
2004	139,286	13,979	333	51	153,649	2,706	156,355	652,037
2005	140,660	16,354	341	53	157,408	2,706	160,114	771,683
2006	134,664	17,781	1,375	54	153,874	10,564	164,438	887,605
2007	133,861	19,477	2,151	55	155,544	16,177	171,721	1,001,809
2008	140,779	21,377	2,204	57	164,417	16,177	180,594	1,115,116
2009	146,344	21,786	2,687	58	170,875	21,014	191,889	1,228,695
2010	151,025	22,491	3,063	59	176,638	24,470	201,108	1,340,992
2011	154,193	23,851	3,588	61	181,693	29,552	211,245	1,452,273
2012	163,594	24,759	4,003	62	192,418	33,182	225,600	1,564,390
2013	149,915	27,434	6,771	64	184,184	42,523	226,707	1,670,679
2014	146,054	29,013	8,870	66	184,003	49,195	233,198	1,773,822
2015	148,919	29,972	9,092	67	188,051	49,195	237,246	1,872,817
2016	153,640	31,194	9,319	69	194,223	49,195	243,417	1,968,637
2017	156,543	32,174	9,552	71	198,340	49,195	247,535	2,060,562
2018	162,156	33,036	9,791	72	205,055	49,195	254,250	2,149,637
2019	166,000	34,178	10,036	74	210,288	49,195	259,483	2,235,400

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case
Scenario: Southern-Florida FMPA AEO

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	101,705	6,268	0	0	107,973	0	107,973	107,973
2001	111,995	10,218	0	0	122,212	0	122,212	223,267
2002	125,685	11,762	0	0	137,446	0	137,446	345,594
2003	134,364	12,555	807	(30)	147,696	206	147,902	469,776
2004	142,841	13,486	3,203	(119)	159,410	825	160,235	596,697
2005	150,963	16,183	3,205	(119)	170,232	825	171,057	724,521
2006	133,144	18,252	5,453	(120)	156,729	16,823	173,553	846,869
2007	126,112	20,125	7,136	(120)	153,252	28,251	181,503	967,579
2008	139,184	22,638	7,237	(121)	168,939	28,251	197,190	1,091,298
2009	141,310	23,844	8,445	(122)	173,477	36,713	210,190	1,215,709
2010	144,644	24,882	9,378	(122)	178,782	42,758	221,539	1,339,416
2011	153,086	26,616	9,535	(123)	189,114	42,758	231,872	1,461,563
2012	161,661	27,652	9,696	(123)	198,886	42,758	241,643	1,581,652
2013	169,499	28,701	9,346	(124)	207,421	42,758	250,179	1,698,946
2014	174,766	29,927	8,194	(124)	212,761	52,332	265,093	1,816,196
2015	180,244	31,100	9,302	(125)	220,521	59,170	279,691	1,932,902
2016	189,058	32,407	9,534	(126)	230,874	59,170	290,045	2,047,077
2017	195,679	33,356	9,773	(126)	238,681	59,170	297,852	2,157,688
2018	206,800	34,577	10,017	(127)	251,267	59,170	310,437	2,266,448
2019	217,412	35,652	10,268	(128)	263,203	59,170	322,374	2,372,997

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA AEO

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	12	2013.417	183,051	15,746

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	101,705	6,268	0	448	0	0	107,973	107,973
2001	111,995	10,218	0	381	0	0	122,212	223,267
2002	125,685	11,762	0	351	0	0	137,446	345,594
2003	134,409	12,554	325	481	13	677	147,976	469,837
2004	142,998	13,470	333	547	51	2,706	159,558	596,223
2005	151,205	16,166	341	718	53	2,706	170,470	723,608
2006	133,392	18,245	2,594	604	54	18,704	172,990	845,558
2007	126,338	20,124	4,283	605	55	30,132	180,932	965,889
2008	139,542	22,631	4,390	705	57	30,132	196,751	1,089,332
2009	147,906	23,296	4,927	695	58	34,969	211,155	1,214,315
2010	154,604	24,012	5,359	810	59	38,424	222,459	1,338,535
2011	169,397	25,028	5,942	1,200	61	43,507	243,935	1,467,037
2012	185,181	26,153	6,415	1,330	62	47,137	264,948	1,598,708
2013	174,537	27,901	7,794	2,043	64	56,322	266,618	1,723,709
2014	178,463	29,333	8,870	1,667	66	62,883	279,615	1,847,383
2015	185,630	30,256	9,092	1,542	67	62,883	287,928	1,967,525
2016	196,136	31,508	9,319	1,815	69	62,883	299,916	2,085,586
2017	203,595	32,406	9,552	1,692	71	62,883	308,507	2,200,154
2018	214,711	33,437	9,791	1,618	72	62,883	320,895	2,312,578
2019	225,836	34,501	10,036	1,867	74	62,883	333,329	2,422,748

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Southern-Florida FMPA OUC + AEO

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,723	10,284	0	0	140,008	0	140,008	251,814
2002	145,527	11,812	0	0	157,339	0	157,339	391,845
2003	157,642	12,711	807	(30)	171,130	206	171,336	535,702
2004	170,934	13,860	3,203	(119)	187,877	825	188,702	685,172
2005	188,055	16,291	3,205	(119)	207,433	825	208,258	840,794
2006	167,744	19,094	5,453	(120)	192,171	16,823	208,995	988,127
2007	160,047	21,231	7,136	(120)	188,293	28,251	216,544	1,132,141
2008	183,083	23,907	7,237	(121)	214,107	28,251	242,358	1,284,199
2009	188,223	24,998	8,445	(122)	221,544	36,713	258,258	1,437,061
2010	194,627	25,948	9,378	(122)	229,830	42,758	272,588	1,589,273
2011	221,448	26,835	9,535	(123)	257,696	42,758	300,453	1,747,548
2012	234,724	27,860	9,696	(123)	272,156	42,758	314,914	1,904,051
2013	246,667	28,938	9,346	(124)	284,827	42,758	327,584	2,057,635
2014	255,573	30,091	8,194	(124)	293,733	52,332	346,065	2,210,700
2015	263,713	31,192	9,302	(125)	304,082	59,170	363,253	2,362,273
2016	277,766	32,540	9,534	(126)	319,715	59,170	378,885	2,511,420
2017	288,039	33,436	9,773	(126)	331,121	59,170	390,292	2,656,360
2018	304,754	34,645	10,017	(127)	349,289	59,170	408,460	2,799,461
2019	321,785	35,757	10,268	(128)	367,681	59,170	426,851	2,940,541

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case
Scenario: Self Build FMPA OUC + AEO

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,723	10,284	0	0	140,008	0	140,008	251,814
2002	145,527	11,812	0	0	157,339	0	157,339	391,845
2003	157,705	12,708	325	13	170,750	677	171,427	535,778
2004	171,296	13,846	333	51	185,527	2,706	188,233	684,876
2005	188,401	16,271	341	53	205,066	2,706	207,772	840,135
2006	168,248	19,096	2,594	54	189,992	18,704	208,696	987,258
2007	160,476	21,241	4,283	55	186,054	30,132	216,186	1,131,034
2008	183,656	23,902	4,390	57	212,004	30,132	242,136	1,282,953
2009	196,411	24,561	4,927	58	225,956	34,969	260,925	1,437,395
2010	206,837	25,397	5,359	59	237,653	38,424	276,077	1,591,555
2011	245,826	25,413	5,942	61	277,242	43,507	320,749	1,760,521
2012	270,132	26,580	6,415	62	303,190	47,137	350,327	1,934,623
2013	254,563	28,335	7,794	64	290,756	56,478	347,233	2,097,419
2014	261,319	29,581	8,870	66	299,836	63,150	362,985	2,257,968
2015	272,159	30,507	9,092	67	311,825	63,150	374,974	2,414,432
2016	287,861	31,829	9,319	69	329,079	63,150	392,229	2,568,831
2017	299,699	32,622	9,552	71	341,944	63,150	405,094	2,719,268
2018	316,932	33,743	9,791	72	360,539	63,150	423,688	2,867,705
2019	334,520	34,757	10,036	74	379,387	63,150	442,536	3,013,969

Notes:

[1] Includes start-up costs

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water

Florida Municipal Power Agency

Case
Scenario: Southern-Florida FMPA No Real

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed [2] ($1,000)	Fees and Credits [3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,433	10,285	0	0	139,717	0	139,717	251,540
2002	144,959	11,950	0	0	156,909	0	156,909	391,188
2003	156,195	12,898	807	(30)	169,870	206	170,076	533,988
2004	167,660	13,950	3,203	(119)	184,694	825	185,519	680,936
2005	182,845	16,416	3,205	(119)	202,348	825	203,173	832,758
2006	165,238	19,087	5,453	(120)	189,659	16,823	206,483	978,320
2007	160,200	21,212	7,136	(120)	188,428	28,251	216,679	1,122,424
2008	180,184	23,877	7,237	(121)	211,177	28,251	239,428	1,272,644
2009	185,202	24,973	8,445	(122)	218,499	36,713	255,212	1,423,704
2010	190,746	25,897	9,378	(122)	225,898	42,758	268,656	1,573,720
2011	208,945	26,822	9,535	(123)	245,180	42,758	287,937	1,725,402
2012	219,536	27,848	9,696	(123)	256,957	42,758	299,714	1,874,350
2013	228,536	28,939	9,346	(124)	266,696	42,758	309,454	2,019,435
2014	234,649	30,083	8,194	(124)	272,801	52,332	325,133	2,163,241
2015	239,322	31,195	9,302	(125)	279,694	59,170	338,864	2,304,637
2016	248,732	32,498	9,534	(126)	290,639	59,170	349,809	2,442,339
2017	254,564	33,418	9,773	(126)	297,628	59,170	356,799	2,574,841
2018	265,354	34,615	10,017	(127)	309,860	59,170	369,030	2,704,128
2019	275,427	35,734	10,268	(128)	321,300	59,170	380,471	2,829,879

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA No Real

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,433	10,285	0	0	139,717	0	139,717	251,540
2002	144,959	11,950	0	0	156,909	0	156,909	391,188
2003	156,304	12,895	325	13	169,536	677	170,213	534,102
2004	168,018	13,943	333	51	182,346	2,706	185,052	680,680
2005	183,182	16,401	341	53	199,976	2,706	202,682	832,136
2006	165,706	19,093	2,594	54	187,447	18,704	206,152	977,465
2007	160,610	21,208	4,283	55	186,156	30,132	216,288	1,121,309
2008	180,678	23,878	4,390	57	209,003	30,132	239,135	1,271,345
2009	192,603	24,485	4,927	58	222,073	34,969	257,042	1,423,488
2010	201,733	25,241	5,359	59	232,392	38,424	270,816	1,574,710
2011	229,472	25,379	5,942	61	260,853	43,507	304,360	1,735,043
2012	248,492	26,607	6,415	62	281,577	47,137	328,714	1,898,404
2013	235,148	28,302	7,794	64	271,309	56,478	327,786	2,052,083
2014	239,406	29,634	8,870	66	277,976	63,150	341,125	2,202,963
2015	245,907	30,561	9,092	67	285,627	63,150	348,776	2,348,495
2016	256,737	31,732	9,319	69	297,857	63,150	361,007	2,490,604
2017	264,211	32,673	9,552	71	306,507	63,150	369,657	2,627,881
2018	274,680	33,720	9,791	72	318,264	63,150	381,413	2,761,507
2019	285,239	34,839	10,036	74	330,188	63,150	393,338	2,891,510

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA High Load

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2005.417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal	223	256,581	42	2011.417	360,726	31,030
WH 501F 1x1	125	73,984	23	2017.417	117,459	10,104

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,515	10,771	0	0	163,286	0	163,286	284,887
2002	163,022	13,022	0	0	176,044	0	176,044	441,566
2003	169,249	14,239	325	13	183,825	677	184,501	596,477
2004	171,547	15,842	333	51	187,773	2,706	190,479	747,354
2005	161,062	18,325	1,341	53	180,781	10,372	191,154	890,195
2006	162,262	20,772	3,123	54	186,211	23,706	209,917	1,038,178
2007	170,426	22,715	3,943	55	197,139	29,319	226,458	1,188,786
2008	179,488	26,011	5,118	57	210,674	37,575	248,249	1,344,540
2009	191,383	27,550	6,025	58	225,016	43,472	268,488	1,503,458
2010	203,108	29,026	6,176	59	238,369	43,472	281,841	1,660,837
2011	203,301	31,723	8,870	61	243,955	61,573	305,528	1,821,785
2012	212,916	33,585	10,929	62	257,492	74,502	331,994	1,986,776
2013	221,139	35,107	11,202	64	267,512	74,502	342,014	2,147,125
2014	235,427	36,538	11,482	66	283,513	74,502	358,015	2,305,475
2015	245,739	38,099	11,769	67	295,675	74,502	370,177	2,459,937
2016	258,937	39,796	12,064	69	310,865	74,502	385,367	2,611,635
2017	270,580	41,081	12,886	71	324,617	80,396	405,013	2,762,043
2018	286,514	42,790	13,584	72	342,961	84,606	427,567	2,911,838
2019	298,848	44,309	13,924	74	357,155	84,606	441,760	3,057,846

Notes

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Southern-Florida FMPA High Load

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833	[redacted]	
WH 501F 2x1	257	129,241	24	2005.417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
GE 7FA SC	156	76,681	12	2008.417	95,993	8,257
Pulverized Coal	223	256,581	42	2011.417	360,726	31,030
WH 501F 2x1	257	129,241	23	2014.417	190,537	16,390

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,515	10,771	0	0	163,286	0	163,286	284,887
2002	163,022	13,022	0	0	176,044	0	176,044	441,566
2003	169,186	14,247	807	(30)	184,209	206	184,416	596,405
2004	171,257	15,849	3,203	(119)	190,190	825	191,016	747,707
2005	160,860	18,344	4,206	(119)	183,290	8,491	191,782	891,017
2006	161,958	20,775	5,982	(120)	188,595	21,825	210,421	1,039,356
2007	169,876	22,703	7,191	(120)	199,649	27,438	227,087	1,190,382
2008	181,898	25,813	7,579	(121)	215,169	32,255	247,424	1,345,619
2009	195,433	27,327	7,692	(122)	230,330	35,696	266,026	1,503,079
2010	207,560	28,707	7,807	(122)	243,952	35,696	279,648	1,659,232
2011	206,194	31,400	10,465	(123)	247,936	53,796	301,732	1,818,181
2012	213,359	33,353	12,486	(123)	259,075	66,725	325,800	1,980,094
2013	223,236	34,843	12,205	(124)	270,160	66,725	336,885	2,138,039
2014	234,332	36,394	11,125	(124)	281,726	76,286	358,012	2,296,388
2015	244,510	38,037	12,306	(125)	294,729	83,115	377,844	2,454,049
2016	259,005	39,683	12,614	(126)	311,176	83,115	394,292	2,609,260
2017	269,145	41,060	12,929	(126)	323,008	83,115	406,124	2,760,080
2018	297,003	42,264	13,253	(127)	352,393	83,115	435,508	2,912,658
2019	302,149	44,168	13,584	(128)	359,773	83,115	442,888	3,059,038

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Southern-Florida FMPA Low Load

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011.417	360,726	31,030

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,881	9,360	0	0	133,241	0	133,241	234,135
2002	129,660	10,905	0	0	140,565	0	140,565	359,238
2003	129,669	11,138	807	(30)	141,583	206	141,789	478,287
2004	128,251	12,391	3,203	(119)	143,726	825	144,551	592,785
2005	126,341	13,255	3,205	(119)	142,682	825	143,507	700,021
2006	133,877	14,881	3,208	(120)	151,847	825	152,672	807,649
2007	141,111	16,176	3,212	(120)	160,378	825	161,203	914,858
2008	140,274	18,757	4,292	(121)	163,201	9,081	172,282	1,022,950
2009	142,419	19,546	5,101	(122)	166,944	14,978	181,922	1,130,630
2010	148,281	20,308	5,151	(122)	173,619	14,978	188,597	1,235,941
2011	142,003	22,441	7,743	(123)	172,064	33,079	205,143	1,344,008
2012	141,972	23,791	9,696	(123)	175,336	46,008	221,344	1,454,009
2013	146,156	24,496	9,346	(124)	179,874	46,008	225,881	1,559,911
2014	153,488	25,137	6,945	(124)	185,445	46,008	231,453	1,662,283
2015	158,332	25,832	7,118	(125)	191,158	46,008	237,165	1,761,244
2016	165,536	26,900	7,296	(126)	199,607	46,008	245,615	1,857,929
2017	170,136	27,458	7,479	(126)	204,947	46,008	250,954	1,951,125
2018	178,290	28,380	7,666	(127)	214,209	46,008	260,216	2,042,290
2019	184,949	29,209	7,857	(128)	221,887	46,008	267,895	2,130,833

Notes:

* FMPA assumed to finance the Southern-Florida project at a 8.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency

Case

Scenario: Self Build FMPA Low Load

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011.417	360,726	31,030

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,881	9,360	0	0	133,241	0	133,241	234,135
2002	129,660	10,905	0	0	140,565	0	140,565	359,238
2003	129,741	11,136	325	13	141,215	677	141,891	478,373
2004	128,388	12,375	333	51	141,146	2,706	143,852	592,317
2005	126,518	13,246	341	53	140,158	2,706	142,864	699,073
2006	134,083	14,876	350	54	149,362	2,706	152,068	806,275
2007	141,303	16,174	358	55	157,890	2,706	160,596	913,080
2008	140,491	18,758	1,444	57	160,749	10,962	171,711	1,020,814
2009	142,629	19,547	2,259	58	164,493	16,859	181,352	1,128,156
2010	148,528	20,307	2,316	59	171,211	16,859	188,069	1,233,173
2011	142,304	22,437	4,914	61	169,716	34,959	204,675	1,340,994
2012	142,356	23,781	6,873	62	173,073	47,889	220,962	1,450,805
2013	146,428	24,505	7,045	64	178,042	47,889	225,931	1,556,730
2014	152,850	25,213	7,221	66	185,350	47,889	233,238	1,659,891
2015	157,458	25,898	7,402	67	190,825	47,889	238,714	1,759,498
2016	164,562	26,980	7,587	69	199,198	47,889	247,087	1,856,763
2017	169,080	27,567	7,777	71	204,495	47,889	252,383	1,950,489
2018	177,143	28,457	7,971	72	213,643	47,889	261,532	2,042,115
2019	183,745	29,322	8,170	74	221,312	47,889	269,201	2,131,090

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010142-EM EXHIBIT NO 1 (Part 5 of 1)
COMPANY/
WITNESS: Orlando Utilities Commission
DATE: 4-23-01

1A.2.0 Overview and Summary

1A.2.1 Overview

Stanton A will be the third unit installed at the Stanton Energy Center site located approximately 12 miles southeast of Orlando, Florida. Stanton A is being planned for a nominal net generating capacity of 633 MW at 70° F based on new and clean conditions.

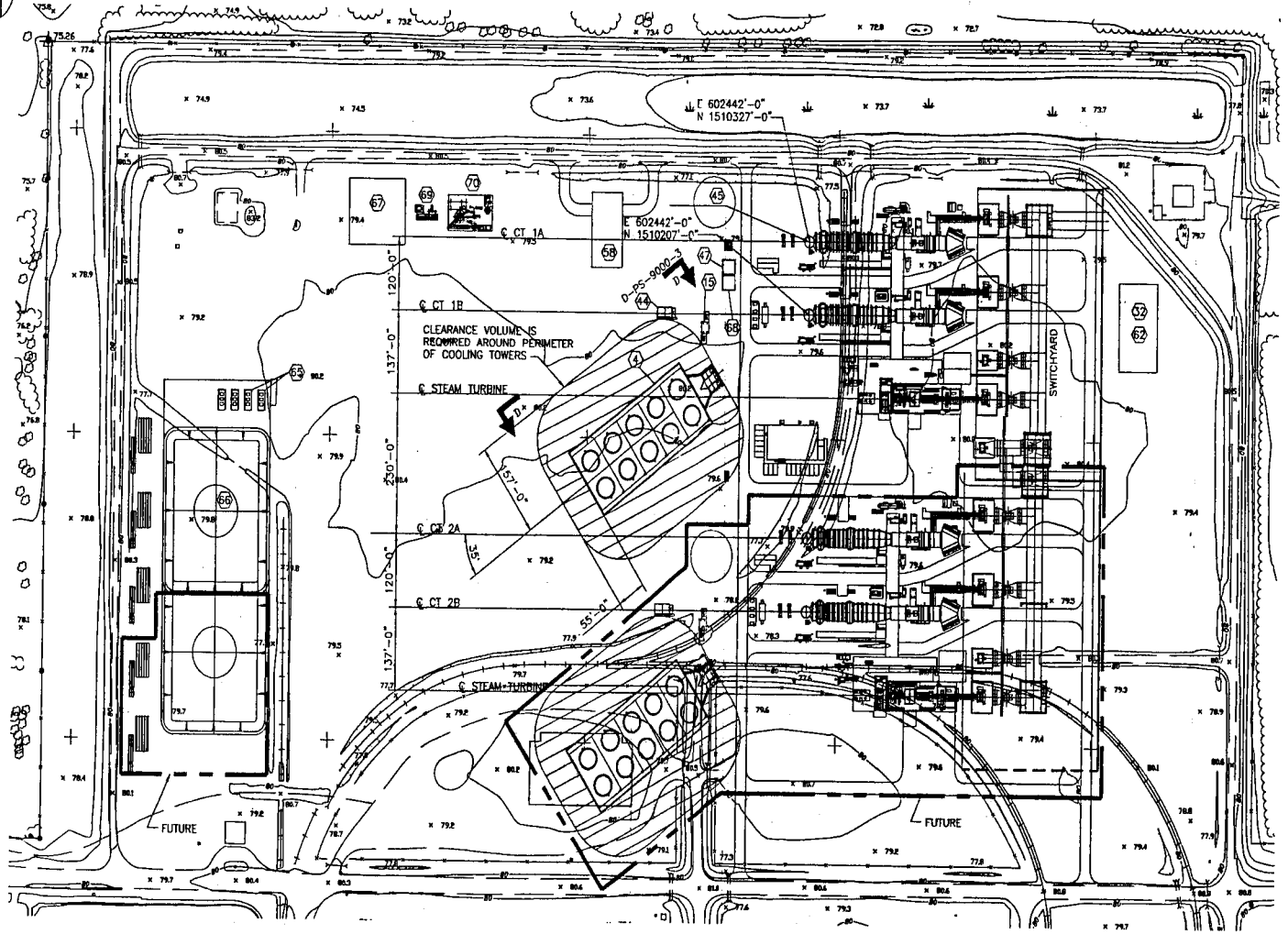
Stanton A is jointly owned by OUC, KUA, FMPA, and Southern-Florida as follows:

- OUC - 28 percent.
- KUA - 3.5 percent.
- FMPA - 3.5 percent.
- Southern-Florida - 65 percent.
- OUC, KUA, and FMPA will purchase all of the capacity owned by Southern-Florida, pursuant to the PPAs, for a minimum 10 year term. The PPAs provide OUC, KUA, and FMPA the unilateral option to acquire Southern-Florida capacity for a term of up to 30 years, which is assumed to be the life of the plant. The purchased capacity will be allocated among these utilities as follows:
  - OUC - 80 percent.
  - KUA - 10 percent.
  - FMPA - 10 percent.

The details of the PPAs are set forth in Section 1A.4.0.

1A.2.2 Summary

Stanton A is planned to utilize a 2 x 1 combined cycle configuration with two General Electric PG-7241 FA combustion turbines, two heat recovery steam generators, and a steam turbine. The estimated capital cost for OUC's, KUA's, and FMPA's collective share is [redacted] including costs for the power block as well as interconnection facilities. Stanton A is projected to have a new and clean output of 633 MW at 70° F with a higher heating value (HHV) heat rate of [redacted] Btu/kWh. Stanton A is planned to be equipped with evaporative inlet cooling, duct firing, and power augmentation to increase output. Natural gas is the primary fuel for Stanton A and No. 2 oil is the planned backup fuel. Stanton A will not be equipped with bypass stacks and dampers, but will have the condenser sized such that both combustion turbines can be operated at full load with the steam turbine out of service.



NOTES:

NEW STACK COORDINATES BASED ON NAD83 FLORIDA STATE PLANES, EASTERN ZONE, U.S. FOOT:

CENTER UNIT 1A HRSG STACK:	E 602442'-0" N 1510327'-0"
CENTER UNIT 1B HRSG STACK:	E 602442'-0" N 1510207'-0"
CENTER UNIT 2A HRSG STACK:	E 602442'-0" N 1509840'-0"
CENTER UNIT 2B HRSG STACK:	E 602442'-0" N 1509720'-0"

NEW STACK COORDINATES BASED ON NAD83 UTM, ZONE 16 NORTH, METER:

CENTER UNIT 1A HRSG STACK:	E 1071425.2056 N 3165216.3816
CENTER UNIT 1B HRSG STACK:	E 1071427.0434 N 3165178.7166
CENTER UNIT 2A HRSG STACK:	E 1071432.6637 N 3165067.5830
CENTER UNIT 2B HRSG STACK:	E 1071434.5014 N 3165030.9181

⬡ DENOTES EQUIP. NO. – SEE D-PS-9000-2 FOR DESCRIPTION

REFERENCES:

D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=30'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"

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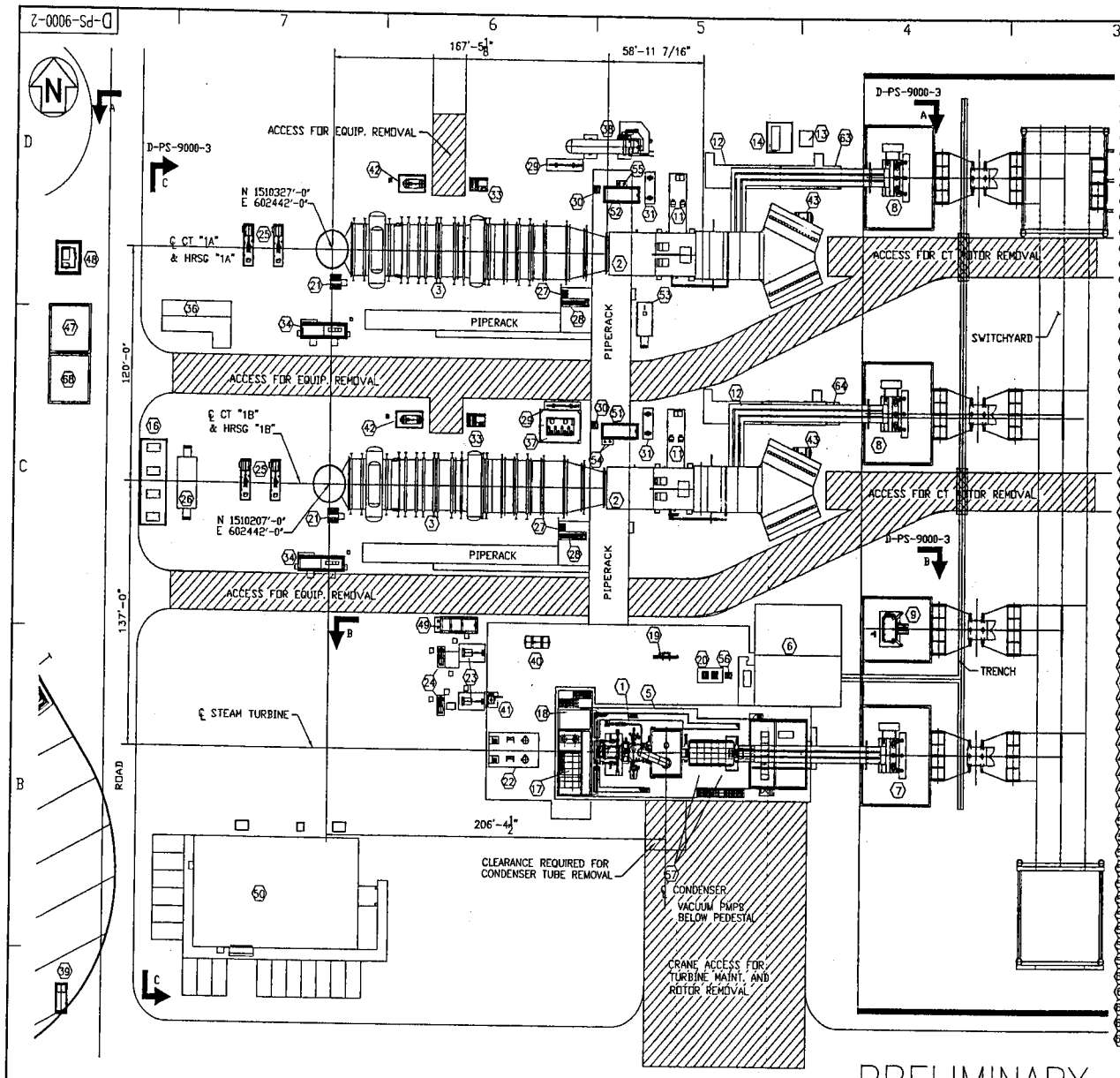
Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=100'-0"

REVISION	DATE	DESCRIPTION	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
E	02/02/01	3. (CONT'D.) RELOCATED ITEM (65) FUEL OIL FORWARDING PUMPS AND ITEM (66) FUEL OIL STORAGE TANK.	SHW						
E	02/02/01	1. DELETED ITEM NO. (67) IPC. 2. ADDED BRINE CONCENTRATOR (68), CRYSTALLIZER (70) AND BRINE CRYSTALLIZER POND (67). 3. RELOCATED ITEM (62) GAS CONDITIONING, ITEM (32) GAS METERING STATION,	SHW						
D	01/16/00	1. REVISED TITLE BLOCK	SHW						
C	12/7/00	1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	DWR						
B	10/24/00	1. ADDED SERVICE WATER COOLER 1. ADDED LOCATION OF FUTURE BLOCK.	SHW						
A	9/22/00	ISSUED FOR REVIEW	SHW						

DESIGNED SHW | DRAWN SHW | CHECKED
SCALE 1"=100'-0" | PROJECT I.D. | DRAWING NUMBER D-PS-9000-1 | REV. E



LEGEND

1. STEAM TURBINE
2. COMBUSTION TURBINE
3. HEAT RECOVERY STEAM GENERATOR
4. COOLING TOWER (SEE D-PS-9000-1)
5. CONDENSER
6. ELECTRICAL BUILDING
7. STEAM GENERATOR GSU
8. COMBUSTION TURBINE GSU
9. STATION SERVICE TRANSFORMER
10. AUX. TRANSFORMER (N.A.)
11. COMBUSTION TURBINE ACCESSORY MOD.
12. COMBUSTION TURBINE PEEC
13. DC LINK TRANSFORMER
14. ISOLATION TRANSFORMER
15. 480V TRANSFORMER & MCC (SEE DWG. D-PS-9000-1)
16. FEEDWATER TRANSFORMER
17. STEAM TURBINE LUBE OIL SKID
18. STEAM TURBINE HPU
19. GLAND STEAM CONDENSER
20. CONDENSATE PUMPS
21. CONDENSATE RECIRC PUMPS
22. AIR COMPRESSOR
23. SERVICE WATER HEAT EXCHANGER
24. SERVICE WATER PUMPS
25. BOILER FEED PUMPS
26. BOILER FEED PUMP DRIVE SKID
27. SCANNER AIR BLOWER
28. FUEL GAS PIPING MODULES
29. FUEL GAS HEATER
30. FUEL GAS ELECTRIC WATER HEATER
31. FUEL GAS FILTER
32. GAS METERING STATION (SEE D-PS-9000-1)
33. SCR AMMONIA BLR/CONTROL
34. CEMS BUILDING
35. WATER TREATMENT BUILDING (N/A)
36. WATER ANALYSIS BUILDING
37. PHOSPHATE FEED PUMP SKID
38. AMMONIA SUPPLY SYSTEM
39. CO2 SKID
40. CLOSED LOOP COOLING WTR TANK
41. STEAM TURBINE BLOWDOWN TANK
42. HRSG BLOWDOWN TANK
43. CT CO2 TANK
44. CHEMICAL FEED TANKS (SEE D-PS-9000-1)
45. DEMIN STORAGE TANK (SEE DWG. D-PS-9000-1)
46. RAW WATER STORAGE TANK (N/A)
47. WASTE WATER SUMP
48. OIL/WATER SEPARATOR
49. MAIN STEAM SUMP
50. CONTROL/ADMIN BLDG
51. SUMP 'A'
52. SUMP 'B'
53. WASH WATER SKID
54. SUMP 'A' PUMPS
55. SUMP 'B' PUMPS
56. TURBINE SEAL OIL SKID
57. VACUUM PUMPS
58. WAREHOUSE (SEE DWG. D-PS-9000-1)
59. FIRE PROT. PUMP HSE (N/A)
60. FIRE PROT. STORAGE TK (N/A)
61. FILTERED WTR STORAGE TK (N/A)
62. GAS CONDITIONING STATION (SEE DWG. D-PS-9000-1)
63. LCI EXCITATION COMPT (LEC)
64. STATIC EXCITATION COMPT (EC)
65. FUEL OIL FORWARDING PUMPS (SEE DWG. D-PS-9000-1)
66. FUEL OIL STORAGE TANK (SEE DWG. D-PS-9000-1)
67. BRINE CRYSTALLIZER POND (SEE DWG. D-PS-9000-1)
68. CONCENTRATION WASTE BLOWDOWN SUMP
69. BRINE CONCENTRATOR (SEE DWG. D-PS-9000-1)
70. CRYSTALLIZER (SEE DWG. D-PS-9000-1)

REFERENCES:

D-PS-9000-1	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=100'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS
D-PS-9000-4	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=200'-0"

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PRELIMINARY

REVISION	DATE

REVISION E	DATE 02/02/01
1. DELETED ITEM NO. 67 IPC 2. ADDED ITEM NO. 67 BRINE CRYSTALLIZER POND. ADDED ITEM NO. 69 CRYSTALLIZER ADDED ITEM NO. 70 BRINE CONCENTRATOR.	

BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
SHW						

REVISION D	DATE 01/16/01
1. REVISED TITLE BLOCK.	

BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
SHW						

REVISION C	DATE 12/7/00
1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68	

BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
DWR						

REVISION B	DATE 10/24/00
ADDED ITEM NO. 67 IPC	

BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
SHW						

REVISION A	DATE 9/22/00
ISSUED FOR REVIEW	

BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
SHW						

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Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

STANTON ENERGY CENTER – UNIT A
1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=30'-0"

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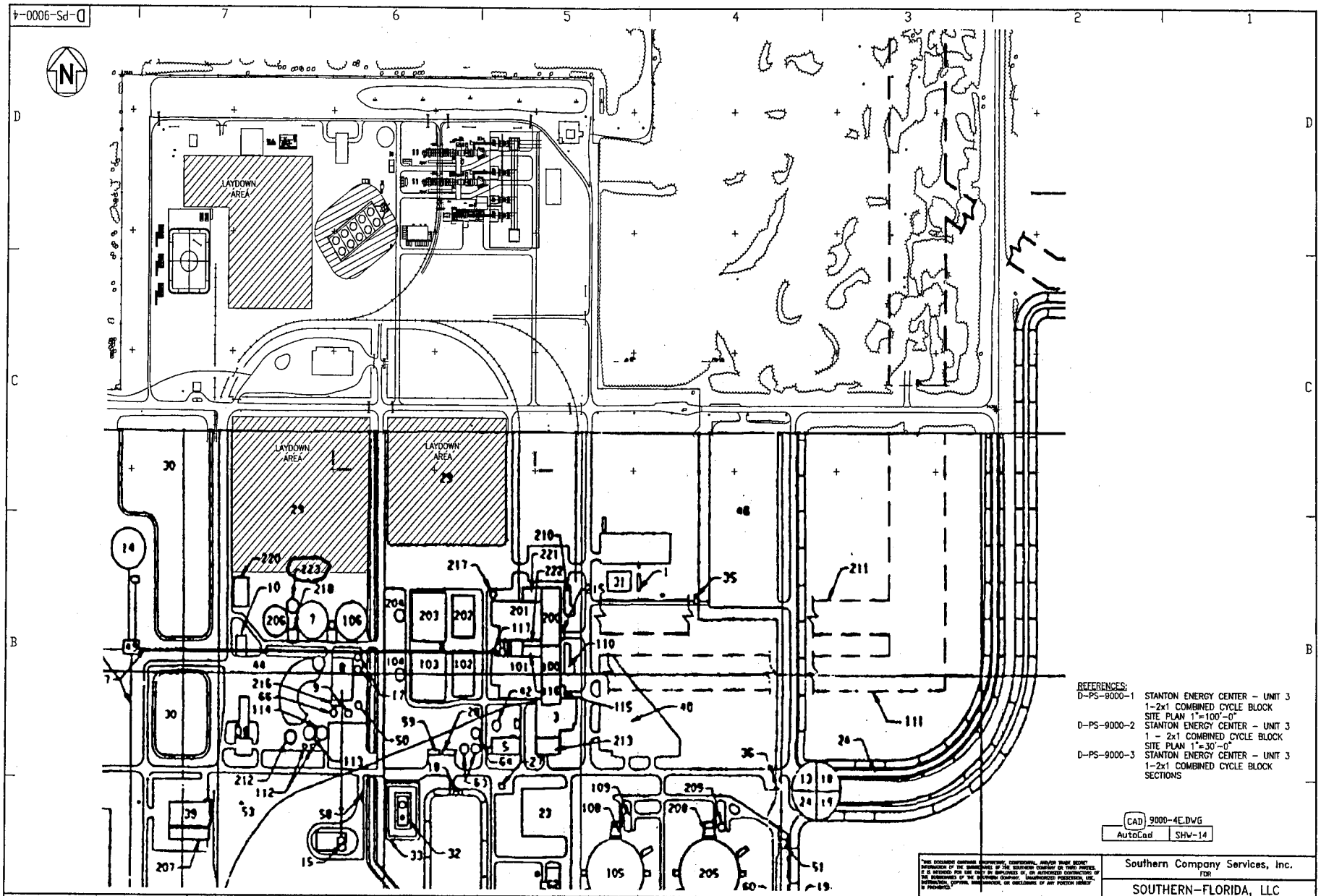

REFERENCES:

D-PS-9000-1	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=100'-0"
D-PS-9000-2	STANTON ENERGY CENTER – UNIT 3 1 – 2x1 COMBINED CYCLE BLOCK SITE PLAN 1"=30'-0"
D-PS-9000-3	STANTON ENERGY CENTER – UNIT 3 1-2x1 COMBINED CYCLE BLOCK SECTIONS

CAD 9000-4E.DWG
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1-2x1 COMBINED CYCLE BLOCK
SITE PLAN 1"=200'-0"

REVISION	DATE	BY	CHK'D	APPR. 1	APPR. 2	APPR. 3	APPR. 4	APPR. 5
REVISION E	DATE 02/02/01	SHW						
1. ADDED BRINE CRYSTALLIZER POND, CRYSTALLIZER AND BRINE CONCENTRATOR. 2. RELOCATED GAS METERING/CONDITIONING, RELOCATED FUEL OIL FORWARDING PUMPS AND FUEL OIL STORAGE TANK.								
REVISION D	DATE 01/16/01	SHW						
1. REVISED TITLE BLOCK.								
REVISION C	DATE 12/7/00	SHW						
1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP								
REVISION B	DATE 10/27/00	SHW						
ADDED IPC								
REVISION A	DATE 9/22/00	SHW						
ISSUED FOR REVIEW								

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1A.5.0 Evaluation Criteria

1A.5.1 Economic Parameters

With several different entities having ownership interests in Stanton A, the economic parameters used for evaluation vary between the various participants primarily due to differences in their cost of money. Other economic parameters such as general inflation rates and escalation rates which do not vary between the participants are kept consistent for evaluation purposes. Because Southern-Florida is the majority owner of Stanton A, its economic parameters are used for decisions dealing with equipment selection. Because OUC is the agent for KUA and FMPA and has the largest entitlement to output from the project, OUC's economic criteria are used to determine the cost-effectiveness of the project as a whole. KUA's and FMPA's economic parameters are described in Volumes 1C and 1D and are used to determine the cost-effectiveness of their portion of the project for their respective systems.

1A.5.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is assumed to be 2.5 percent.

1A.5.1.2 Cost of Capital

Southern-Florida uses a real interest rate of [redacted] percent, which with the general inflation rate of 2.5 percent corresponds to a nominal interest rate of [redacted] percent. The real interest rate of [redacted] percent is used to evaluate emission control equipment in accordance with the Environmental Protection Agency guidelines.

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio, which is approximately 70/30, the embedded debt rate, which is approximately 6.6 percent, and the return on equity, which is approximately 10.3 percent. The weighted average cost of capital is thus approximately 7.7 percent. For economic evaluation for the need for power, the weighted average cost of capital is rounded to 8 percent.

1A.5.1.3 Present Worth Discount Rate

Southern-Florida uses a real present worth discount rate of [redacted] percent, corresponding to Southern-Florida's real interest rate.

OUC's present worth discount rate is assumed to be equal to the weighted average cost of capital of 8.0 percent.

1A.5.1.4 Interest During Construction Interest Rate

The interest during construction interest rate is assumed to be 6.0 percent.

1A.5.1.5 Levelized Fixed Charge Rate

The levelized fixed charge rate is assumed to be the sum of the capital recovery rate and insurance rate. Based on the weighted average cost of capital of 8.0 percent, a 1.0 percent annual insurance cost, and a capital recovery period of 20 years, the levelized fixed charge rate is assumed to be 11.19 percent.

1A.5.2 Fuel Price Projections

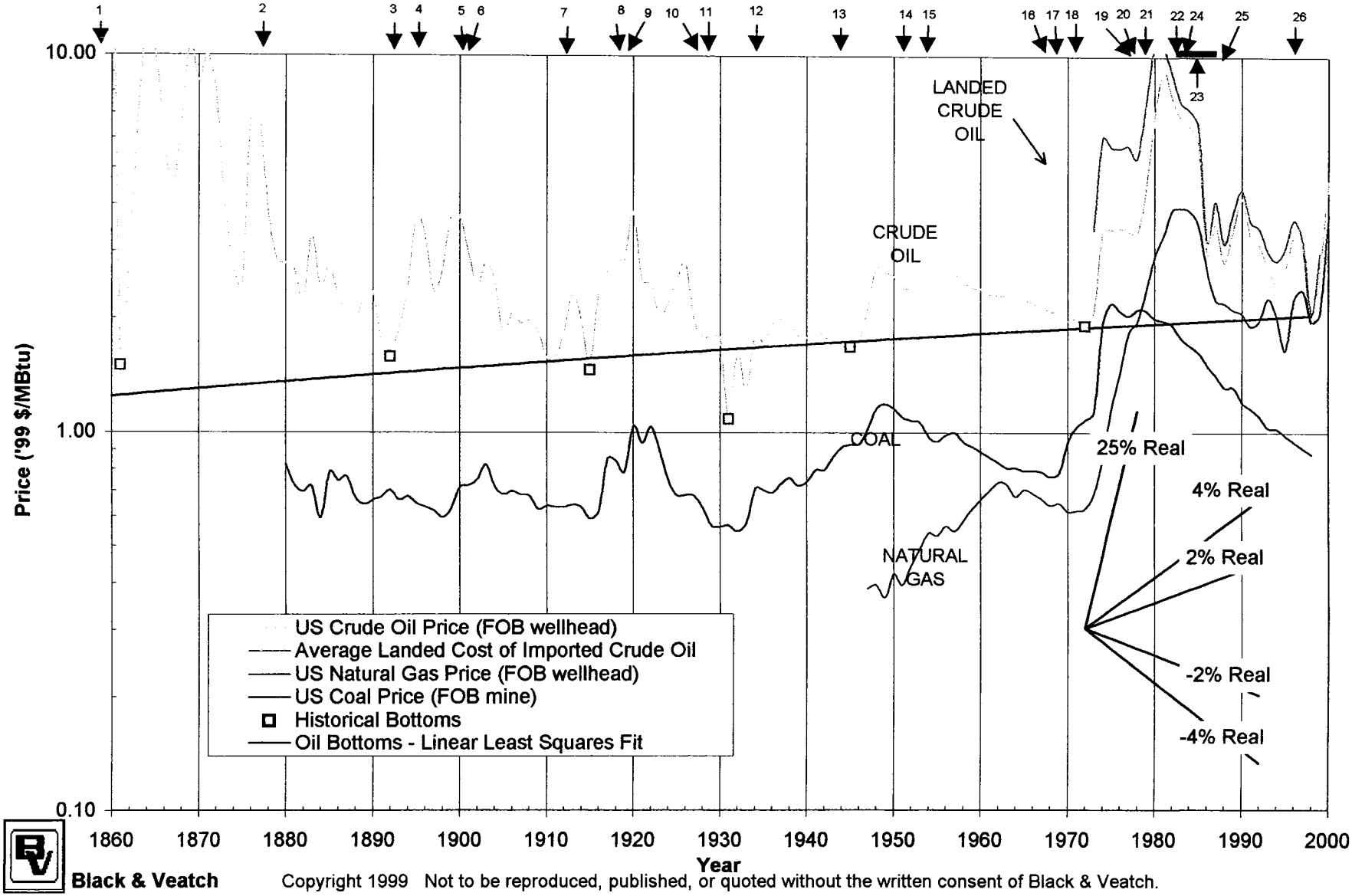
This section presents the fuel price projections for coal, petroleum coke, natural gas, oil, and nuclear fuel. For consistency, a single set of fuel price projections is developed to apply to OUC, KUA, and FMPA. In general, the projections are developed based on projected prices for OUC since OUC has the largest amount of generation of the three applicants. Also, many of the generating units are jointly owned by the three applicants and thus have similar fuel costs. Natural gas and oil are generally fungible and would be expected to have generally the same costs for each of the utilities for the same general geographical region over time.

The base case forecasts are based on forecasts provided by Energy Ventures Analysis, Inc. (EVA) who were commissioned by OUC and Southern-Florida because of its fuel forecasting expertise and the belief that the EVA forecast would be the best available. EVA developed fuel forecasts for natural gas, coal, West Texas Intermediate (WTI) crude oil, and petroleum coke.

Fuel prices are highly volatile and are dependent not only on supply and demand, but also political stability and interdependent markets. Even the best forecasters face a tough job of forecasting in such a volatile market. Figure 1A.5-1 shows historical US fuel prices and the wide range of fluctuations and responses to market conditions. Because of the difficulty of forecasting in this environment, several sensitivity scenarios have been developed. These sensitivity scenarios include a high and low forecast based on the forecast developed from the EVA forecast, a scenario where OUC's actual 2000 fuel prices remain constant throughout the evaluation period in real terms, the 2001 Annual Energy Outlook (AEO) projections developed by the United States Department of Energy (DOE), and, finally, a scenario in which OUC's actual 2000 fuel prices escalate based on the 2001 AEO escalation rates for the various fuels.

Historical US Fuel Prices

1. First US Oil Well (1859)
2. Thomas Edison Invents Electric Light Bulb (1878)
3. 4-year Depression Ends (1893)
4. First Offshore Oil Well in California (1896)
5. Spindletop Field near Beaumont, Texas (January, 1901)
6. Rotary Drilling Rig (1902)
7. Cushing Field in Oklahoma (1914)
8. Growth of Venezuelan Production
9. Windfall Profits Tax (1920)
10. Stock Market Crash (10/'29); First Well Logs (1929)
11. East Texas Field Discovered (10/'30)
12. Seismic For Exploration (1936)
13. United Mine Workers of America Defies Truman and Strikes (4/'46)
14. Control of Natural Gas Wellhead Prices (1954)
15. Suez Crisis (10/'56)
16. Coal Mine Health and Safety Act ('69)
17. Nixon Imposes Price Controls (8/'71)
18. Nixon Removes Price Controls on New Oil (8/'73)
19. Iranian Revolution (2/'79)
20. Start of Iran/Iraq War (9/'80); Windfall Profits Tax (1980)
21. Reagan Removes Oil Price Controls (1/'81)
22. End of Coal Miners' Strike (3/'85)
23. The Wellhead Price of Natural Gas was Deregulated between '85 and '89
24. OPEC Introduces Netback Pricing ('86)
25. Iraq Invades Kuwait (8/'90)
26. Propose Tax Code Revision for U.S. Oil and Gas Industry (1998)



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1A.5.2.1 EVA Fuel Price Projections

EVA developed projections for natural gas, coal, WTI crude oil, and petroleum coke on a real price basis.

1A.5.2.1.1 Natural Gas. The natural gas price projections are for Henry Hub. The greatest concern with the forecast is in the years 2003 and 2004. The industry has entered a new era in which short-term supply increases cannot keep pace with short-term demand increases. This imbalance has resulted in very high gas prices. Despite record levels of drilling in both the United States and Canada, it appears this era will last for at least 3 years and could last up to 5 years. The big variable in the length of this era is the severity of winter weather in each of the forthcoming years 2002 through 2004, as the difference between a mild and cold winter can represent between 1.5 and 2.0 BCFD per year in additional demand. The projection does not assume any carbon taxes or other such major pieces of legislation that could significantly impact supply and demand. The Henry Hub natural gas projection in constant 2001 dollars is presented in Table 1A.5-1.

1A.5.2.1.2 Coal. The long-term coal price projection is based on low sulfur (1.8-2.5 lb SO_2/MBtu with a 12,500 Btu/lb heating value) Appalachian coal delivered to Orlando in railcars. The projection by mine and rail costs in constant 2001 dollars is presented in Table 1A.5-2.

1A.5.2.1.3 WTI Crude Oil. Crude oil prices are expected to decline. The projected WTI crude oil prices in constant 2000 dollars are presented in Table 1A.5-3.

1A.5.2.1.4 Petroleum Coke. The petroleum coke forecast is a delivered price where the initial delivery is via barge from the Gulf Coast refineries and then offloaded to railcars. Crude oil prices, which are the largest cost component, are expected to decline as indicated in Table 1A.5-3. Larger coke volumes are projected to be produced as crude oil becomes heavier. Refinery upgrades are producing a larger gasoline fraction from residue, which increases coke production, which has risen 36 percent in the last 3 years. Higher value markets for petroleum coke are limited including calcined coke for aluminum production and needle grade for steel refineries. Fuel grade (green coke) is the lowest value use for petroleum coke, but also is the only remaining expansion market. Petroleum coke is a thinly traded commodity and is at risk of rapid price escalation with large increases in demand. However, the cap is set by alternative coal prices ($1.80/MBtu) in the US market and alternative fuels in Europe. Fuel use, however, has discounted value because of the high metals content, high sulfur content, and low volatile content. Market potential for petroleum coke could grow and the price increase if more flue gas desulfurization (FGD) systems are retrofitted on existing plants. The projected power demand and projected price of petroleum coke delivered to Stanton Energy Center in constant 2001 dollars are presented in Table 1A.5-4.

Table 1A.5-1
EVA Forecast Natural Gas Prices At Henry Hub ($2001)

Year	[$/MBtu]
2000	4.30
2001	5.64
2002	4.24
2003	3.27
2004	2.75
2005	2.65
2006	2.59
2007	2.63
2008	2.67
2009	2.71
2010	2.75
2011	2.80
2012	2.85
2013	2.90
2014	2.95
2015	3.01
2016	3.07
2017	3.13
2018	3.20
2019	3.26

Table 1A.5-2
EVA Forecast Long-Term Coal Prices ($2001)

Year	Mine $/ton	Rail $/ton	Delivered $/ton	Delivered $/MBtu
2000	23.43	19.95	43.38	1.74
2001	28.97	19.50	48.47	1.94
2002	25.85	19.07	44.92	1.80
2003	24.99	18.77	43.76	1.75
2004	24.89	18.50	43.39	1.74
2005	24.65	18.42	43.07	1.72
2006	24.45	18.29	42.74	1.71
2007	24.31	18.15	42.45	1.70
2008	24.17	18.01	42.18	1.69
2009	24.10	17.88	41.98	1.68
2010	24.03	17.75	41.78	1.67
2011	23.98	17.64	41.62	1.66
2012	23.92	17.54	41.46	1.66
2013	23.87	17.43	41.30	1.65
2014	23.79	17.33	41.12	1.64
2015	23.74	17.23	40.96	1.64
2016	23.69	17.14	40.84	1.63
2017	23.68	17.06	40.74	1.63
2018	23.68	16.98	40.65	1.63
2019	23.66	16.89	40.55	1.62

Note: Long-term delivered cost to Stanton Energy Center based on Appalachian low-sulfur coal with 12,500 Btu/lb heating value and 1.8 to 2.5 lb SO_2/MBtu.

Table 1A.5-3
EVA Forecast WTI Crude Oil Price ($2000)

Year	WTI Crude Oil [$/BBL]
2000	30.82
2001	27.36
2002	24.14
2003	21.00
2004	19.50
2005	18.50
2006	18.25
2007	18.25
2008	18.25
2009	18.25
2010	18.50
2011	18.50
2012	18.50
2013	18.50
2014	18.50
2015	18.50
2016	18.75
2017	18.75
2018	18.75
2019	18.75

Table 1A.5-4
EVA Forecast Petroleum Coke Demand and Delivered Prices ($2001)

Year	Power Demand 1,000 tons	Most Probable $/MBtu	Low $/MBtu	High $/MBtu
2000	3,254	1.29	0.83	1.64
2001	3,686	1.28	0.75	1.64
2002	3,686	1.20	0.74	1.64
2003	3,761	1.14	0.73	1.63
2004	3,987	1.12	0.73	1.63
2005	4,101	1.11	0.72	1.63
2006	4,214	1.09	0.72	1.63
2007	4,341	1.09	0.71	1.62
2008	4,471	1.08	0.70	1.62
2009	4,605	1.08	0.70	1.62
2010	4,743	1.09	0.69	1.61
2011	4,886	1.09	0.68	1.61
2012	5,032	1.10	0.68	1.61
2013	5,183	1.12	0.67	1.61
2014	5,338	1.13	0.66	1.60
2015	5,498	1.15	0.66	1.60
2016	5,663	1.17	0.65	1.60
2017	5,833	1.19	0.66	1.60
2018	6,008	1.21	0.65	1.59
2019	6,189	1.23	0.64	1.59

1A.5.2.2 Base Case Fuel Price Projections

The coal price projections are assumed to apply to McIntosh 3 as well as units at Stanton Energy Center.

The annual general inflation rate of 2.5 percent is added to EVA's constant dollar fuel price forecasts to obtain nominal fuel price projections for evaluation purposes which are presented in Table 1A.5-5.

For natural gas, transportation charges must be added to obtain a delivered fuel cost. OUC, KUA, and FMPA, as well as FMPA's generating member cities, all have varying amounts of natural gas transportation capability from Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs. The FTS-2 tariff is expected to change as additional expansions are conducted on FGT's system. In general, it is expected that FTS-2 tariff rates will lower somewhat as additional expansions are added. Also impacting the natural gas transportation situation is the proposed Gulfstream pipeline. In general, increased competition would be expected to increase pressure to lower transportation costs. Finally, the impacts of transportation capacity being bought and sold on the secondary market will also influence the average natural gas transportation costs. For the purposes of this evaluation, OUC has assumed that natural gas transportation costs will be approximately $0.75/MBtu over the evaluation period. The $0.75/MBtu natural gas transportation cost is assumed to remain constant over the forecast period and is included in the natural gas price forecast in Table 1A.5-5.

EVA did not provide forecasts for No. 2 and No. 6 oil. Delivered projections of No. 2 and No. 6 oil were developed by comparing OUC's actual delivered cost for No. 2 and No. 6 oil in 2000 to EVA's projected 2000 WTI crude oil price and applying the percentage difference in cost to EVA's WTI crude oil price.

Projections for nuclear fuel prices are based on OUC's actual 2000 nuclear fuel cost escalating at the general inflation rate.

1A.5.2.3 High and Low Case Fuel Price Projections

High and low case fuel price projections for all fuels except petroleum coke are developed by applying a 2 percent higher annual escalation rate to the base case fuel price projections for the high case and a 2 percent lower annual escalation rate to the base case projections for the low case except for the petroleum coke projections which apply the 2.5 percent general inflation rate to the EVA high and low projections. The high and low petroleum coke forecasts were provided directly by EVA. The high and low case fuel price projections are presented in Tables 1A.5-6 and 1A.5-7, respectively.

Table 1A.5-5
Base Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	1.26
2001	1.94	6.39	5.27	4.02	0.53	1.28
2002	1.85	5.10	4.76	3.64	0.55	1.23
2003	1.84	4.19	4.25	3.24	0.56	1.20
2004	1.87	3.71	4.04	3.09	0.57	1.21
2005	1.90	3.56	3.93	3.00	0.59	1.23
2006	1.93	3.68	3.98	3.04	0.60	1.23
2007	1.97	3.80	4.08	3.11	0.62	1.26
2008	2.01	3.92	4.18	3.19	0.63	1.28
2009	2.05	4.05	4.28	3.27	0.65	1.32
2010	2.09	4.18	4.45	3.40	0.67	1.36
2011	2.12	4.33	4.56	3.48	0.68	1.40
2012	2.20	4.49	4.67	3.57	0.70	1.44
2013	2.22	4.65	4.79	3.66	0.72	1.51
2014	2.26	4.82	4.91	3.75	0.73	1.56
2015	2.32	5.00	5.03	3.84	0.75	1.62
2016	2.36	5.20	5.23	3.99	0.77	1.69
2017	2.42	5.40	5.36	4.09	0.79	1.77
2018	2.48	5.62	5.49	4.19	0.81	1.84
2019	2.53	5.83	5.63	4.30	0.83	1.92
Average Annual Escalation (%)	2.12%	0.87%	-0.15%	-0.15%	2.50	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-6
High Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	1.60
2001	1.97	6.47	5.38	4.11	0.54	1.64
2002	1.92	5.26	4.98	3.80	0.57	1.68
2003	1.95	4.40	4.54	3.46	0.59	1.71
2004	2.02	3.98	4.41	3.37	0.62	1.76
2005	2.09	3.88	4.38	3.34	0.65	1.80
2006	2.17	4.08	4.51	3.44	0.68	1.84
2007	2.26	4.28	4.72	3.60	0.71	1.88
2008	2.35	4.50	4.93	3.76	0.74	1.93
2009	2.44	4.72	5.15	3.93	0.77	1.97
2010	2.53	4.96	5.45	4.16	0.81	2.01
2011	2.63	5.23	5.70	4.35	0.84	2.06
2012	2.78	5.51	5.96	4.55	0.88	2.11
2013	2.86	5.81	6.22	4.75	0.92	2.17
2014	2.97	6.13	6.50	4.96	0.96	2.21
2015	3.10	6.49	6.80	5.19	1.01	2.26
2016	3.22	6.86	7.20	5.49	1.05	2.32
2017	3.37	7.26	7.52	5.74	1.10	2.38
2018	3.52	7.70	7.86	6.00	1.15	2.42
2019	3.65	8.15	8.21	6.27	1.20	2.48
Average Annual Escalation (%)	4.12%	2.66%	1.86%	1.86%	4.50%	2.33%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-7
Low Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.70	4.95	5.79	4.42	0.52	0.81
2001	1.91	6.31	5.15	3.93	0.52	0.75
2002	1.77	4.91	4.56	3.48	0.53	0.76
2003	1.73	3.94	3.97	3.03	0.53	0.77
2004	1.73	3.46	3.70	2.83	0.53	0.79
2005	1.72	3.26	3.53	2.69	0.53	0.79
2006	1.72	3.32	3.49	2.67	0.54	0.81
2007	1.72	3.37	3.51	2.68	0.54	0.82
2008	1.71	3.43	3.53	2.69	0.54	0.83
2009	1.71	3.48	3.55	2.71	0.54	0.85
2010	1.71	3.54	3.61	2.76	0.55	0.86
2011	1.71	3.60	3.63	2.77	0.55	0.87
2012	1.74	3.67	3.65	2.79	0.55	0.89
2013	1.72	3.74	3.67	2.80	0.55	0.90
2014	1.71	3.80	3.69	2.81	0.56	0.91
2015	1.72	3.88	3.71	2.83	0.56	0.93
2016	1.72	3.96	3.78	2.88	0.56	0.94
2017	1.73	4.04	3.79	2.90	0.57	0.96
2018	1.74	4.14	3.81	2.91	0.57	0.99
2019	1.73	4.22	3.83	2.93	0.57	1.00
Average Annual Escalation (%)	0.11%	-0.83%	-2.15%	-2.15%	0.50%	1.11%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

1A.5.2.4 Constant 2000 Fuel Price Projections

The constant 2000 fuel price projection assumes that the actual OUC 2000 fuel costs remain constant in real terms over the forecast period. The constant 2000 fuel price projection thus applies the 2.5 percent general inflation rate to OUC's actual 2000 fuel costs for all fuels except petroleum coke. The constant 2000 projection for petroleum coke was developed by applying the 2.5 percent general inflation rate to the base case forecast provided by EVA. Figure 1A.5-1 indicates that it would be unprecedented for high fuel prices such as those occurring in 2000 to continue in real terms for an entire 20 year period. Nevertheless, the constant 2000 fuel price projection offers the opportunity to evaluate the cost effectiveness of Stanton A with continuing high fuel prices. The constant 2000 fuel price projection is presented in Table 1A.5-8. For purposes of this evaluation, the delivered gas price projection assumes the commodity portion of the price escalates at the 2.5 percent general inflation rate and the $0.75/MBtu transportation cost remains constant over the forecast period. This results in the delivered cost of natural gas escalating at slightly less than the general inflation rate of 2.5 percent. The constant 2000 fuel price projection for natural gas is 33 percent higher than the base case by 2019.

1A.5.2.5 2001 Annual Energy Outlook Fuel Price Projections

The final two fuel price projections used in the sensitivity evaluations are based on the Annual Energy Outlook (AEO) fuel price data published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2001 energy data is a comprehensive and reliable source of domestic and international energy supply, consumption, and price information.

AEO provides energy forecasts through the year 2020 and takes into account a number of important factors, some of which include:

- Restructuring of the US electricity markets
- Current regulations and legislation affecting the energy markets
- Current energy issues:
  - Appliance, gasoline, and diesel fuel, and renewable portfolio standards.
  - Expansion of natural gas industry
  - Carbon emissions
  - Competitive energy pricing

AEO 2001 energy information is objective and nonpartisan. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

Table 1A.5-8
Constant 2000 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.67	5.03	5.79	4.42	0.52	1.26
2001	1.71	5.14	5.94	4.53	0.53	1.29
2002	1.75	5.25	6.09	4.64	0.55	1.32
2003	1.80	5.36	6.24	4.76	0.56	1.36
2004	1.84	5.47	6.39	4.88	0.57	1.39
2005	1.89	5.59	6.55	5.00	0.59	1.43
2006	1.94	5.71	6.72	5.13	0.60	1.46
2007	1.99	5.84	6.88	5.25	0.62	1.50
2008	2.03	5.96	7.06	5.39	0.63	1.54
2009	2.09	6.10	7.23	5.52	0.65	1.57
2010	2.14	6.23	7.41	5.66	0.67	1.61
2011	2.19	6.37	7.60	5.80	0.68	1.65
2012	2.25	6.51	7.79	5.94	0.70	1.69
2013	2.30	6.65	7.98	6.09	0.72	1.74
2014	2.36	6.80	8.18	6.25	0.73	1.78
2015	2.42	6.95	8.39	6.40	0.75	1.82
2016	2.48	7.10	8.60	6.56	0.77	1.87
2017	2.54	7.26	8.81	6.73	0.79	1.92
2018	2.60	7.43	9.03	6.89	0.81	1.97
2019	2.67	7.59	9.26	7.07	0.83	2.01
Average Annual Escalation (%)	2.50%	2.19%	2.50%	2.50%	2.50%	2.50%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

AEO 2001 publishes 1999, 2005, 2010, 2015, and 2020 fuel price projections, which are presented in Table 1A.5-9. From these projections, real compound annual escalation rates (CAERs) can be calculated for 1999 through 2005, 2005 through 2010, 2010 through 2015, and 2015 through 2020 periods. These real CAERs are used to develop annual fuel price projections to which the 2.5 percent general inflation rate is applied. The AEO 2001 fuel price projections are presented in Table 1A.5-10. The delivered price of natural gas adds a constant $0.75/MBtu transportation cost to the AEO 2001 commodity projection. AEO does not project nuclear or petroleum coke prices. The nuclear and petroleum coke projections are those presented in the base case in Table 1A.5-5. The AEO 2001 fuel price projections for 2000 are much lower than the actual 2000 OUC fuel prices shown in Table 1A.5-8. Furthermore, the AEO projections are on a national average basis, which is heavily weighted by low cost western coal and do not reflect the relatively higher coal transportation costs to Florida. As a result, the AEO projections understate coal costs for Florida.

The second fuel price projection based on the AEO 2001 fuel price projections applies the AEO 2001 real escalation rates along with the 2.5 percent annual general inflation rate to the actual 2000 OUC fuel prices. These fuel price projections are presented in Table 1A.5-11. The nuclear and petroleum coke projections are those presented in the base case in Table 1A.5-5. This projection initially matches the actual 2000 OUC fuel prices and continues to escalate them into the future. High fuel prices continuing to escalate for a 20 year period would be unprecedented compared to historical prices presented in Figure 1A.5-1.

1A.5.3 Fuel Availability

Plentiful coal and natural gas reserves exist both in the United States and North American mainland and coastal regions. Large coal reserves within the east, central, and western United States are adequate to supply power generation needs for the foreseeable future. Oil reserves are dependent on both domestic and offshore production and imports. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home heating and power production is contributing to the volatility of its price, which in turn has provided incentives for increased production. A somewhat cyclic effect is expected, where short-term demand and volatility will drive increased production and future price stability.

1A.5.3.1 Service to Proposed Plant Site.

FGT's 26 inch pipeline is located approximately 2.5 miles south of the Stanton Energy Center site.

Table 1A.5-9
2001 Annual Energy Outlook Real Fuel Price Projections and CAERs

	1999	2005	2010	2015	2020
No. 2 Oil,* $/MBtu	4.05	4.65	4.84	5.10	5.28
Residual Oil,* $/MBtu	2.42	3.52	3.88	4.00	4.07
Coal,* $/MBtu	1.21	1.13	1.05	1.01	0.98
Natural Gas,** $/MBtu	2.08	2.49	2.69	2.83	3.13
	1999-2005	2005-2010	2010-2015	2015-2020	1999-2020
No. 2 Oil* Real CAERs, percent	2.33	0.80	1.05	0.70	1.27
Residual Oil* Real CAERs, percent	6.49	1.97	0.61	0.35	2.51
Coal* Real CAERs, percent	-1.13	-1.46	-0.77	-0.60	-1.00
Natural Gas** Real CAERs, percent	3.04	1.56	1.02	2.04	1.97

*Delivered price.

**Well head price.

Source: DOE Energy Information Administration web site

Table 1A.5-10
AEO 2001 Fuel Price Forecast ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.23	2.95	4.25	2.64	0.52	1.26
2001	1.25	3.07	4.46	2.88	0.53	1.28
2002	1.26	3.20	4.68	3.14	0.55	1.23
2003	1.28	3.34	4.90	3.43	0.56	1.20
2004	1.30	3.48	5.14	3.74	0.57	2.21
2005	1.31	3.64	5.40	4.08	0.59	2.23
2006	1.33	3.76	5.57	4.27	0.60	1.23
2007	1.34	3.88	5.76	4.46	0.62	1.26
2008	1.35	4.01	5.95	4.66	0.63	1.28
2009	1.37	4.14	6.15	4.87	0.65	1.32
2010	1.38	4.28	6.35	5.09	0.67	1.36
2011	1.41	4.40	6.58	5.25	0.68	1.40
2012	1.43	4.53	6.82	5.41	0.70	1.44
2013	1.45	4.67	7.06	5.58	0.72	1.51
2014	1.48	4.81	7.31	5.76	0.73	1.56
2015	1.50	4.95	7.57	5.94	0.75	1.62
2016	1.53	5.14	7.82	6.11	0.77	1.69
2017	1.56	5.35	8.07	6.28	0.79	1.77
2018	1.59	5.56	8.33	6.46	0.81	1.84
2019	1.62	5.78	8.60	6.65	0.83	1.92
Average Annual Escalation (%)	1.46%	3.61%	3.78%	4.98%	2.50%	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

Table 1A.5-11
AEO 2001 Escalation Applied to 2000 OUC Fuel Prices ($/MBtu)

Year	Coal	Natural Gas	No. 2 Oil	No. 6 Oil	Nuclear	Petroleum Coke
2000	1.67	5.03	5.79	4.42	0.52	1.26
2001	1.69	5.27	6.08	4.82	0.53	1.28
2002	1.71	5.52	6.37	5.26	0.55	1.23
2003	1.74	5.79	6.68	5.74	0.56	1.20
2004	1.76	6.08	7.01	6.26	0.57	2.21
2005	1.78	6.38	7.35	6.83	0.59	2.23
2006	1.80	6.61	7.60	7.14	0.60	1.23
2007	1.82	6.85	7.85	7.46	0.62	1.26
2008	1.84	7.10	8.11	7.80	0.63	1.28
2009	1.86	7.36	8.38	8.15	0.65	1.32
2010	1.88	7.63	8.66	8.52	0.67	1.36
2011	1.91	7.87	8.97	8.79	0.68	1.40
2012	1.94	8.12	9.29	9.06	0.70	1.44
2013	1.97	8.38	9.62	9.35	0.72	1.51
2014	2.01	8.65	9.97	9.64	0.73	1.56
2015	2.04	8.93	10.32	9.94	0.75	1.62
2016	2.08	9.31	10.65	10.22	0.77	1.69
2017	2.12	9.70	11.00	10.52	0.79	1.77
2018	2.16	10.11	11.35	10.82	0.81	1.84
2019	2.20	10.54	11.72	11.13	0.83	1.92
Average Annual Escalation (%)	1.46%	3.97%	3.78%	4.98%	2.50%	2.24%

Note: Fuel prices in nominal dollars including the general inflation rate. Natural gas prices include estimated transportation.

1A.5.3.2 Florida Gas Transmission Company

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 5,000 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation which, in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and El Paso Energy Corporation, one of the largest independent producers of natural gas in the United States.

The FGT pipeline system accesses a diversity of natural gas supply regions, including:

- Anadarko Basin (Texas, Oklahoma, and Kansas).
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana – Mississippi – Alabama Salt Basin.
- Mobile Bay.

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

1A.5.3.3 Florida Gas Transmission Market Area Pipeline System

The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

1A.5.3.4 Florida Gas Transmission Expansion Project

FGT filed for FERC approvals of the Phase IV expansion project December 2, 1998. The filing consists of expanding services to southwest Florida with 139 miles of underground pipelines. The $268 million Phase IV project will add more than 38,000 horsepower of compression, and associated facilities and will provide approximately 197 million cubic feet per day (MMcf/d) of incremental firm transportation service on an average annual basis. FGT announced in May of 2000 that construction related to the Phase IV had begun and is scheduled for service by the May 2001 target.

FGT's Phase V expansion project, filed with the FERC on December 1, 1999, will deliver natural gas to a variety of new and current FGT customers and make natural gas available to areas that have not previously had gas service. The Phase V expansion project is intended to add approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. The result of this expansion will be the addition of more than 428 MMcf/d of incremental mainline capacity to Florida. With an estimated cost of $466 million, the Phase V expansion plan has a target in-service date of April 1, 2002.

The Phase V expansion faced many changes that caused it to file an amended project application with FERC. After the Florida Supreme Court ruling that limited the ability of nonutility merchant plants to use the Florida Electrical Power Plant Siting Act, two major Phase V customers, Enron and Dynergy, withdrew from Phase V. However, FGT subsequently gained back some of the lost market by signing a long-term contract with Tampa Electric Company as a Phase V customer. FERC granted preliminary approval to the expansion in November of 2000. The Phase V expansion still requires final environmental approval.

FGT recently concluded an open season for Phase VI. FGT received what it defined as 'a positive response' to the open season. The intent of the project is to provide incremental firm transportation service to Florida. The new pipeline is proposed to extend from Savannah, Georgia, to Jacksonville, Florida, with access to Southern LNG Company's liquefied natural gas. Phase VI is scheduled for an in-service date of Spring 2003.

FERC approved in November of 2000 FGT's request for the purchase of an undivided interest in Koch Gateway Pipeline's Mobile Bay Lateral. This purchase will give FGT the right to an additional 300,000 MMcf/d of input capacity. The acquisition is set to become effective April 1, 2002.

1A.5.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida

There is currently one transportation company serving Peninsular Florida: FGT. Two additional pipelines, Buccaneer and Gulfstream, received preliminary approval from the Federal Energy Regulatory Commission (FERC) in April of last year. In September of last year, both pipelines also received one of the two required approvals from FERC.

In November of 2000, the developers of the Buccaneer gas pipeline, Williams Energy and Duke Energy, announced their intent to purchase the Gulfstream pipeline from Coastal Corporation. The purchase is subject to federal regulatory approvals and conditioned upon completion of the Coastal/El Paso Energy Corporation merger.

Duke Energy and Williams Energy will collaborate on the Gulfstream pipeline in lieu of the Buccaneer pipeline. Gulfstream has precedent agreements with 10 large Florida utilities and power generation facilities representing long-term commitments for the majority of its 1.1 billion cubic feet of gas per day capacity. The Gulfstream pipeline was designed primarily to serve Florida utilities and power generation facilities that plan on using high efficiency natural gas turbines to meet the incremental demand for electrical energy. The pipeline is discussed below. At this time, it is uncertain as to what effect the purchase will have on the pipeline configuration.

FGT, El Paso Merchant, and Gulfstream have all made competitive proposals to provide gas transportation to Stanton A.

1A.5.3.5.1 Gulfstream Pipeline. The Gulfstream pipeline is a 744 mile pipeline originally proposed by the Coastal Corporation. The pipeline will originate from the Mobile Bay region, crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline is expected to supply Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida.

The 1.6 billion dollar pipeline won FERC approval, subject to environmental review, on April 24, 2000. Final environmental and routing approvals by FERC are expected in March of 2001. Construction for the Gulfstream pipeline is scheduled to begin in June of 2001, with an estimated operation date of June of 2002. The first major acquisition of right-of-way occurred July 20, 2000, with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained the permanent right-of-way easement to cross through Port Manatee. In addition to a payment to Port Manatee, Coastal Corporation will lease up to 190 acres of vacant land at Port Manatee to serve as a logistics base during Gulfstream's construction phase.

- Decreases or increases in revenue due to demand-side programs will impact rate levels and will be passed on to all customers.
- Additional conservation taking place after the next deferred generating unit will affect subsequent units.

1A.8.1.1.1 FIRE Model Inputs. There are two types of FIRE Model input files. The first input file contains data specific to the utility's next proposed unit, the avoided unit. The second input file contains data specific to the DSM measure being tested for cost-effectiveness. Input data for the avoided unit is placed on a per kW basis. Because the avoided unit data is input on a per kW basis, the potential DSM measures can be tested individually to determine cost-effectiveness.

1A.8.1.1.2 Avoided Unit. The avoided unit used in the DSM analysis is the proposed Southern-Florida 633 MW 2 x 1 combined cycle unit. Stanton A is unique because it entails 35 percent ownership by OUC, KUA, and FMPA, which have a right to the remaining 65 percent of Stanton A capacity pursuant to PPAs with Southern-Florida. Therefore, the 35 percent ownership capacity will be considered the avoided unit since it represents the utility's ownership interest.

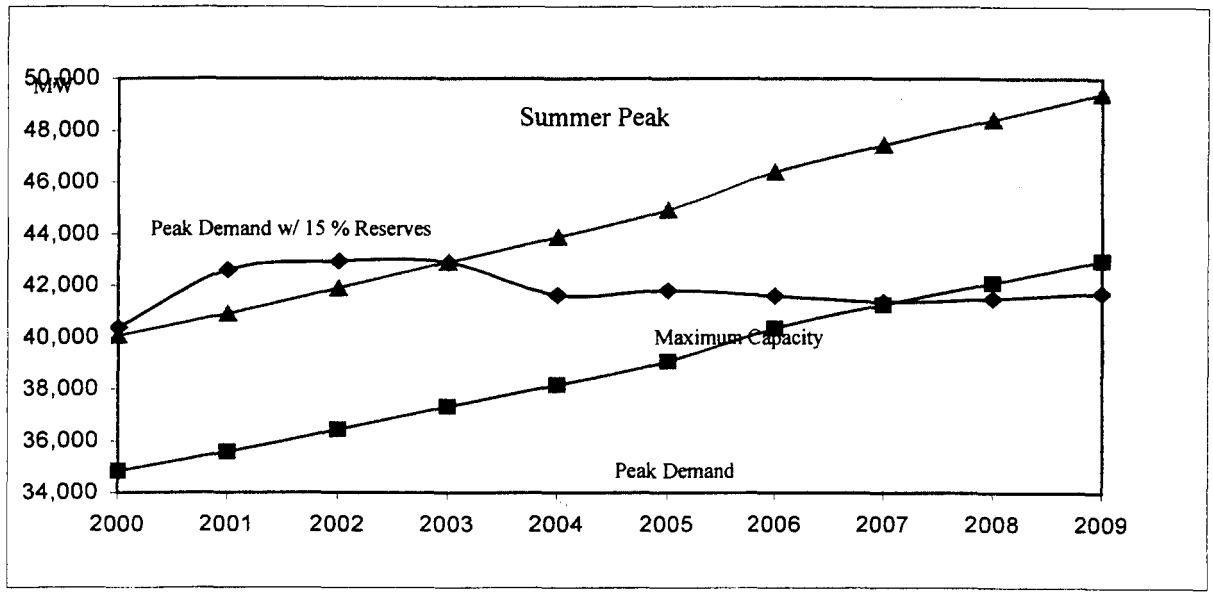
1A.8.1.1.3 DSM Measures. Potential DSM measures for cost-effective analyses were selected based on the potential to be cost-effective. OUC, KUA, and FMPA did not model each possible DSM measure; instead, OUC, KUA, and FMPA focused on alternatives that were expected to have the highest potential for being cost-effective.

The DSM measures analyzed were compiled from measures deemed cost-effective in the 2000 Demand-Side Management Plan of Florida Power & Light (FPL). By testing the most cost-effective measures from FPL, the assumption was made that if the most cost-effective measure for FPL did not prove cost-effective for OUC, KUA, and FMPA, then FPL's lesser cost-effective measures would also fail the analysis. Using this methodology, OUC, KUA, and FMPA have effectively screened all of FPL's measures.

FPL's most cost-effective residential measure is Direct Load Control and its most cost-effective commercial/industrial measure is Off-Peak Battery Charging. OUC, KUA, and FMPA separately tested both FPL measures. The FIRE Model results for OUC, KUA, and FMPA can be found in Volumes 1B, 1C, and 1D, respectively.

1A.8.1.2 FIRE Model Outputs

FIRE Model results are presented in the form of three cost-effectiveness tests. All the DSM cost-effectiveness tests are based on the comparison of discounted present worth benefits to costs for a specific DSM measure. Each test is designed to measure costs and benefits from a different perspective.



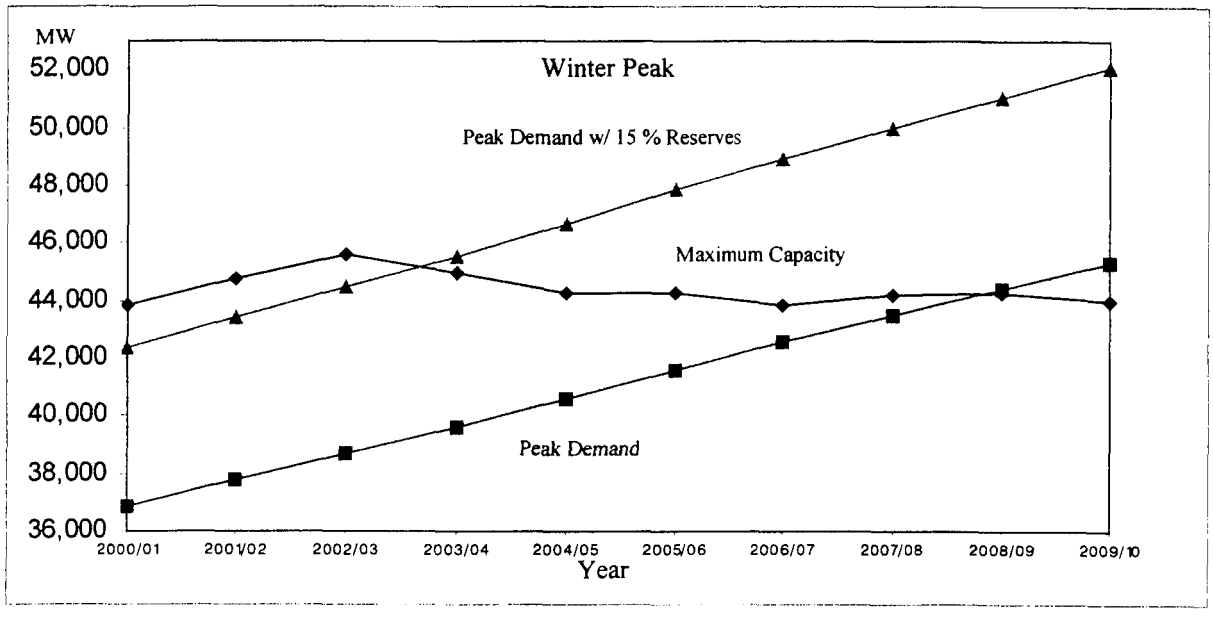


Figure 1A.9-1
2000 Load and Resource Plan – Peak Demand and Reserve Margin
Excluding Capacity Required to be Approved Under the Florida Electrical Power Plant Siting Act but Not Yet Approved

Stanton Energy Center Combined Cycle Unit A

Need for Power Application

Orlando Utilities Commission - Volume 1B

Project Number 97185

March 5, 2001

BLACK & VEATCH

11401 Lamar, Overland Park, Kansas, 66211, USA (913) 458-2000

Table 1B.2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability[1]	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	41.400	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	41.400	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	122.040	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	122.040	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.580	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	464.580	319.3	319.3
McIntosh	3	Polk	ST	BIT	REF	RR	TK	09/82	Unknown	363.870	133	136
Crystal River	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	890.460	13	13
St. Lucie[2]	2	St. Lucie	NP	UR	---	TK	---	08/83	Unknown	839.000	51	52
St. Cloud[3]	1	Osceola	IC	NG	FO2	PL	TK	07/82	11/04	2.000	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	11/04	5.850	5.85	5
	3		IC	NG	FO2	PL	TK	09/82	11/04	2.000	2	1.825
	4		IC	NG	FO2	PL	TK	08/61	11/04	3.750	3	3
	6		IC	NG	FO2	PL	TK	03/67	11/04	3.750	3	3
	7		IC	NG	FO2	PL	TK	09/82	11/04	6.300	6	6
	8		IC	NG	FO2	PL	TK	04/77	11/04	6.445	6	6

OUC ownership share.

OUC owns St. Lucie Unit No. 2. Reliability exchange divides 50% power from Unit No. 1 and 50% power from Unit No. 2.

St. Cloud No. 8 has never been connected to the grid and, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

and water conservation. Students are taught how electricity is generated and are encouraged to perform mini electric and water audits on their own homes.

1B.5.1.6 Commercial Energy Survey Program

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. The program is focused on commercial customers to increase the energy efficiency and energy conservation. OUC has also developed an alliance with a large performance contractor in order to provide large commercial customers with a more complete solution to their needs.

1B.5.2 Analysis of Demand-Side Management Alternatives

OUC used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8. The results of that analysis are as follows.

1B.5.2.1 FIRE Model Output Analysis

OUC requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, OUC has concluded that there are no cost-effective DSM measures reasonably available that would avoid or defer the need for Stanton A. Table 1B.5-2 presents the FIRE model results of the DSM analysis.

Table 1B.5-2
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.49	1.00	2.33
Commercial			
Off-Peak Battery Charging	0.98	0.00	0.62

The results of the DSM analysis are not surprising due to the previously performed analysis for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for Cane Island Unit 3 (Docket

nature of OUC's relatively small, high interconnected system, LOLP for OUC's system is driven almost entirely by the interconnections. Since the reliability of the interconnections is driven by the capacity from other systems available to the interconnection, the reliability of interconnections is difficult to predict and is generally out of the control of OUC. For these reasons, OUC does not use LOLP as the reliability criterion and instead uses the reserve margin criterion. LOLP is much better suited for measuring reliability of large systems such as FRCC.

1B.6.2 Reliability Need

Since OUC has elected to use a 15 percent reserve margin criterion, OUC applies it to St. Cloud's load as well as partial requirements (PR) purchases and sales. Tables 1B.6-1 and 1B.6-2 display the forecast reserve margins for OUC and St. Cloud for the winter and summer seasons, respectively.

Table 1B.6-1 indicates that additional capacity will be needed by the winter of 2002. Furthermore, Table 1B.6-2 shows that additional capacity will be necessary to satisfy forecast demand requirements for the summer of 2002. The majority of the capacity required in 2002 and 2003 can be satisfied by exercising the additional 10 percent option on the Reliant contract, which represents 52.5 MW. Regardless, OUC will need a substantial amount of capacity beginning with the expiration of the Reliant agreement on October 1, 2003.

1B.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of OUC's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine OUC's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluation analyses are presented in Section 1B.5.0. The proposal evaluations are presented in Section 1A.6. The sensitivity analyses are discussed in Section 1B.8.0.

1B.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan. OUC's and St. Cloud's systems were combined for purposes of expansion planning.

1B.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation represent the conventional alternatives presented in Section 1A.7. Table 1B.7-1 summarizes the expansion alternatives considered for OUC in the optimization study for supply-side alternatives.

Table 1B.7-1
Summary of OUC Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal	513,163	446	3.73	14.17	Coal	9,979	3.0	30	2006
Fluidized Bed	366,076	267	5.53	23.55	Pet. Coke	10,543	3.0	28	2005
501F 2x1 CC (standard)	275,756[4]	514	[redacted]	[redacted]	Nat. Gas	7,074	4.0	[redacted]	2005
501F 2x1 CC (oversized)	288,211[4]	610	[redacted]	[redacted]	Nat. Gas	7,542	4.0	[redacted]	2005
7FA SC	68,615	156	2.33	5.13	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[3]	232,169[4]	488	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[3]	[redacted]	171	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	[redacted]	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. (2003 $)
3. Reflects OUC's portion of total generation alternative capacity.
4. Mixed year dollars to reflect commercial operation date of October 1, 2003.
5. October 1, 2003.

1B.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7 and summarized in Table 1B.7-1. Production costs were modeled at temperatures which closely approximate (within 2 degrees) the average annual temperature for OUC. Winter and summer unit ratings were used to determine capacity requirements.

The expansion plan outlined in Table 1B.7-2 shows that the joint development project with Southern-Florida is the least-cost capacity addition plan for OUC under the base case scenario. For comparison purposes, Table 1B7-3 displays the least-cost expansion capacity addition plan for OUC that does not include the joint-development project with Southern-Florida. The units and power purchases comprising the expansion plans are listed in the tables according to their year of commercial operation. Tables 1B.7-4 through 1B.7-7 present the summer and winter capacity balances for the expansion plans presented in Tables 1B.7-2 and 1B.7-3, respectively. Appendix 1B.B presents tables showing the fuel, O&M, and capital costs for expansion plans on an annual basis.

The addition of the Southern-Florida joint development project and the self-build General Electric 7FA 2x1 combined cycle represent the only two available alternatives that allow OUC to meet OUC's reserve requirements in 2004. In fact, even the self-build General Electric 7FA 2x1 combined cycle is no longer an option because it was based on obtaining the General Electric 7FA combustion turbines that KUA had under option with General Electric. The option for the two General Electric 7FA combustion turbines expired on September 30, 2000. However, the option was available during the time that OUC was evaluating the joint development and purchase power proposals and is presented to demonstrate the prudence of the selection of the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement does not provide sufficient capacity for OUC to meet its capacity requirements in 2004 without the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement would still result in a 93 MW shortfall for OUC in the summer of 2004 as demonstrated by Table 1B.6-2. OUC is precluded from installing other options until at least 2005 as shown in Table 1B.7-1 due to the delivery schedule for combustion turbines.

It is clear from a comparison of Tables 1B.7-2 and 1B.7-3 that the joint development project with Southern-Florida provides the most cost-effective solution to satisfy OUC's forecast capacity requirements. The joint development project with Southern-Florida results in a projected $6.611 million in cumulative present worth savings over the self-build alternative while providing the flexibility and strategic advantages discussed in Section 1A.6.4.

Table 1B.7-2
OUC Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,239	294,508
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,252	441,329
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	162,007	585,812
2004	171 MW Joint Development with Southern – Florida (10/03)	220,059	747,562
	317 MW Southern – Florida Power Purchase (10/03)		
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	221,751	898,482
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	216,636	1,034,999
2007	156 MW GE 7FA Simple Cycle (06/07)	230,334	1,169,397
2008	156 MW GE 7FA Simple Cycle (06/08)	245,040	1,301,784
2009		264,023	1,433,862
2010		271,624	1,559,676
2011		280,395	1,679,933
2012		294,709	1,796,966
2013	Terminate 317 MW Southern – Florida Power Purchase (11/13)	306,249	1,909,573
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		333,383	2,023,077
2015		348,476	2,132,931
2016		361,220	2,238,368
2017		374,723	2,339,644
2018		393,013	2,437,995
2019		413,921	2,533,905

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.7-3
OUC Base Case Expansion Plan – Runner Up #1

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,239	294,508
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,252	441,329
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	183,056	586,644
2004	488 MW Self-Build GE 7FA 2x1 (10/03)	219,114	747,699
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	220,746	897,935
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	218,215	1,035,448
2007	156 MW GE 7FA Simple Cycle (06/07)	233,111	1,171,466
2008	156 MW GE 7FA Simple Cycle (06/08)	243,714	1,303,137
2009		263,213	1,434,809
2010		271,205	1,560,429
2011		278,923	1,680,055
2012		294,851	1,797,144
2013		307,495	1,910,209
2014		339,450	2,025,779
2015		339,155	2,132,694
2016	156 MW GE 7FA Simple Cycle (06/16)	364,773	2,239,168
2017		378,698	2,341,518
2018		406,327	2,443,201
2019		419,978	2,540,516

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.7-4
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1213	465	1679	219	196	23
2005	1227	172	1399	1192	449	1641	242	201	41
2006	1254	139	1393	1192	434	1626	233	203	29
2007	1278	139	1417	1332	324	1656	239	210	28
2008	1306	142	1448	1472	324	1796	348	215	133
2009	1339	144	1483	1472	324	1796	313	220	92
2010	1372	146	1518	1472	324	1796	278	225	53
2011	1399	0	1399	1472	324	1796	396	208	189
2012	1428	0	1428	1472	324	1796	368	212	156
2013	1463	0	1463	1472	309	1781	318	219	98
2014	1495	0	1495	1953	0	1953	457	224	233
2015	1526	0	1526	1953	0	1953	427	229	198
2016	1557	0	1557	1953	0	1953	395	234	162
2017	1591	0	1591	1953	0	1953	361	239	123
2018	1625	0	1625	1953	0	1953	328	244	84
2019	1656	0	1656	1953	0	1953	297	248	48

[1]Includes St. Cloud.

Table 1B.7-5
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1273	492	1765	293	198	95
2005	1239	172	1411	1252	476	1729	317	203	114
2006	1267	139	1406	1252	461	1714	308	205	103
2007	1292	139	1431	1427	351	1779	348	212	135
2008	1323	142	1465	1602	351	1954	489	218	271
2009	1356	144	1500	1602	351	1954	454	223	231
2010	1386	146	1532	1602	351	1954	422	228	194
2011	1416	0	1416	1602	351	1954	537	210	327
2012	1449	0	1449	1602	351	1954	505	215	290
2013	1480	0	1480	1602	336	1939	458	222	236
2014	1512	0	1512	2166	0	2166	655	227	428
2015	1542	0	1542	2166	0	2166	624	231	393
2016	1572	0	1572	2166	0	2166	594	236	358
2017	1608	0	1608	2166	0	2166	558	241	316
2018	1643	0	1643	2166	0	2166	523	246	277
2019	1675	0	1675	2166	0	2166	491	251	240

[1]Includes St. Cloud.

Table 1B.7-6
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1523	156	1679	219	196	23
2005	1227	172	1399	1501	140	1641	242	201	41
2006	1254	139	1393	1501	125	1626	233	203	29
2007	1278	139	1417	1641	15	1656	239	210	28
2008	1306	142	1448	1781	15	1796	348	215	133
2009	1339	144	1483	1781	15	1796	313	220	92
2010	1372	146	1518	1781	15	1796	278	225	53
2011	1399	0	1399	1781	15	1796	396	208	189
2012	1428	0	1428	1781	15	1796	368	212	156
2013	1463	0	1463	1781	0	1781	318	219	98
2014	1495	0	1495	1781	0	1781	285	224	61
2015	1526	0	1526	1781	0	1781	255	229	26
2016	1557	0	1557	1921	0	1921	363	234	130
2017	1591	0	1591	1921	0	1921	330	239	91
2018	1625	0	1625	1921	0	1921	296	244	52
2019	1656	0	1656	1921	0	1921	265	248	17

[1]Includes St. Cloud.

Table 1B.7-7
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1609	156	1765	293	198	95
2005	1239	172	1411	1589	140	1729	317	203	114
2006	1267	139	1406	1589	125	1714	308	205	103
2007	1292	139	1431	1764	15	1779	348	212	135
2008	1323	142	1465	1939	15	1954	489	218	271
2009	1356	144	1500	1939	15	1954	454	223	231
2010	1386	146	1532	1939	15	1954	422	228	194
2011	1416	0	1416	1939	15	1954	537	210	327
2012	1449	0	1449	1939	15	1954	505	215	290
2013	1480	0	1480	1939	0	1939	458	222	236
2014	1512	0	1512	1939	0	1939	427	227	200
2015	1542	0	1542	1939	0	1939	397	231	166
2016	1572	0	1572	1939	0	1939	366	236	130
2017	1608	0	1608	2114	0	2114	505	241	264
2018	1643	0	1643	2114	0	2114	471	246	224
2019	1675	0	1675	2114	0	2114	439	251	187

[1]Includes St. Cloud.

1B.8.0 Sensitivity Analysis

OUC performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1B.8.1 through 1B.8.7 and include low and high fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1B.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1B.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1B.8-2 presents the runner-up expansion plan. The plan including the joint development alternative is $18.96 million lower than the plan with the self-build alternative indicating the benefit of flexibility with the joint development project.

1B.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1B.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1B.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $4.55 million cumulative present worth savings over the self-build plan.

1B.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1B.8-5. Table 1B.8-6 presents the

runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $6 million lower in cumulative present worth cost.

1B.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1B.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1B.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows its increasing value with a $284 million savings over the plan with the self-build project.

1B.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1B.8-9 and Table 1B.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $9 million.

1B.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1B.4. Tables 1B.8-11 and 1B.8-12 indicate the summer and winter need for capacity based upon the high load and energy forecast.

As indicated in Table 1B.8-11, the high load and energy growth scenario results in a 59 MW capacity shortfall in the summer of 2002. Since the only option available to OUC for the summer of 2002 and 2003 is the additional 52.5 MW purchase from the Reliant Agreement, it has been assumed that OUC will purchase power on the spot market to make up the resultant deficit.

As indicated in Table 1B.8-12, the high load and energy growth scenario results in a capacity shortfall in the winter of 2002. The additional 52.5 MW purchase from the Reliant Agreement will satisfy OUC's needs for the winter of 2002 as well as for the winter of 2003.

Table 1B.8-13 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1B.8-14 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the self-build alternative is $24.4 million lower in cost than the plan including joint development project. It is not surprising that continued assured high growth would favor the self-build plan. The joint development project has been structured to provide relatively greater protection to OUC in scenarios that would have negative consequences such as loss of retail load or increases in the cost of fuel than it would be scenarios that would have positive consequences such as higher load growth or lower fuel prices.

1B.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1B.4.0. Tables 1B.8-15 and 1B.8-16 indicate the summer and winter need for capacity based upon the low load and energy forecast.

Capacity is required beginning in the summer of 2002 and the winter of 2004 for the low load and energy forecast. The extension of the 52.5 MW Reliant Agreement option will satisfy OUC's capacity requirements in the summer of 2002 and 2003 for the low load and energy growth scenario.

Table 1B.8-17 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1B.8-18 presents the runner-up expansion plan. Over the entire 20 year planning horizon, the cumulative present worth cost of the joint development alternative is only $90,000 over the cost of the self-build alternative. Notably, closer examination of Tables 1B.8-17 and 1B.8-18 indicate that the joint development alternative was lower in cumulative present worth cost every year until 2019. As discussed in Section 1A.4.1, the PPA has provisions for reducing the contract demand beginning in the sixth year. While this provision has not been explicitly evaluated, it would have significant economic benefit to OUC in a scenario such as this with low load and energy growth.

Table 1B.8-1
OUC High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,296	296,413
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	174,126	448,270
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	190,849	599,772
2004	171 MW Joint Development with Southern–Florida (10/03)	231,489	769,923
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	236,101	930,610
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	233,753	1,077,914
2007	156 MW GE 7FA SC (06/07)	251,687	1,224,771
2008	156 MW GE 7FA SC (06/08)	270,915	1,371,138
2009		295,247	1,518,834
2010		307,799	1,661,405
2011		323,212	1,800,025
2012		344,259	1,936,735
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	363,258	2,070,305
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		396,384	2,205,258
2015		419,684	2,337,560
2016		441,382	2,466,395
2017		465,221	2,592,130
2018		496,565	2,716,395
2019		529,979	2,839,197

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-2
OUC High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,296	296,413
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,126	418,270
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	191,948	600,644
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	230,795	770,286
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	235,695	930,695
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	235,886	1,079,344
2007	156 MW GE 7FA Simple Cycle (06/07)	254,957	1,228,108
2008	156 MW GE 7FA Simple Cycle (06/08)	270,225	1,374,102
2009		294,810	1,521,581
2010		307,904	1,664,200
2011		322,025	1,802,311
2012		344,937	1,939,290
2013		365,063	2,073,523
2014		405,479	2,211,573
2015		414,694	2,342,302
2016	156 MW GE 7FA Simple Cycle (06/16)	451,016	2,473,949
2017		475,406	2,602,437
2018		518,102	2,732,091
2019		544,055	2,858,155

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-3
OUC Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,192	292,613
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,871	433,963
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,094	571,371
2004	171 MW Joint Development with Southern–Florida (10/03)	208,994	724,988
	317 MW Southern-Florida Power Purchase (10/03)		
2005	100 MW Reliant Power Purchase (10/03 - 09/04)		
2006	100 MW Reliant Power Purchase (10/04 - 09/05)	207,750	866,379
2007	100 MW Reliant Power Purchase (10/05 - 09/06)	200,626	992,807
2008	156 MW GE 7FA SC (06/07)	210,874	1,115,850
2009	156 MW GE 7FA SC (06/08)	221,690	1,235,622
2010		236,622	1,353,992
2011		240,421	1,465,354
2012		245,689	1,570,725
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	254,781	1,671,903
	514 MW WH 501F 2x1 Combined Cycle (11/13)	261,501	1,768,056
2014			
2015		283,548	1,864,593
2016		292,001	1,956,644
2017		298,822	2,043,867
2018		306,041	2,126,580
2019		317,550	2,206,047
		328,694	2,282,209

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-4
OUC Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	168,192	292,613
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,871	433,963
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	174,271	572,305
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	208,291	725,406
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	207,098	866,353
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	202,650	994,057
2007	156 MW GE 7FA Simple Cycle (06/07)	213,997	1,118,922
2008	156 MW GE 7FA Simple Cycle (06/08)	220,775	1,238,200
2009		235,859	1,356,188
2010		240,138	1,467,419
2011		244,155	1,572,132
2012		254,857	1,673,340
2013		262,395	1,769,822
2014		288,183	1,867,937
2015		281,862	1,956,791
2016	156 MW GE 7FA Simple Cycle (06/16)	300,532	2,044,514
2017		308,417	2,127,869
2018		326,864	2,209,667
2019		332,718	2,286,762

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,921	118,921
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,380	238,256
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	130,892	344,455
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	148,674	462,477
2004	171 MW Joint Development with Southern–Florida (10/03)	190,039	602,161
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	193,703	733,992
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	188,233	852,611
2007	156 MW GE 7FA Simple Cycle (06/07)	199,987	969,301
2008	156 MW GE 7FA Simple Cycle (06/08)	213,237	1,084,507
2009		233,123	1,201,126
2010		238,759	1,311,718
2011		245,150	1,416,859
2012		256,120	1,518,567
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	266,644	1,616,612
	446 MW Pulverized Coal (11/13)		
2014		302,925	1,719,746
2015		310,247	1,817,549
2016		320,120	1,910,989
2017		327,099	1,999,393
2018		340,022	2,084,484
2019		356,216	2,167,023

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-6
OUC AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,921	118,921
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,380	232,236
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	130,892	344,455
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	149,656	463,257
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	189,375	602,453
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	193,434	734,101
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	190,400	854,085
2007	156 MW GE 7FA Simple Cycle (06/07)	203,025	972,548
2008	156 MW GE 7FA Simple Cycle (06/08)	212,032	1,087,102
2009		232,397	1,203,359
2010		238,513	1,313,836
2011		243,586	1,418,306
2012		256,263	1,520,072
2013		268,753	1,618,891
2014		300,157	1,721,083
2015		296,715	1,814,620
2016	156 MW GE 7FA Simple Cycle (06/16)	319,793	1,907,965
2017		332,233	1,997,757
2018		356,987	2,087,092
2019		370,876	2,173,029

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,466	282,967
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,039	437,322
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	203,058	598,516
2004	171 MW Joint Development with Southern–Florida (10/03)	253,620	784,934
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	258,420	960,810
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	250,414	1,118,614
2007	446 MW Pulverized Coal (06/07)	269,942	1,276,122
2008		288,247	1,431,853
2009		303,651	1,583,754
2010		310,518	1,727,584
2011		315,782	1,863,017
2012		327,195	1,992,951
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	340,189	2,118,038
	156 MW GE 7FA Simple Cycle (11/13)		
2014		338,452	2,233,268
2015		349,052	2,343,304
2016	156 MW GE 7FA Simple Cycle (06/08)	366,711	2,450,343
2017		382,870	2,553,821
2018		402,287	2,654,493
2019		428,066	2,753,681

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,466	282,967
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,039	437,522
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	201,995	597,672
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	251,916	782,838
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	258,438	958,726
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	252,843	1,118,060
2007	446 MW Pulverized Coal (06/07)	267,861	1,274,354
2008		285,990	1,428,866
2009		303,410	1,580,647
2010		312,674	1,725,475
2011		312,870	1,859,660
2012		327,155	1,989,578
2013		344,194	2,116,137
2014		362,857	2,239,676
2015		369,949	2,356,299
2016		389,837	2,470,089
2017		395,058	2,576,861
2018		412,529	2,680,096
2019		440,054	2,782,062

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	197,052	589,686
2004	171 MW Joint Development with Southern–Florida (10/03)	247,056	771,280
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	251,529	942,466
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	244,615	1,096,615
2007	156 MW GE 7FS Simple Cycle (06/07)	260,608	1,248,677
2008	156 MW GE 7FS Simple Cycle (06/08)	276,878	1,398,266
2009		303,257	1,549,970
2010		311,701	1,694,348
2011		319,979	1,831,581
2012		335,338	1,964,749
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	349,905	2,093,408
	446 MW Pulverized Coal (11/13)		
2014		380,309	2,222,888
2015		392,229	2,346,535
2016		407,450	2,465,466
2017		416,981	2,578,163
2018		431,843	2,686,231
2019		452,146	2,790,999

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	196,022	588,868
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	245,124	769,042
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	250,986	939,859
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	246,819	1,095,397
2007	267 MW Circulating Fluidized Bed (06/07)	270,023	1,252,952
2008		283,728	1,406,242
2009		303,691	1,558,163
2010		311,841	1,702,606
2011		317,723	1,838,872
2012		333,218	1,971,197
2013		350,713	2,100,154
2014		383,039	2,230,564
2015		385,175	2,351,987
2016	156 MW GE 7FA Simple Cycle (06/16)	407,963	2,471,067
2017		418,305	2,584,122
2018		439,226	2,694,038
2019		457,245	2,799,987

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-11
OUC Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1100	341	1441	1047	608	1655	214	177	37
2002	1139	323	1462	1047	540	1587	125	184	(59)
2003	1180	312	1492	1047	540	1587	95	191	(96)
2004	1222	263	1485	1047	15	1062	-423	199	(622)
2005	1265	172	1437	1025	15	1040	-397	207	(604)
2006	1301	139	1440	1025	15	1040	-400	210	(610)
2007	1337	139	1476	1025	15	1040	-436	219	(655)
2008	1375	142	1517	1025	15	1040	-477	225	(702)
2009	1413	144	1557	1025	15	1040	-517	231	(749)
2010	1453	146	1599	1025	15	1040	-559	238	(797)
2011	1493	0	1493	1025	0	1025	-468	224	(691)
2012	1533	0	1533	1025	0	1025	-508	230	(738)
2013	1575	0	1575	1025	0	1025	-550	236	(786)
2014	1618	0	1618	1025	0	1025	-593	243	(836)
2015	1662	0	1662	1025	0	1025	-637	249	(886)
2016	1708	0	1708	1025	0	1025	-683	256	(939)
2017	1755	0	1755	1025	0	1025	-730	263	(993)
2018	1803	0	1803	1025	0	1025	-778	270	(1048)
2019	1852	0	1852	1025	0	1025	-827	278	(1105)

Table 1B.8-12
OUC Winter Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1092	341	1433	1092	608	1700	267	176	91
2002	1135	323	1458	1092	540	1632	174	183	(9)
2003	1179	312	1491	1092	540	1632	141	191	(51)
2004	1225	263	1488	1092	15	1107	-381	200	(581)
2005	1273	172	1445	1071	15	1086	-359	208	(567)
2006	1309	139	1448	1071	15	1086	-362	212	(574)
2007	1347	139	1486	1071	15	1086	-400	221	(621)
2008	1386	142	1528	1071	15	1086	-442	227	(668)
2009	1425	144	1569	1071	15	1086	-483	233	(716)
2010	1466	146	1612	1071	15	1086	-526	240	(766)
2011	1505	0	1505	1071	0	1071	-434	226	(660)
2012	1546	0	1546	1071	0	1071	-475	232	(707)
2013	1587	0	1587	1071	0	1071	-516	238	(755)
2014	1630	0	1630	1071	0	1071	-559	245	(804)
2015	1674	0	1674	1071	0	1071	-603	251	(854)
2016	1720	0	1720	1071	0	1071	-649	258	(907)
2017	1767	0	1767	1071	0	1071	-696	265	(961)
2018	1815	0	1815	1071	0	1071	-744	272	(1017)
2019	1865	0	1865	1071	0	1071	-794	280	(1074)

Table 1B.8-13
OUC High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,316	295,505
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,482	444,237
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,502	592,289
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	224,943	757,629
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	230,976	914,827
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	226,792	1,057,744
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	244,455	1,200,381
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	258,724	1,340,162
2009		286,270	1,483,368
2010		296,837	1,620,861
2011		306,477	1,752,304
2012		322,542	1,880,389
2013		337,271	2,004,403
2014		359,225	2,126,705
2015		370,994	2,243,658
2016		391,488	2,357,930
2017		412,787	2,469,493
2018		433,819	2,578,056
2019	156 MW GE 7FA Simple Cycle (06/19)	459,965	2,684,636

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-14
OUC High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,316	295,505
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,482	444,237
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,448	592,246
2004	171 MW Joint Development with Southern-Florida (10/03)	229,304	760,791
	317 MW Southern-Florida Power Purchase (10/03)		
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	232,466	919,004
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	229,273	1,063,485
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	246,638	1,207,396
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	259,828	1,347,773
2009		288,881	1,492,285
2010		299,302	1,630,920
2011		308,461	1,763,213
2012		324,990	1,892,271
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	336,629	2,016,049
	156 MW GE 7FA Simple Cycle (11/13)		
2014		346,693	2,134,084
2015	156 MW GE 7FA Simple Cycle (06/15)	369,997	2,250,723
2016		391,959	2,365,132
2017		415,571	2,477,448
2018	267 MW Circulating Fluidized Bed (06/18)	459,699	2,592,487
2019		502,907	2,709,017

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-15
OUC Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1084	341	1425	1047	608	1655	230	175	55
2002	1106	323	1429	1047	540	1587	158	179	(21)
2003	1129	312	1441	1047	540	1587	146	184	(38)
2004	1152	263	1415	1047	15	1062	-353	189	(542)
2005	1176	172	1348	1025	15	1040	-308	194	(502)
2006	1192	139	1331	1025	15	1040	-291	194	(485)
2007	1209	139	1348	1025	15	1040	-308	200	(508)
2008	1226	142	1368	1025	15	1040	-328	203	(531)
2009	1243	144	1387	1025	15	1040	-347	206	(552)
2010	1260	146	1406	1025	15	1040	-366	209	(575)
2011	1275	0	1275	1025	0	1025	-250	191	(442)
2012	1291	0	1291	1025	0	1025	-266	194	(460)
2013	1307	0	1307	1025	0	1025	-282	196	(478)
2014	1323	0	1323	1025	0	1025	-298	198	(496)
2015	1339	0	1339	1025	0	1025	-314	201	(515)
2016	1355	0	1355	1025	0	1025	-330	203	(533)
2017	1371	0	1371	1025	0	1025	-346	206	(551)
2018	1387	0	1387	1025	0	1025	-362	208	(570)
2019	1403	0	1403	1025	0	1025	-378	211	(589)

Table 1B.8-16
OUC Winter Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1078	341	1419	1092	608	1700	281	174	107
2002	1106	323	1429	1092	540	1632	203	179	24
2003	1134	312	1446	1092	540	1632	186	184	1
2004	1163	263	1426	1092	15	1107	-319	191	(510)
2005	1193	172	1365	1071	15	1086	-279	196	(475)
2006	1210	139	1349	1071	15	1086	-263	197	(459)
2007	1227	139	1366	1071	15	1086	-280	203	(482)
2008	1244	142	1386	1071	15	1086	-300	206	(506)
2009	1261	144	1405	1071	15	1086	-319	209	(528)
2010	1279	146	1425	1071	15	1086	-339	212	(551)
2011	1294	0	1294	1071	0	1071	-223	194	(418)
2012	1310	0	1310	1071	0	1071	-239	197	(436)
2013	1326	0	1326	1071	0	1071	-255	199	(454)
2014	1342	0	1342	1071	0	1071	-271	201	(472)
2015	1358	0	1358	1071	0	1071	-287	204	(491)
2016	1374	0	1374	1071	0	1071	-303	206	(509)
2017	1390	0	1390	1071	0	1071	-319	209	(528)
2018	1407	0	1407	1071	0	1071	-336	211	(547)
2019	1423	0	1423	1071	0	1071	-352	213	(566)

Table 1B.8-17
OUC Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	161,522	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,665	436,942
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	156,304	576,898
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	211,593	732,425
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,802	877,935
2006		207,424	1,008,647
2007	156 MW GE 7FA SC (06/07)	211,585	1,132,105
2008		220,912	1,251,457
2009		239,899	1,371,467
2010		241,165	1,483,172
2011		246,476	1,588,882
2012		259,106	1,691,776
2013		268,149	1,790,374
2014		299,017	1,892,178
2015		292,159	1,984,278
2016		313,582	2,075,810
2017		307,061	2,158,799
2018		333,532	2,242,265
2019		339,328	2,320,891

Note: Capacity is stated at average annual temperature for OUC.

Table 1B.8-18
OUC Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,665	436,942
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	172,724	574,056
2004	171 MW Joint Development with Southern–Florida (10/03)	214,166	731,474
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,366	876,687
2006		203,692	1,005,047
2007	156 MW GE 7FA SC (06/07)	216,845	1,131,574
2008		225,042	1,253,157
2009		237,138	1,371,786
2010		241,196	1,483,506
2011		247,667	1,589,726
2012		259,560	1,692,801
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	264,093	1,789,907
	Extension of 317 MW Southern-Florida Power Purchase (11/13)		
2014		297,971	1,891,355
2015		291,445	1,983,230
2016		313,141	2,074,633
2017		308,630	2,158,046
2018	Terminate 317 MW Southern–Florida Power Purchase (11/18)	331,107	2,240,905
	514 MW WH 501F 2x1 Combined Cycle (11/18)		
2019		345,582	2,320,981

Note: Capacity is stated at average annual temperature for OUC.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Base Case
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833		
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,239	0	162,239	294,506
2002	147,392	20,870	2,989	0	171,252	0	171,252	441,329
2003	147,248	22,448	10,227	(219)	179,705	2,303	182,007	585,812
2004	150,345	26,676	34,710	(882)	210,848	9,210	220,059	747,562
2005	151,703	28,059	33,674	(895)	212,540	9,210	221,751	898,462
2006	149,461	27,782	31,091	(908)	207,426	9,210	216,636	1,034,999
2007	160,655	29,669	26,251	(921)	215,653	14,681	230,334	1,169,397
2008	164,045	30,469	27,266	(935)	220,845	24,195	245,040	1,301,784
2009	176,711	32,318	27,744	(949)	235,824	28,199	264,023	1,433,862
2010	183,009	33,559	27,820	(964)	243,425	28,199	271,624	1,559,876
2011	190,023	35,252	27,898	(978)	252,195	28,199	280,395	1,679,935
2012	202,945	36,580	27,979	(993)	266,510	28,199	294,709	1,796,966
2013	211,868	39,047	24,629	(1,009)	274,535	31,714	306,249	1,909,573
2014	215,684	40,435	7,717	(1,025)	263,011	70,372	333,383	2,023,077
2015	228,878	42,358	7,910	(1,041)	278,104	70,372	348,476	2,132,931
2016	239,262	44,537	8,107	(1,058)	290,848	70,372	361,220	2,238,368
2017	250,972	46,144	8,310	(1,075)	304,351	70,372	374,723	2,339,644
2018	266,669	48,547	8,518	(1,093)	322,641	70,372	393,013	2,437,995
2019	285,248	50,680	8,731	(1,111)	343,548	70,372	413,921	2,533,905

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Base Case
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,239	0	162,239	294,508
2002	147,392	20,870	2,989	0	171,252	0	171,252	441,329
2003	149,126	22,460	4,430	0	176,015	7,040	183,056	586,644
2004	154,106	26,841	10,006	0	190,952	28,161	219,114	747,699
2005	154,186	28,253	10,146	0	192,585	28,161	220,746	897,935
2006	153,546	27,837	8,671	0	190,054	28,161	218,215	1,035,448
2007	166,024	30,032	3,424	0	199,480	33,631	233,111	1,171,466
2008	165,379	30,704	4,486	0	200,569	43,145	243,714	1,303,137
2009	178,683	32,368	5,012	0	216,063	47,150	263,213	1,434,809
2010	185,254	33,664	5,137	0	224,055	47,150	271,205	1,560,429
2011	191,052	35,455	5,265	0	231,773	47,150	278,923	1,680,055
2012	205,553	36,751	5,397	0	247,700	47,150	294,851	1,797,144
2013	215,617	39,196	5,532	0	260,345	47,150	307,495	1,910,209
2014	245,428	41,202	5,670	0	292,300	47,150	339,450	2,025,779
2015	243,011	43,182	5,812	0	292,005	47,150	339,155	2,132,694
2016	258,930	45,207	6,654	0	310,792	53,982	364,773	2,239,168
2017	265,300	47,212	7,325	0	319,836	58,861	378,698	2,341,516
2018	290,162	49,797	7,508	0	347,466	58,861	406,327	2,443,201
2019	301,583	51,839	7,696	0	361,117	58,861	419,978	2,540,516

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	143,279	20,266	751	0	164,296	0	164,296	296,413
2002	153,267	20,870	2,989	0	177,126	0	177,126	438,270
2003	156,086	22,452	10,227	(219)	188,547	2,303	190,849	599,772
2004	161,763	26,687	34,710	(882)	222,278	9,210	231,489	769,923
2005	166,048	28,063	33,674	(895)	226,891	9,210	236,101	930,610
2006	166,494	27,865	31,091	(908)	224,542	9,210	233,753	1,077,914
2007	181,924	29,753	26,251	(921)	237,007	14,681	251,687	1,224,771
2008	189,810	30,579	27,266	(935)	246,720	24,195	270,915	1,371,138
2009	207,620	32,433	27,744	(949)	267,047	28,199	295,247	1,518,834
2010	219,088	33,705	27,820	(964)	279,600	28,199	307,799	1,661,405
2011	232,814	35,278	27,898	(978)	295,012	28,199	323,212	1,800,025
2012	252,380	36,695	27,979	(993)	316,060	28,199	344,259	1,936,766
2013	268,829	39,095	24,629	(1,009)	331,545	31,714	363,258	2,070,305
2014	278,866	40,454	7,717	(1,025)	326,012	70,372	396,384	2,205,258
2015	300,032	42,411	7,910	(1,041)	349,312	70,372	419,684	2,337,580
2016	319,497	44,464	8,107	(1,058)	371,010	70,372	441,382	2,466,496
2017	341,508	46,106	8,310	(1,075)	394,849	70,372	465,221	2,592,130
2018	370,212	48,556	8,518	(1,093)	426,193	70,372	496,565	2,716,305
2019	401,252	50,735	8,731	(1,111)	459,607	70,372	529,979	2,839,147

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	$ 134,287
2001	143,279	20,266	751	0	164,296	0	164,296	286,413
2002	153,267	20,870	2,989	0	177,126	0	177,126	438,270
2003	158,012	22,465	4,430	0	184,908	7,040	191,948	600,644
2004	165,779	26,849	10,006	0	202,634	28,161	230,795	770,286
2005	169,130	28,257	10,146	0	207,533	28,161	235,695	930,695
2006	171,139	27,914	8,671	0	207,725	28,161	235,886	1,079,344
2007	187,781	30,120	3,424	0	221,325	33,631	254,957	1,226,108
2008	191,774	30,819	4,486	0	227,079	43,145	270,225	1,374,102
2009	210,166	32,483	5,012	0	247,660	47,150	294,810	1,521,581
2010	221,824	33,793	5,137	0	260,754	47,150	307,904	1,664,200
2011	234,154	35,455	5,265	0	274,875	47,150	322,025	1,802,511
2012	255,516	36,873	5,397	0	297,787	47,150	344,937	1,939,290
2013	273,162	39,218	5,532	0	317,913	47,150	365,063	2,073,528
2014	311,401	41,258	5,670	0	358,329	47,150	405,479	2,211,578
2015	318,413	43,319	5,812	0	367,544	47,150	414,694	2,342,302
2016	345,089	45,291	6,654	0	397,034	53,982	451,016	2,475,949
2017	361,891	47,329	7,325	0	416,544	58,861	475,406	2,602,437
2018	401,865	49,867	7,508	0	459,241	58,861	518,102	2,732,091
2019	425,450	52,048	7,696	0	485,194	58,861	544,055	2,858,755

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,174	20,267	751	0	160,192	0	160,192	292,613
2002	141,016	20,867	2,989	0	164,871	0	164,871	433,963
2003	138,342	22,441	10,227	(219)	170,791	2,303	173,094	571,371
2004	139,286	26,670	34,710	(882)	199,784	9,210	208,994	724,966
2005	137,802	27,958	33,674	(895)	198,540	9,210	207,750	866,579
2006	133,452	27,780	31,091	(908)	191,415	9,210	200,626	992,807
2007	141,198	29,666	26,251	(921)	196,193	14,681	210,874	1,115,850
2008	140,694	30,471	27,266	(935)	197,495	24,195	221,690	1,235,822
2009	149,337	32,291	27,744	(949)	208,423	28,199	236,622	1,353,992
2010	151,791	33,574	27,820	(964)	212,221	28,199	240,421	1,466,354
2011	155,350	35,220	27,898	(978)	217,489	28,199	245,689	1,570,725
2012	163,034	36,563	27,979	(993)	226,582	28,199	254,781	1,671,903
2013	167,163	39,003	24,629	(1,009)	229,787	31,714	261,501	1,768,056
2014	166,066	40,417	7,717	(1,025)	213,176	70,372	283,548	1,864,593
2015	172,350	42,410	7,910	(1,041)	221,628	70,372	292,001	1,956,644
2016	176,910	44,491	8,107	(1,058)	228,450	70,372	298,822	2,043,867
2017	182,329	46,105	8,310	(1,075)	235,669	70,372	306,041	2,126,680
2018	191,214	48,539	8,518	(1,093)	247,178	70,372	317,550	2,206,047
2019	200,034	50,668	8,731	(1,111)	258,322	70,372	328,694	2,282,209

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,174	20,267	751	0	160,192	0	160,192	292,613
2002	141,016	20,867	2,989	0	164,871	0	164,871	433,963
2003	140,358	22,443	4,430	0	167,231	7,040	174,271	572,805
2004	143,286	26,838	10,006	0	180,130	28,161	208,291	725,406
2005	140,638	28,153	10,146	0	178,937	28,161	207,098	866,383
2006	137,988	27,830	8,671	0	174,489	28,161	202,650	994,057
2007	146,915	30,027	3,424	0	180,365	33,631	213,997	1,116,922
2008	142,432	30,712	4,486	0	177,630	43,145	220,775	1,238,200
2009	151,354	32,344	5,012	0	188,709	47,150	235,859	1,356,186
2010	154,170	33,661	5,137	0	192,988	47,150	240,138	1,467,419
2011	156,318	35,421	5,265	0	197,004	47,150	244,155	1,572,132
2012	165,583	36,727	5,397	0	207,707	47,150	254,857	1,673,340
2013	170,557	39,155	5,532	0	215,245	47,150	262,396	1,769,822
2014	194,192	41,171	5,670	0	241,033	47,150	288,183	1,867,937
2015	185,792	43,107	5,812	0	234,711	47,150	281,862	1,956,791
2016	194,753	45,143	6,654	0	246,550	53,982	300,532	2,044,514
2017	196,120	47,112	7,325	0	249,556	58,861	308,417	2,127,869
2018	210,689	49,807	7,508	0	268,003	58,861	326,864	2,209,687
2019	214,446	51,716	7,696	0	273,856	58,861	332,718	2,286,702

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
Pulverized Coal	446	513,163	42	2013.912	767,298	85,861

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,303	19,618	0	0	118,921	0	118,921	118,921
2001	101,306	20,324	751	0	122,380	0	122,380	232,236
2002	106,949	20,954	2,989	0	130,892	0	130,892	344,455
2003	113,861	22,502	10,227	(219)	146,371	2,303	148,674	482,477
2004	120,254	26,748	34,710	(882)	180,829	9,210	190,039	662,161
2005	123,706	28,008	33,674	(895)	184,493	9,210	193,703	833,992
2006	121,032	27,807	31,091	(908)	179,022	9,210	188,233	982,911
2007	130,310	29,668	26,251	(921)	185,307	14,681	199,987	1,139,301
2008	132,236	30,477	27,266	(935)	189,043	24,195	213,237	1,284,507
2009	145,831	32,297	27,744	(949)	204,923	28,199	233,123	1,421,126
2010	150,116	33,587	27,820	(964)	210,560	28,199	238,759	1,511,715
2011	154,774	35,256	27,898	(978)	216,951	28,199	245,150	1,618,559
2012	164,381	36,555	27,979	(993)	227,921	28,199	256,120	1,518,567
2013	167,780	39,128	25,391	(1,009)	231,289	35,355	266,644	1,616,612
2014	136,093	41,412	12,386	(1,025)	188,865	114,060	302,925	1,719,746
2015	141,067	43,466	12,695	(1,041)	196,187	114,060	310,247	1,817,549
2016	148,389	45,716	13,013	(1,058)	206,060	114,060	320,120	1,910,980
2017	153,367	47,409	13,338	(1,075)	213,038	114,060	327,099	1,999,393
2018	163,416	49,968	13,671	(1,093)	225,962	114,060	340,022	2,084,484
2019	176,831	52,422	14,013	(1,111)	242,156	114,060	356,216	2,167,023

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,303	19,618	0	0	118,921	0	118,921	118,921
2001	101,306	20,324	751	0	122,380	0	122,380	232,236
2002	106,949	20,954	2,989	0	130,892	0	130,892	344,455
2003	115,677	22,509	4,430	0	142,616	7,040	149,656	469,257
2004	124,286	26,922	10,006	0	161,214	28,161	189,375	602,453
2005	126,901	28,226	10,146	0	165,273	28,161	193,434	734,101
2006	125,694	27,873	8,671	0	162,239	28,161	190,400	854,085
2007	135,944	30,026	3,424	0	169,394	33,631	203,025	972,545
2008	133,699	30,702	4,486	0	168,887	43,145	212,032	1,087,102
2009	147,883	32,352	5,012	0	185,246	47,150	232,397	1,203,359
2010	152,521	33,705	5,137	0	191,362	47,150	238,513	1,313,856
2011	155,725	35,446	5,265	0	196,436	47,150	243,586	1,418,306
2012	166,993	36,722	5,397	0	209,113	47,150	256,263	1,520,072
2013	176,906	39,165	5,532	0	221,602	47,150	268,753	1,618,891
2014	206,114	41,222	5,670	0	253,007	47,150	300,157	1,721,083
2015	200,548	43,205	5,812	0	249,565	47,150	296,715	1,814,620
2016	213,941	45,216	6,654	0	265,811	53,982	319,793	1,907,965
2017	218,853	47,194	7,325	0	273,372	58,861	332,233	1,997,757
2018	240,877	49,741	7,508	0	298,126	58,861	356,987	2,087,092
2019	252,457	51,863	7,696	0	312,015	58,861	370,876	2,173,029

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: OUC 2000 + 2001 AEO Escalators
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833		
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,398	20,317	751	0	151,466	0	151,466	282,967
2002	156,097	20,953	2,989	0	180,039	0	180,039	437,322
2003	168,251	22,497	10,227	(219)	200,756	2,303	203,058	598,516
2004	183,770	26,812	34,710	(882)	244,410	9,210	253,620	784,934
2005	188,395	28,036	33,674	(895)	249,209	9,210	258,420	960,810
2006	183,187	27,834	31,091	(908)	241,204	9,210	250,414	1,118,614
2007	159,170	29,723	30,097	(921)	218,068	51,874	269,942	1,276,122
2008	142,314	31,101	33,418	(935)	205,898	82,348	288,247	1,431,863
2009	155,865	32,751	33,636	(949)	221,303	82,348	303,651	1,585,764
2010	160,948	34,326	33,860	(964)	228,169	82,348	310,518	1,727,584
2011	164,402	35,922	34,089	(978)	233,434	82,348	315,782	1,863,017
2012	174,107	37,409	34,324	(993)	244,847	82,348	327,195	1,992,951
2013	187,823	39,486	30,623	(1,009)	256,923	83,266	340,189	2,116,038
2014	193,236	41,631	11,254	(1,025)	245,095	93,357	338,452	2,233,288
2015	201,337	43,865	11,535	(1,041)	255,695	93,357	349,052	2,343,304
2016	209,158	45,902	12,521	(1,058)	266,523	100,188	366,711	2,450,343
2017	218,126	47,414	13,338	(1,075)	277,802	105,068	382,870	2,553,821
2018	234,588	50,052	13,671	(1,093)	297,219	105,068	402,287	2,654,493
2019	257,506	52,589	14,013	(1,111)	322,998	105,068	428,066	2,756,681

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: OUC 2000 + 2001 AEO Escalators
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,398	20,317	751	0	151,466	0	151,466	282,967
2002	156,097	20,953	2,989	0	180,039	0	180,039	437,322
2003	168,004	22,521	4,430	0	194,955	7,040	201,995	597,672
2004	186,763	26,986	10,006	0	223,755	28,161	251,916	782,838
2005	191,897	28,233	10,146	0	230,277	28,161	258,438	958,726
2006	187,994	28,017	8,671	0	224,682	28,161	252,843	1,118,060
2007	159,864	29,902	7,271	0	197,036	70,825	267,861	1,274,364
2008	142,807	31,246	10,638	0	184,691	101,299	285,990	1,428,068
2009	158,237	32,970	10,904	0	202,111	101,299	303,410	1,580,647
2010	165,638	34,561	11,176	0	211,375	101,299	312,674	1,725,475
2011	163,955	36,161	11,456	0	211,571	101,299	312,870	1,859,660
2012	176,595	37,518	11,742	0	225,856	101,299	327,155	1,989,578
2013	191,109	39,751	12,036	0	242,895	101,299	344,194	2,118,137
2014	207,583	41,639	12,337	0	261,558	101,299	362,857	2,239,676
2015	212,627	43,378	12,645	0	268,650	101,299	369,949	2,356,299
2016	229,515	46,062	12,961	0	288,538	101,299	389,837	2,470,089
2017	233,293	47,181	13,285	0	293,759	101,299	395,058	2,576,861
2018	247,653	49,960	13,617	0	311,230	101,299	412,529	2,680,096
2019	272,734	52,063	13,958	0	338,755	101,299	440,054	2,782,062

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
WH 501 F 2x1 (large)	630	267,633	24	2008.417	340,709	38,125
GE 7FA SC	156	68,615	12	2019.417	112,703	12,611

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,244	20,321	751	0	163,316	0	163,316	295,505
2002	149,486	21,006	2,989	0	173,482	0	173,482	444,237
2003	150,899	22,633	5,930	0	179,462	7,040	186,502	592,289
2004	153,835	26,966	15,981	0	196,782	28,161	224,943	757,629
2005	157,834	28,704	16,277	0	202,814	28,161	230,976	914,827
2006	153,715	28,340	16,575	0	198,631	28,161	226,792	1,057,744
2007	173,347	30,512	12,435	0	216,294	28,161	244,455	1,200,381
2008	171,395	31,838	5,090	0	208,323	50,401	258,723	1,340,152
2009	179,920	33,289	6,774	0	219,983	66,286	286,270	1,469,938
2010	188,465	35,122	6,944	0	230,551	66,286	296,837	1,591,861
2011	196,135	36,938	7,117	0	240,190	66,286	306,477	1,702,904
2012	210,110	38,850	7,295	0	256,255	66,286	322,542	1,800,380
2013	222,094	41,413	7,478	0	270,985	66,286	337,271	2,004,405
2014	241,706	43,567	7,665	0	292,938	66,286	359,225	2,126,795
2015	250,970	45,881	7,856	0	304,707	66,286	370,994	2,243,656
2016	268,465	48,685	8,053	0	325,202	66,286	391,488	2,357,950
2017	287,674	50,572	8,254	0	346,500	66,286	412,787	2,469,493
2018	305,215	53,857	8,460	0	367,532	66,286	433,819	2,578,056
2019	320,697	56,202	9,423	0	386,322	73,643	459,965	2,684,636

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purhase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
WH 501F 2x1 (large)	630	267,633	24	2008.417	340,709	38,125
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2015.417	102,103	11,425
CFB PC	267	366,076	36	2018.417	606,660	67,885

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,244	20,321	751	0	163,316	0	163,316	296,505
2002	149,486	21,006	2,989	0	173,482	0	173,482	444,237
2003	160,010	22,627	11,728	(219)	184,146	2,303	186,448	592,246
2004	153,337	26,954	40,685	(882)	220,094	9,210	229,304	760,791
2005	155,720	28,626	39,805	(895)	223,256	9,210	232,466	919,004
2006	153,632	28,343	38,996	(908)	220,062	9,210	229,273	1,069,485
2007	172,635	30,453	35,261	(921)	237,427	9,210	246,638	1,207,396
2008	169,703	31,740	27,870	(935)	228,378	31,450	259,828	1,347,773
2009	179,708	33,280	29,507	(949)	241,545	47,336	288,881	1,492,285
2010	188,183	35,120	29,627	(964)	251,966	47,336	299,302	1,638,920
2011	195,446	36,907	29,750	(978)	261,128	47,336	308,481	1,785,215
2012	209,974	38,797	29,877	(993)	277,654	47,336	324,990	1,932,271
2013	221,903	41,417	26,065	(1,009)	288,376	48,253	336,629	2,075,049
2014	239,218	43,574	6,582	(1,025)	288,349	58,344	346,693	2,134,084
2015	252,507	46,095	7,426	(1,041)	304,988	65,009	369,997	2,250,725
2016	266,418	48,726	8,104	(1,058)	322,189	69,770	391,959	2,365,132
2017	287,726	50,844	8,307	(1,075)	345,801	69,770	415,571	2,477,448
2018	279,329	57,829	14,264	(1,093)	350,330	109,369	459,699	2,592,487
2019	284,771	62,813	18,779	(1,111)	365,252	137,655	502,907	2,709,017

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	143,940	20,736	2,989	0	167,665	0	167,665	436,942
2003	142,628	22,206	4,430	0	169,264	7,040	176,304	676,858
2004	147,356	26,070	10,006	0	183,432	28,161	211,593	792,425
2005	149,764	27,309	8,568	0	185,641	28,161	213,802	877,935
2006	148,127	27,133	4,003	0	179,263	28,161	207,424	1,008,647
2007	151,825	28,174	3,424	0	183,423	28,161	211,585	1,132,105
2008	154,361	28,870	3,914	0	187,144	33,768	220,912	1,251,457
2009	167,869	30,246	4,011	0	202,127	37,773	239,899	1,371,467
2010	168,194	31,086	4,112	0	203,392	37,773	241,165	1,485,772
2011	172,166	32,323	4,215	0	208,703	37,773	246,476	1,588,682
2012	183,619	33,494	4,320	0	221,433	37,773	259,106	1,691,776
2013	190,701	35,247	4,428	0	230,376	37,773	268,149	1,790,374
2014	219,961	36,745	4,539	0	261,244	37,773	299,017	1,892,178
2015	211,723	38,011	4,652	0	254,386	37,773	292,159	1,984,278
2016	231,234	39,807	4,768	0	275,809	37,773	313,582	2,076,810
2017	223,667	40,744	4,888	0	269,288	37,773	307,061	2,158,799
2018	247,470	43,280	5,010	0	295,760	37,773	333,532	2,242,265
2019	252,503	43,917	5,135	0	301,555	37,773	339,328	2,320,891

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
WH 501F 2x1 (small)	514	258,481	24	2018.912	426,403	47,715

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,156
2002	143,940	20,735	2,989	0	167,665	0	167,665	436,042
2003	142,501	22,190	5,949	(219)	170,421	2,303	172,724	574,066
2004	145,194	25,933	34,710	(882)	204,955	9,210	214,168	731,474
2005	145,807	27,148	32,095	(895)	204,155	9,210	213,366	876,687
2006	142,133	26,833	26,423	(908)	194,481	9,210	203,692	1,005,047
2007	148,815	28,020	26,251	(921)	202,164	14,681	216,845	1,131,574
2008	152,046	28,650	26,693	(935)	206,454	18,588	225,042	1,263,157
2009	162,720	30,036	26,744	(949)	218,551	18,588	237,138	1,371,786
2010	165,872	30,905	26,795	(964)	222,608	18,588	241,196	1,483,506
2011	171,633	32,177	26,848	(978)	229,079	18,588	247,667	1,589,729
2012	181,861	33,203	26,901	(993)	240,972	18,588	259,560	1,699,891
2013	184,072	34,329	28,114	(1,009)	245,506	18,588	264,093	1,799,907
2014	210,726	35,743	33,940	(1,025)	279,383	18,588	297,971	1,901,915
2015	202,964	36,836	33,998	(1,041)	272,857	18,588	291,445	1,993,260
2016	222,714	38,840	34,057	(1,058)	294,553	18,588	313,141	2,074,653
2017	217,363	39,635	34,119	(1,075)	290,042	18,588	308,630	2,156,049
2018	237,723	42,228	29,683	(1,093)	308,543	22,564	331,107	2,240,905
2019	230,264	42,676	7,450	(1,111)	279,279	66,302	345,582	2,320,991

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Table of Contents (Continued)

1C.5.1.3 Commercial Cooling 5-4
1C.5.1.4 Residential Fix Up 5-5
1C.5.2 Analysis of Demand-Side Management Alternatives 5-5
1C.5.2.1 FIRE Model Output Analysis 5-5

1C.6.0 Reliability Criteria 6-1
1C.6.1 Development of Reliability Criteria 6-1
1C.6.1.1 Traditional Reserve Margin 6-1
1C.6.1.2 Loss of Load Probability 6-1
1C.6.2 Reliability Need 6-2

1C.7.0 Economic Analysis 7-1
1C.7.1 Methodology 7-1
1C.7.2 Expansion Candidates 7-1
1C.7.3 Results of Economic Analysis 7-3

1C.8.0 Sensitivity Analysis 8-1
1C.8.1 High Fuel Price Escalation 8-1
1C.8.2 Low Fuel Price Escalation 8-1
1C.8.3 AEO Fuel Price Projections 8-1
1C.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation 8-2
1C.8.5 Constant 2000 Fuel Price Projections 8-2
1C.8.6 High Load and Energy Growth 8-2
1C.8.7 Low Load and Energy Growth 8-3
1C.8.8 Sensitivity Analysis Summary 8-3

1C.9.0 Financial Analysis 9-1

Appendix 1C.A Economic Evaluation Spreadsheets

Tables

Table 1C.2-1 Kissimmee Utility Authority Existing Generating Facilities 2-3
Table 1C.2-2 KUA's Purchase Power 2-6
Table 1C.4-1 Scheduled Rate Increases 4-4

KUA believes that Stanton 2 represents the minimal cost and performance risk to its customers due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be KUA's most cost-effective alternative through exhaustive evaluations as well as a thorough test of the marketplace.

1C.1.2 Summary

KUA historically has been one of the fastest growing utilities in the United States with a 5.7 percent annual growth rate in peak demand over the last 10 years. Rapid growth is projected to continue with a 3.7 percent annual growth rate in peak demand projected through the end of the 20 year planning period. The development of the proposed World Exposition Center (Expo Center) in KUA's service territory is projected to contribute significantly to KUA's load growth. KUA has incorporated estimates of the direct loads from the Expo Center into KUA's forecast. Indirect loads from the Expo Center are likely to be significant and currently are only considered in sensitivity projections.

KUA is currently using a 15 percent reserve margin for planning purposes. KUA has a supplemental resale contract with Florida Power Corporation which allows KUA to purchase the capacity necessary to maintain a 15 percent reserve margin with the Expo Center's loads. While this purchase has not been explicitly included in KUA's expansion plans, KUA can implement it, if necessary, as the Expo Center loads develop. In 2004, KUA's reserve margin is projected to be negative with and without the Expo Center requiring the addition of capacity.

KUA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under the base case and all but one sensitivity condition.

would avoid or defer the need for Stanton A. Table 1C.5-3 presents the FIRE model results of the DSM analysis.

Table 1C.5-3
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
BuildSmart - EPI Less Than 90 - New Construction	0.44	0.71	[redacted]
Commercial			
Off-Peak Battery Charging	0.37	0.04	[redacted]

The results of the DSM analysis are not surprising due to the previously performed analyses for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for KUA and FMPA for Cane Island Unit 3 (Docket No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand-Side Management Ten Year Plans for OUC (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1C.8.0 Sensitivity Analysis

KUA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1C.8.1 through 1C.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1C.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1C.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1C.8-2 presents the runner-up expansion plan. The plan including the self build alternative on a cumulative present worth basis over a 20 year planning horizon is only $170,000 lower than the plan with the joint development project.

1C.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1C.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1C.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $0.8 million cumulative present worth savings over the self build plan.

1C.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1C.8-5 and Table 1C.8-6 presents

the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $1.8 million lower in cumulative present worth cost.

1C.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1C.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1C.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $467,000 savings over the plan with the self build project.

1C.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1C.8-9 and Table 1C.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $2.9 million.

1C.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1C.4. Table 1C.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1C.8-11, the high load and energy growth scenario results in a minimal 4 MW capacity shortfall in the summer of 2003 growing to a 53 MW shortfall in 2004. It has been assumed that KUA will purchase power on the spot market to make up the resultant deficit in 2003.

Table 1C.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1C.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is $5.4 million lower in cost than the plan including self build alternative.

1C.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1C.4.0. Table 1C.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast, however, for evaluations the effect of adding the joint development project and the self build project are presented in Tables 1C.8-15 and 1C.8-16, respectively.

Table 1C.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1C.8-16 presents the runner-up expansion plan. Again, the plan with the joint development project is least cost by $6.0 million in cumulative present worth cost over the 20 year period.

1C.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but one of the sensitivity analyses. In several of these analyses, the extension of the PPA for an additional five years is part of the expansion plan. Since extension of the PPA must be done collectively, it may not be possible for KUA to obtain the five year extension. Costs would then increase for the plans with the joint development project. However, a more realistic comparison would be to compare a plan that does not include participation in any project at Stanton Energy Center. For that comparison there would be substantial savings associated with the Southern-Florida joint development project.

Table 1C.8-1
KUA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	55,134	236,258
2004		52,393	274,769
2005		53,463	311,155
2006		58,080	347,755
2007		64,441	385,356
2008	36 MW LM6000 Simple Cycle (06/08)	70,300	423,337
2009		77,383	462,047
2010		82,516	500,268
2011	36 MW LM6000 Simple Cycle (06/11)	92,858	540,093
2012		99,036	579,422
2013	36 MW LM6000 Simple Cycle (06/13)	107,486	618,944
2014		117,083	658,807
2015		125,664	698,421
2016	36 MW LM6000 Simple Cycle (06/16)	135,677	738,024
2017		147,901	777,997
2018	36 MW LM6000 Simple Cycle (06/18)	161,858	818,502
2019		174,712	858,985

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-2
KUA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		75,945	142,482
2002		58,330	192,491
2003	21 MW Joint Development with Southern–Florida (10/03)	55,251	236,351
	40 MW Southern-Florida Power Purchase (10/03)		
2004		50,776	273,673
2005		52,967	309,721
2006		58,544	346,614
2007		64,405	384,194
2008	78 MW 7FA Simple Cycle (06/08)	71,372	422,754
2009		78,956	462,252
2010		84,118	501,215
2011		94,251	541,637
2012		97,760	580,459
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	105,300	619,177
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	115,693	658,566
2015		126,525	698,452
2016	36 MW LM6000 Simple Cycle (06/16)	136,912	738,415
2017			
2018	36 MW LM6000 Simple Cycle (06/18)	148,923	778,665
	Terminate 40 MW Southern–Florida Power Purchase (11/18)	160,795	818,904
2019	36 MW LM6000 Simple Cycle (06/19)	173,713	859,155

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-3
KUA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	21 MW Joint Development with Southern–Florida (10/03)	50,186	227,576
	40 MW Southern-Florida Power Purchase (10/03)		
2004		44,908	260,585
2005		45,684	291,677
2006		49,457	322,843
2007		52,975	353,753
2008	78 MW 7FA Simple Cycle (06/08)	57,608	384,877
2009		62,455	416,120
2010		64,847	446,157
2011		70,494	476,391
2012		71,114	504,631
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	74,479	532,017
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	80,276	559,348
2015		86,031	586,468
2016	36 MW LM6000 Simple Cycle (06/16)	91,895	613,291
2017		97,631	639,678
2018	36 MW LM6000 Simple Cycle (06/18)	104,038	665,713
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	111,040	691,443

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-4
KUA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,163	72,163
2001		74,370	141,024
2002		54,486	187,737
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	50,050	227,467
2004		46,423	261,590
2005		46,092	292,960
2006		48,902	323,776
2007		52,675	354,512
2008	78 MW 7FA Simple Cycle (06/08)	57,488	385,571
2009		62,157	416,665
2010		64,692	446,630
2011		70,273	476,768
2012		70,967	504,950
2013		74,322	532,278
2014	36 MW LM6000 Simple Cycle (06/14)	79,835	559,459
2015		85,500	586,412
2016	36 MW LM6000 Simple Cycle (06/16)	91,341	613,074
2017		97,153	639,331
2018	78 MW 7FA Simple Cycle (06/18)	106,187	665,905
2019		113,472	692,198

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		48,822	48,822
2001		41,165	86,958
2002		37,509	118,096
2003	21 MW Joint Development with Southern–Florida (10/03)	43,272	153,447
	40 MW Southern-Florida Power Purchase (10/03)		
2004		44,535	186,181
2005		49,253	219,702
2006		53,733	253,363
2007		58,268	287,562
2008	78 MW 7FA Simple Cycle (06/08)	64,026	322,153
2009		70,247	357,294
2010		73,908	391,528
2011		81,160	426,336
2012		82,476	459,088
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	87,174	491,142
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	94,617	523,355
2015		101,482	555,347
2016	36 MW LM6000 Simple Cycle (06/16)	108,994	587,161
2017		116,826	618,735
2018	36 MW LM6000 Simple Cycle (06/18)	125,108	650,044
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	134,249	681,151

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-6
KUA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		48,822	48,822
2001		41,164	86,937
2002		37,509	119,095
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	43,138	153,339
2004		46,070	187,202
2005		49,704	221,029
2006		53,210	254,561
2007		57,990	288,397
2008	78 MW 7FA Simple Cycle (06/08)	63,931	322,937
2009		69,980	357,945
2010		73,760	392,110
2011		80,960	426,832
2012		82,367	459,541
2013		87,044	491,547
2014	36 MW LM6000 Simple Cycle (06/14)	94,244	523,633
2015		100,958	555,460
2016	36 MW LM6000 Simple Cycle (06/16)	108,452	587,116
2017		116,417	618,579
2018	78 MW 7FA Simple Cycle (06/18)	128,587	650,758
2019		138,921	682,948

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		64,554	132,729
2002		60,498	184,596
2003	21 MW Joint Development with Southern–Florida (10/03)	69,202	239,531
	40 MW Southern-Florida Power Purchase (10/03)		
2004		72,519	292,835
2005		79,665	347,053
2006		86,359	401,474
2007		93,455	456,004
2008	112 MW Pulverized Coal (06/08)	100,551	510,329
2009		110,304	565,508
2010		114,492	618,540
2011		122,878	671,240
2012		125,171	720,947
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	132,347	769,611
2014	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2015		140,199	817,343
2016		147,468	863,831
2017		156,121	909,402
2018	36 MW LM6000 Simple Cycle (06/17)	168,832	955,032
2019	Terminate 40 MW Southern–Florida Power Purchase (11/18)	181,750	1,000,514
	78 MW 7FA Simple Cycle (06/19)	196,997	1,046,161

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		64,554	132,729
2002		60,498	184,596
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	69,234	239,556
2004		73,928	293,896
2005		80,072	348,391
2006		85,735	402,419
2007		93,268	456,840
2008	112 MW Pulverized Coal (06/08)	100,392	511,079
2009		109,962	566,087
2010		114,305	619,032
2011		122,635	671,628
2012		125,119	721,314
2013		132,074	769,878
2014		139,678	817,433
2015		147,109	863,808
2016	36 MW LM6000 Simple Cycle (06/16)	158,398	910,042
2017		170,625	956,157
2018		181,365	1,001,543
2019	36 MW LM6000 Simple Cycle (06/19)	194,570	1,046,628

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,899	131,197
2002		57,961	180,889
2003	21 MW Joint Development with Southern–Florida (10/03)	64,881	232,394
	40 MW Southern-Florida Power Purchase (10/03)		
2004		65,887	280,822
2005		71,296	329,345
2006		76,525	377,569
2007		82,100	425,474
2008	78 MW 7FA Simple Cycle (06/08)	88,299	473,179
2009		95,686	521,046
2010		99,875	567,307
2011		109,396	614,225
2012		110,759	658,209
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	116,444	701,025
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	36 MW LM6000 Simple Cycle (06/14)	124,728	743,490
2015		132,312	785,200
2016	36 MW LM6000 Simple Cycle (06/16)	139,525	825,927
2017		147,465	865,782
2018	36 MW LM6000 Simple Cycle (06/18)	154,721	904,501
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	36 MW LM6000 Simple Cycle (06/19)	163,339	942,348

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		72,957	72,957
2001		62,898	131,196
2002		57,961	180,889
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	64,735	232,277
2004		67,382	281,805
2005		71,828	330,690
2006		76,052	378,616
2007		81,875	426,389
2008	78 MW 7FA Simple Cycle (06/08)	88,273	474,080
2009		95,446	521,827
2010		99,797	568,053
2011		109,258	614,911
2012		110,758	658,895
2013		116,399	701,695
2014	36 MW LM6000 Simple Cycle (06/14)	124,528	744,091
2015		131,855	785,658
2016	36 MW LM6000 Simple Cycle (06/16)	139,069	826,251
2017		147,135	866,017
2018	78 MW 7FA Simple Cycle (06/18)	159,363	905,897
2019		169,780	945,237

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-11
KUA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	247	0	0	176	108.1	284	37	37	0
2001	265	0	0	297	68.1	365	100	40	60
2002	292	0	0	297	68.1	365	73	44	29
2003	321	0	0	297	68.1	365	44	48	(4)
2004	346	0	0	297	48.1	345	0	53	(53)
2005	368	0	0	297	48.1	345	0	78	(78)
2006	391	0	0	297	48.1	345	0	105	(105)
2007	410	0	0	297	48.1	345	0	127	(127)
2008	431	0	0	297	48.1	345	0	151	(151)
2009	452	0	0	297	48.1	345	0	175	(175)
2010	474	0	0	297	48.1	345	0	200	(200)
2011	497	0	0	297	48.1	345	0	227	(227)
2012	520	0	0	297	48.1	345	0	253	(253)
2013	545	0	0	297	48.1	345	0	282	(282)
2014	571	0	0	297	48.1	345	0	312	(312)
2015	598	0	0	297	48.1	345	0	343	(343)
2016	625	0	0	297	48.1	345	0	374	(374)
2017	653	0	0	297	48.1	345	0	406	(406)
2018	682	0	0	297	48.1	345	0	439	(439)
2019	713	0	0	297	48.1	345	0	475	(475)

Table 1C.8-12
KUA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	21 MW Joint Development with Southern–Florida (10/03)	59,209	251,028
	40 MW Southern-Florida Power Purchase (10/03)		
2004	36 MW LM6000 Simple Cycle (06/04)	54,817	291,320
2005	78 MW 7FA Simple Cycle (06/05)	62,223	333,668
2006		70,369	378,012
2007		76,554	422,680
2008		81,721	466,832
2009	36 MW LM6000 Simple Cycle (06/09)	89,568	511,638
2010	36 MW LM6000 Simple Cycle (06/10)	98,818	557,410
2011		109,719	604,467
2012	36 MW LM6000 Simple Cycle (06/12)	116,344	650,668
2013	36 MW LM6000 Simple Cycle (06/13)	126,625	697,228
	Terminate 40 MW Southern–Florida Power Purchase (11/13)		
	Extension of 40 MW Southern-Florida Power Purchase (11/13)		
2014	78 MW 7FA Simple Cycle (06/14)	137,302	743,974
2015	36 MW LM6000 Simple Cycle (06/15)	149,361	791,059
2016	36 MW LM6000 Simple Cycle (06/16)	160,972	838,045
2017	36 MW LM6000 Simple Cycle (06/17)	172,454	884,654
2018	36 MW LM6000 Simple Cycle (06/18)	185,799	931,150
	Terminate 40 MW Southern–Florida Power Purchase (11/18)		
2019	78 MW 7FA Simple Cycle (06/19)	203,166	978,226

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-13
KUA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		76,013	76,013
2001		80,875	150,897
2002		61,970	204,026
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	59,114	250,953
2004	36 MW LM6000 Simple Cycle (06/04)	56,249	292,298
2005	78 MW 7FA Simple Cycle (06/05)	62,535	334,858
2006		69,686	378,772
2007		76,349	423,321
2008		81,604	467,409
2009	36 MW LM6000 Simple Cycle (06/09)	89,408	512,135
2010	36 MW LM6000 Simple Cycle (06/10)	98,585	557,799
2011		109,371	604,707
2012	36 MW LM6000 Simple Cycle (06/12)	115,988	650,767
2013	36 MW LM6000 Simple Cycle (06/13)	127,355	697,595
2014	78 MW 7FA Simple Cycle (06/14)	140,771	745,522
2015		152,841	793,704
2016	36 MW LM6000 Simple Cycle (06/16)	163,127	841,319
2017	36 MW LM6000 Simple Cycle (06/17)	175,725	888,812
2018	36 MW LM6000 Simple Cycle (06/18)	189,140	936,145
2019	36 MW LM6000 Simple Cycle (06/19)	204,936	983,631

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-14
KUA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 15% Reserve Margin (MW)
2000	237	0	0	176	108.1	284	47	36	11
2001	238	0	0	297	68.1	365	127	36	91
2002	245	0	0	297	68.1	365	120	37	83
2003	252	0	0	297	68.1	365	113	38	75
2004	259	0	0	297	48.1	345	86	39	47
2005	263	0	0	297	48.1	345	82	39	42
2006	266	0	0	297	48.1	345	79	40	39
2007	267	0	0	297	48.1	345	78	40	38
2008	267	0	0	297	48.1	345	78	40	38
2009	268	0	0	297	48.1	345	77	40	36
2010	269	0	0	297	48.1	345	76	40	35
2011	268	0	0	297	48.1	345	77	40	36
2012	267	0	0	297	48.1	345	78	40	38
2013	266	0	0	297	48.1	345	79	40	39
2014	264	0	0	297	48.1	345	81	40	41
2015	263	0	0	297	48.1	345	82	39	42
2016	260	0	0	297	48.1	345	85	39	46
2017	257	0	0	297	48.1	345	88	39	49
2018	254	0	0	297	48.1	345	91	38	53
2019	251	0	0	297	48.1	345	94	38	56

Table 1C.8-15
KUA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	21 MW Joint Development with Southern–Florida (10/03)	45,187	209,895
	40 MW Southern-Florida Power Purchase (10/03)		
2004		41,431	240,348
2005		42,026	268,950
2006		44,718	297,130
2007		46,696	324,377
2008		48,112	350,370
2009		49,486	375,125
2010		50,945	398,723
2011		53,364	421,610
2012		54,278	443,164
2013	Terminate 40 MW Southern–Florida Power Purchase (11/13)	54,739	463,292
2014		53,210	481,408
2015		54,930	498,724
2016		56,028	515,078
2017		57,482	530,613
2018		59,263	545,444
2019		60,249	559,404

Note: Capacity is stated at average annual temperature for KUA.

Table 1C.8-16
KUA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		68,424	68,424
2001		67,713	131,121
2002		50,042	174,024
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	45,017	209,760
2004		42,677	241,129
2005		42,243	269,878
2006		43,900	297,542
2007		46,321	324,570
2008		47,659	350,319
2009		49,017	374,840
2010		50,479	398,221
2011		52,909	420,913
2012		53,934	442,331
2013		55,067	462,579
2014		56,657	481,868
2015		58,612	500,345
2016		60,030	517,867
2017		61,718	534,548
2018		63,238	550,373
2019		64,947	565,422

Note: Capacity is stated at average annual temperature for KUA.

Kissimmee Utility Authority Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Joint 7FA SC	70	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.417	53,095	5,941
LM 6000	36	36,778	8	2016.417	55,783	6,242
LM 6000	36	36,778	8	2018.417	58,607	6,558
LM 6000	36	36,778	8	2019.417	60,072	6,722

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	44,573	4,250	0	0	48,822	0	48,822	48,822
2001	37,176	3,989	0	0	41,165	0	41,165	86,939
2002	33,675	3,835	0	0	37,509	0	37,509	119,696
2003	37,961	4,226	807	(9)	42,984	288	43,272	150,447
2004	38,728	4,602	89	(35)	43,384	1,151	44,535	186,181
2005	41,899	4,931	1,306	(35)	48,102	1,151	49,253	218,702
2006	44,926	5,237	2,453	(35)	52,582	1,151	53,733	253,563
2007	48,383	5,557	3,212	(35)	57,117	1,151	58,268	287,562
2008	50,689	5,786	3,417	(34)	59,857	4,170	64,026	322,153
2009	54,294	6,089	3,572	(34)	63,921	6,326	70,247	357,294
2010	57,585	6,448	3,584	(34)	67,583	6,326	73,908	391,528
2011	64,501	6,771	3,596	(34)	74,834	6,326	81,160	426,336
2012	65,395	7,180	3,609	(34)	76,150	6,326	82,476	459,088
2013	69,622	7,577	3,684	(34)	80,848	6,326	87,174	491,142
2014	72,562	7,882	4,415	(34)	84,825	9,792	94,617	523,356
2015	76,146	8,366	4,736	(34)	89,215	12,267	101,482	556,347
2016	79,263	8,655	5,201	(34)	93,088	15,908	108,994	587,161
2017	83,707	9,086	5,557	(33)	98,317	18,509	116,826	619,735
2018	87,928	9,390	5,487	(33)	102,773	22,335	125,106	650,044
2019	92,471	9,352	3,471	(33)	105,260	28,989	134,249	681,151

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority Economic Evaluation

Case
Scenario: AEO Fuel Price Projections Self Build

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	44,573	4,250	0	0	48,822	0	48,822	48,822
2001	37,175	3,989	0	0	41,164	0	41,164	86,937
2002	33,675	3,835	0	0	37,509	0	37,509	119,095
2003	37,941	4,223	82	13	42,258	880	43,138	153,339
2004	38,937	4,598	(1,037)	51	42,550	3,520	46,070	187,202
2005	42,141	4,936	(947)	53	46,183	3,520	49,704	221,029
2006	45,261	5,232	(857)	54	49,690	3,520	53,210	254,651
2007	48,499	5,557	358	55	54,470	3,520	57,990	289,387
2008	50,984	5,782	570	57	57,392	6,539	63,931	324,937
2009	54,410	6,087	730	58	61,285	8,695	69,980	359,816
2010	57,812	6,446	749	59	65,065	8,695	73,760	392,110
2011	64,664	6,773	767	61	72,265	8,695	80,960	425,832
2012	65,643	7,180	786	62	73,672	8,695	82,367	459,541
2013	69,900	7,580	806	64	78,349	8,695	87,044	491,547
2014	72,897	7,884	1,238	66	82,084	12,160	94,244	523,633
2015	76,324	8,365	1,567	67	86,323	14,635	100,958	555,460
2016	79,422	8,647	2,038	69	90,175	18,276	108,452	587,116
2017	83,990	9,078	2,402	71	95,540	20,877	116,417	618,579
2018	91,488	9,565	2,721	72	103,847	24,740	128,587	650,758
2019	98,320	10,050	2,977	74	111,421	27,500	138,921	682,948

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority Economic Evaluation

Case
Scenario: OUC 2000 + 2001 AEO Escalators Joint Development

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Coal	112	128,291	42	2008.417	167,486	18,742
LM 6000	36	36,778	8	2017.417	57,178	6,398
Joint 7FA SC	70	36,939	12	2019.417	60,674	6,789

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	60,547	4,007	0	0	64,554	0	64,554	132,729
2002	56,662	3,836	0	0	60,498	0	60,498	184,596
2003	63,893	4,223	807	(9)	68,914	288	69,202	239,531
2004	66,711	4,603	89	(35)	71,368	1,151	72,519	292,835
2005	72,317	4,926	1,306	(35)	78,514	1,151	79,665	347,055
2006	77,550	5,238	2,453	(35)	85,207	1,151	86,359	401,474
2007	83,587	5,539	3,212	(35)	92,304	1,151	93,455	456,904
2008	77,956	6,200	4,343	(34)	88,467	12,084	100,551	510,929
2009	76,519	6,795	5,191	(34)	90,411	19,893	110,304	565,508
2010	82,251	7,136	5,244	(34)	94,599	19,893	114,492	619,540
2011	90,258	7,464	5,298	(34)	102,986	19,893	122,878	671,240
2012	92,064	7,895	5,353	(34)	105,278	19,893	125,171	720,947
2013	98,698	8,318	5,471	(34)	112,454	19,893	132,347	769,611
2014	105,803	8,702	5,835	(34)	120,306	19,893	140,199	817,343
2015	112,511	9,203	5,894	(34)	127,575	19,893	147,468	863,831
2016	120,612	9,694	5,956	(34)	136,228	19,893	156,121	909,402
2017	128,666	10,113	6,461	(33)	145,207	23,625	168,832	955,032
2018	138,584	10,628	6,280	(33)	155,459	26,291	181,750	1,000,514
2019	151,951	11,073	3,754	(33)	166,746	30,252	196,997	1,046,161

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Kissimmee Utility Authority Economic Evaluation

Case
Scenario: OUC 2000 + 2001 AEO Escalators Self Build

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	63			2003.833	31,458	3,520
Joint 7FA SC	78	36,939	12	2008.417	46,242	5,175
LM 6000	36	36,778	8	2014.412	53,089	5,941
LM 6000	36	36,778	8	2016.412	55,776	6,241
Joint 7FA SC	78	36,939	12	2018.412	59,187	6,623

Finance	
Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	68,740	4,217	0	0	72,957	0	72,957	72,957
2001	60,547	4,007	0	0	64,554	0	64,554	132,729
2002	56,662	3,836	0	0	60,498	0	60,498	184,596
2003	64,040	4,220	82	13	68,354	880	69,234	239,556
2004	66,794	4,600	(1,037)	51	70,408	3,520	73,928	293,896
2005	72,521	4,925	(947)	53	76,552	3,520	80,072	348,391
2006	77,780	5,238	(857)	54	82,215	3,520	85,735	402,410
2007	83,795	5,540	358	55	89,748	3,520	93,268	456,840
2008	78,193	6,194	1,496	57	85,939	14,453	100,392	511,079
2009	78,559	6,734	2,350	58	87,700	22,262	109,962	566,087
2010	82,440	7,136	2,408	59	92,043	22,262	114,305	619,032
2011	90,383	7,461	2,469	61	100,373	22,262	122,635	671,628
2012	92,371	7,893	2,530	62	102,857	22,262	125,119	721,314
2013	98,838	8,316	2,593	64	109,812	22,262	132,074	769,678
2014	105,990	8,702	2,658	66	117,416	22,262	139,678	817,433
2015	112,853	9,202	2,725	67	124,847	22,262	147,109	863,808
2016	119,559	9,641	3,225	69	132,495	25,903	158,398	910,042
2017	128,339	10,093	3,619	71	142,121	28,504	170,625	956,157
2018	138,451	10,628	3,709	72	152,861	28,504	181,365	1,001,543
2019	148,677	11,126	4,268	74	162,145	32,425	194,570	1,046,628

Notes:

(1) Includes start-up costs.

(2) Fixed costs are included only for new units.

(3) Includes fees for site lease as well as credit for services and cooling water.

Table of Contents (Continued)
Tables (Continued)

Table 1D.8-4 FMPA Low Fuel Price Escalation Runner-Up Expansion Plan 8-7
Table 1D.8-5 AEO Fuel Price Projection Expansion Plan 8-8
Table 1D.8-6 FMPA AEO Fuel Price Projection Runner-Up Expansion Plan 8-9
Table 1D.8-7 OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan 8-10
Table 1D.8-8 OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan 8-11
Table 1D.8-9 OUC Constant 2000 Fuel Price Projection Expansion Plan 8-12
Table 1D.8-10 OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan 8-13
Table 1D.8-11 FMPA Summer Reserve Requirements - High Load and Energy Growth Scenario 8-14
Table 1D.8-12 FMPA High Load and Energy Growth Expansion Plan 8-15
Table 1D.8-13 FMPA High Load and Energy Growth Runner-Up Expansion Plan 8-16
Table 1D.8-14 FMPA Summer Reserve Requirements - Low Load and Energy Growth Scenario 8-17
Table 1D.8-15 FMPA Low Load and Energy Growth Expansion Plan 8-18
Table 1D.8-16 FMPA Low Load and Energy Growth Runner-Up Expansion Plan 8-19

Figures

Figure 1D.2-1 Member Cities 2-3

As discussed in the remainder of this application, FMPA has evaluated appropriate alternatives to Stanton A to determine if they are lower in cumulative present worth revenue requirements.

FMPA believes that Stanton A represents the minimal cost and performance risk to its members due to the proven performance of the "F" class combined cycle technology. As demonstrated in this application, Stanton A has proven to be FMPA's most cost-effective through exhaustive evaluations as well as a thorough test of the marketplace.

1D.1.2 Summary

FMPA's All-Requirements has been growing rapidly through the addition of new members, with Lake Worth projected to join in 2002. FMPA's peak demand is projected to grow at a 1.8 percent average annual rate from 2000 through the end of the planning period in 2019. The projected load growth assumes no new members will join after Lake Worth in 2002.

FMPA uses an 18 percent summer reserve margin and a 15 percent winter reserve margin as reliability criterion. FMPA's reserve margin is projected to drop to 14.1 percent during the summer of 2003, dictating the need to add capacity.

FMPA has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the least-cost alternative under both base and all but two sensitivity analysis.

FMPA member cities within Peninsular Florida. Table 1D.2-2 provides a summary of the existing FMPA generating facilities with project capacities combined where appropriate.

1D.2.1.1 St. Lucie Project

On May 12, 1983, the Agency purchased from Florida Power & Light Company (FPL) an 8.806 percent undivided ownership interest in St. Lucie 2 (the St. Lucie Project), a nuclear generating unit with a summer Seasonal Net Capability of approximately 839 MW and a winter Seasonal Net Capability of approximately 853 MW. St. Lucie 2 was declared in commercial operation August 8, 1983, and in Firm Operation, as defined in the participation agreement, on August 14, 1983. Fifteen of the Agency's members are participants in the St. Lucie Project and nine of the fifteen (ten of the fifteen including the City of Lake Worth which is projected to become a member in 2002) are also members of the All-Requirements Project.

1D.2.1.2 Stanton Project

On August 13, 1984, the Agency purchased from Orlando Utilities Commission (OUC) a 14.8193 percent undivided ownership interest in Stanton 1. Stanton 1 is a pulverized coal unit that went into commercial operation July 1, 1987. Six of the Agency's members are participants in the Stanton Project and three of the six are also members of the All-Requirements Project.

1D.2.1.3 Tri-City Project

On March 22, 1985, the FMPA Board approved the agreements associated with the Tri-City Project. The Tri-City Project involves the purchase from OUC of an additional 5.3012 percent undivided ownership interest in Stanton 1. Three of the Agency's members are participants in the Tri-City Project and two of the three are also members of the All-Requirements Project.

1D.2.1.4 Stanton II Project

On June 6, 1991, the Agency, under the Stanton II Project, purchased from OUC a 23.2 percent undivided ownership interest in OUC's Stanton 2, a coal fired unit virtually identical to Stanton Unit 1. The unit commenced commercial operation in June 1996. Seven of the Agency's members are participants in the Stanton II Project and four of the seven are also members of the All-Requirements Project.

1D.3.0 Evaluation Criteria

1D.3.1 Economic Parameters

1D.3.1.1 Escalation Rates

The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital cost and Operations and Maintenance (O&M) expenses is also assumed to be 2.5 percent.

1D.3.1.2 Bond Interest Rates

The long-term tax-exempt bond interest rate is assumed to be 6.0 percent. For smaller financing requirements, such as the Stanton A joint development project, FMPA can utilize the FMPA Pooled Loan Project, which has a 5.0 percent interest rate.

1D.3.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the 6.0 percent long-term bond interest rate.

1D.3.1.4 Interest During Construction

The interest during construction interest rate is assumed to be 6.0 percent.

1D.3.1.5 Levelized Fixed Charge Rate

FMPA plans to use the FMPA Pooled Loan Project for small financing requirements such as the equity portion of Stanton A. The fixed charge rate for the equity portion of Stanton A is merely the capital recovery factor over a 20 year period at the FMPA Pooled Loan Project interest rate of 5.0 percent plus one percent for insurance, resulting in a rate of 9.02 percent.

For larger financing requirements, FMPA issues tax-exempt bonds. The fixed charge rate for these larger requirements is 8.602 percent based on a bond term of 30 years with a 6.0 percent bond interest rate, 2.9 percent bond issuance fee, a 1 year debt service reserve fund earning interest at the 6.0 percent bond interest rate, and one percent for insurance.

1D.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of FMPA's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine FMPA's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluations were discussed in 1D.5.0. The sensitivity analyses are discussed in Section 1D.8.0. The proposal evaluations were discussed in Section 1A.5.0.

1D.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. The program operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options while maintaining user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 18 percent. All capacity expansion plans were analyzed over a twenty-year period from 2000 to 2019.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO was used to obtain the annual production cost for the expansion plan.

1D.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation were discussed in Section 1A.7.0. Table 1D.7-1 Summarizes the expansion alternatives considered for FMPA in the optimization study for supply-side alternatives.

Table 1D.7-1
Summary of FMPA Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal (50%)	256,581	212.5	3.73	14.17	Coal	9,979	3.0	30	2005
501F 2x1 CC (50%) (standard)	129,594[2]	257	3.68[3]	6.32[3]	Nat. Gas	7,074	1.0	14	2005
501F 1x1 CC (50%)	73,984	125	2.49	4.66	Nat. Gas	10,841	2.86	15	2005
7FA SC	76,681	156	2.24	3.63	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[4]	29,021[2]	61	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[4]	[redacted]	21	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	14	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. Mixed year dollars to reflect commercial operation date of October 1, 2003.
3. (2003 $)
4. Reflects FMPA's portion of total generation alternative capacity.
5. October 1, 2003.

1D.7.3 Results of Economic Analysis

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics described in detail in Section 1A.7.0 and summarized in Table 1D.7-1. The expansion plan outlined in Table 1D.7-2 represents the least-cost capacity addition plan for FMPA under the base case scenario. The units comprising the least-cost capacity addition plan are listed in the table according to their year of commercial operation. Table 1D.7-3 displays the reserve margins for the base case after the construction of the generating resources identified.

Table 1D.7-4 provides the runner up to the least-cost expansion plan identified in Table 1D.7-2. Comparing the two plans indicates that the plan with the Southern-Florida joint development project is $38.7 million lower in cumulative present worth costs over the 20 year evaluation period.

Table 1D.7-2
FMPA Base Case Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,836	259,281
2002		156,804	398,836
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	162,459	535,240
2004		163,011	664,360
2005		169,962	791,366
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	176,667	915,909
2007		186,924	1,040,224
2008		199,823	1,165,595
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	214,675	1,292,661
2010		227,849	1,419,891
2011		237,135	1,544,811
2012		248,146	1,668,132
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	260,548	1,790,287
2014	156 MW GE 7FA Simple Cycle (06/14)	274,706	1,911,789
2015		289,042	2,032,397
2016		301,313	2,151,007
2017		311,359	2,266,635
2018		325,154	2,380,551
2019		338,956	2,492,580

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.7-3
Projected Reliability Levels – Summer/Base Case with Expansion Plan Identified in Table 1D.7-2

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand (MW)		Reserve Margin (MW)		Excess / (Deficit) to Maintain 18 % Reserve Margin (MW)	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
2000	377.0	675.9	0.0	1,177.9	996.0	992.0	20.9	21.4	25.1	29.8
2001	497.0	620.9	0.0	1,202.9	1,024.4	1,020.2	19.0	19.5	9.4	14.4
2002	525.5	683.8	0.0	1,356.3	1,123.5	1,119.0	23.8	24.4	57.0	62.3
2003	525.5	622.8	0.0	1,283.3	1,145.7	1,141.0	13.6	14.1	(44.3)	(38.8)
2004	546.3	616.5	0.0	1,297.8	1,167.8	1,163.0	12.6	13.1	(55.9)	(50.3)
2005	646.3	594.5	0.0	1,400.8	1,189.0	1,184.0	20.6	21.2	26.5	32.4
2006	887.3	573.5	0.0	1,580.8	1,209.1	1,204.0	34.1	34.8	175.6	181.6
2007	887.3	551.5	0.0	1,558.8	1,228.2	1,223.0	29.8	30.4	131.1	137.2
2008	887.3	551.5	0.0	1,483.8	1,246.3	1,241.0	19.8	20.3	21.2	27.5
2009	1,128.3	551.5	0.0	1,724.8	1,273.3	1,268.0	36.8	37.3	230.4	236.6
2010	1,128.3	551.5	0.0	1,724.8	1,290.0	1,285.0	34.9	35.5	210.7	216.6
2011	1,128.3	451.5	0.0	1,579.8	1,306.0	1,301.0	21.0	21.4	38.7	44.6
2012	1,128.3	451.5	0.0	1,579.8	1,322.0	1,317.0	19.5	20.0	19.8	25.7
2013	1,128.3	451.5	0.0	1,579.8	1,336.0	1,331.0	18.2	18.7	3.3	9.2
2014	1,268.3	412.8	0.0	1,681.1	1,350.0	1,345.0	24.5	25.0	88.1	94.0
2015	1,268.3	412.8	0.0	1,681.1	1,363.0	1,358.0	23.3	23.8	72.8	78.7
2016	1,268.3	412.8	0.0	1,681.1	1,376.0	1,371.0	22.2	22.6	57.4	63.3
2017	1,268.3	412.8	0.0	1,681.1	1,387.0	1,382.0	21.2	21.6	44.5	50.4
2018	1,268.3	412.8	0.0	1,681.1	1,398.0	1,393.0	20.3	20.7	31.5	37.4
2019	1,268.3	412.8	0.0	1,681.1	1,408.0	1,403.0	19.4	19.8	19.7	25.6

Table 1D.7-4
FMPA Base Case Runner Up Expansion Plan

Year	Expansion Plan	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		147,836	259,281
2002		156,804	398,836
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (61 MW)	162,497	535,272
2004		162,210	663,757
2005		169,264	790,241
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	175,990	914,307
2007		186,224	1,038,156
2008		199,187	1,163,128
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	214,367	1,290,012
2010		227,486	1,417,039
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	244,783	1,545,987
2012		266,257	1,678,309
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	272,869	1,806,241
2014		288,761	1,933,960
2015		297,482	2,058,089
2016		310,564	2,180,342
2017		320,421	2,299,334
2018		334,374	2,416,480
2019		347,209	2,531,237

Note: Capacity is stated at average annual temperature for FMPA.

1D.8.0 Sensitivity Analysis

FMPA performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1D.8.1 through 1D.8.7 and includes high and low fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1D.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1D.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1D.8-2 presents the runner-up expansion plan. The plan including joint development is $52.4 million lower than the plan with the self build alternative.

1D.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1D.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1D.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with an $8.4 million cumulative present worth savings over the self build plan.

1D.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1D.8-5 and Table 1D.8-6 presents the runner-up expansion plan. Under this scenario, the expansion plan with the joint development project is $45 million lower in cumulative present worth cost.

1D.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1D.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1D.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows a $75.7 million savings over the plan with the self build project.

1D.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1D.8-9 and Table 1D.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $60.7 million.

1D.8.6 High Load and Energy Growth

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. The high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-11 indicates the summer need for capacity based upon the high load and energy forecast.

As indicated in Table 1D.8-11, the high load and energy growth scenario results in capacity shortfall beginning the summer of 2000. Since there are no capacity alternatives identified which can be placed in operation until Stanton A, it has been assumed that FMPA will purchase power on the spot market to make up the resultant deficits.

Table 1D.8-12 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1D.8-13 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the joint development project is slightly higher in cost ($3.711 million) than the plan including self build alternative.

1D.8.7 Low Load and Energy Growth

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 1D.4.0. Table 1D.8-14 indicates the summer need for capacity based upon the low load and energy forecast.

Capacity additions are not required for the low load and energy forecast until 2006. Nevertheless, for evaluation purposes, Table 1D.8-15 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1D.8-16 presents the runner-up expansion plan with the joint development and self build projects installed for October 1, 2003 commercial operation. The plan with the joint development project is slightly higher in cumulative present worth cost ($1.17 million) over the 20 year period.

1D.8.8 Sensitivity Analysis Summary

The plan with the Southern-Florida joint development project is the lowest cost in all but two of the sensitivity analyses. However, it should be noted that for the sensitivity scenarios in which the self build alternative shows as the more cost-effective approach the margins are relatively small. These cumulative present worth savings do not even compare to those provided by participation in the joint development project with Southern-Florida for the remaining five sensitivity cases.

Table 1D.8-1
FMPA High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,660	260,058
2002		158,920	401,497
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	163,162	538,491
2004		169,032	672,380
2005		179,688	806,653
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,731	939,701
2007		202,500	1,074,376
2008		224,015	1,214,926
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	239,447	1,356,654
2010		257,341	1,500,352
2011		274,357	1,644,879
2012		291,476	1,789,734
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	311,077	1,935,580
2014	223 MW Pulverized Coal (06/14)	330,687	2,081,843
2015		352,962	2,229,121
2016		371,162	2,375,228
2017		386,758	2,518,856
2018		408,501	2,661,972
2019		428,619	2,803,636

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-2
FMPA High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		148,660	260,058
2002		158,920	401,497
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	163,230	538,548
2004		168,247	671,815
2005		178,972	805,553
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	188,065	938,132
2007		201,832	1,072,361
2008		223,390	1,212,519
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	239,348	1,354,189
2010		256,709	1,497,534
2011	156 MW GE 7FA Simple Cycle (06/11)	285,583	1,647,976
2012		316,364	1,805,199
2013		325,395	1,957,757
2014		346,356	2,110,951
2015	223 MW Pulverized Coal (06/15)	360,946	2,261,561
2016		383,855	2,412,664
2017		400,768	2,561,495
2018		422,567	2,709,539
2019		443,282	2,856,050

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-3
FMPA Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,984	258,477
2002		164,419	393,909
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	154,827	523,905
2004		157,104	650,346
2005		160,968	770,631
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	165,185	887,080
2007		172,529	1,001,822
2008		181,576	1,115,745
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	192,980	1,229,970
2010		203,000	1,343,324
2011		206,796	1,452,261
2012		213,425	1,558,327
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	219,715	1,661,338
2014	125 MW WH 501F 1x1 Combined Cycle (06/14)	229,638	1,762,907
2015		238,172	1,862,288
2016		245,122	1,958,779
2017		249,724	2,051,518
2018		257,401	2,141,697
2019	125 MW WH 501F 1x1 Combined Cycle	270,289	2,231,031

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-4
FMPA Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,813	119,813
2001		146,984	258,477
2002		154,419	395,909
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	154,868	525,940
2004		156,320	649,760
2005		163,110	771,645
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	164,503	887,613
2007		171,834	1,001,893
2008		180,912	1,115,399
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	192,366	1,229,260
2010		201,641	1,341,856
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	212,068	1,453,570
2012		227,536	1,566,649
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	227,505	1,673,312
2014		233,718	1,776,686
2015		237,878	1,875,944
2016		244,188	1,972,068
2017		248,022	2,064,174
2018		254,827	2,153,451
2019		260,008	2,239,387

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		105,189	105,189
2001		117,096	215,657
2002		131,554	332,739
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	141,534	451,574
2004		152,985	572,752
2005		162,639	694,286
2006	223 MW Pulverized Coal (06/06)	167,911	812,656
2007		176,666	930,149
2008		190,593	1,049,730
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	203,398	1,170,121
2010		213,640	1,289,416
2011		221,962	1,406,343
2012		230,575	1,520,932
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	238,134	1,632,579
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	252,457	1,744,241
2015		264,925	1,854,785
2016		274,341	1,962,778
2017		281,747	2,067,409
2018		292,775	2,169,981
2019		303,548	2,270,308

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-6
FMPA AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		105,189	105,189
2001		117,096	215,657
2002		151,554	332,739
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	141,572	451,606
2004		152,208	572,168
2005		161,957	693,192
2006	223 MW Pulverized Coal (06/06)	167,225	811,079
2007		175,966	928,106
2008		190,048	1,047,345
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	204,022	1,168,105
2010		214,226	1,287,728
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	232,341	1,410,122
2012		251,177	1,534,950
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	254,015	1,654,042
2014		266,475	1,771,904
2015		272,762	1,885,718
2016		283,254	1,997,220
2017		291,485	2,105,467
2018		302,823	2,211,559
2019		314,010	2,315,344

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,103	251,903
2002		157,841	392,381
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	172,324	537,068
2004		190,802	688,201
2005		218,431	851,426
2006	223 MW Pulverized Coal (06/06)	212,677	1,001,354
2007		220,451	1,147,966
2008		248,207	1,303,694
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	265,350	1,460,755
2010		279,944	1,617,074
2011		311,381	1,781,105
2012		326,130	1,943,182
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	339,036	2,102,135
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	357,715	2,260,353
2015		373,682	2,416,277
2016		389,927	2,569,771
2017		401,874	2,719,012
2018		420,993	2,866,505
2019		439,636	3,011,810

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		140,103	251,903
2002		157,841	392,381
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	172,381	537,116
2004		190,249	687,811
2005		217,770	850,541
2006	223 MW Pulverized Coal (06/06)	212,320	1,000,219
2007		220,032	1,146,552
2008		247,858	1,302,062
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	268,438	1,460,950
2010		284,035	1,619,554
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	332,485	1,794,703
2012		362,590	1,974,899
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	359,154	2,143,284
2014		375,277	2,309,269
2015		385,421	2,470,092
2016		403,718	2,629,014
2017		416,866	2,783,824
2018		436,195	2,936,642
2019		456,319	3,087,461

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		135,217	251,540
2002		136,909	391,188
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	170,402	534,009
2004		185,622	681,039
2005		203,276	832,938
2006	223 MW Pulverized Coal (06/06)	206,585	978,573
2007		216,782	1,122,745
2008		239,531	1,273,030
2009	257 MW WH 501F 2x1 Combined Cycle (06/09)	255,315	1,424,150
2010		268,759	1,574,224
2011		288,040	1,725,960
2012		299,817	1,874,960
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	309,557	2,020,092
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	325,236	2,163,944
2015		338,967	2,305,383
2016		349,912	2,443,125
2017		356,902	2,575,665
2018		369,133	2,704,989
2019		380,574	2,830,773

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		119,731	119,731
2001		139,717	251,540
2002		156,909	391,188
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	170,213	534,102
2004		185,052	680,680
2005		202,682	832,136
2006	223 MW Pulverized Coal (06/06)	206,152	977,465
2007		216,288	1,121,309
2008		239,135	1,271,345
2009	125 MW WH 501F 1x1 Combined Cycle (06/09)	257,042	1,423,488
2010		270,816	1,574,710
2011	125 MW WH 501F 1x1 Combined Cycle (06/11)	304,360	1,735,043
2012		328,714	1,898,404
2013	257 MW WH 501F 2x1 Combined Cycle (06/13)	327,786	2,052,083
2014		341,125	2,202,963
2015		348,776	2,348,495
2016		361,007	2,490,604
2017		369,657	2,627,881
2018		381,413	2,761,507
2019		393,338	2,891,510

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-11
FMPA Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/(Deficit) to Maintain 18% Reserve Margin (MW)
2000	1,049.0	0	0	377.0	800.9	1,177.9	151	189	(37.4)
2001	1,098.1	0	0	497.0	705.9	1,202.9	120	198	(77.6)
2002	1,226.0	0	0	525.5	830.8	1,356.3	157	221	(63.9)
2003	1,271.0	0	0	525.5	757.8	1,283.3	37	229	(192.2)
2004	1,316.0	0	0	525.5	712.8	1,238.3	0	237	(290.3)
2005	1,357.0	0	0	625.5	715.8	1,341.3	13	244	(231.2)
2006	1,397.0	0	0	625.5	654.8	1,280.3	0	251	(346.6)
2007	1,435.0	0	0	625.5	632.8	1,258.3	0	258	(413.4)
2008	1,471.0	0	0	625.5	557.8	1,183.3	0	265	(544.4)
2009	1,515.0	0	0	625.5	557.8	1,183.3	0	273	(596.3)
2010	1,548.0	0	0	625.5	557.8	1,183.3	0	279	(635.2)
2011	1,581.0	0	0	625.5	412.8	1,038.3	0	285	(827.3)
2012	1,611.0	0	0	625.5	412.8	1,038.3	0	290	(862.7)
2013	1,640.0	0	0	625.5	412.8	1,038.3	0	295	(896.9)
2014	1,668.0	0	0	625.5	412.8	1,038.3	0	300	(929.9)
2015	1,694.0	0	0	625.5	412.8	1,038.3	0	305	(960.6)
2016	1,719.0	0	0	625.5	412.8	1,038.3	0	309	(990.1)
2017	1,742.0	0	0	625.5	412.8	1,038.3	0	314	(1,017.3)
2018	1,764.0	0	0	625.5	412.8	1,038.3	0	318	(1,043.2)
2019	1,784.0	0	0	625.5	412.8	1,038.3	0	321	(1,066.8)

Table 1D.8-12
FMPA High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		130,844	130,844
2001		153,269	284,271
2002		176,044	441,558
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	184,415	596,388
2004		191,718	748,247
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	194,543	893,621
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	209,974	1,041,644
2007		226,571	1,192,327
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	248,273	1,348,096
2009		268,295	1,506,900
2010		281,619	1,664,154
2011	223 MW Pulverized Coal (06/11)	305,973	1,825,337
2012		332,430	1,990,545
2013		342,363	2,151,058
2014		356,581	2,308,774
2015		370,256	2,463,269
2016		386,211	2,615,300
2017	125 MW WH 501F 1x1 Combined Cycle (06/17)	405,219	2,765,783
2018		428,557	2,915,926
2019		442,826	3,062,285

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-13
FMPA High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
20000		130,844	130,844
2001		163,269	284,871
2002		176,044	441,550
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	184,356	596,339
2004		192,367	748,711
2005	257 MW WH 501F 2x1 Combined Cycle (06/05)	195,230	894,598
2006	257 MW WH 501F 2x1 Combined Cycle (06/06)	210,580	1,043,048
2007		227,306	1,194,220
2008	156 MW GE 7FA Simple Cycle (06/08)	247,749	1,349,661
2009		266,457	1,507,376
2010		280,141	1,663,805
2011	223 MW Pulverized Coal (06/11)	302,943	1,823,392
2012		326,578	1,985,691
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	337,603	2,143,973
2014	257 MW WH 501F 2x1 Combined Cycle (06/14)	358,148	2,302,382
2015		378,403	2,460,276
2016		395,097	2,615,805
2017		406,606	2,766,804
2018		438,050	2,920,272
2019		440,903	3,065,996

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-14
FMPA Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 18% Reserve Margin (MW)
2000	943.0	0	0	377.0	800.9	1,177.9	257.4	170	87.7
2001	959.6	0	0	497.0	705.9	1,202.9	258.6	173	85.9
2002	1,043.0	0	0	525.5	830.8	1,356.3	339.8	188	152.0
2003	1,055.0	0	0	525.5	757.8	1,283.3	252.6	190	62.7
2004	1,066.0	0	0	525.5	712.8	1,238.3	196.6	192	4.7
2005	1,076.0	0	0	625.5	715.8	1,341.3	294.1	194	100.4
2006	1,086.0	0	0	625.5	654.8	1,280.3	215.9	195	20.4
2007	1,095.0	0	0	625.5	632.8	1,258.3	184.9	197	(12.2)
2008	1,104.0	0	0	625.5	557.8	1,183.3	87.4	199	(111.3)
2009	1,122.0	0	0	625.5	557.8	1,183.3	69.4	202	(132.6)
2010	1,131.0	0	0	625.5	557.8	1,183.3	60.4	204	(143.2)
2011	1,139.0	0	0	625.5	412.8	1,038.3	0	205	(305.7)
2012	1,146.0	0	0	625.5	412.8	1,038.3	0	206	(314.0)
2013	1,154.0	0	0	625.5	412.8	1,038.3	0	208	(323.4)
2014	1,160.0	0	0	625.5	412.8	1,038.3	0	209	(330.5)
2015	1,167.0	0	0	625.5	412.8	1,038.3	0	210	(338.8)
2016	1,173.0	0	0	625.5	412.8	1,038.3	0	211	(345.8)
2017	1,179.0	0	0	625.5	412.8	1,038.3	0	212	(352.9)
2018	1,184.0	0	0	625.5	412.8	1,038.3	0	213	(358.8)
2019	1,189.0	0	0	625.5	412.8	1,038.3	0	214	(364.7)

Table 1D.8-15
FMPA Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		133,277	234,169
2002		140,585	359,272
2003	61 MW Self Build GE 7FA 2x1 Combined Cycle (10/03)	141,860	478,380
2004		143,832	592,308
2005		145,491	701,028
2006		152,205	808,326
2007		160,806	915,271
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	172,067	1,023,229
2009		181,598	1,130,717
2010		188,277	1,235,850
2011	223 MW Pulverized Coal (06/11)	205,232	1,343,963
2012		221,209	1,453,897
2013		226,240	1,559,968
2014		233,441	1,663,219
2015		239,015	1,762,951
2016		247,548	1,860,398
2017		252,705	1,954,243
2018		261,927	2,046,008
2019		269,491	2,135,078

Note: Capacity is stated at average annual temperature for FMPA.

Table 1D.8-16
FMPA Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000		108,436	108,436
2001		135,277	234,169
2002		141,565	359,272
2003	21 MW Joint Development with Southern-Florida (10/03) 40 MW Southern-Florida Power Purchase (10/03)	141,784	478,317
2004		144,643	592,887
2005		146,196	702,133
2006		152,897	809,920
2007		161,523	917,342
2008	257 MW WH 501F 2x1 Combined Cycle (06/08)	172,734	1,025,717
2009		182,252	1,133,592
2010		188,968	1,239,110
2011	223 MW Pulverized Coal (06/11)	205,771	1,347,508
2012		221,702	1,457,687
2013	Terminate 40 MW Southern-Florida Power Purchase (11/13)	226,326	1,563,797
2014		232,028	1,666,423
2015		238,207	1,765,819
2016		246,184	1,862,728
2017		251,522	1,956,134
2018		260,800	2,047,504
2019		268,514	2,136,251

Note: Capacity is stated at average annual temperature for FMPA.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Base Case
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
GE 7FA SC	156	76,681	12	2014.417	111,323	9,576

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,753	10,083	0	0	147,836	0	147,836	259,251
2002	144,902	11,902	0	0	156,804	0	156,804	398,836
2003	148,809	12,641	807	(30)	162,227	232	162,459	535,240
2004	145,329	13,671	3,203	(119)	162,083	928	163,011	664,360
2005	149,502	16,446	3,205	(119)	169,034	928	169,962	791,366
2006	146,399	17,368	4,234	(120)	167,881	8,786	176,667	915,809
2007	148,696	18,945	5,004	(120)	172,525	14,399	186,924	1,040,224
2008	158,809	21,685	5,052	(121)	185,424	14,399	199,823	1,166,895
2009	162,951	22,780	6,205	(122)	191,814	22,861	214,675	1,290,561
2010	168,130	23,855	7,081	(122)	198,943	28,906	227,849	1,410,891
2011	175,742	25,429	7,181	(123)	208,230	28,906	237,135	1,524,611
2012	185,638	26,443	7,284	(123)	219,241	28,906	248,146	1,666,132
2013	197,417	27,476	6,873	(124)	231,642	28,906	260,548	1,790,287
2014	207,288	28,172	4,879	(124)	240,214	34,492	274,706	1911,769
2015	216,297	29,047	5,341	(125)	250,561	38,482	289,042	2032,397
2016	227,168	30,315	5,474	(126)	262,832	38,482	301,313	2151,007
2017	236,256	31,136	5,611	(126)	272,877	38,482	311,359	2,266,635
2018	248,772	32,276	5,752	(127)	286,673	38,482	325,154	2,380,551
2019	261,385	33,322	5,895	(128)	300,475	38,482	338,956	2,492,580

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Base Case
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	137,753	10,083	0	0	147,836	0	147,836	259,281
2002	144,902	11,902	0	0	156,804	0	156,804	398,836
2003	148,842	12,641	325	13	161,820	677	162,497	536,272
2004	145,468	13,652	333	51	159,503	2,706	162,210	663,757
2005	149,725	16,440	341	53	166,558	2,706	169,264	790,241
2006	146,627	17,370	1,375	54	165,426	10,564	175,990	914,307
2007	148,897	18,944	2,151	55	170,047	16,177	186,224	1,038,156
2008	159,063	21,686	2,204	57	183,010	16,177	199,187	1,169,126
2009	168,411	22,197	2,687	58	193,353	21,014	214,367	1,290,012
2010	176,758	23,136	3,063	59	203,016	24,470	227,486	1,417,036
2011	187,591	23,991	3,588	61	215,231	29,552	244,783	1,545,987
2012	204,029	24,982	4,003	62	233,075	33,182	266,257	1,679,309
2013	198,239	26,722	5,321	64	230,347	42,523	272,869	1,806,241
2014	205,149	28,017	6,336	66	239,567	49,195	288,761	1,933,960
2015	212,701	29,025	6,494	67	248,288	49,195	297,482	2,058,089
2016	224,413	30,230	6,656	69	261,369	49,195	310,564	2,180,342
2017	233,417	30,916	6,823	71	271,226	49,195	320,421	2,299,334
2018	245,935	32,179	6,993	72	285,179	49,195	334,374	2,416,480
2019	257,786	32,986	7,168	74	298,014	49,195	347,209	2,531,237

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: High Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
Pulverized Coal	223	256,581	42	2014.417	388,463	33,416

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,595	10,065	0	0	148,660	0	148,660	260,958
2002	147,028	11,892	0	0	158,920	0	158,920	401,407
2003	149,678	12,475	807	(30)	162,930	232	163,162	536,491
2004	151,486	13,534	3,203	(119)	168,104	928	169,032	672,360
2005	159,877	16,297	3,205	(119)	179,760	928	180,688	806,663
2006	158,565	17,267	4,234	(120)	179,946	6,786	186,731	959,701
2007	164,361	18,857	5,004	(120)	188,101	14,399	202,500	1,074,376
2008	182,854	21,832	5,052	(121)	209,616	14,399	224,015	1,214,926
2009	187,528	22,974	6,205	(122)	216,586	22,861	239,447	1,386,854
2010	197,491	23,986	7,081	(122)	228,436	28,906	257,341	1,560,352
2011	212,378	26,015	7,181	(123)	245,451	28,906	274,357	1,744,579
2012	228,370	27,041	7,284	(123)	262,571	28,906	291,476	1,931,734
2013	247,319	28,104	6,873	(124)	282,172	28,906	311,078	2,095,560
2014	245,522	29,747	7,145	(124)	282,289	46,308	328,597	2,281,843
2015	250,316	31,148	9,302	(125)	290,641	62,321	352,962	2,429,191
2016	266,969	32,463	9,534	(126)	308,841	62,321	371,162	2,579,228
2017	281,463	33,328	9,773	(126)	324,437	62,321	386,758	2,518,858
2018	301,777	34,512	10,017	(127)	346,180	62,321	408,501	2,581,972
2019	320,536	35,622	10,268	(128)	366,298	62,321	428,619	2,603,638

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: High Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
GE 7FA SC	156	76,681	12	2011.417	103,374	8,892
Pulverized Coal	223	256,581	42	2015.417	398,174	34,251

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	138,595	10,065	0	0	148,660	0	148,660	260,058
2002	147,028	11,892	0	0	158,920	0	158,920	401,497
2003	149,744	12,473	325	13	162,554	677	163,230	536,548
2004	151,631	13,526	333	51	165,541	2,706	168,247	671,916
2005	159,586	16,286	341	53	176,266	2,706	178,972	805,553
2006	158,796	17,277	1,375	54	177,501	10,564	188,065	939,132
2007	164,578	18,871	2,151	55	185,655	16,177	201,832	1,072,361
2008	183,122	21,830	2,204	57	207,213	16,177	223,390	1,212,519
2009	193,212	22,377	2,687	58	218,334	21,014	239,348	1,354,189
2010	205,672	23,446	3,063	59	232,240	24,470	256,709	1,497,634
2011	227,762	24,529	3,575	61	255,927	29,657	285,583	1,647,976
2012	253,513	25,447	3,980	62	283,003	33,362	316,364	1,808,199
2013	261,578	26,312	4,079	64	292,033	33,362	325,395	1,967,757
2014	281,542	27,206	4,181	66	312,994	33,362	346,356	2,130,951
2015	270,881	29,567	7,090	67	307,605	53,342	360,946	2,281,561
2016	275,363	31,516	9,294	69	316,243	67,613	383,855	2,412,664
2017	291,202	32,356	9,527	71	333,156	67,613	400,769	2,561,495
2018	311,618	33,499	9,765	72	354,954	67,613	422,567	2,709,539
2019	331,041	34,545	10,009	74	375,670	67,613	443,282	2,856,050

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 1x1	125	73,984	23	2014.417	109,072	9,382
WH 501F 1x1	125	73,984	23	2019.417	123,406	10,615

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,916	10,068	0	0	146,984	0	146,984	258,477
2002	142,131	12,288	0	0	154,419	0	154,419	395,909
2003	141,314	12,505	807	(30)	154,595	232	154,827	525,905
2004	139,095	13,997	3,203	(119)	156,176	928	157,104	650,346
2005	140,584	16,370	3,205	(119)	160,040	928	160,968	770,631
2006	134,506	17,779	4,234	(120)	156,399	8,788	165,185	897,080
2007	133,777	19,470	5,004	(120)	158,130	14,399	172,528	1,001,622
2008	140,844	21,403	5,052	(121)	167,177	14,399	181,576	1,116,745
2009	141,454	22,582	6,205	(122)	170,119	22,861	192,980	1,229,870
2010	143,385	23,749	7,081	(122)	174,094	28,906	203,000	1,343,324
2011	145,433	25,398	7,181	(123)	177,890	28,906	206,796	1,452,267
2012	150,942	26,417	7,284	(123)	184,520	28,906	213,426	1,559,927
2013	156,775	27,286	6,873	(124)	190,810	28,906	219,715	1,661,936
2014	162,596	27,895	4,893	(124)	195,259	34,379	229,638	1,762,907
2015	165,821	28,824	5,365	(125)	199,884	38,288	238,172	1,862,288
2016	171,429	30,031	5,499	(126)	206,834	38,288	245,122	1,956,779
2017	175,108	30,818	5,637	(126)	211,436	38,288	249,724	2,051,518
2018	181,509	31,954	5,778	(127)	219,114	38,288	257,401	2,141,697
2019	186,677	32,790	6,469	(128)	225,809	44,480	270,289	2,231,991

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	114,059	5,754	0	0	119,813	0	119,813	119,813
2001	136,916	10,068	0	0	146,984	0	146,984	256,477
2002	142,131	12,288	0	0	154,419	0	154,419	396,969
2003	141,367	12,487	325	13	154,191	677	154,868	525,940
2004	139,259	13,972	333	51	153,614	2,706	156,320	648,760
2005	143,374	16,636	341	53	160,404	2,706	163,110	771,645
2006	134,722	17,788	1,375	54	153,939	10,564	164,503	887,613
2007	133,983	19,469	2,151	55	155,658	16,177	171,834	1,001,893
2008	141,072	21,402	2,204	57	164,735	16,177	180,912	1,115,399
2009	146,791	21,816	2,687	58	171,352	21,014	192,366	1,229,260
2010	151,566	22,483	3,063	59	177,172	24,470	201,641	1,341,859
2011	155,070	23,796	3,588	61	182,516	29,552	212,068	1,453,670
2012	165,576	24,713	4,003	62	194,354	33,182	227,536	1,566,649
2013	150,775	27,373	6,771	64	184,983	42,523	227,505	1,679,312
2014	146,674	28,914	8,870	66	184,524	49,195	233,719	1,776,599
2015	149,680	29,844	9,092	67	188,683	49,195	237,878	1,875,944
2016	154,501	31,105	9,319	69	194,994	49,195	244,188	1,972,068
2017	157,137	32,067	9,552	71	198,827	49,195	248,022	2,064,174
2018	162,750	33,019	9,791	72	205,632	49,195	254,827	2,153,451
2019	166,552	34,151	10,036	74	210,813	49,195	260,008	2,239,987

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: AEO Fuel Price Projections Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	98,538	6,651	0	0	105,189	0	105,189	105,189
2001	106,579	10,518	0	0	117,096	0	117,096	215,657
2002	119,526	12,028	0	0	131,554	0	131,554	332,739
2003	127,514	13,011	807	(30)	141,302	232	141,534	451,574
2004	134,962	14,011	3,203	(119)	152,057	928	152,985	572,752
2005	142,371	16,254	3,205	(119)	161,711	928	162,639	694,298
2006	127,452	18,199	5,453	(120)	150,984	16,926	167,911	812,686
2007	121,182	20,115	7,136	(120)	148,313	28,354	176,666	930,149
2008	132,565	22,558	7,237	(121)	162,240	28,354	190,593	1,049,730
2009	134,585	23,674	8,445	(122)	166,582	36,816	203,398	1,170,121
2010	136,780	24,745	9,378	(122)	170,780	42,860	213,640	1,289,416
2011	143,354	26,336	9,535	(123)	179,102	42,860	221,962	1,406,349
2012	150,765	27,377	9,696	(123)	187,715	42,860	230,575	1,520,932
2013	157,638	28,415	9,346	(124)	195,274	42,860	238,134	1,632,579
2014	162,471	29,482	8,194	(124)	200,023	52,435	252,457	1,744,241
2015	165,873	30,603	9,302	(125)	205,652	59,273	264,925	1,854,785
2016	173,776	31,884	9,534	(126)	215,068	59,273	274,341	1,962,778
2017	180,020	32,808	9,773	(126)	222,474	59,273	281,747	2,067,469
2018	189,592	34,020	10,017	(127)	233,502	59,273	292,775	2,169,981
2019	199,077	35,058	10,268	(128)	244,275	59,273	303,548	2,270,398

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	12	2013.417	183,051	15,746

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	98,538	6,651	0	0	105,189	0	105,189	105,189
2001	106,579	10,518	0	0	117,096	0	117,096	215,657
2002	119,526	12,028	0	0	131,554	0	131,554	332,739
2003	127,555	13,003	325	13	140,895	677	141,572	451,606
2004	135,131	13,986	333	51	149,502	2,706	152,208	572,168
2005	142,616	16,241	341	53	159,251	2,706	161,957	693,192
2006	127,682	18,191	2,594	54	148,521	18,704	167,225	811,079
2007	121,388	20,108	4,283	55	145,834	30,132	175,966	928,106
2008	132,920	22,550	4,390	57	159,916	30,132	190,048	1,047,345
2009	140,907	23,161	4,927	58	169,053	34,969	204,022	1,169,106
2010	146,459	23,924	5,359	59	175,802	38,424	214,226	1,287,726
2011	157,816	25,015	5,942	61	188,834	43,507	232,341	1,410,122
2012	171,422	26,140	6,415	62	204,040	47,137	251,177	1,534,950
2013	162,057	27,779	7,794	64	197,693	56,322	254,015	1,664,042
2014	165,615	29,041	8,870	66	203,592	62,883	266,476	1,771,904
2015	170,787	29,933	9,092	67	209,879	62,883	272,762	1,869,218
2016	179,788	31,196	9,319	69	220,371	62,883	283,254	1,997,229
2017	186,901	32,079	9,552	71	228,602	62,883	291,485	2,106,467
2018	196,994	33,082	9,791	72	239,940	62,883	302,823	2,211,559
2019	206,857	34,160	10,036	74	251,127	62,883	314,010	2,316,344

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: OUC 2000 + 2001 AEO Escalators
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,908	10,196	0	0	140,103	0	140,103	251,903
2002	146,035	11,806	0	0	157,841	0	157,841	382,581
2003	158,585	12,730	807	(30)	172,092	232	172,324	537,068
2004	172,699	13,892	3,203	(119)	189,674	928	190,602	688,201
2005	197,980	16,437	3,205	(119)	217,503	928	218,431	851,426
2006	171,291	19,126	5,453	(120)	195,750	16,926	212,677	1,001,354
2007	163,815	21,267	7,136	(120)	192,097	28,354	220,451	1,147,966
2008	188,764	23,973	7,237	(121)	219,853	28,354	248,207	1,303,694
2009	195,166	25,044	8,445	(122)	228,534	36,816	265,350	1,460,755
2010	201,863	25,965	9,378	(122)	237,084	42,860	279,944	1,617,074
2011	232,249	26,859	9,535	(123)	268,520	42,860	311,381	1,781,105
2012	245,803	27,894	9,696	(123)	283,269	42,860	326,130	1,943,182
2013	257,988	28,966	9,346	(124)	296,175	42,860	339,035	2,102,135
2014	267,090	30,122	8,194	(124)	305,280	62,435	367,715	2,260,359
2015	274,010	31,222	9,302	(125)	314,409	59,273	373,682	2,414,277
2016	288,710	32,535	9,534	(126)	330,654	59,273	389,927	2,569,771
2017	299,511	33,443	9,773	(126)	342,600	59,273	401,874	2,719,012
2018	317,153	34,676	10,017	(127)	361,720	59,273	420,993	2,866,505
2019	334,436	35,787	10,268	(128)	380,363	59,273	439,636	3,011,810

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: OUC 2000 + 2001 AEO Escalators Self Build

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 1x1	125	73,984	23	2009.417	96,404	8,293
WH 501F 1x1	125	73,984	23	2011.417	101,285	8,713
WH 501F 2x1	257	129,241	24	2013.417	186,150	16,013

Finance	
Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,906	10,196	0	0	140,103	0	140,103	251,903
2002	146,035	11,806	0	0	157,841	0	157,841	392,381
2003	158,640	12,727	325	13	171,704	677	172,381	537,116
2004	173,274	13,885	333	51	187,543	2,706	190,249	687,811
2005	198,245	16,426	341	53	215,064	2,706	217,770	880,541
2006	171,833	19,135	2,594	54	193,616	18,704	212,320	1,000,219
2007	164,297	21,264	4,283	55	189,900	30,132	220,032	1,146,562
2008	189,309	23,971	4,390	57	217,727	30,132	247,858	1,302,062
2009	203,813	24,671	4,927	58	233,469	34,969	268,438	1,460,950
2010	214,680	25,513	5,359	59	245,611	38,424	284,035	1,619,654
2011	257,498	25,478	5,942	61	288,979	43,507	332,485	1,784,703
2012	282,330	26,645	6,415	62	315,453	47,137	362,590	1,974,899
2013	266,423	28,395	7,794	64	302,676	56,478	359,154	2,149,284
2014	273,463	29,728	8,870	66	312,127	63,150	375,277	2,309,269
2015	282,465	30,647	9,092	67	322,271	63,150	385,421	2,479,092
2016	299,271	31,910	9,319	69	340,569	63,150	403,719	2,659,014
2017	311,291	32,802	9,552	71	353,717	63,150	416,867	2,853,624
2018	329,359	33,823	9,791	72	373,045	63,150	436,195	3,058,538
2019	348,174	34,886	10,036	74	393,170	63,150	456,320	3,267,464

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Constant 2000 Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
Pulverized Coal	223	256,581	42	2006.417	318,830	27,426
WH 501F 2x1	257	129,241	24	2009.417	168,643	14,507
WH 501F 2x1	257	129,241	24	2014.417	190,804	16,413

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	113,987	5,744	0	0	119,731	0	119,731	119,731
2001	129,433	10,285	0	0	139,717	0	139,717	251,540
2002	144,959	11,950	0	0	156,909	0	156,909	391,188
2003	156,195	12,898	807	(30)	169,870	232	170,102	534,009
2004	167,660	13,950	3,203	(119)	184,694	928	185,622	661,039
2005	182,845	16,416	3,205	(119)	202,348	928	203,276	832,938
2006	165,238	19,087	5,453	(120)	189,659	16,926	206,586	978,573
2007	160,200	21,212	7,136	(120)	188,428	28,354	216,782	1,122,745
2008	180,184	23,877	7,237	(121)	211,177	28,354	239,531	1,273,030
2009	185,202	24,973	8,445	(122)	218,498	36,816	255,315	1,426,150
2010	190,746	25,897	9,378	(122)	225,898	42,860	268,759	1,574,224
2011	208,945	26,822	9,535	(123)	245,180	42,860	288,040	1,725,960
2012	219,536	27,848	9,696	(123)	256,957	42,860	299,817	1,874,960
2013	228,636	28,939	9,346	(124)	266,696	42,860	309,557	2,020,092
2014	234,649	30,083	8,194	(124)	272,801	52,436	325,236	2,163,044
2015	239,322	31,195	9,302	(125)	279,694	59,273	338,967	2,305,883
2016	248,732	32,498	9,534	(126)	290,639	59,273	349,912	2,443,125
2017	254,564	33,418	9,773	(126)	297,628	59,273	356,902	2,575,685
2018	265,354	34,615	10,017	(127)	309,860	59,273	369,133	2,704,969
2019	275,427	35,734	10,268	(128)	321,300	59,273	380,574	2,830,773

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: High Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2005.417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal	223	256,581	42	2011.417	360,726	31,030
WH 501F 1x1	125	73,984	23	2017.417	117,459	10,104

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,479	10,790	0	0	163,269	0	163,269	284,671
2002	163,022	13,022	0	0	176,044	0	176,044	431,850
2003	169,170	14,232	325	13	183,738	677	184,416	596,398
2004	172,689	15,940	333	51	189,012	2,706	191,718	748,247
2005	163,200	19,577	1,341	53	184,171	10,372	194,543	893,921
2006	162,316	20,775	3,123	54	186,268	23,706	209,974	1,041,644
2007	170,520	22,734	3,943	55	197,252	29,319	226,571	1,192,327
2008	179,512	26,011	5,118	57	210,698	37,575	248,273	1,348,096
2009	191,192	27,548	6,025	58	224,823	43,472	268,295	1,508,900
2010	202,890	29,021	6,176	59	238,147	43,472	281,619	1,664,154
2011	203,754	31,715	8,870	61	244,400	61,573	305,973	1,825,337
2012	213,357	33,580	10,929	62	257,928	74,502	332,430	1,990,545
2013	221,514	35,081	11,202	64	267,862	74,502	342,363	2,151,059
2014	233,956	36,575	11,482	66	282,080	74,502	356,581	2,308,774
2015	245,838	38,080	11,769	67	295,754	74,502	370,256	2,463,269
2016	259,828	39,749	12,064	69	311,709	74,502	386,211	2,615,300
2017	270,824	41,043	12,886	71	324,823	80,396	405,219	2,766,784
2018	287,596	42,698	13,584	72	343,951	84,606	428,557	2,915,926
2019	299,997	44,225	13,924	74	358,221	84,606	442,828	3,063,365

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case
Scenario: High Load and Energy Growth Joint Development

Economic	
CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2005.417	152,782	13,142
WH 501F 2x1	257	129,241	24	2006.417	156,602	13,471
GE 7FA SC	156	76,681	12	2008.417	95,993	8,257
Pulverized Coal	223	256,581	42	2011.417	360,726	31,030
WH 501F 2x1	257	129,241	23	2014.417	190,537	16,390

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,613	6,230	0	0	130,844	0	130,844	130,844
2001	152,479	10,790	0	0	163,269	0	163,269	284,871
2002	163,022	13,022	0	0	176,044	0	176,044	441,550
2003	169,108	14,240	807	(30)	184,124	232	184,356	596,339
2004	172,411	15,944	3,203	(119)	191,439	928	192,367	748,711
2005	162,960	19,589	4,206	(119)	186,635	8,594	195,230	894,598
2006	162,008	20,781	5,982	(120)	188,651	21,928	210,580	1,043,048
2007	169,984	22,711	7,191	(120)	199,765	27,541	227,306	1,194,220
2008	182,116	25,815	7,579	(121)	215,391	32,358	247,749	1,349,881
2009	195,803	27,285	7,692	(122)	230,659	35,799	266,457	1,507,376
2010	207,973	28,684	7,807	(122)	244,342	35,799	280,141	1,663,805
2011	207,367	31,334	10,465	(123)	249,044	53,889	302,933	1,823,992
2012	214,098	33,288	12,486	(123)	259,750	66,826	326,576	1,985,691
2013	223,946	34,747	12,205	(124)	270,775	66,826	337,603	2,143,978
2014	234,422	36,336	11,125	(124)	281,759	76,389	358,148	2,302,382
2015	245,028	37,976	12,306	(125)	295,185	83,218	378,403	2,460,278
2016	259,780	39,611	12,614	(126)	311,879	83,218	395,097	2,615,805
2017	269,589	40,996	12,929	(126)	323,388	83,218	406,606	2,766,804
2018	299,516	42,191	13,253	(127)	354,832	83,218	438,050	2,920,272
2019	300,041	44,187	13,584	(128)	357,684	83,218	440,903	3,065,996

Notes:

* FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Low Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
						825.149507
Self Build	61			2003.833	31,458	2,706
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011.417	360,726	31,030

Finance

Fixed Charge Rate:	8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,915	9,362	0	0	133,277	0	133,277	234,169
2002	129,660	10,905	0	0	140,565	0	140,565	359,272
2003	129,714	11,132	325	13	141,183	677	141,860	478,380
2004	128,373	12,369	333	51	141,126	2,706	143,832	592,308
2005	127,993	14,398	341	53	142,785	2,706	145,491	701,928
2006	134,209	14,887	350	54	149,499	2,706	152,205	808,326
2007	141,514	16,172	358	55	158,100	2,706	160,806	915,271
2008	140,832	18,773	1,444	57	161,106	10,962	172,067	1,023,229
2009	142,880	19,542	2,259	58	164,740	16,859	181,598	1,130,717
2010	148,745	20,298	2,316	59	171,419	16,859	188,277	1,235,850
2011	142,909	22,389	4,914	61	170,273	34,959	205,232	1,343,963
2012	142,636	23,748	6,873	62	173,320	47,889	221,209	1,453,897
2013	146,769	24,474	7,045	64	178,352	47,889	226,240	1,559,968
2014	153,084	25,181	7,221	66	185,552	47,889	233,441	1,663,219
2015	157,763	25,894	7,402	67	191,126	47,889	239,015	1,762,951
2016	165,075	26,928	7,587	69	199,659	47,889	247,548	1,860,396
2017	169,450	27,519	7,777	71	204,817	47,889	252,706	1,954,243
2018	177,605	28,390	7,971	72	214,039	47,889	261,927	2,046,608
2019	184,124	29,233	8,170	74	221,602	47,889	269,491	2,136,078

Notes:

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Florida Municipal Power Agency Economic Evaluation

Case

Scenario: Low Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	6.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	21			2003.833		
WH 501F 2x1	257	129,241	24	2008.417	164,529	14,153
Pulverized Coal PC	223	256,581	42	2011.417	360,726	31,030

Finance

Fixed Charge Rate:	*8.60%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed[2] ($1,000)	Fees and Credits[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	103,096	5,340	0	0	108,436	0	108,436	108,436
2001	123,915	9,362	0	0	133,277	0	133,277	234,169
2002	129,660	10,905	0	0	140,565	0	140,565	359,274
2003	129,843	11,133	807	(30)	141,552	232	141,784	478,317
2004	128,242	12,389	3,203	(119)	143,715	928	144,643	592,887
2005	127,770	14,412	3,205	(119)	145,268	928	146,196	702,133
2006	133,990	14,890	3,208	(120)	151,969	928	152,897	809,920
2007	141,334	16,170	3,212	(120)	160,595	928	161,523	917,342
2008	140,603	18,776	4,292	(121)	163,550	9,184	172,734	1,026,717
2009	142,650	19,542	5,101	(122)	167,171	15,081	182,252	1,133,592
2010	148,557	20,300	5,151	(122)	173,887	15,081	188,968	1,239,110
2011	142,570	22,399	7,743	(123)	172,589	33,182	205,771	1,342,506
2012	142,261	23,758	9,696	(123)	175,691	46,111	221,802	1,457,687
2013	146,536	24,458	9,346	(124)	180,216	46,111	226,326	1,564,797
2014	154,002	25,095	6,945	(124)	185,917	46,111	232,028	1,668,428
2015	159,331	25,773	7,118	(125)	192,096	46,111	238,207	1,766,619
2016	166,076	26,827	7,296	(126)	200,073	46,111	246,184	1,862,728
2017	170,647	27,412	7,479	(126)	205,412	46,111	251,522	1,956,134
2018	178,868	28,282	7,666	(127)	214,689	46,111	260,800	2,047,504
2019	185,552	29,122	7,857	(128)	222,404	46,111	268,514	2,136,251

Notes:

*FMPA assumed to finance the Southern-Florida project at a 9.02 percent rate.

[1] Includes start-up costs.

[2] Fixed costs are included only for new units.

[3] Includes fees for site lease as well as credit for services and cooling water.

Table 1A.2-1
Utility Summer Deficits (MW)

Year	OUC	KUA	FMPA	Total
2000	17	0	0	17
2001	0	0	0	0
2002	55	0	0	55
2003	85	0	0	85
2004	593*	11	110	714
2005	560	27	27	614
2006	557	42	119	718
2007	587	53	163	803
2008	623	66	273	962
2009	663	78	305	1,046
2010	703	91	325	1,119
2011	567	104	497	1,168
2012	600	118	516	1,234
2013	640	130	532	1,302
2014	695	144	549	1,388
2015	730	159	564	1,453
2016	766	173	580	1,519
2017	805	187	593	1,585
2018	844	201	605	1,650
2019	879	216	617	1,712

* Reliant purchase power agreement expires September 30, 2003.