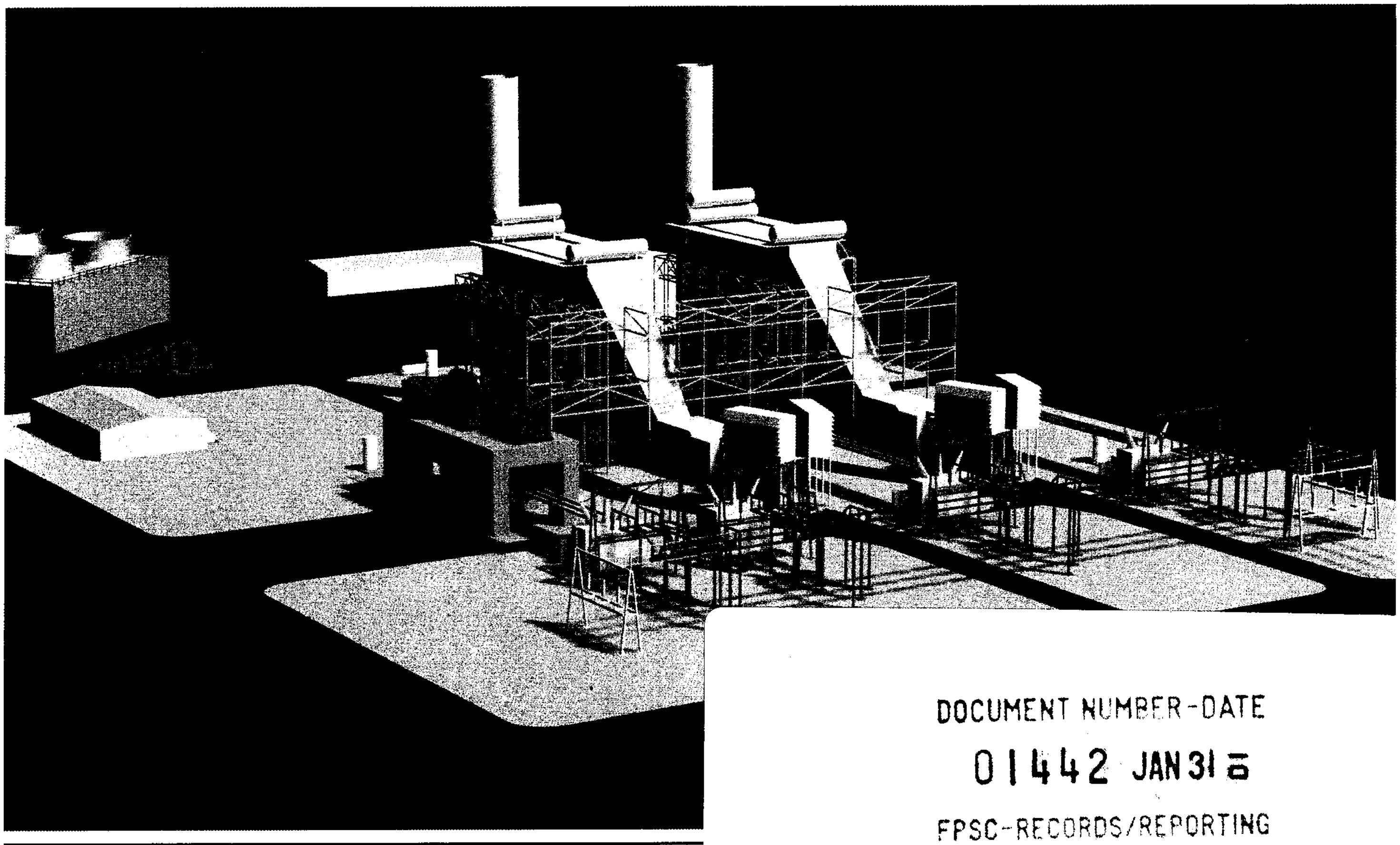
# Need for Power Application

# Volume 1F – Confidential Exhibit B 01



DOCUMENT NUMBER-DATE
01442 JAN 31 ō
FPSC-RECORDS/REPORTING

# Orlando Utilities Commission
# Curtis H. Stanton Energy Center
# Combined Cycle Unit A

5-13-0

DECLASSIFIED

**B&V Project 97185**

**y 2001**

FMPA

KUA
KISSIMMEE UTILITY AUTHORITY

OUC
The *Reliable* One

SOUTHERN COMPANY
*Energy to Serve Your World*

# 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

BLACK & VEATCH

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

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# 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

## 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 $94.916 million, 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 7,230 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 663 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 | 61 | 665 |
| 2005 | 560 | 27 | 55 | 642 |
| 2006 | 557 | 42 | 140 | 739 |
| 2007 | 587 | 53 | 184 | 824 |
| 2008 | 623 | 66 | 280 | 969 |
| 2009 | 663 | 78 | 312 | 1,053 |
| 2010 | 703 | 91 | 332 | 1,126 |
| 2011 | 567 | 104 | 496 | 1,167 |
| 2012 | 600 | 118 | 515 | 1,233 |
| 2013 | 640 | 130 | 532 | 1,302 |
| 2014 | 695 | 144 | 548 | 1,387 |
| 2015 | 730 | 159 | 563 | 1,452 |
| 2016 | 766 | 173 | 579 | 1,518 |
| 2017 | 805 | 187 | 592 | 1,584 |
| 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.

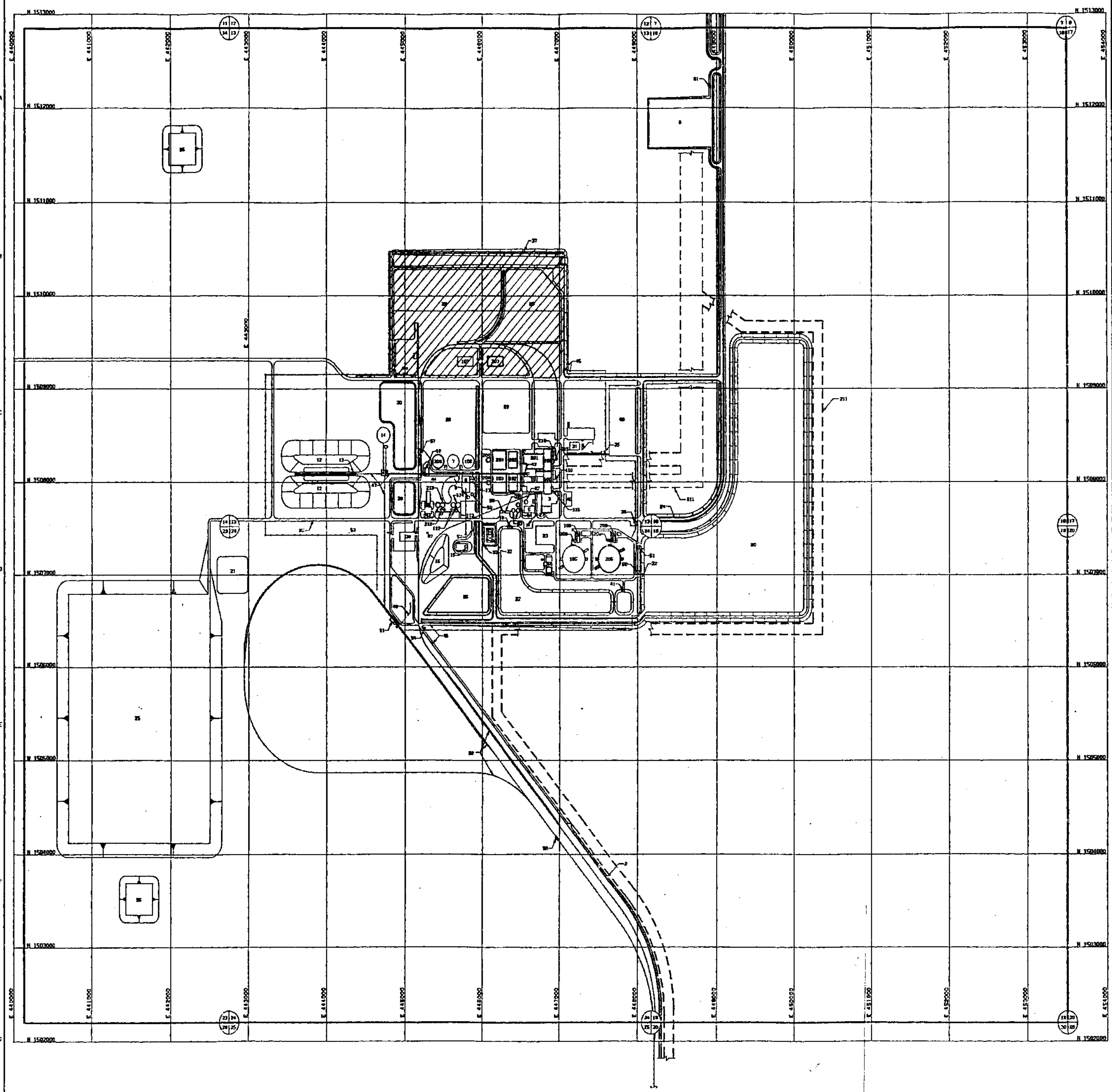
### *1A.3.1.1 Stanton Energy Center*

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.



| NO | COMMON FACILITIES |
|---|---|
| 1 | FIRST AID TRAILER |
| 2 | ALTERNATE ACCESS ROAD |
| 3 | ADMINISTRATION AND PLANT SERVICES BUILDING |
| 4 | CONTROL CENTER BUILDING |
| 5 | WATER MANAGEMENT BUILDING |
| 6 | SUBSTATION |
| 7 | THICKENER |
| 8 | SLUDGE CONDITIONING BUILDING |
| 9 | FLY ASH SILO |
| 10 | COAL CRUSHER BUILDING |
| 11 | COAL CAR UNLOADING BUILDING |
| 12 | COAL STORAGE AREA |
| 13 | STACKER RECLAIMER |
| 14 | EMERGENCY STOCKOUT AND RECLAIM |
| 15 | SCRUBBER ADDITIVE RECLAIM AND COVER |
| 16 | SCRUBBER ADDITIVE STORAGE |
| 17 | SCRUBBER ADDITIVE STORAGE TANK |
| 18 | SCRUBBER MAKEUP WATER PUMP STRUCTURE |
| 19 | CIRCULATING WATER MAKEUP PUMP STRUCTURE |
| 20 | MAKEUP WATER SUPPLY STORAGE POND |
| 21 | ACTIVE COMBUSTION WASTE AREA RUNOFF POND |
| 22 | RECYCLE BASIN |
| 23 | ADMINISTRATION AND PLANT SERVICES PARKING LOT |
| 24 | MAIN PLANT ACCESS ROAD |
| 25 | COMBUSTION WASTE STORAGE AREA |
| 26 | COMBUSTION WASTE HAUL ROAD |
| 27 | COMPRESSED GAS STORAGE BUILDING |
| 28 | WATER STORAGE PUMP BUILDING |
| 29 | CONSTRUCTION LAYDOWN AREA |
| 30 | COAL STORAGE AREA RUNOFF POND |
| 31 | CONSTUCTION OFFICE BUILDING |
| 32 | FUEL OIL STORAGE |
| 33 | OIL SPILL CONTAINMENT BERM |
| 34 | CONCRETE BATCH PLANT (OFFSITE) |
| 35 | GUARD STATION |
| 36 | SECURITY BUILDING |
| 37 | SECURITY FENCE |
| 38 | YARD SERVICES BUILDING |
| 39 | PERMANENT WAREHOUSE |
| 40 | VISITORS PARKING LOT |
| 41 | WASTEWATER RETURN PUMP STRUCTURE |
| 42 | NEUTRALIZATION BASIN |
| 43 | CONDENSATE STORAGE TANK |
| 44 | COMBUSTION WASTE LOADING AREA |
| 45 | PLANT SERVICE ROADS |
| 46 | CONSTRUCTION PARKING |
| 47 | YARD COAL CONVEYOR |
| 48 | FUTURE YARD SCRUBBER ADDITIVE CONVEYOR |
| 49 | COAL TRANSFER STRUCTURE |
| 50 | LIME STORAGE SILO |
| 51 | SEWAGE TREATMENT PLANT |
| 52 | RAILROAD |
| 53 | WELL WATER PUMP HOUSE |
| 54 | ACCESS ROAD GUARDHOUSE |
| 55 | TOPSOIL COVER STOCKPILE |
| 56 | TRACK SCALE |
| 57 | FUTURE LIME UNLOADING BUILDING |
| 58 | TRUCK SCALE |
| 59 | EMERGENCY GENERATOR BUILDING |
| 60 | GIS BUILDING |
| 61 | SUBSTATION ACCESS ROAD |
| 62 | WASTEWATER TREATMENT BUILDING |
| 63 | SERVICE WATER STORAGE TANKS |
| 64 | DEMINERALIZED WATER STORAGE TANKS |
| 65 | RECYCLE BASIN SURGE AREA |

| NO | UNIT 1 FACILITIES |
|---|---|
| 100 | TURBINE ROOM |
| 101 | STEAM GENERATOR |
| 102 | PRECIPITATOR |
| 103 | AIR QUALITY CONTROL BUILDING |
| 104 | CHIMNEY |
| 105 | COOLING TOWER |
| 106 | THICKENER |
| 107 | CONSTRUCTION WAREHOUSE |
| 108 | CIRCULATING WATER PUMP STRUCTURE |
| 109 | CIRCULATING WATER CHEMICAL FEED BUILDING |
| 110 | GENERATOR TRANSFORMER AREA |
| 111 | SITE TRANSMISSION CORRIDOR |
| 112 | ASH DEWATERING TANK |
| 113 | ASH SETTLING TANK |
| 114 | ASH WATER STORAGE TANK |
| 115 | LUBE OIL STORAGE ROOM |

| NO | UNIT 2 FACILITIES |
|---|---|
| 200 | TURBINE ROOM |
| 201 | STEAM GENERATOR |
| 202 | PRECIPITATOR |
| 203 | AIR QUALITY CONTROL BUILDING |
| 204 | CHIMNEY |
| 205 | COOLING TOWER |
| 206 | THICKENER |
| 207 | CONSTRUCTION WAREHOUSE |
| 208 | CIRCULATING WATER PUMP STRUCTURE |
| 209 | CIRCULATING WATER CHEMICAL FEED BUILDING |
| 210 | GENERATOR TRANSFORMER AREA |
| 211 | SITE TRANSMISSION CORRIDOR |
| 212 | ASH DEWATERING TANK |
| 213 | ASH SETTLING TANK |
| 214 | ASH WATER STORAGE TANK |
| 215 | LUBE OIL STORAGE ROOM |

STANTON A SITE

**NOT TO BE USED FOR CONSTRUCTION**

DATE OF ISSUE ______

400' 200' 0 400' 800'

1"=400'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA

SIGNED ______

DATE ______ REG NO. ______

BLACK & VEATCH ENGINEERS-ARCHITECTS

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2

GENERAL SITE ARRANGEMENT
UNIT 2 FACILITIES PLOT PLAN

PROJECT 16805-2STU-S1000

FIGURE 1A.3-1

| NO | DATE | REVISIONS AND RECORD OF ISSUE | BY |
|---|---|---|---|

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 |

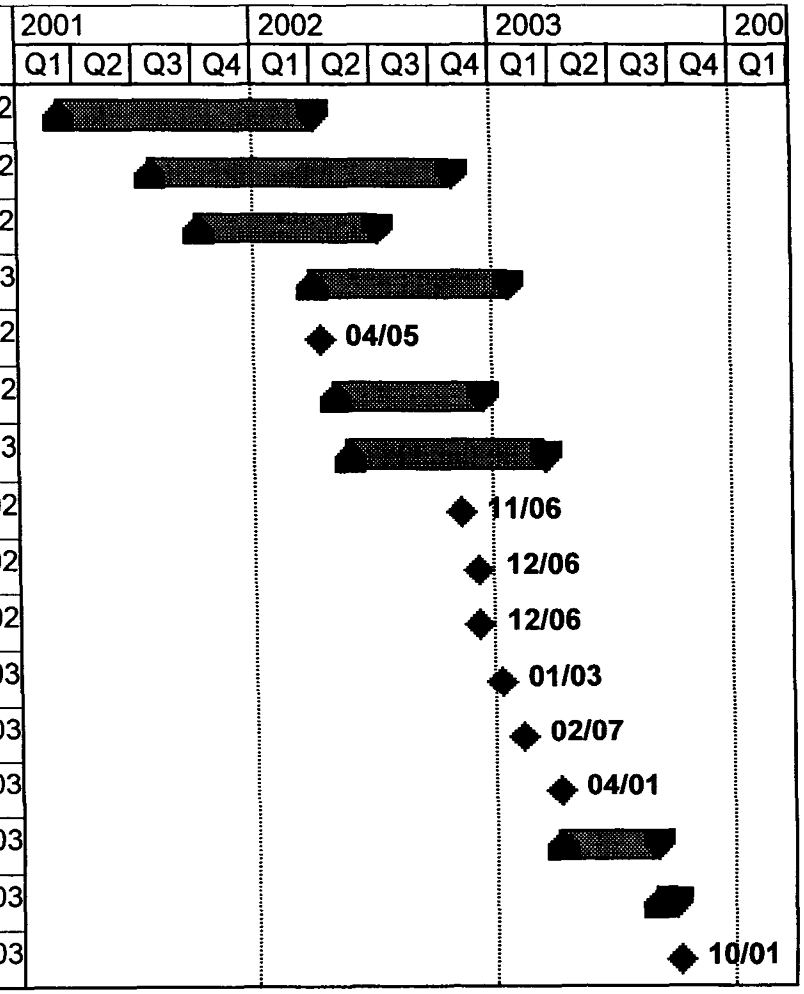
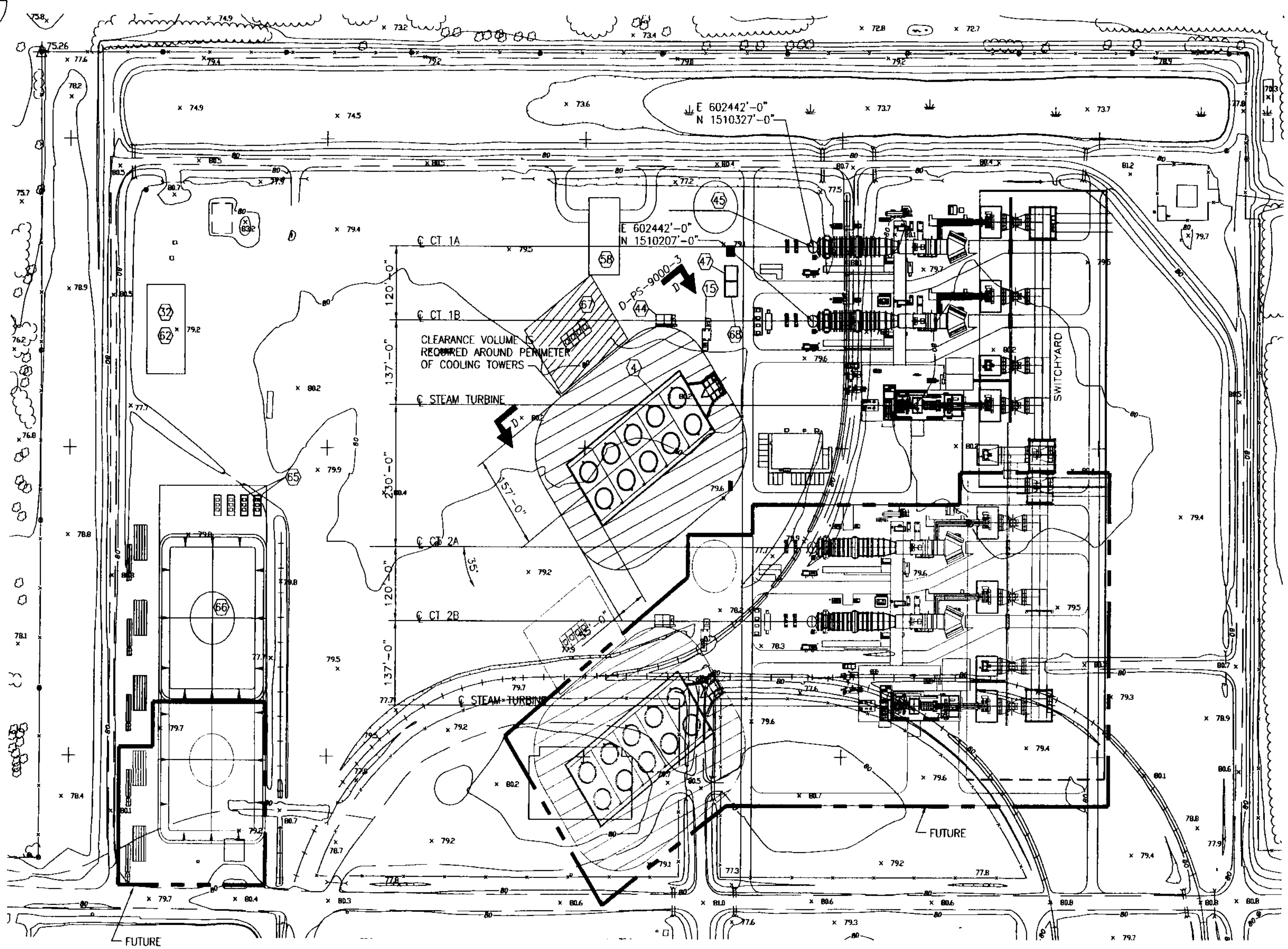



Figure 1A.3-2
Stanton A Construction Schedule




NOTES:

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

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

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

| | |
|---|---|
| CENTER UNIT 1A HRSG STACK: | E 1071425.2056<br>N 3165216.3816 |
| CENTER UNIT 1B HRSG STACK: | E 1071427.0434<br>N 3165179.7166 |
| CENTER UNIT 2A HRSG STACK: | E 1071432.6637<br>N 3165067.5830 |
| CENTER UNIT 2B HRSG STACK: | E 1071434.5014<br>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 SHW-14

PRELIMINARY



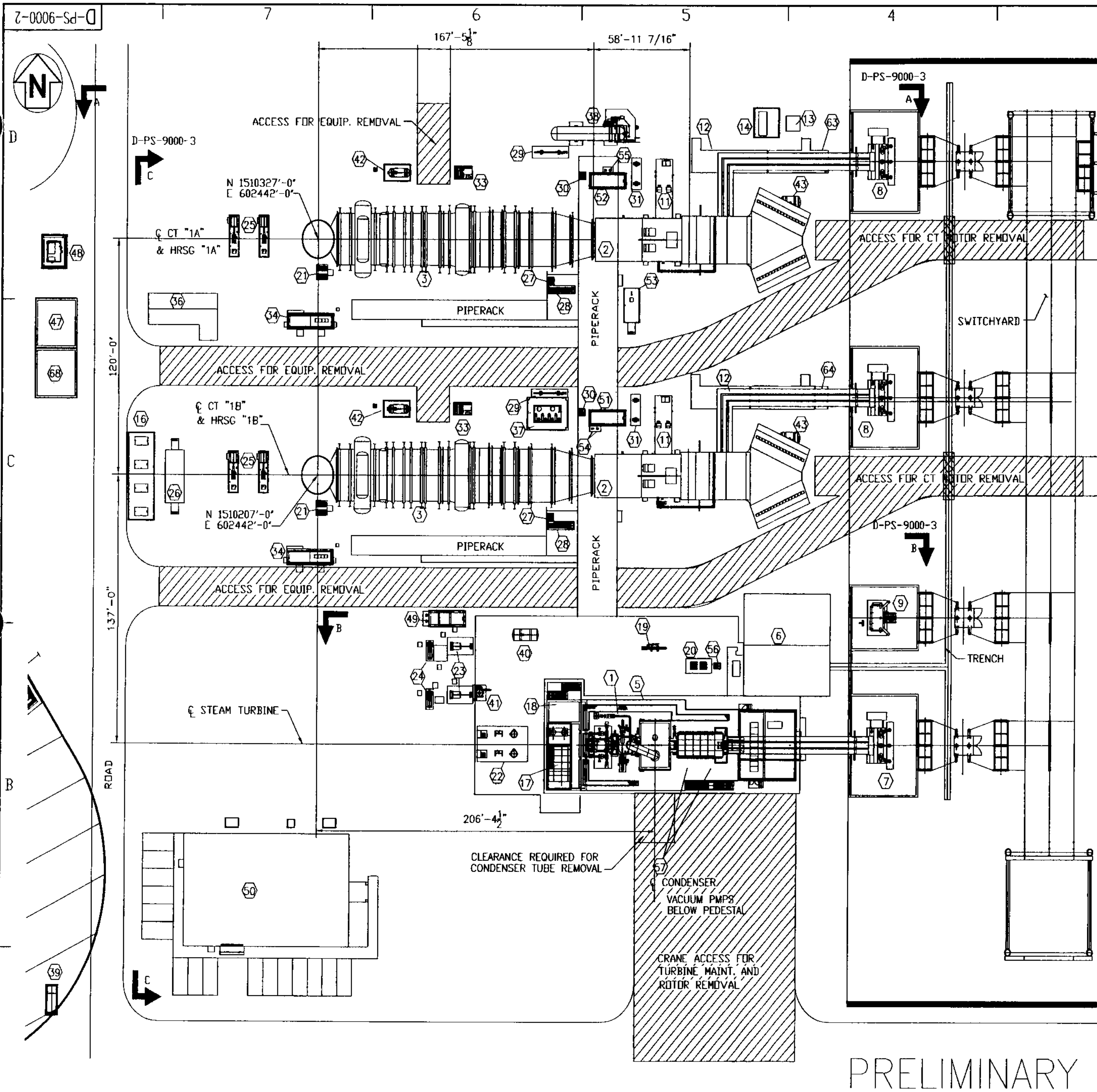
Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

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

| REVISION | DATE | DESCRIPTION | BY |
|---|---|---|---|
| REVISION D | 01/16/00 | 1. REVISED TITLE BLOCK | SHW |
| REVISION C | 12/7/00 | 1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68 | DWR |
| REVISION B | 10/24/00 | 1. ADDED SERVICE WATER COOLER<br>1. ADDED LOCATION OF FUTURE BLOCK. | SHW |
| REVISION A | 9/22/00 | ISSUED FOR REVIEW | SHW |

| DESIGNED | DRAWN | CHECKED | SCALE | PROJECT I.D. | DRAWING NUMBER | REV. |
|---|---|---|---|---|---|---|
| SHW | SHW | | 1"=200'-0" | | D-PS-9000-1 | D |

D-PS-9000-1




## 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



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 | DESCRIPTION | BY |
|---|---|---|---|
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| REVISION C | 12/7/00 | 1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP ITEM NO. 68 | DWR |
| REVISION B | 10/24/00 | ADDED ITEM NO. 67 IPC | SHW |
| REVISION A | 9/22/00 | ISSUED FOR REVIEW | SHW |

| DESIGNED | DRAWN | CHECKED | SCALE | PROJECT I.D. | DRAWING NUMBER | REV. |
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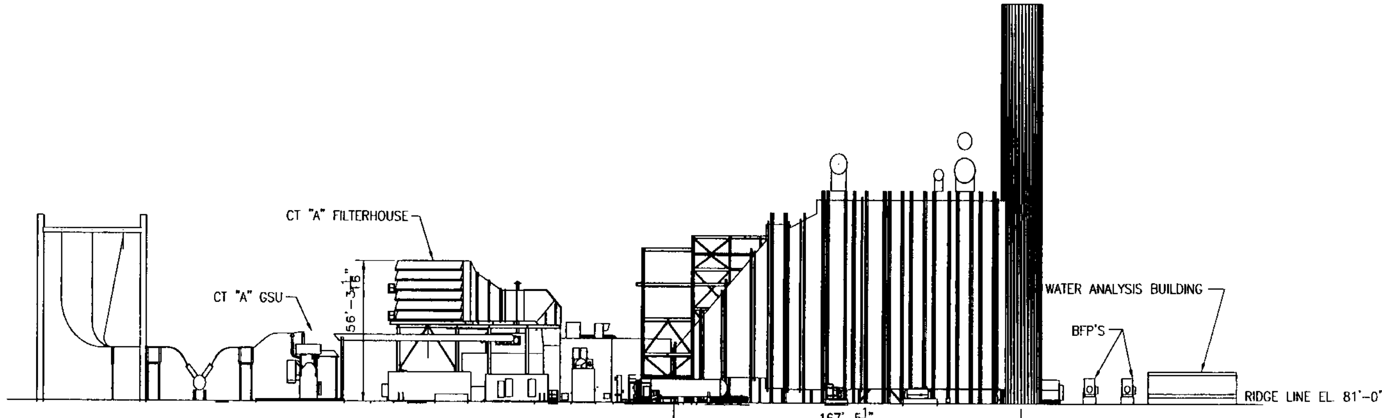
D-PS-9000-3




SECTION A-A
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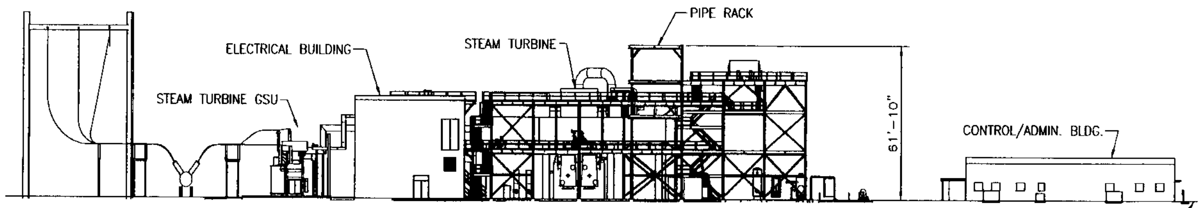


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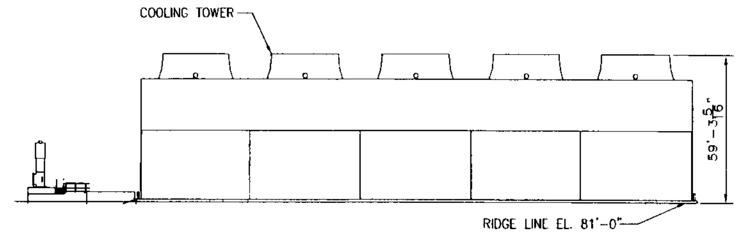


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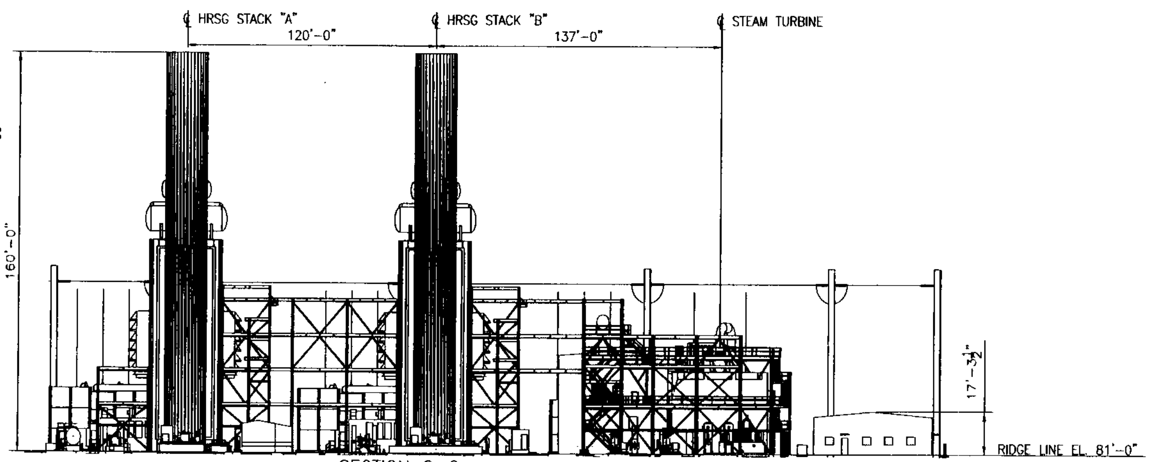


SECTION C-C
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DWG. D-PS-9000-2

REFERENCES:

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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 9000-3B.DWG
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Southern Company Services, Inc.
FOR
SOUTHERN-FLORIDA, LLC

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

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

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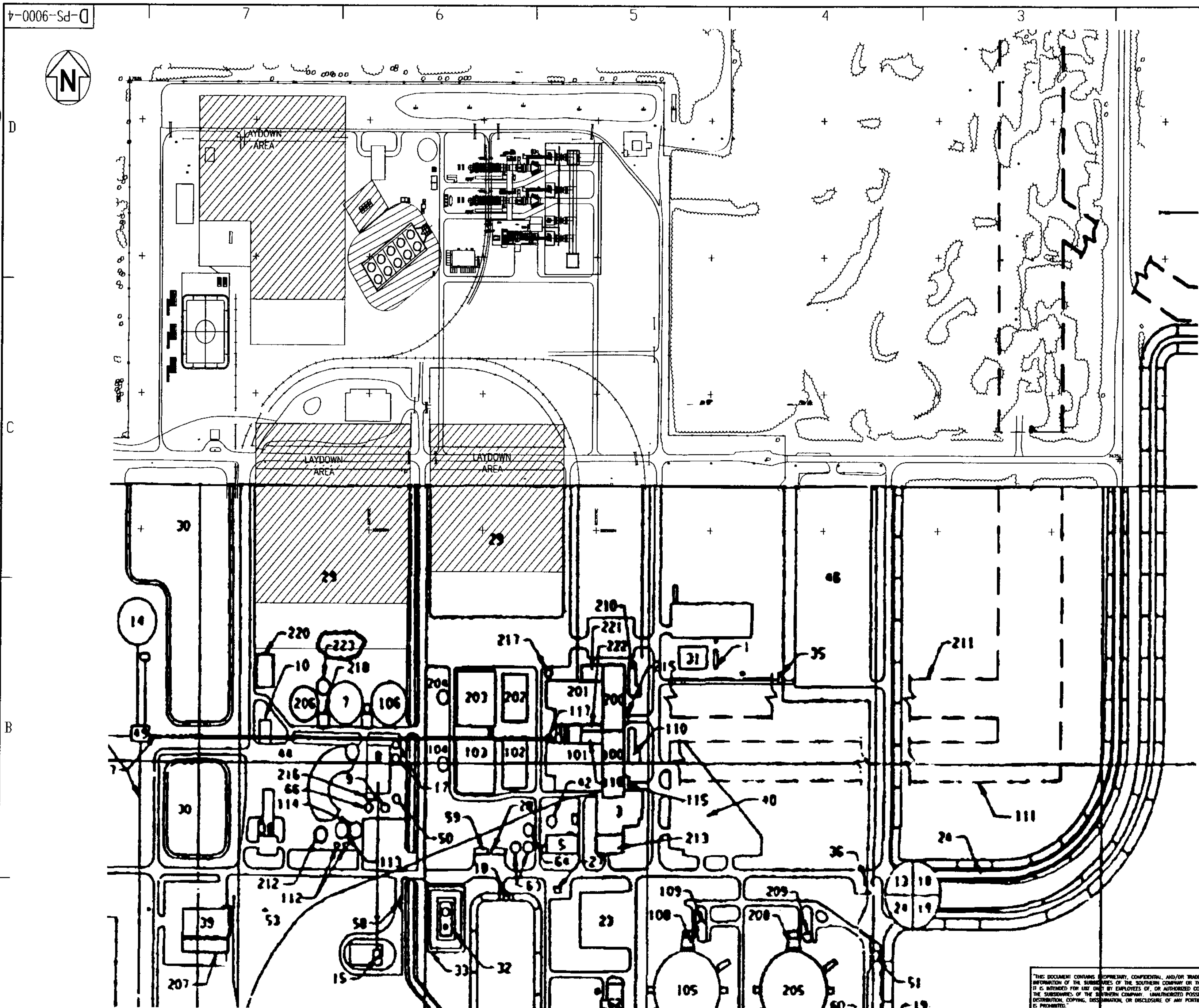
| AS NOTED | | D-PS-9000-3 | B |




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

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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"=400'-0"

| REVISION | DATE | DESCRIPTION | BY |
|---|---|---|---|
| REVISION | DATE | | |
| REVISION | DATE | | |
| REVISION C | DATE 01/16/01 | 1. REVISED TITLE BLOCK. | SHW |
| REVISION C | DATE 12/7/00 | 1. ADDED CONCENTRATION WASTE BLOWDOWN SUMP | SHW |
| REVISION B | DATE 10/27/00 | ADDED IPC | SHW |
| REVISION A | DATE 9/22/00 | ISSUED FOR REVIEW | SHW |

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

- 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 $43.222 million, 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 $34.362 and $40.362 million (the "BOP Capital Cost Range"), adjusted for any changes to the scope of the project. For evaluation purposes, a BOP Capital Cost midpoint of $37.362 million 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 35 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 $94.916 million. 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 $5,322/MW-year (base year 2003 dollars) in its proposal.

| Table 1A.3-1<br>Stanton A Capital Cost for OUC, KUA, and FMPA | |
|---|---|
| | $ (Millions) |
| Capital Equipment Cost | 43.222 |
| Adjusted BOP Capital Costs[1] | 37.637 |
| Total Capital Equipment and Adjusted BOP Costs for OUC, KUA, and FMPA | 80.589 |
| Adjustment to Remove Allowance for OUC Provided Materials and Services[2] | (1.925) |
| Resulting Capital Equipment and BOP Costs for OUC, KUA, and FMPA | 78.664 |
| Electrical Interconnection Costs | 11.524 |
| Need for Power and Site Certification Permitting | 2.176 |
| Other Interconnection Costs | 2.552 |
| Total Capital Cost for OUC, KUA, and FMPA | 94.916 |

[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 $0.73/MWh in 2003 dollars plus the hourly variable O&M cost presented in Table 1A.3-2. Thus, total variable O&M cost assuming an 81 percent capacity factor based on the 70° F rating is $3.68/MWh 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 three times 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% | 986 |
| 70% | 1,021 |
| 60% | 1,191 |
| 50% | 1,429 |
| 40% | 1,787 |
| 30% | 2,383 |
| 20% | 3,574 |
| 10% | 7,149 |

*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 ($) |
|---|---|
| 1 through 64 | 0 |
| 64 through 99 | 9,783 |
| 100 and greater | 16,307 |

### *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 $520,000 per year, escalating annually at the Gross Domestic Product Deflator.

## 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 1.84 and 3.72 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) |
|---|---|---|---|---|
| Estimates for 70° F Ambient Temperature | | | | |
| Off | Off | Off | 284,290.8 | 7,863.7 |
| Off | Off | Off | 385,569.6 | 7,206.9 |
| Off | Off | Off | 490,323.2 | 6,875.1 |
| On | Off | Off | 496,854.9 | 6,867.6 |
| On | On | Off | 594,264.2 | 7,226.1 |
| On | On | On | 609,880.8 | 7,363.3 |
| Estimates for 45° F Ambient Temperature | | | | |
| Off | Off | Off | 303,126.0 | 7,776.2 |
| Off | Off | Off | 410,955.8 | 7,138.7 |
| Off | Off | Off | 521,872.3 | 6,857.8 |
| Off | On | Off | 629,470.0 | 7,196.5 |
| Estimates for 95° F Ambient Temperature | | | | |
| Off | Off | Off | 263,760.0 | 7,962.8 |
| Off | Off | Off | 356,507.5 | 7,326.9 |
| On | Off | Off | 474,645.0 | 6,928.7 |
| On | On | Off | 566,013.8 | 7,280.7 |
| On | On | On | 595,728.6 | 7,432.9 |
| Estimates for 30° F Ambient Temperature | | | | |
| On | On | Off | 647,057.4. | 7,216.1 |
| Estimates for 97° F Ambient Temperature | | | | |
| On | On | On | 594,677.3 | 7,436.2 |
| *Including degradation. | | | | |

## 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 81 percent capacity factor, the annual cost for cooling water will be approximately $532,000 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 70° F and 45 percent relative humidity rating of the unit.

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 $350,000 in either of the foregoing costs categories, the capacity payment changes (up or down) by $0.035/kW-mo

Based on the BOP Capital Cost adjustments presented in Table 1A.3-1, the capacity payment decreases $0.193/kW-mo as shown in Table 1A.4-1.

Table 1A.4-1
Capacity Charges

| Term Years | Capacity Charge $/kW-mo | | |
|---|---|---|---|
| | Base | Adjustment | Total |
| 0 - 10 | 6.68 | -0.193 | 6.487 |
| 11 - 15 | 8.50 | -0.193 | 8.307 |
| 15 - 20 | 9.61* | -0.193 | 9.417 |
| 21 - 25 | 10.87* | -0.193 | 10.677 |
| 26 - 30 | 12.30* | -0.193 | 12.107 |

*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 $0.73/MWh and an hourly variable O&M rate as presented in Table 1A.4-2. Both are in 2003 dollars and are escalated at the Consumer Price Index. 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 three. 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) |
|---|---|
| Greater than or equal to 73 | 986 |
| 70 | 1,021 |
| 60 | 1,191 |
| 50 | 1,429 |
| 40 | 1,787 |
| 30 | 2,383 |
| 20 | 3,574 |
| 10 | 7,149 |

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 $ |
|---|---|
| 1 through 64 | 0 |
| 65 through 99 | 9,783 |
| 100 and greater | 16,307 |

## 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 95 percent by Southern-Florida. For availability below 95 percent, capacity payments are reduced by the difference in the actual availability and 97 percent during peak periods, and by 50 percent of the difference during off-peak periods. When availability under capacity purchased under the PPA exceeds 99 percent, a 3 percent bonus on the capacity payment is paid during peak periods, and 3 percent bonus on one-half 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 7 percent, which with the general inflation rate of 2.5 percent corresponds to a nominal interest rate of 9.7 percent. The real interest rate of 7 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 7 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*

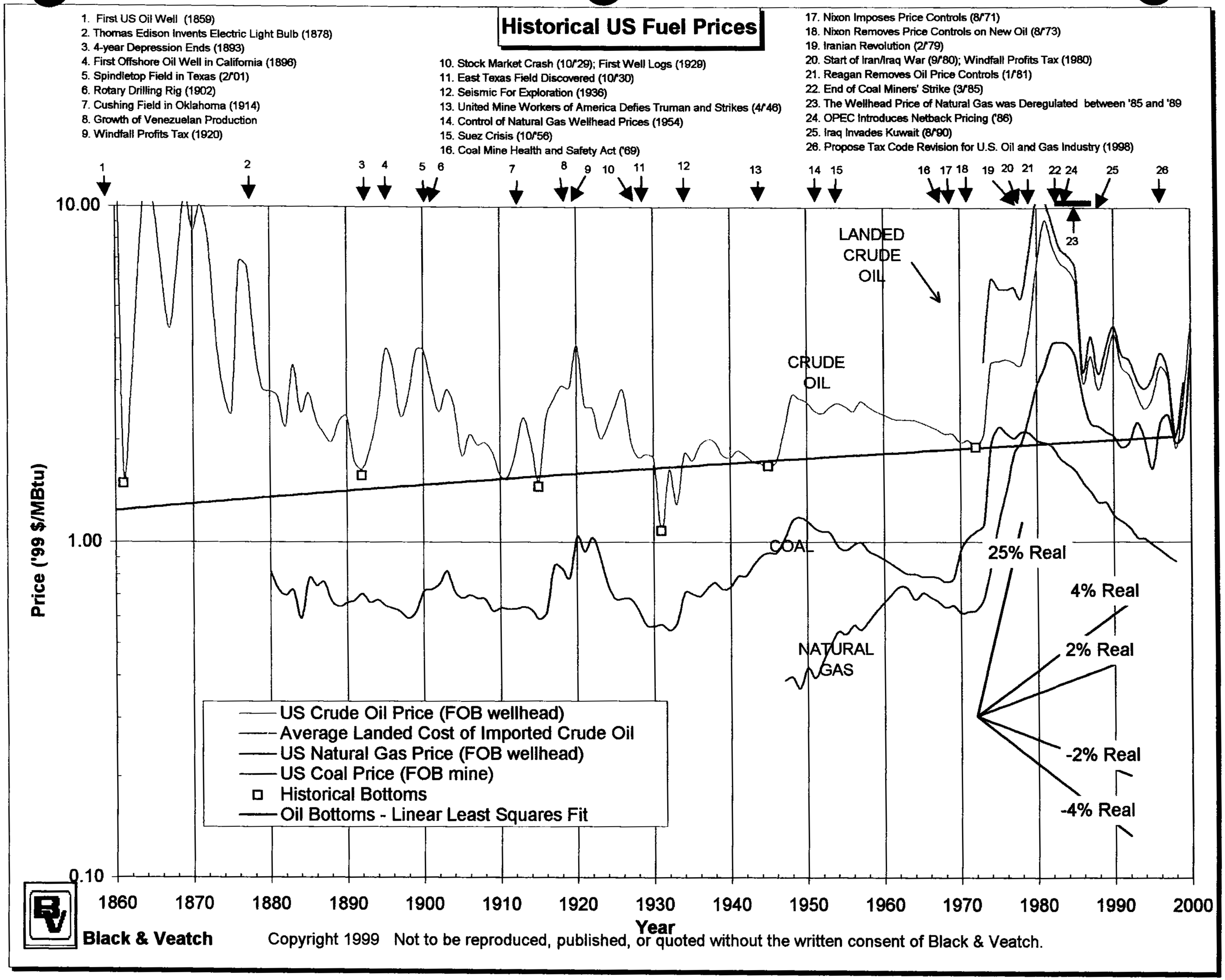
The levelized fixed charge rate is assumed to be the sum of the capital recovery rate and insurance rate. Based on the weighted average cost of capital of 8.0 percent, a 1.0 percent annual insurance cost, and a capital recovery period of 20 years, the levelized fixed charge rate is assumed to be 11.19 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).



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 in Texas (2/'01)
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)
LANDED CRUDE OIL
CRUDE OIL
COAL
NATURAL GAS
25% Real
4% Real
2% Real
-2% Real
-4% Real
US Crude Oil Price (FOB wellhead)
Average Landed Cost of Imported Crude Oil
US Natural Gas Price (FOB wellhead)
US Coal Price (FOB mine)
Historical Bottoms
Oil Bottoms - Linear Least Squares Fit
Price ('99 $/MBtu)
10.00
1.00
0.10
1860
1870
1880
1890
1900
1910
1920
1930
1940
1950
1960
1970
1980
1990
2000
Year
Black & Veatch



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<br>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 folllowing 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 96 percent availability guarantee for purchase power for OUC, KUA, and FMPA. The availability guarantee contained in the PPA calls for a deadband between 95 and 99 percent for which there is no penalty or bonus. If availability of purchase power falls below 95 percent, penalties are calculated from 97 percent, which is higher than the proposed 96 percent 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 | 6.32 ($/kW-mo) | Initial 7 years | 6.54 ($/kW-mo) | Initial 10 years | 6.68 ($/kW-mo |
| Optional 5 year extension (years 6-10) | 7.33 ($/kW-mo) | | | | |
| Average (years 1-10) | 6.83 ($/kW-mo) | | | | |
| Optional 5 year extension (years 11-15) | 8.50 ($/kW-mo) | | | Optional 5 year extension (years 11-15) | 8.50 ($/kW-mo |
| | | | | Optional 5 year extension (years 16-20) | 9.61 ($/kW-mo) |
| | | | | Optional 5 year extension (years 21-25) | 10.87 ($/kW-mo) |
| | | | | Optional 5 year extension (years 26-30) | 12.30 ($/kW-mo) |

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.

[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 mismatched 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<br>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<br>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, magnetohydro-dynamics, 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<br>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)<br>7FA (78 MW)<br>(50% share)<br>LM6000 (39 MW) | 7FA (156 MW) |
| Combined Cycle | 501F 2 x 1 Standard<br>(514 W)<br>501F 2 x 1 Oversized<br>(610 W) | 501F 1x1 ( 125MW)<br>(50% share) | 501F 2 x 1 (257 MW)<br>(50 % share)<br>501F 1x1 (125 MW)<br>(50% share) |
| Solid Fueled Unit | PC (446 MW)<br>CFB (267 MW) | PC (111.5 MW)<br>(25% share) | PC (223 MW)<br>(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 infrastructure 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 ($/kW-yr) | 6.32 | 5.32 |
| Variable O&M Cost, 2003 ($/MWh) | 3.68 | 3.68 |
| Equivalent Forced Outage Rate (percent) | 4.00 | 4.00 |
| Planned Maintenance (days/year) | 14 | 14 |
| Construction Period (months) | 24 | 24 |
| 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% |

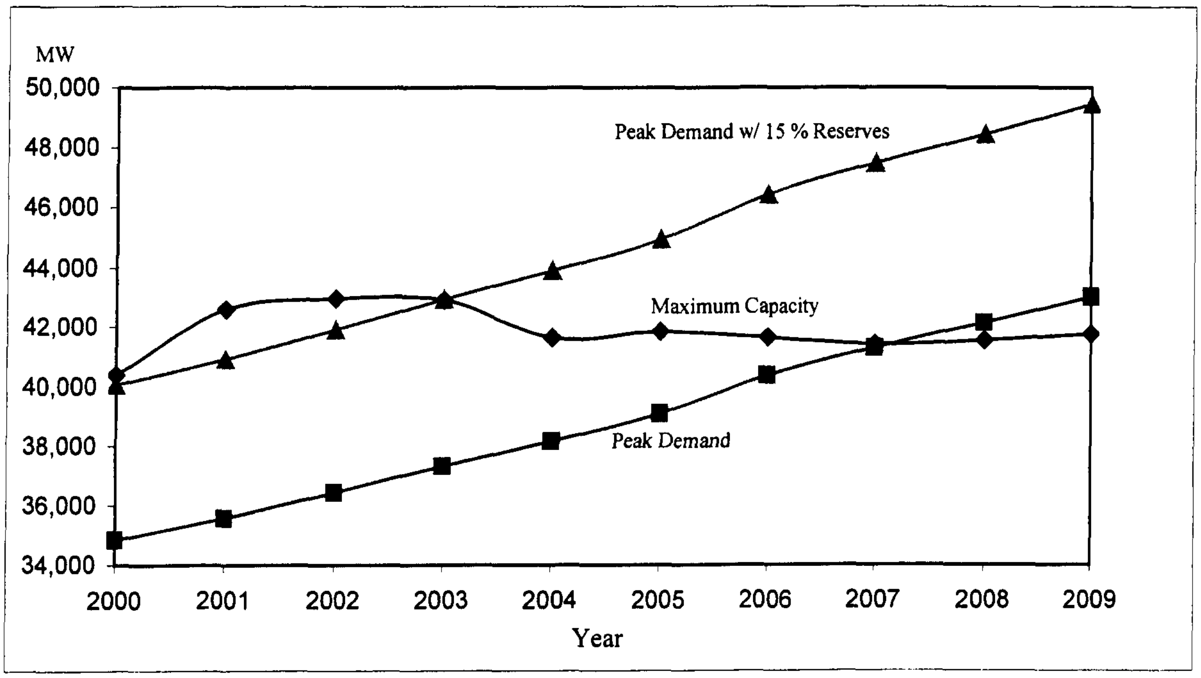
Table 1A.9-2
2000 Load and Resource Plan -- Peninsular Florida Peak Demand and Available Capacity
Excluding Capacities Pending Approval Under the Florida Electrical Power Plant Siting Act but Not Yet Approved

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% |



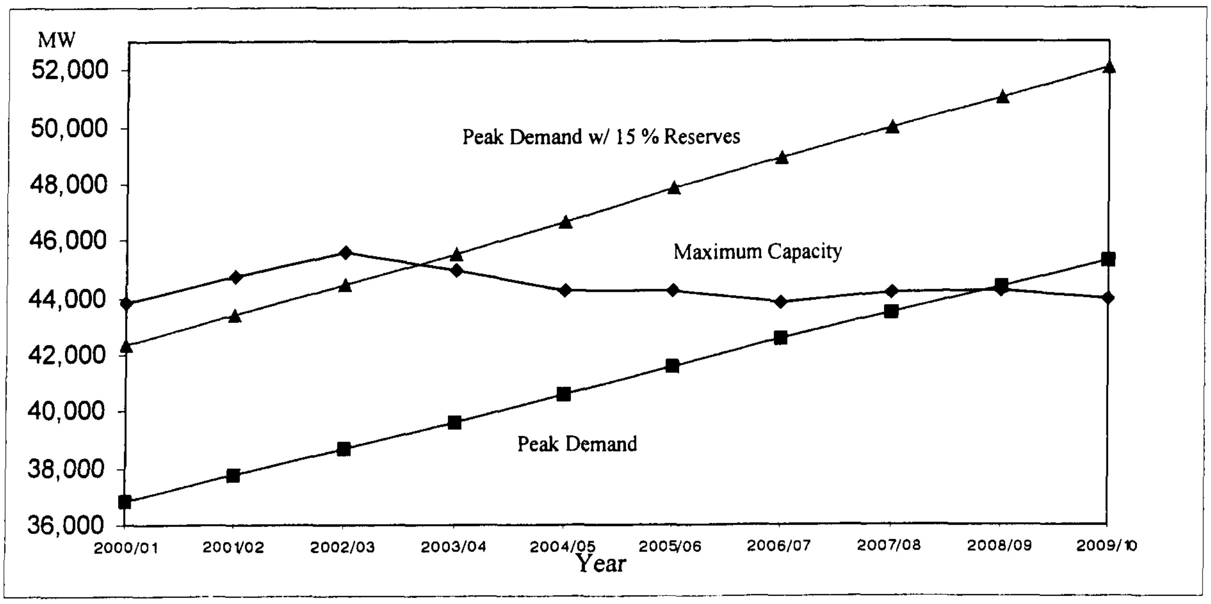




Figure 1A.9-1
2000 Load and Resource Plan – Peak Demand and Reserve Margin
Excluding Capacity Required to be Approved Under the Florida Electrical Power Plant Siting Act but Not Yet Approved

## 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.

Table 1B.7-1
Summary of OUC Generation Alternatives (2000 $, unless otherwise noted)

| Description | Capital Costs | Capacity[1] | O&M Costs Variable | O&M Costs Fixed | Fuel Type | Full Load Heat Rate (HHV)[1] | Forced Outage Rate | Scheduled Maintenance | First Year Available |
|---|---|---|---|---|---|---|---|---|---|
| | $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 | 3.68[2] | 6.32[2] | Nat. Gas | 7,074 | 4.0 | 14 | 2005 |
| 501F 2x1 CC (oversized) | 288,211[4] | 610 | 3.68[2] | 5.32[2] | Nat. Gas | 7,542 | 4.0 | 14 | 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 | 3.68[2] | 5.32[2] | Nat. Gas | 7,363 | 4.0 | 14 | 2003[5] |
| 7FA 2x1 CC ( joint development)[3] | 75,933[4] | 171 | 3.68[2] | 5.32[2] | Nat. Gas | 7,363 | 4.0 | 14 | 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.

# Orlando Utilities Commission Economic Evaluation

| Case | Economic | |
|---|---|---|
| Scenario: Base Case | CPW Discount Rate: | 8.0% |
| Joint Development | 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 | 82,309 | 9,210 |
| 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.

13.B-2

# Orlando Utilities Commission Economic Evaluation

| Case | Economic | |
|---|---|---|
| Scenario: High Fuel Price Projections | CPW Discount Rate: | 8.0% |
| Joint Development | 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] | [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.

1 B. B-4

# 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 | 82,309 | 9,210 |
| 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.

1B.B-6

# Orlando Utilities Commission Economic Evaluation

| Case |
|---|
| Scenario: AEO Fuel Price Projections<br>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 | 82,309 | 9,210 |
| 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: OUC 2000 + 2001 AEO Escalators<br>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 | 82,309 | 9,210 |
| 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.

1B. B-10

# Orlando Utilities Commission Economic Evaluation

| Case | |
|---|---|
| Scenario: Constant 2000 Fuel Price Projections<br>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 | 82,309 | 9,210 |
| 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: High Load and Energy Growth<br>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 | 82,309 | 9,210 |
| 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.

1B. B-15

# Orlando Utilities Commission Economic Evaluation

| Case |
|---|
| Scenario: Low Load and Energy Growth<br>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 | 82,309 | 9,210 |
| 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.

Table 1C.7-1
Summary of KUA Generation Alternatives (2000 $, unless otherwise noted)

| Description | Capital Costs | Capacity[1] | O&M Costs Variable | O&M Costs Fixed | Fuel Type | Full Load Heat Rate (HHV)[1] | Forced Outage Rate | Scheduled Maintenance | First Year Available |
|---|---|---|---|---|---|---|---|---|---|
| | $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 | 3.68[2] | 5.32[2] | Nat. Gas | 7,363 | 4.0 | 14 | 2003[5] |
| 7FA 2x1 CC ( joint development)[3] | 9,492[4] | 21 | 3.68[2] | 5.32[2] | Nat. Gas | 7,363 | 4.0 | 14 | 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.

# 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 | 10,289 | 1,151 |
| 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: 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 | 10,289 | 1,151 |
| 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: 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 | 10,289 | 1,151 |
| 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.

1C-A-7

# 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 | 10,289 | 1,151 |
| 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.

10. A-8

# Kissimmee Utility Authority

| Case | Economic | |
|---|---|---|
| Scenario: Southern-Florida AEO | 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 | 10,289 | 1,151 |
| 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: 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 | 10,289 | 1,151 |
| 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: 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 | 10,289 | 1,151 |
| 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: | 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] | [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: 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.

Table 1D.7-1
Summary of FMPA Generation Alternatives (2000 $, unless otherwise noted)

| Description | Capital Costs | Capacity[1] | O&M Costs Variable | O&M Costs Fixed | Fuel Type | Full Load Heat Rate (HHV)[1] | Forced Outage Rate | Scheduled Maintenance | First Year Available |
|---|---|---|---|---|---|---|---|---|---|
| | $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 | 3.68[3] | 5.32[3] | Nat. Gas | 7,363 | 4.0 | 14 | 2003[5] |
| 7FA 2x1 CC ( joint development)[4] | 9,492[2] | 21 | 3.68[3] | 5.32[3] | Nat. Gas | 7,363 | 4.0 | 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.

# 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 | 10,289 | 825 |
| 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.

ID. A-2

# 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 | 10,289 | 825 |
| 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.

1 D. A-4

# 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 | 10,289 | 825 |
| 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: | 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 | 10,289 | 825 |
| 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 | Economic | |
|---|---|---|
| Scenario: Southern-Florida FMPA OUC + AEO | 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 | 10,289 | 825 |
| 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: 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 | 10,289 | 825 |
| 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: 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 | 10,289 | 825 |
| 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 | 10,269 | 826 |
| 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.

# 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

# 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.

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# 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.

[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) $6.68 per kilowatt per month for that portion of the Initial Term before the end of the day of May 31, 2014 , (ii) $8.50 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 $9.61 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 $10.89 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 $12.30 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 $0.035 per kilowatt per month for every three hundred and fifty thousand dollar ($350,000) 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 $0.035 per kilowatt per month for every three hundred and fifty thousand dollar ($350,000) 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 $0.035 per kilowatt per month for every three hundred and fifty thousand dollar ($350,000) increase in the Fixed Amount that occurs pursuant to Section 6.7.2(b) of the Ownership Agreement, and (iv) decreased by $0.035 per kilowatt per month for every three hundred and fifty thousand dollar ($350,000) 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 (unless caused by Seller's willful misconduct or failure to follow Prudent Utility Practice); 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 (unless caused by the applicable Party's willful misconduct or failure to follow Prudent Utility Practice); 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 (excluding in the case of Seller any strike, lockout or labor difficulty that is limited only to employees of either Seller or its affiliates, and excluding in the case of Purchaser any strike, lockout or labor difficulty limited only to the employees of Purchaser); 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 three and one half percent (3.5%) during the first Contract Year, one percent (1%) during the second Contract Year and zero for each succeeding Contract Year. The degradation adjustment shall be applied in a linear manner over each month of the first two Contract Years.

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 72 hours 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 (or, if more stringent, any of the practices, methods and acts engaged in, or approved by, a significant portion of the electric utility industry in the region covered by the FRCC) operating facilities of a size and technology similar to the Facility during the relevant time period 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 twice each Contract Year, 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 fifty-eight (58)-hour 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 forty-five (45) day 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 (6th) Contract Year and ending with the tenth (10th) 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 first forty-five (45) days 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 forty-five (45) days, then Purchaser shall not be required to make Capacity Payments attributable to any continued period of Force Majeure declaration after the end of such forty-five (45) day 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 \$0.73/MWh (in January 1, 2003 dollars, escalated based upon the U.S. Consumer Price Index on January 1 of each year); 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) |
|---|---|
| Greater than or equal to 73% | $986 |
| 70% | $1,021 |
| 60% | $1,191 |
| 50% | $1,429 |
| 40% | $1,787 |
| 30% | $2,383 |
| 20% | $3,574 |
| 10% | $7,149 |

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 sixty-five percent (65%), the Hourly Variable O&M Rate shall be $1.106.

3) The dollar amounts shown in Table A are expressed in January 1, 2003 dollars and shall be escalated based upon the U.S. Consumer Price Index on January 1 of each year.

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 fifty-eight (58) hour pre-testing maintenance 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 seventy-three percent (73%). 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 three (3) times the rate used for VOMR in Section 4.2.1, 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 three (3) times the HVOM rate for such hour that would have been applicable from Table A (and its accompanying Notes) of Section 4.2.1 had the Facility been operated on natural gas, 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) |
|---|---|
| 1 through 64 | $0 |
| 65 through 99 | $9,783 |
| 100 and greater | $16,307 |

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. There shall be no

charge for the first 64 start-ups during a given Contract Year, 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 the U.S. Consumer Price Index on January 1 of each year.

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 6,935 MMBtus per MWh, if the amount of Energy requested and delivered in the hour is 500 MWhs or less; or (ii) the heat rate of 7,295 MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than 500 MWhs but less than or equal to 600 MWhs; or (iii) 7,445 MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than 600 MWhs,

when the Facility is available, then $HR_{ij}$ for an hour = (i) the heat rate of 5,550 MMBtus per MWh, if the amount of Energy requested and delivered in the hour is 500 MWhs or less; or (ii) the heat rate of 6,650 MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than 500 MWhs but less than or equal to 600 MWhs; or (iii) 6,950 MMBtus per MWh, if the amount of Energy requested and delivered in the hour is greater than 600 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) the Gas Daily Midpoint Price Posting for Louisiana-Onshore South, FGT Zone 2, published for the day on which the gas is utilized plus two cents ($0.02) per MMBtu; 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 zero (-0-), *provided however*, that in such case Customers shall pay for the gas associated with their respective Requests for Energy and transferred by the Fuel Supply Agent to the alternate delivery point in accordance with the provisions of the Operating Agreement. Seller shall be entitled to retain any and all revenues associated with any subsequent resale of the gas delivered to such alternate delivery point; 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 zero (-0-); *provided however*, that in such case the Customers shall pay for the gas associated with their respective Requests for Energy. The proceeds from the sale of gas remarketed by the Fuel Supply Agent at Seller's direction shall be paid to Seller, except for an amount equal to two percent (2%) of such proceeds, which shall be retained by Fuel Supply Agent for its role in arranging the resale of such gas.

4.3 Availability Guarantee.

4.3.1 Seller guarantees that the Actual Availability of the Facility for each of the Peak and Off-Peak Periods of each Contract Year will equal or exceed ninety-five percent (95%) ("Availability Guarantee"); *provided, however*, that (i) the first three months 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 forty-eight (48) hours per combustion turbine unit in any Contract Year in order to meet Purchaser's Request for Energy, then for every additional ten (10) hours that the Facility is fired using fuel oil, the lower end of the Availability Guarantee range, and the factors .95 and .97 in Sections 4.3.5.1 and 4.3.5.2, shall be reduced by one (1) percentage point 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 (where the first three months are excluded) or the last Contract Year, Seller shall be entitled to an availability incentive payment from Purchaser ("Availability Incentive Payment") equal to (a) three percent (3%) of the sum of the Capacity Payments attributable to the Peak Period during such Contract Year when the Actual Availability of the Facility exceeds ninety-nine percent (99%) during the Peak Period, and/or (b) three percent (3%) of one-half of the sum of the Capacity Payment for the Off-Peak Period during such Contract Year when the Actual Availability of the Facility exceeds ninety-nine percent (99%) 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 (where the first three months are excluded) or the last Contract Year, shall be calculated as follows and then rounded up or down to the nearest tenth of a percentage point (based on the method that the rounding is up if the succeeding decimal is 5 or higher or otherwise the rounding is down); *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 fifty-eight (58) hours 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 (where the first three months are excluded) 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 = (.97 - Actual Availability for the Peak Period of such Contract Year (must be less than .95))*(sum of Capacity Payments for such Peak Period)

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 = (.97 - Actual Availability for the Off-Peak Period of such Contract Year (must be less than .95))*(sum of Capacity Payments for such Off-Peak Period)*0.5

4.3.5.3 In both of Sections 4.3.5.1 and 4.3.5.2, the factors 97 and 95 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 [$ ], 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 [$ ], 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 633 MW and an Availability Performance of 0.97 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 first forty-five (45) days 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 forty-five (45) day

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[5] This number will vary among Participants, but all numbers will together total $19,461,000.

[6] This number will vary among Participants, but all numbers will together total $19,461,000.

period, then Purchaser shall recommence making Capacity Payments starting at the beginning of the forty-sixth (46th) 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 four (4) successful start-ups without experiencing any abnormal operating conditions and has generated continuously for a period of not less than sixteen (16) hours while synchronized to the Grid at a net Capacity output of at least ninety percent (90%) 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 four (4) such Minor Maintenance events distributed approximately evenly over the Off-Peak Period, with a maximum of six (6) 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 OUC's sole discretion.

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 eleven (11) months 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 eight (8) months prior to the anticipated Commercial Operation Date, but in no event earlier than January 15, 2003. Without limiting OUC's obligation under the previous sentence, if at any time from the date that is eleven (11) months prior to the anticipated Commercial Operation Date until the date that is eight (8) months 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 at net book value of Seller's entire ownership interest in the Facility 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) $47 per kilowatt 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) $31 per kilowatt 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) $16 per kilowatt 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 ten (10) Business Days of Seller's written request therefor, Eligible Collateral in an amount equal to the lesser of: (i) nine (9) months of Capacity Payments, or (ii) fifty percent (50%) 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) BBB- (Standard & Poors) or Baa3 (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) nine (9) months of Capacity Payments, or (ii) fifty percent (50%) 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 thirty (30) days 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 ten (10) Business Days 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 fifty percent (50%) 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 fifty percent (50%) 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 sixty (60) continuous 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 fifty percent (50%) 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 sixty (60) continuous days (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 fifty percent (50%) 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 ten (10) Business Days of the date of such occurrence, Eligible Collateral, as defined above, in an amount equal to nine (9) months 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 <u>INDEMNITIES</u>.

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 **<u>LIMITATION ON DAMAGES</u>. 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 BBB- (Standard & Poors) and Baa3 (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) 5300 MMBtu/hr*
- Nominal N.G. Higher Heating Value 23,339 Btu/lb
- Minimum Fuel Supply Temperature (after PRV) 25 °F
- Fuel Pressure at Gas Control Valve** 450 PSIG (nominal)

475 PSIG maximum

* Based on Winter Peaking (19°F) 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 60°F and higher.

- The Facility will require 60 gallons per minute of de-mineralized water for Mode 1 (Normal Operation).

- The expected maximum allowable rate of load increase for the Facility will be 32 MW per minute. 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 fifty percent (50%) load or two CTs each at part of (fifty percent (50%)) 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.

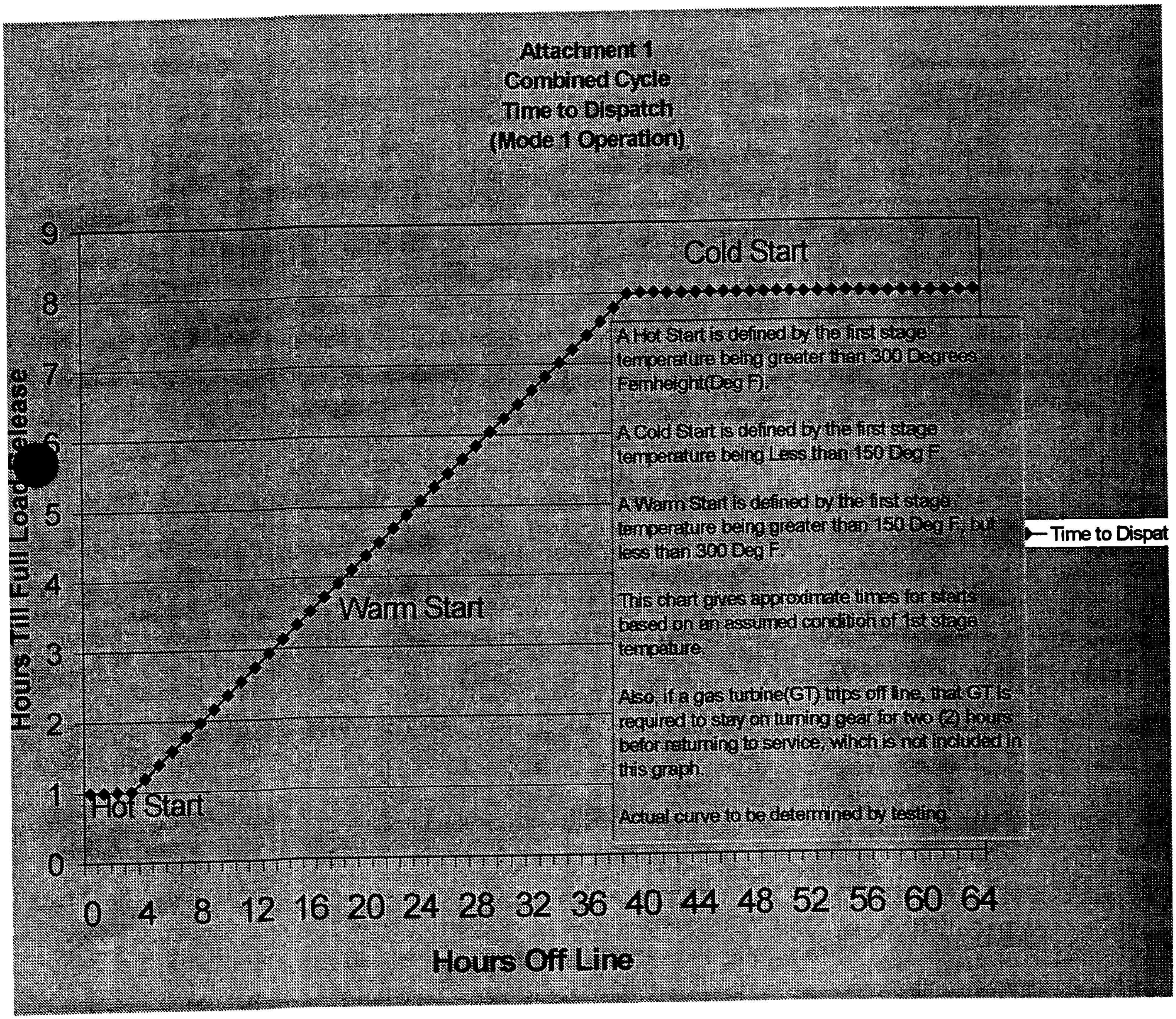
  Mode 2 (Supplemental Firing Operation): 1-2 hours from one hundred percent (100%) Mode 1 (Normal Operation).

  Mode 3 (Power Augmentation Operation): 2 hours from one hundred percent (100%) Mode 1 (Normal Operation) or 1 hour 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 1000 hours/year 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 one hundred percent (100%) CT load.

- The Facility's CT evaporative coolers should not be operated at ambient temperatures less 7than sixty degrees Fahrenheit (60°F) to prevent freezing at the CT compressor inlet.


Attachment 1
Combined Cycle
Time to Dispatch
(Mode 1 Operation)
Cold Start
Warm Start
Hot Start
A Hot Start is defined by the first stage temperature being greater than 300 Degrees Fernheight(Deg F).
A Cold Start is defined by the first stage temperature being Less than 150 Deg F.
A Warm Start is defined by the first stage temperature being greater than 150 Deg F, but less than 300 Deg F.
This chart gives approximate times for starts based on an assumed condition of 1st stage tempature.
Also, if a gas turbine(GT) trips off line, that GT is required to stay on turning gear for two (2) hours befor returning to service, which is not included in this graph.
Actual curve to be determined by testing.
Time to Dispat
Hours Till Full Load Release
Hours Off Line
0
1
2
3
4
5
6
7
8
9
0 4 8 12 16 20 24 28 32 36 40 44 48 52 56 60 64

## 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 5:00 p.m. 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 80 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 80 MW, the Customers shall pay Seller $2.50 per MW-hour for the difference between the amount of the Delivered Energy and the amount that is 80 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 5 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 60 minutes 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 five (5) minutes of receipt of the notification. If the actual output of the Facility does not equal the Request for Energy within five (5) minutes 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 five (5) minutes 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 five (5) minutes 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 two (2) hours (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 two (2) hours (or the amount of time in which an RTO has determined that the PTRs may be recalled) and thirty (30) minutes 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 two (2) hours 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 thirty (30) minutes 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 3:15 p.m. Seller gives notice no later than 3:45 p.m. if Seller will arrange to deliver Energy from Alternate

Resources. Delivery from Alternate Resources should begin no later than 5:00 p.m.) 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 fifteen (15) minutes 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 thirty (30) minutes 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 thirty (30) minutes prior to the start of such Schedule and preferably at least two (2) hours prior. 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 the top of the next full hour following the hour 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 two (2) hours (or the amount of time in which an RTO has determined that the PTRs may be recalled) and thirty (30) minutes 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 11:00 a.m. and 7:00 p.m. (prevailing Eastern Time) and will be conducted over an eight consecutive hour 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 2,774 MMBtus of gas transportation and/or commodity determined as follows:
400 MWh x 6.935 MMBtus/MWh = 2,774 MMBtus

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 4,012 MMBtus of gas transportation and/or commodity determined as follows:
550 MWh x 7.295 MMBtus/MWh = 4,012 MMBtus

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 555 MMBtus of gas transportation and/or commodity determined as follows:

100 MWh x 5.550 MMBtus/MWh = 555 MMBtus

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 1,330 MMBtus of gas transportation and/or commodity determined as follows:
200 MWh x 6.650 MMBtus/MWh = 1,330 MMBtus

**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. <u>Existing Steam Generating Units</u>.

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. <u>Reservation of Rights.</u>

(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 Smyma 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. <u>750 MW Option</u>. 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. <u>Cane Island Option</u>. 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. <u>Annual User Fees for Certain Common Facilities</u>

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. <u>Cooling Water</u>

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. <u>Cooling Tower Blowdown Treatment</u>

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.

<u>SECTION 3.</u> <u>DISCLOSURE AND USE OF CONFIDENTIAL INFORMATION.</u> 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.

<u>SECTION 4.</u> <u>REQUIRED DISCLOSURE.</u> 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.

<u>SECTION 5.</u> <u>RETURN OF DOCUMENTS.</u> 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.

<u>SECTION 6.</u> <u>SURVIVAL OF OBLIGATIONS.</u> 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.

<u>SECTION 7.</u> <u>NATURE OF INFORMATION.</u> 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.

<u>SECTION 8.</u> <u>GOVERNING LAW.</u> 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:

Print Name:______________________

Print Name:______________________

RESPONDENT

By:______________________
Print Name:______________________
Title:______________________

[AFFIX CORPORATE SEAL HERE]

## 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<br>95 F Ambient Temperature<br>Sea Level Pressure<br>Natural Gas Fuel | | |
| Unit Winter Net Rating<br>45 F Ambient Temperature<br>Sea Level Pressure<br>Natural Gas Fuel | | |
| Unit Net Heat Rate HHV<br>Summer Conditions, Full Load<br>Summer Conditions, Half Load<br>Winter Conditions, Full Load<br>Winter Conditions, Half Load | | |
| Project Minimum Load Under Automatic Generator Control | | |
| Project Maximum Load Change Rate | | |
| Cooling Water Consumption at Full Load<br>Summer Conditions and 80% RH and 80% Capacity Factor | | |
| Project Estimated Annual Deionized Water Consumption<br>80% Capacity Factor | | |

Attachment 4 – Project Performance Data

# CANE ISLAND POWER PARK PROPOSAL DATA SHEETS

## PROJECT PERFORMANCE DATA

| | |
|---|---|
| Unit Summer Net Rating<br>95 F Ambient Temperature<br>Sea Level Pressure<br>Natural Gas Fuel | ________ |
| Unit Winter Net Rating<br>45 F Ambient Temperature<br>Sea Level Pressure<br>Natural Gas Fuel | ________ |
| Unit Net Heat Rate HHV<br>Summer Conditions, Full Load<br>Summer Conditions, Half Load<br>Winter Conditions, Full Load<br>Winter Conditions, Half Load | ________ |
| Project Minimum Load Under Automatic Generator Control | ________ |
| Project Maximum Load Change Rate | ________ |
| Cooling Water Consumption at Full Load<br>Summer Conditions and 80% RH and 80% Capacity Factor | ________ |
| Project Estimated Annual Deionized Water Consumption<br>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

# Table of Contents

# 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.

# 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 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 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.

**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.

**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.

| TABLE 3-1-3<br>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.

### 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.

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

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.

| 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 | | | | | |

| Table 3-2-2<br>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 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) 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.

**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.

### 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.

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 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' 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 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.

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.

## 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

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

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.

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 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 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.

## 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.

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.

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.

**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.

## 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 |

RFP Form 1-A

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: ____________________

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: ______________________

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.

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.

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 | | | | | | |
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| 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. ______

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 | | | | | | | | |
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| 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. ______________________________

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

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).

ORLANDO UTILITIES COMMISSION
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# 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

**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.*

# 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 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).

## 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.

(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 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.

(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.

# 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.

## 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.

## 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.

# 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 |

## 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.

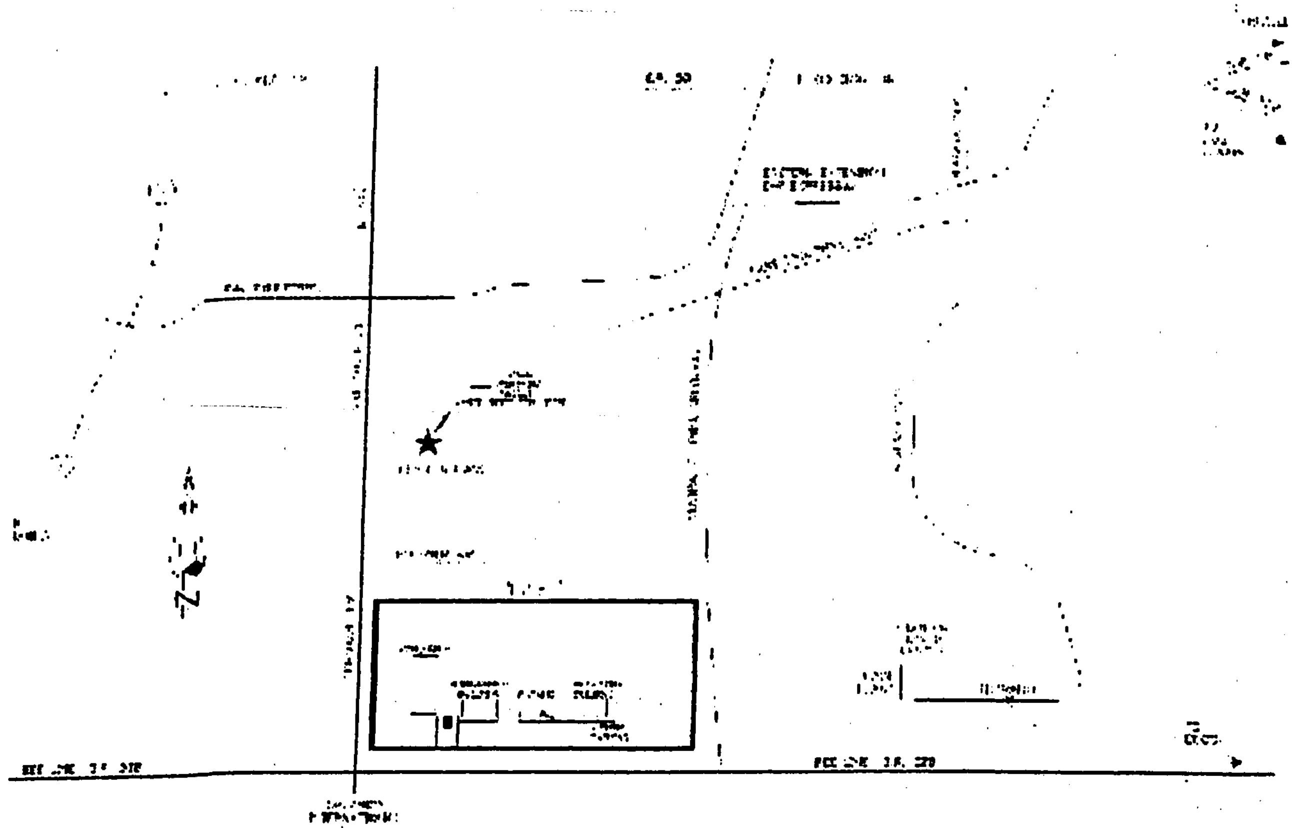
WITNESS my hand and official seal this _____ day of ____________________, 2000.

Notary Public - State of _________________

My Commission expires _________________

_______________________________________
(Printed typed or stamped commissioned name of
Notary Public)

# ORLANDO UTILITIES COMMISSION
# PERSHING FACILITY



# Appendix 1A.D

## Orlando Utilities Commission

## Stanton Energy Center

## Stanton Unit 3 – 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.

<u>**Chemical**</u>

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.

<u>Civil/Structural</u>

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.

<u>EPC Contract Liquidated Damages Cap</u>

| | |
|---|---|
| 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 3 – 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.

<u>OPTION 3:</u>
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**
**<u>PERFORMANCE</u>**

**(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<br>(Sized for 3 days of base load operation) | 2 | 1,000,000 gallons |
| Demineralized Water Storage Tank<br>(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)