Cane Island Power Park
Unit 3

BLACK & VEATCH LLP

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Introduction

This Site Certification Application (SCA) is being submitted jointly by Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for the addition of Unit 3 to the Cane Island Power Park, and for the existing Units 1 and 2, in accordance with the Florida Electrical Power Plant Siting Act. Cane Island Unit 3 is a proposed combined cycle unit with a nominal rating of approximately 250 MW, consisting of a F class combustion turbine, heat recovery steam generator (HRSG), and steam turbine.

The SCA is comprised of three volumes. The first volume of the application is divided into subvolumes labeled 1A,1B, and 1C, and contains Section 1 of the SCA. These subvolumes contain the Public Service Commission Need for Power (NFP) Application portion of the SCA. The joint need for power application is based on the needs of both KUA and FMPA who are each 50 percent joint owners in Cane Island Unit 3 and existing Units 1 and 2. Subvolumes 1A, 1B, and 1C contain the following information.

- 1A - NFP information common to both participants.
- 1B - NFP information specific to KUA.
- 1C - NFP information specific to FMPA.

Volumes 2 and 3 contain information regarding all other aspects of the SCA other than the need for power, including environmental information associated with the proposed facility and existing units.

KUA was the project manager for licensing and construction of the existing Cane Island Units 1 and 2. KUA is also the operator for Units 1 and 2. Likewise, KUA is the project manager for licensing and construction of Unit 3 and will be the operator. Unit 1 consists of a simple cycle General Electric LM 6000 combustion turbine with a nameplate rating of 42 MW. Unit 2 consists of a General Electric 7EA 1 x 1 combined cycle with a nameplate rating of 120 MW.

Site certification for the proposed Unit 3 is being sought under the Florida Electrical Power Plant Siting Act, Sections 403.501-403.518, Fla. Stat., and as such, the determination of need for the proposed Unit 3 is being sought under Section 403.519, Fla. Stat.. As existing units, site certification for Units 1 and 2 is being sought under Section 403.5175, Fla. Stat.. In accordance with Section 403.5175(1), Fla. Stat., a determination of need is not required for Units 1 and 2. Notices regarding the project should be sent to KUA's attention.

Applicant's Official Names and Mailing Addresses

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

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, Florida 32809

Address of Official Headquarters

Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Florida Municipal Power Agency
7201 Lake Ellenor Drive
Orlando, Florida 32809

Business Entity

Kissimmee Utility Authority (KUA) is a body politic, duly organized, and legally existing as part of the government of the City of Kissimmee, engaged in the generation, transmission, and distribution of electric power to persons within the service area.

Florida Municipal Power Agency (FMPA) is a joint agency formed pursuant to the Interlocal Cooperation Act which 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.

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

A.K. Sharma
Kissimmee Utility Authority
1701 W. Carroll St.
Kissimmee, FL 34741
Ph. (407) 933-7777, ext. 1232
Fax (407) 847-0787

Site Location

Osceola County

Nearest Incorporated City

Kissimmee

Longitude and Latitude

Lat: 28 degrees, 16 minutes, 50 seconds

Long: 81 degrees, 32 minutes, 00 seconds

UTMs (Center of Site)

3,128,000 North

447,500 East

Section, Township, Range

Sec 29, 32/T25S/R28E

Location of Any Directly Associated Transmission Facilities

Osceola County

Nameplate Generating Capacity

The nameplate rating of Cane Island Unit 3 will depend upon the exact combustion turbine selected and the design of the steam turbine. It is estimated that Cane Island Unit 3 will have a nameplate gross generating capacity of approximately 270 megawatts (MW) at 59° F.

Commercial Operation Date

Cane Island Unit 3 is scheduled for commercial operation on June 1, 2001.

1A.1.0 Overview and Summary

1A.1.1 Overview

Cane Island Unit 3 will be the third unit installed at the Cane Island Power Park site located approximately 13 miles west of Kissimmee, Florida. Cane Island Unit 3 is being planned for a *nominal net* generating capacity of approximately 250 MW.

KUA and FMPA are both 50 percent joint owners of the Cane Island Unit 3 facility. This ownership arrangement mirrors the ownership arrangement of the existing Cane Island Unit 1 and Unit 2 facilities.

1A.1.2 Summary

Cane Island Unit 3 is planned to utilize a 1 x 1 configuration with an F-class combustion turbine and a 100 MW steam turbine. The estimated 2001 installed capital cost is $117,567,000, which includes interest during construction and an associated 230 kV transmission line from Cane Island to Florida Power Corporation's Intercession City Plant. Cane Island Unit 3 is projected to have a net degraded output of 262 MW at 59° F with a higher heating value (HHV) heat rate of 6,815 Btu/kWh. Cane Island Unit 3 is planned to be equipped with evaporative inlet cooling and duct firing to increase output during the summer. Cane Island Unit 3 will be natural gas fueled and is planned to have No. 2 oil as backup fuel. Cane Island Unit 3 is also planned to be equipped with a bypass damper and stack to enable operation in simple cycle mode.

1A.2.0 Description of the Project

1A.2.1 Description of Facilities

The Cane Island Power Park (Power Park) currently includes two existing units, Units 1 and 2, and support facilities as shown on the Site Arrangement Drawing Figure 1A.2-1. Unit 1 consists of a simple cycle General Electric LM 6000 combustion turbine (CT) with a nameplate rating of 42 MW. Unit 2 consists of a General Electric 7EA 1 x 1 combined cycle with a nameplate rating of 120 MW. The proposed Unit 3 is also shown on Figure 1A.2-1, and will consist of an F-class 1 x 1 combined cycle with a nominal rating of approximately 250 MW. The actual size of Unit 3 will depend upon the combustion turbine vendor selected and the design and size of the steam turbine. Output will also vary with degradation and ambient conditions. Electricity generated by the Cane Island Units is stepped up in voltage by generator step-up transformers to 230 kV for transmission via the power grid.

The basic power generation cycle for Unit 3 consists of an F-class combustion turbine, a heat recovery steam generator (HRSG), a condensing steam turbine, and a mechanical draft cooling tower. The HRSG will be a three pressure design. Duct burners will be installed in the HRSG inlet to allow the steam turbine to be fully loaded at higher ambient temperatures. The HRSG will be provided with a bypass stack and diverter damper to accommodate operation in simple cycle mode.

Natural gas will be the primary fuel for the combustion turbine and the only fuel for the HRSG duct burners. Low sulfur (0.05 percent), No. 2 fuel oil is currently planned to be the emergency backup fuel for the combustion turbine. The Unit 1 fuel oil storage tank has a capacity of 0.3 million gallons and the Unit 2 tank has a capacity of 0.7 million gallons, for a total existing storage capacity of 1.0 million gallons. An additional 1.0 million gallon tank is currently planned to be installed to provide backup fuel oil for Unit 3. The combined storage capacity, 2.0 million gallons, will provide more than 3 days of fuel oil supply for full load operation of Units 1, 2 and 3.

Flue gas is the only byproduct of the combustion process whether burning natural gas or No. 2 fuel oil. Both are low sulfur, low ash fuels. The manufacturer guarantees full load NO_x emission levels of 12 to 15 ppm, while burning natural gas, will be attained by implementing dry low NO_x combustor technology. Therefore, installation of an SCR will not be required for Unit 3. For air emissions, Unit 3 will be considered a major stationary emission source and will be subject to Prevention of Significant Deterioration (PSD) permitting requirements. Unit 3 will be considered a minor stationary emission source with respect to SO_2 and will be permitted under a federally enforceable annual SO_2 emission limit of 40 tons per year. Unit 3 emissions will be maintained below the 40 tons per year threshold by limiting fuel oil firing to approximately 30 days per year. Units 1 and 2 are each permitted for fuel oil firing a maximum of 800 hours per year (33 days).

Cane Island Unit 3 waste heat will be rejected to the atmosphere by a cooling cycle using a mechanical draft cooling tower. The source of cooling water makeup will be treated sewage effluent from the City of Kissimmee's effluent pipeline. Provisions will be included to utilize well water as an emergency source of cooling water makeup. It is estimated that six new wells will be required to accommodate new process uses and emergency well water demands. The estimated cooling water withdrawal rate from the City of Kissimmee's effluent pipeline for Unit 3 is 1,895,000 gpd, at full load, with the evaporative cooler operating. When the combustion turbine inlet air evaporative cooler operates, 43,000 gpd of the Unit 3 evaporative cooler blowdown will be routed to the cooling tower and will provide the balance of the Unit 3 cooling water makeup requirement.

Cane Island Unit 3 will have five major sources of wastewater. These wastes include sanitary waste, oil/water separator waste, cooling tower blowdown, chemical wastes, and boiler blowdown. Similar to the methods used for the existing units, the process wastewaters will be treated and discharged at three locations. Oil/water separator effluent will be routed to an onsite percolation pond for ground water recharge. Cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be returned to the City of Kissimmee's effluent pipeline for ultimate disposal at the Imperial Percolation Pond Site. Sanitary wastes will be routed to the existing septic tank/tile field system. For Unit 3, it is estimated that 446,000 gpd of combined wastewater from cooling tower blowdown, neutralization basin effluent, and boiler blowdown will be returned to the City of Kissimmee's effluent pipeline.

Unit 3 will utilize an independent, distributed control system. The existing Unit 2 steam turbine building will be expanded to house the control room expansion, control equipment, and electrical equipment. Units 1-3 will be controlled from the expanded control room.

Other than combustion control measures, such as dry low-NO_x combustors, no other air pollution control techniques are required, although water injection will be required when burning No. 2 oil.

1A.2.2 Fuel Supply

Natural gas is the primary fuel at the Cane Island Power Park and is supplied via a 20 inch diameter natural gas line that is owned by Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) and operated by Florida Gas Transmission (FGT). The natural gas line was installed in 1993 and connects to an existing FGT line near the intersection of Interstate I-4 and State Road 545. The capacity of the line will support a total build out of 1,000 MW at Cane Island.

Existing fuel oil capacity at the Cane Island site is provided by two storage tanks with capacities of 0.3 million gallons and 0.7 million gallons. At ISO conditions, Units 1 and 2 can operate for four days at full load with the existing storage capacity. An additional 1.0 million gallon storage tank is planned to be installed adjacent to the existing fuel oil tanks to provide backup fuel oil to Unit 3. The expanded fuel oil capacity will enable Unit 3 to be fuel oil fired at full load for a period of three days. The tanks will be piped so that all units can draw fuel oil from any tank.

Although backup fuel oil capacity will supply Units 1-3 with the necessary fuel for operation during curtailment or outage of the gas line, the existing backup fuel oil supply has never been required. This is because the Cane Island Power Park has not experienced a gas line outage since installation of the line in 1993. Although new gas supply customers will connect to the St. Petersburg lateral, which supplies the Cane Island Power Park, FGT planning staff have stated that overall reliability of the supply is expected to remain unchanged.

1A.2.2.1 Fuel Quantities

Full load fuel consumption estimates for Units 1-3 are presented in Table 1A.2-1. Fuel usage estimates are based on the full load output of each unit at 95 F.

1A.2.2.2 Fuel Transportation

Natural gas is the primary fuel at the Cane Island Power Park and is supplied via a 20 inch diameter natural gas line that is owned by KUA and FMPA and operated by FGT.

Table 1A.2-1 Fuel Consumption Estimates (MBtu/h)[1]		
Unit	No. 2 Fuel Oil	Gas
Unit 1 - LM6000[2]	459.8	432.6
Unit 2 - 1x1 7EA[2]	976.1	937.3
Unit 3 - 1x1 F-Class[3]	1,808.0	1,736.3
Total Consumption	3,243.9	3,106.2

[1]Based on 95 F full load heat rates.
[2]Actual test data.
[3]Includes degradation.

The natural gas line was installed in 1993 to support the Cane Island Power Park. The line ties into an existing FGT natural gas line near the intersection of Interstate I-4 and State Road 545. The size of the line is based on a total build out of 1,000 MW at the Cane Island Power Park. A more detailed analysis and description of FGT's system is presented in Section 1A.3.3 Fuel Availability.

Number 2 fuel oil is the secondary (backup) fuel for the Cane Island Power Park. The fuel oil is delivered to the Power Park utilizing tanker trucks. Once onsite, the fuel is transferred from the tankers to onsite storage tanks.

1A.2.2.2.1 Natural Gas Delivery and Metering. Natural gas is delivered to Cane Island Power Park as described in Subsection 1A.2.2.2. A metering station was installed in 1993 with the 20 inch natural gas line to support the Cane Island Power Park. The metering station is located at the interconnection location (intersection of I-4 and State Road 545) with the FGT pipeline. This metering station will continue to meter the additional amount of natural gas utilized by Unit 3. There is a common custody grade meter at the Cane Island Power Park. Additionally, Unit 3 will have its own individual gas meter.

1A.2.2.2.2 Fuel Oil Storage and Handling. The existing No. 2 fuel oil storage consists of two aboveground tanks--one 0.3 million gallon tank for Unit 1, and one 0.7 million gallon tank for Unit 2. An additional fuel oil storage tank, with a capacity of 1.0 million gallons, is currently planned to be installed at the Cane Island Power Park for Unit 3. The locations of the storage tanks are indicated on the Site Arrangement, Figure 1A.2-1.

Fuel is delivered to the storage tanks by tanker truck. The fuel oil truck unloading station is located south of the Unit 1 storage tank as indicated on Figure 1A.2-1. Semitrailer tanker trucks enter the site at the main gate, park adjacent to the unloading station, and are connected to the unloading station. Unloading operations are coordinated between the Plant operator(s) and the truck driver and are constantly monitored by both parties.

1A.2.3 Capital Costs

The capital cost estimate is developed on the basis of the current competitive generation market. Indirect costs include the typical items of engineering, construction management, general indirect costs, and contingency. In addition, indirect costs include SCADA interface costs, spares, owner's engineer costs, permitting, training, substation costs to integrate the unit into the Cane Island substation, and costs for a 230 kV transmission line from Cane Island to Florida Power Corporation's Intercession City Plant in order to place the costs on a comparable basis with costs resulting from purchase power bids. Total capital cost is the summation of direct and indirect cost and interest during construction for commercial operation in 2001.

The project cost for Cane Island Unit 3 is estimated to be $117,567,000. The capital cost reflects significant savings associated with the sharing of common site utilities and equipment including the engineering costs of the buildings and associated facilities. Some of these facilities include the site access road, cooling tower makeup water supply pipeline, water treatment and wastewater disposal, and site buildings. A detailed description of capital cost components is listed in Table 1A.2-2.

1A.2.4 O&M Cost

The O&M cost estimates are based on a unit life of 25 years and baseload capacity factor. The estimates also include a 20 percent contingency. For the fixed O&M analysis, it was assumed that fixed costs will remain constant in real dollars over the life of the plant. Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Variable O&M costs include consumables, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation. The estimates of fixed and variable O&M are $2.08/kW-yr and $2.58/MWh (1998 $), respectively. The O&M cost estimates were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors.
- Combustion turbine generator (CTG) maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at $38/man-hour.
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost. These costs are included in the capital cost. The cost of the parts used in the inspections and overhauls are included in the O&M costs.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.

Table 1A.2-2
Cost Estimate
Cane Island Unit 3

Procurement Contracts	
Mechanical	53,037,311
Electrical	4,465,000
Control	1,350,000
Chemical	930,000
Subtotal	59,782,311
Furnish & Erect Contracts	
Structural	144,652
Mechanical	1,770,000
Subtotal	1,914,652
Construction Contracts	
Civil/Structural	5,318,287
Mechanical	13,273,121
Electrical/Control	2,171,823
Chemical	450,000
Construction Services	712,117
Subtotal	21,925,348
Total Direct Cost	83,622,311
Indirect Costs	
General Indirects	175,000
Outside Engineering	6,260,000
Construction Management	1,100,000
Transmission/SCADA/Substation	7,416,006
Spare Parts	4,821,767
Training/Permitting	1,000,000
Contingency	7,529,030
Interest During Construction	5,642,841
Total Indirect Cost	33,944,644
Total Project Cost	117,566,955
Total Project Cost, $/kW	449[1]

[1] Based on ISO rating of 262 MW.

- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- Provision for two additional staff in 2001 are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.

1A.2.5 Heat Rate

The estimates for average net plant heat rate (NPHR) and output for Cane Island Unit 3 are listed in Table 1A.2-3. Plant heat rate and output estimates include a 2 and 4 percent degradation factor, respectively.

1A.2.6 Availability

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. Availability of the F-class Cane Island Unit 3 is estimated to be approximately 91.8 percent per year. The availability estimate includes a 4.1 percent forced outage rate and all scheduled maintenance outages as described in Section 1A.2.4.

1A.2.7 Schedule

The schedule for Cane Island Unit 3 is based on a 20-month construction period. Engineering would start 5 months before the start of construction to complete the design in advance of construction. To meet a June 1, 2001, commercial operation date, construction would start October 1, 1999 upon receiving site certification, and engineering would start May 1, 1999.

The 5-month period for engineering before construction starts includes the time required to procure major equipment and to complete the detailed foundation design. The combustion turbine, steam turbine, HRSG and transformers represent the long lead time equipment.

This project schedule is based on reasonable durations and a logical, efficient approach to the project. This approach will support completing the project on time with minimum total cost. The detailed schedule is presented in Figure 1A.2-2.

Table 1A.2-3 Net Plant Heat Rate (NPHR) HHV				
Output (percent)	59 F		95 F	
	MW	NPHR Btu/kWh	MW	NPHR Btu/kWh
1 00	262	6,815	237[1]	6,945[1]
75	196	7,141	175	7,483
50	139	7,699	123	8,011
25	73	9,894	64	10,474
(1) 244 MW and 6,998 Btu/kWh with duct firing.				

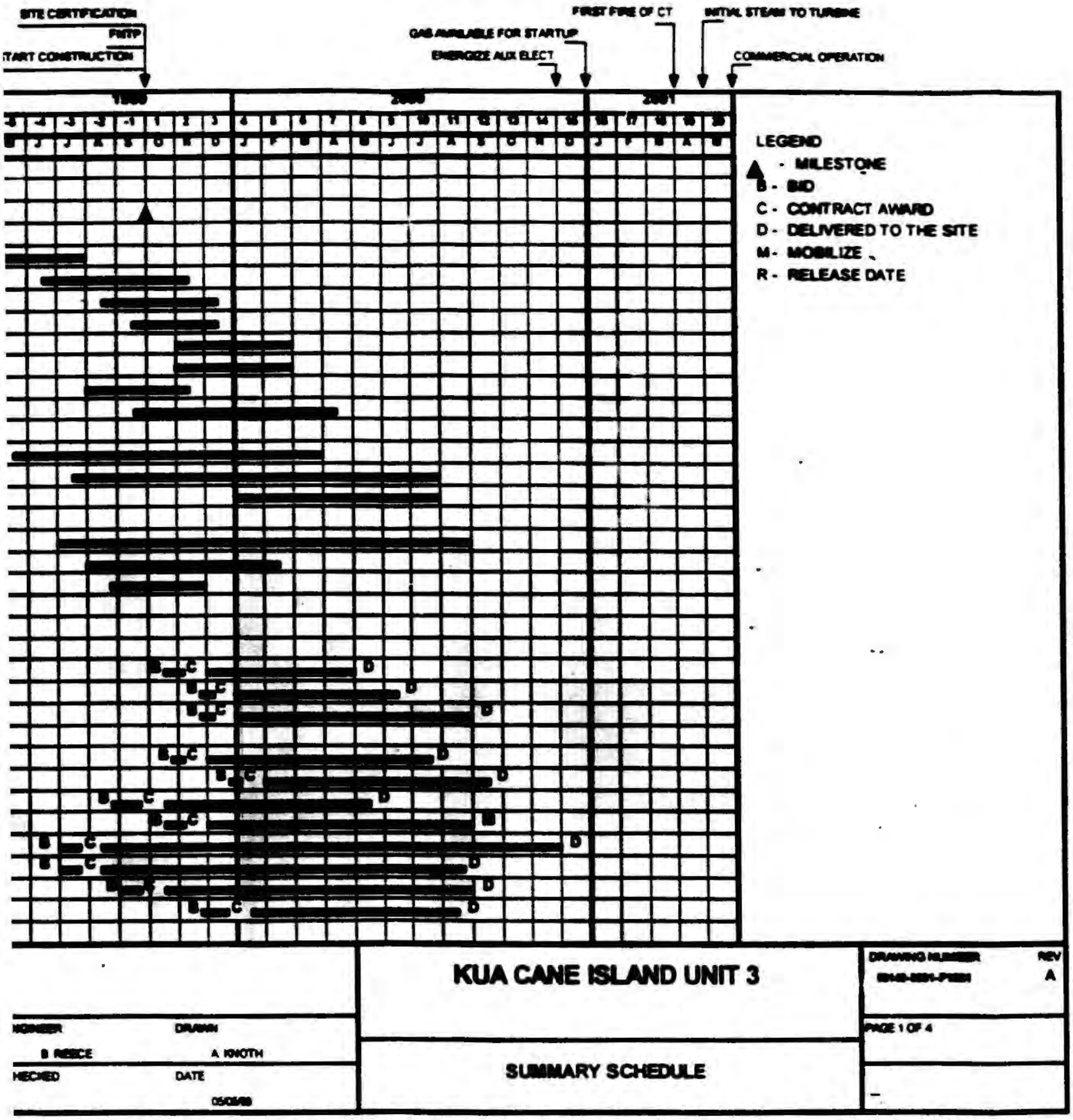


Figure 1A.2-2 (Page 1 of 4)

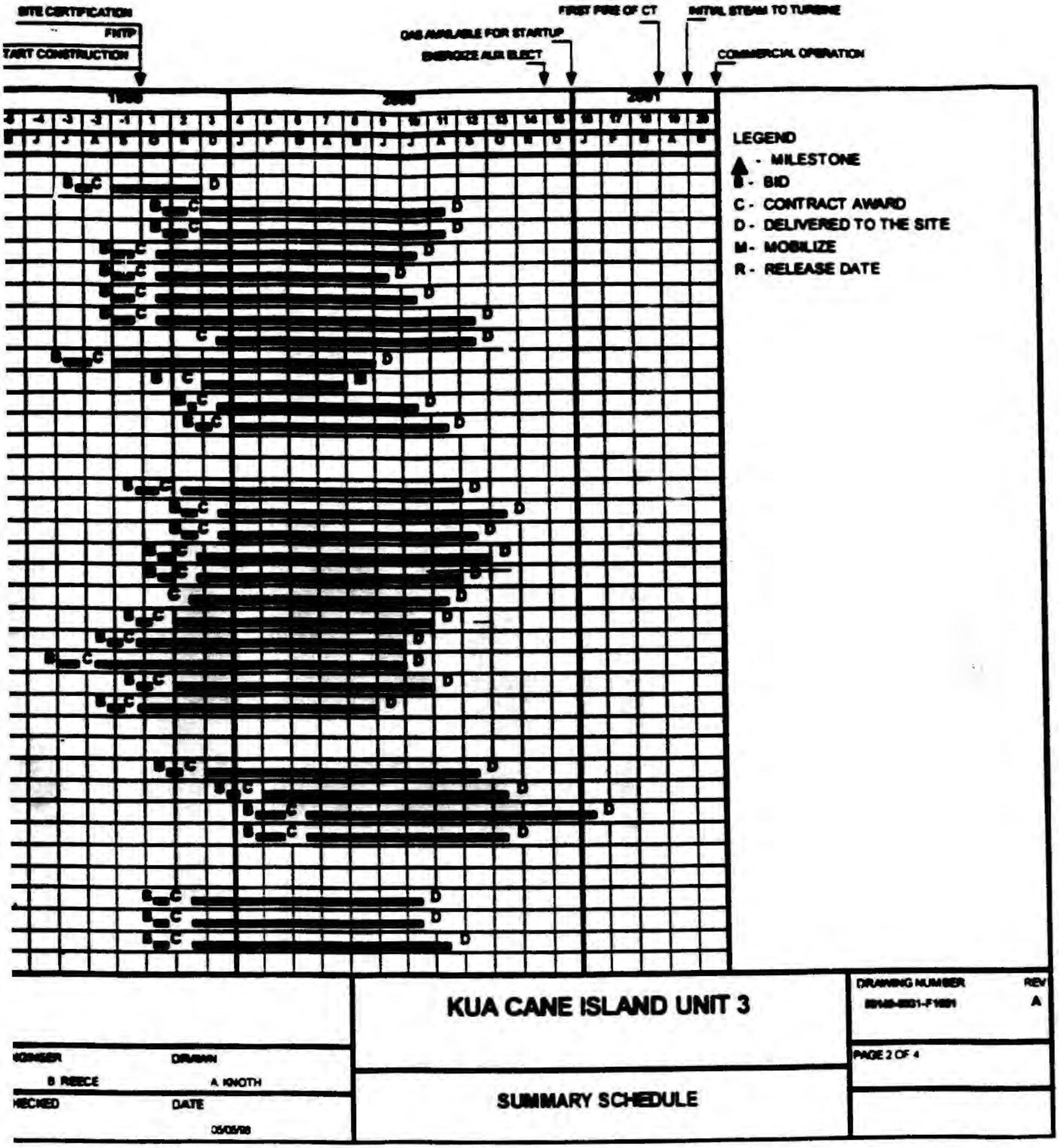


Figure 1A.2-2 (Page 2 of 4)

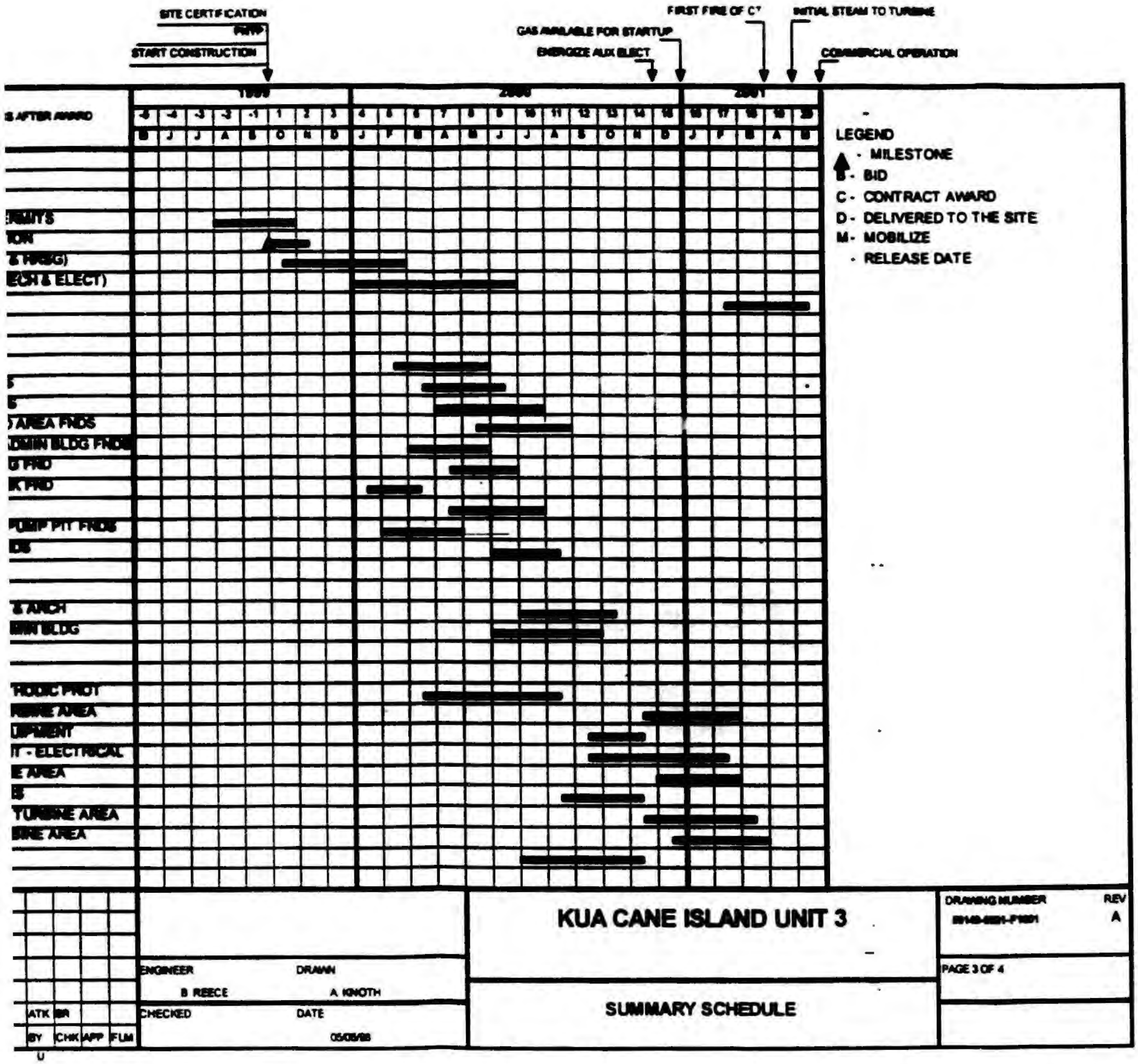


Figure 1A.2-2 (Page 3 of 4)

1A.2.8 Analysis of Clean Air Act Implications

The Cane Island Power Park is required to comply with the Clean Air Act (CAA) and the current Florida air quality requirements stemming from the Act. Section 1A.8.0 presents an analysis of the CAA implications and licensing requirements for construction of Cane Island Unit 3.

1A.2.9 Associated Transmission Line

Load flow studies using the 1998 Florida Reliability Coordinating Council (FRCC) database indicate that with the addition of Cane Island 3 during an outage of the Cane Island-Taft 230 kV transmission line, the Clay Street 230/69 kV auto transformer overloads. With the addition of a second autotransformer at Clay Street, under the same contingency, the Clay Street-Hansel 69 kV transmission line overloads, requiring reconductoring. Planning studies indicated that a new 230 kV transmission line from Cane Island to Florida Power Corporation's Intercession City Plant would solve these contingency problems at a significantly lower cost. The new 230 kV transmission line will be routed on the existing Cane Island-Clay Street transmission line towers to the site boundary and then be routed in the identified utility corridor adjacent to the CSX railroad line to the Intercession City Plant. The Intercession City Plant property directly adjoins the Cane Island site. The transmission line will be treated as an associated facility under the Florida Electrical Power Plant Siting Act.

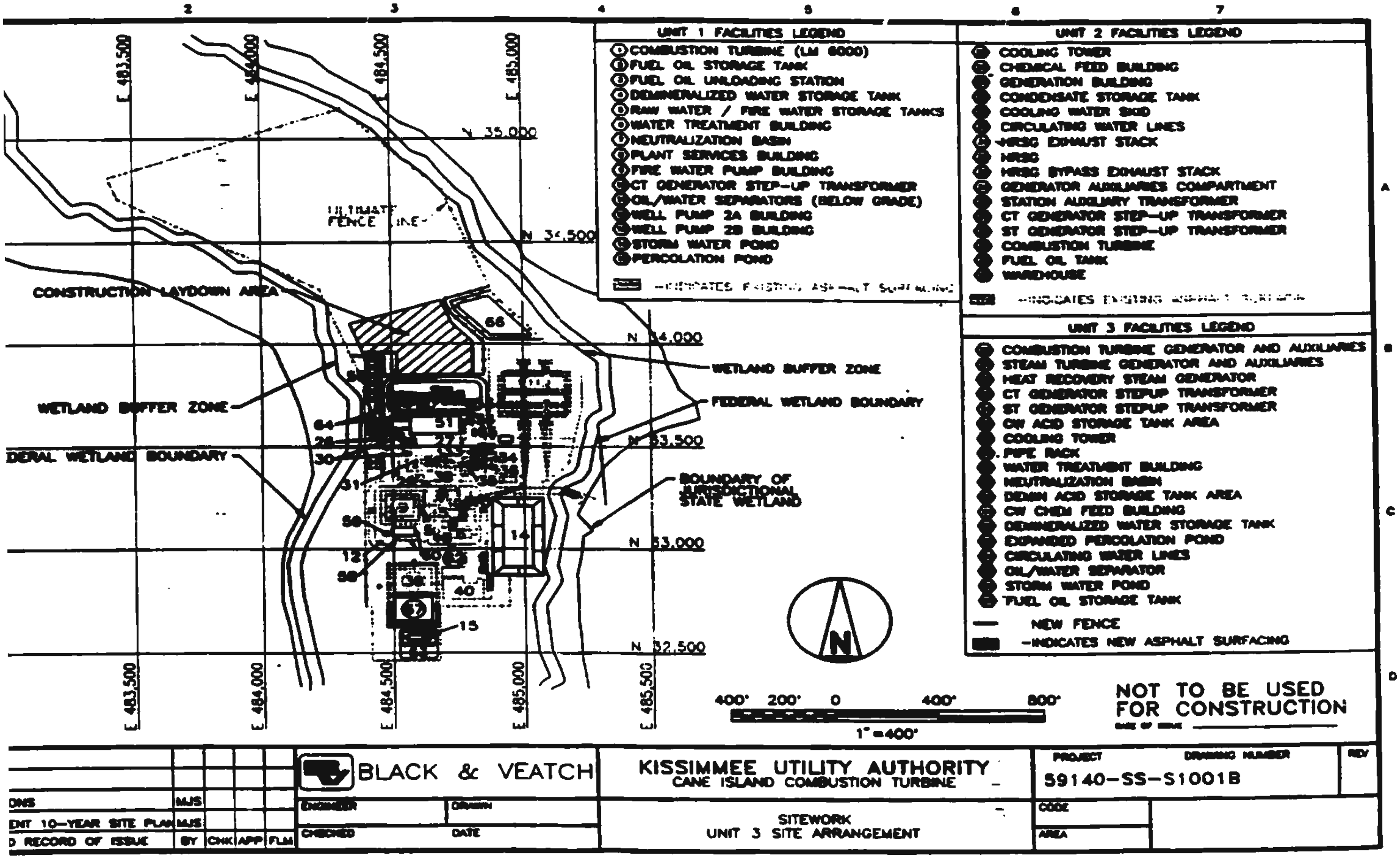

UNIT 1 FACILITIES LEGEND
COMBUSTION TURBINE (LM 6000)
FUEL OIL STORAGE TANK
FUEL OIL UNLOADING STATION
DEMINERALIZED WATER STORAGE TANK
RAW WATER / FIRE WATER STORAGE TANKS
WATER TREATMENT BUILDING
NEUTRALIZATION BASIN
PLANT SERVICES BUILDING
FIRE WATER PUMP BUILDING
CT GENERATOR STEP-UP TRANSFORMER
OIL/WATER SEPARATORS (BELOW GRADE)
WELL PUMP 2A BUILDING
WELL PUMP 2B BUILDING
STORM WATER POND
PERCOLATION POND
UNIT 2 FACILITIES LEGEND
COOLING TOWER
CHEMICAL FEED BUILDING
GENERATION BUILDING
CONDENSATE STORAGE TANK
COOLING WATER SKID
CIRCULATING WATER LINES
HRSG EXHAUST STACK
HRSG
HRSG BYPASS EXHAUST STACK
GENERATOR AUXILIARIES COMPARTMENT
STATION AUXILIARY TRANSFORMER
CT GENERATOR STEP-UP TRANSFORMER
ST GENERATOR STEP-UP TRANSFORMER
COMBUSTION TURBINE
FUEL OIL TANK
WAREHOUSE
UNIT 3 FACILITIES LEGEND
COMBUSTION TURBINE GENERATOR AND AUXILIARIES
STEAM TURBINE GENERATOR AND AUXILIARIES
HEAT RECOVERY STEAM GENERATOR
CT GENERATOR STEPUP TRANSFORMER
ST GENERATOR STEPUP TRANSFORMER
CW ACID STORAGE TANK AREA
COOLING TOWER
PIPE RACK
WATER TREATMENT BUILDING
NEUTRALIZATION BASIN
DEMIN ACID STORAGE TANK AREA
CW CHEM FEED BUILDING
DEMINERALIZED WATER STORAGE TANK
EXPANDED PERCOLATION POND
CIRCULATING WATER LINES
OIL/WATER SEPARATOR
STORM WATER POND
FUEL OIL STORAGE TANK
NEW FENCE
-INDICATES NEW ASPHALT SURFACING
ULTIMATE FENCE LINE
CONSTRUCTION LAYDOWN AREA
WETLAND BUFFER ZONE
FEDERAL WETLAND BOUNDARY
BOUNDARY OF JURISDICTIONAL STATE WETLAND
N 35,000
N 34,500
N 34,000
N 33,500
N 33,000
N 32,500
E 483,500
E 484,000
E 484,500
E 485,000
E 485,500
400' 200' 0 400' 800'
1" =400'
NOT TO BE USED FOR CONSTRUCTION
BLACK & VEATCH
KISSIMMEE UTILITY AUTHORITY
CANE ISLAND COMBUSTION TURBINE
SITEWORK
UNIT 3 SITE ARRANGEMENT
PROJECT
DRAWING NUMBER
59140-SS-S1001B
REV
ENGINEER
DRAWN
CHECKED
DATE
CODE
AREA
MJS
ENT 10-YEAR SITE PLAN
D RECORD OF ISSUE
BY
CHK
APP
FLM

Figure 1A.2-1

1A.3.0 Evaluation Criteria

This section presents the assumptions used for economic parameters and projections of prices used in the need for power analysis. The assumptions stated in this section are applied consistently throughout. Section 1A.3.1 outlines the basic economic assumptions, Section 1A.3.2 discusses the fuel price projections, and Section 1A.3.3 discusses the availability of fuel at the Cane Island Power Park.

1A.3.1 Economic Parameters

1A.3.1.1 Escalation Rates

A 2.5 percent general inflation rate is assumed. A 3.0 percent annual escalation rate is used for operation and maintenance (O&M) costs. A 2.5 percent annual escalation rate is used for capital costs.

1A.3.1.2 Bond Interest Rate

The bond interest rate is assumed to be 5.5 percent.

1A.3.1.3 Present Worth Discount Rate

The present worth discount rate is equal to the bond interest rate of 5.5 percent.

1A.3.1.4 Interest During Construction

Interest during construction is assumed equal to bond interest rate of 5.5 percent.

1A.3.1.5 Fixed Charge Rate

The fixed charge rate is 8.2 percent. The fixed charge rate was developed based on a 30 year bond term including principal and interest, a 1 year debt service reserve fund, interest earnings credit based on the bond interest rate, a 2.9 percent bond issuance fee, and 1.0 percent for property insurance.

1A.3.2 Fuel Price Projections

This section presents the analysis of fuel prices and current market projections based on the Standard and Poor's Analysis of Utility Fuel Prices in the South Atlantic Region which was completed in September of 1997 by DRI. The forecast is presented in Appendix 1A.9.1. Fuel price projections are developed for coal, natural gas, nuclear, No. 6 and No. 2 fuel oil. Delivered fuel cost projections for the base, low, and high cases are presented in Tables 1A.3-1, 1A.3-2, and 1A.3-3, respectively. The forecasted fuel prices are represented graphically on Figure 1A.3-1. The first graph presents all fuel price forecasts in nominal dollars. The second graph presents a comparison of historical spot gas prices to the natural gas forecast. The historical and projected gas prices exclude transportation costs.

1A.3.2.1 Coal Price Forecast

The forecast for delivered price of coal was based on actual 1997 delivered cost of spot coal purchases for Stanton Energy Center from the Resource Data Institute (RDI) POWERdat database and Standard and Poor's Analysis of Utility Fuel Prices in the South Atlantic Region by DRI. The DRI forecast of spot coal prices was converted to 1996 dollars using DRI's implicit price deflator listed in Tabl~ 1A.3-4. The actual delivered cost of coal was then projected by applying DRI's real, annual coal price escalation in 1996 dollars plus 2.5 percent annual inflation to the 1997 actual delivered cost of spot coal purchases for Stanton Energy Center.

1A.3.2.2 No. 6 and No. 2 Oil Price Forecasts

The fuel price forecasts for No. 2 and No. 6 oil were developed based on the actual average delivered cost of No. 2 and No. 6 oil for Florida from the Energy Information Administration (EIA) Cost and Quality of Fuels and Standard and Poor's Analysis of Utility Fuel Prices in the South Atlantic Region by DRI. The DRI distillate fuel price forecast was converted to 1996 dollars using DRI's implicit price deflator listed in Table 1A.3-4. The delivered cost forecasts of No. 2 and No. 6 oil were developed by applying the resulting DRI real, annual distillate price escalation in 1996 dollars plus a 2.5 percent annual inflation rate to the 1997 Florida average delivered cost of No. 2 and No. 6 oil.

Table 1A.3-1
Delivered Fuel Price Forecast--Base Case
($/MBtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas[1]
1998	1.70	2.68	4.47	0.55	2.39
1999	1.71	2.66	4.45	0.56	2.31
2000	1.74	2.75	4.59	0.57	2.22
2001	1.77	2.89	4.82	0.59	2.25
2002	1.81	3.03	5.05	0.60	2.38
2003	1.86	3.16	5.28	0.62	2.46
2004	1.90	3.31	5.52	0.63	2.53
2005	1.93	3.49	5.82	0.65	2.61
2006	1.97	3.65	6.09	0.67	2.70
2007	2.02	3.82	6.37	0.68	2.79
2008	2.06	4.00	6.68	0.70	2.92
2009	2.10	4.18	6.99	0.72	3.02
2010	2.15	4.36	7.29	0.73	3.17
2011	2.20	4.57	7.63	0.75	3.32
2012	2.23	4.78	7.98	0.77	3.45
2013	2.29	5.00	8.34	0.79	3.59
2014	2.34	5.23	8.72	0.81	3.77
2015	2.40	5.46	9.12	0.83	3.92
2016	2.46	5.70	9.52	0.85	4.09
2017	2.51	5.97	9.96	0.87	4.30

(1) Sum of commodity price, fuel charge, GRI demand surcharge, commodity charge, GRI commodity charge, AGA surcharge, unit fuel surcharge, and FGU service charge.

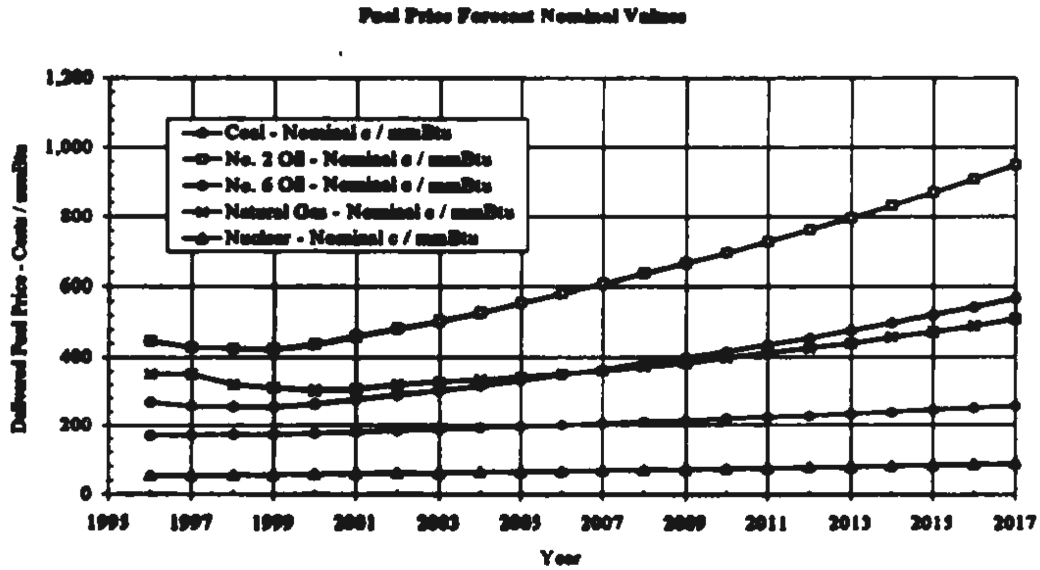
Table 1A.3-2
Delivered Fuel Price Forecast--Low Case
($/MBtu)

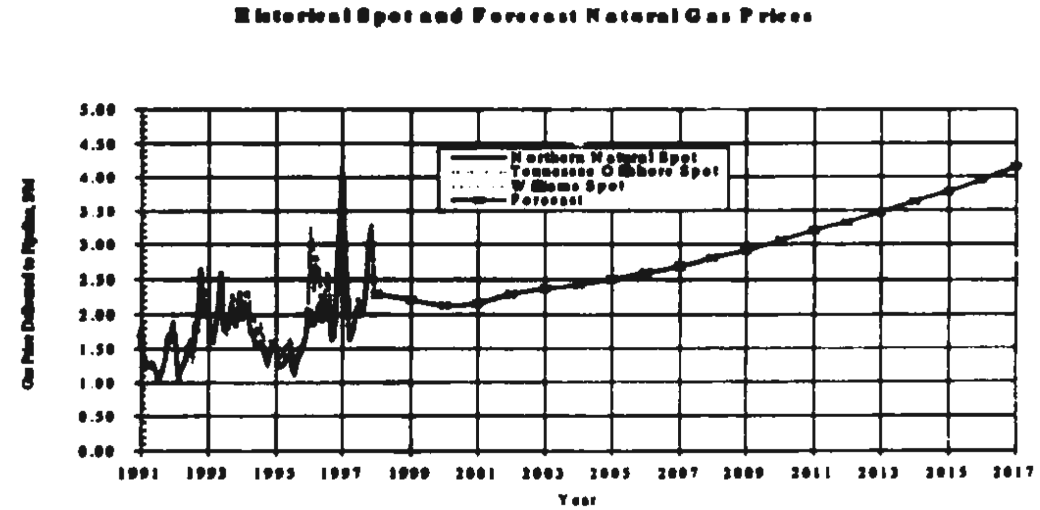
Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas[1]
1998	1.64	2.58	4.30	0.53	2.30
1999	1.62	2.51	4.19	0.53	2.19
2000	1.61	2.54	4.24	0.53	2.06
2001	1.60	2.62	4.37	0.53	2.05
2002	1.61	2.69	4.49	0.54	2.13
2003	1.62	2.75	4.60	0.54	2.17
2004	1.62	2.83	4.72	0.54	2.21
2005	1.62	2.92	4.87	0.54	2.20
2006	1.62	3.00	5.00	0.55	2.25
2007	1.62	3.07	5.13	0.55	2.27
2008	1.63	3.16	5.27	0.55	2.34
2009	1.63	3.24	5.41	0.55	2.38
2010	1.63	3.31	5.53	0.56	2.44
2011	1.64	3.40	5.68	0.56	2.52
2012	1.63	3.49	5.82	0.56	2.56
2013	1.64	3.58	5.97	0.57	2.62
2014	1.64	3.67	6.12	0.57	2.70
2015	1.65	3.76	6.27	0.57	2.76
2016	1.66	3.85	6.42	0.57	2.82
2017	1.66	3.94	6.58	0.58	2.91

(1) Sum of commodity price, fuel charge, GRI demand surcharge, commodity charge, GRI commodity charge, AGA surcharge, unit fuel surcharge, and FGU service charge.

Table 1A.3-3 Delivered Fuel Price Forecast--High Case ($/MBtu)					
Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas[1]
1998	1.77	2.78	4.65	0.57	2.48
1999	1.82	2.82	4.71	0.59	2.45
2000	1.88	2.97	4.96	0.62	2.38
2001	1.95	3.18	5.31	0.65	2.46
2002	2.04	3.40	5.68	0.68	2.66
2003	2.12	3.62	6.04	0.71	2.81
2004	2.21	3.86	6.44	0.74	2.97
2005	2.30	4.15	6.93	0.77	3.07
2006	2.39	4.43	7.39	0.81	3.26
2007	2.49	4.72	7.88	0.84	3.41
2008	2.60	5.04	8.42	0.88	3.64
2009	2.70	5.38	8.98	0.92	3.85
2010	2.82	5.72	9.55	0.96	4.10
2011	2.94	6.11	10.20	1.01	4.39
2012	3.04	6.51	10.87	1.05	4.64
2013	3.18	6.94	11.59	1.10	4.93
2014	3.31	7.40	12.35	1.15	5.26
2015	3.47	7.88	13.16	1.20	5.59
2016	3.62	8.40	14.01	1.25	5.93
2017	3.77	8.95	14.94	1.31	6.35

(1) Sum of commodity price, fuel charge, GRI demand surcharge, commodity charge, GRI commodity charge, AGA surcharge, unit fuel surcharge, and FGU service charge.





Historical and Forecast Fuel Prices
Figure 1A.3-1

Table 1A.3-4 DRI Implicit Price Deflator			
Year	1992 Base	1996 Base	Annual Increase
1997	1.125	1.021	2.1
1998	1.151	1.044	2.3
1999	1.178	1.069	2.4
2000	1.207	1.095	2.5
2001	1.238	1.123	2.6
2002	1.271	1.153	2.6
2003	1.304	1.184	2.7
2004	1.340	1.216	2.7
2005	1.379	1.251	2.9
2006	1.419	1.288	3.0
2007	1.462	1.327	3.0
2008	1.507	1.368	3.1
2009	1.555	1.411	3.1
2010	1.605	1.458	3.2
2011	1.659	1.506	3.4
2012	1.718	1.557	3.4
2013	1.775	1.610	3.4
2014	1.837	1.667	3.5
2015	1.902	1.725	3.5
2016	1.970	1.788	3.6
2017	2.041	1.852	3.6

1A.3.2.3 Natural Gas Price Forecast

1A.3.2.3.1 Commodity. The natural gas commodity price forecast was developed based on Standard & Poor's Analysis of Utility Fuel Prices in the South Atlantic Region by DRI. DRI's gas price forecast is based upon normal weather, which, in combination with adequate storage and a normal output from nuclear stations, predicts moderate short-term prices. The DRI values for Henry Hub and Gulf Coast spot prices for natural gas delivered to pipelines were averaged and converted to 1996 dollars using DRI's implicit price deflator listed in Table 1A.3-4. The final commodity cost was developed by applying the resulting DRI real, annual natural gas price escalation in 1996 dollars plus 2.5 percent annual inflation rate to the average spot prices.

1A.3.2.3.2 Transportation. Natural gas transportation in Florida is supplied by Florida Gas Transmission Company (FGT). Details of FGT's system are presented in Section 1A.3.3. Natural gas transportation from FGT is supplied under two tariffs, FTS-1 and FTS-2. Rates for FTS-2 are based on FGT's Phase III expansion while rates for FTS-1 are based on the Phase II expansion. As discussed in Section 1A.3.3, the Phase III expansion was extensive and rates for FTS-2 transportation are significantly higher than for FTS-1. The Phase IV expansion will be less extensive and thus, transportation rates should be lower. While it is anticipated that Phase IV rates may be lower, the cost for the Phase IV expansion may be rolled in with the Phase III costs, and the resultant rate may not be significantly less than the current Phase III rates.

For purposes of projecting delivered gas prices, for new units it is assumed that the current Phase III transportation rates will apply. Table 1A.3-5 presents the delivered natural gas price forecast based on current FTS-2 rates. Actual rates for natural gas transportation should be less than these. However, for evaluation purposes, this forecast will be used for natural gas for new units.

Both KUA and FMPA are members of Florida Gas Utility (FGU) which is an organization of municipal utilities which manages and schedules member's transportation entitlements and purchases gas for members. The small FGU service charge is included in the forecast in Table 1A.3-5.

Table 1A.3-5
Natural Gas Price Forecast ($/MBtu)

Year	Henry Hub	Gulf Coast	Average	Implicit Price Deflator	Deflated $1996	General Inflation 2.5%	Fuel Charge 3.09%	Demand Reservation	GRI Demand Surcharge	Commodity Charge	GRI Commodity Charge	AGA Surcharge	Unit Fuel Surcharge	FGU Service Charge	Delivered Price
1997	2.60	2.49	2.55	1.02	2.50	2.55	0.08	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.31
1998	2.28	2.19	2.24	1.04	2.14	2.25	0.07	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.20
1999	2.20	2.11	2.16	1.07	2.02	2.17	0.07	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.12
2000	2.12	2.03	2.08	1.10	1.89	2.09	0.07	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.09
2001	2.14	2.06	2.10	1.12	1.87	2.12	0.07	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.06
2002	2.28	2.19	2.24	1.15	1.94	2.25	0.07	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.19
2003	2.36	2.27	2.32	1.18	1.96	2.32	0.07	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.27
2004	2.42	2.34	2.38	1.22	1.96	2.38	0.08	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.34
2005	2.51	2.43	2.47	1.25	1.97	2.47	0.08	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.42
2006	2.61	2.53	2.57	1.29	2.00	2.55	0.08	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.51
2007	2.71	2.63	2.67	1.33	2.01	2.64	0.08	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.60
2008	2.85	2.77	2.81	1.37	2.05	2.76	0.09	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.73
2009	2.97	2.89	2.93	1.41	2.08	2.86	0.09	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.83
2010	3.15	3.07	3.11	1.46	2.13	3.01	0.09	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	3.98
2011	3.32	3.24	3.28	1.51	2.18	3.15	0.10	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.13
2012	3.48	3.41	3.45	1.56	2.21	3.28	0.10	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.26
2013	3.66	3.58	3.62	1.61	2.25	3.42	0.11	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.40
2014	3.88	3.80	3.84	1.67	2.30	3.59	0.11	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.58
2015	4.07	3.99	4.03	1.73	2.34	3.73	0.12	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.73
2016	4.30	4.22	4.26	1.79	2.38	3.90	0.12	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	4.90
2017	4.57	4.48	4.53	1.85	2.44	4.10	0.13	0.0072	0.0085	0.0144	0.0088	0.0022	-0.0019	0.0367	5.11

Notes:
Forecast data is based on Standard & Poor's DRI "Analysis of Utility Fuel Prices in the South Atlantic Region," September, 1997. Implicit Price Deflator from DRI.

1A.3.2.4 Nuclear Fuel Price Forecast

The nuclear fuel price projection is based on the average of the 1996 fuel price for the St. Lucie and Crystal River Nuclear Plants from the Resource Data Institute (RDI) POWERdat database escalated at the underlying general inflation rate of 2.5 percent.

1A.3.3 Fuel Availability

DRI projects that natural gas supply increases are expected to be adequate to possibly excessive by 2000. This is because (1) reserve additions have exceeded production during the past 2 years in the United States and, (2) by 2000, pipeline capacity additions of 5 to 10 Bcf/day from Canada, the Rocky Mountains, and the deep Gulf of Mexico are expected to create a "gas-bubble" even though gas demand is projected to grow by up to 7 Bcf/day. Gas prices are expected to weaken as new supply sources are added to the US market. DRI predicts swift demand growth acting to absorb the new supplies and gas markets permitting a return to a better balance after 2000. DRI expects demand growth for 1997 to 2000 to average about 1.9 Bcf/day per year.

1A.3.3.1 Florida Gas Transmission Company

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 Sonat, Inc., 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:

- Permian Area (West Texas and New Mexico).
- Anadarko Basin (Texas, Oklahoma and Kansas).
- Fort Worth and East Texas Basins.
- 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 14 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

1A.3.3.2 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.3.3.3 Service to Cane Island Power Park

The Cane Island Power Park is served from an existing FGT system delivery point on the St. Petersburg Lateral located in Section 26, T25S, R27E in northwestern Osceola County. From the custody metering installation at the delivery point, the lateral pipeline (the Cane Island Lateral) runs south and then easterly to service the existing generation facilities at the Cane Island site. The Cane Island Lateral is a 20 inch diameter pipeline capable of providing maximum design basis hourly volumes, as limited by the design of the delivery point metering station, of up to 10,000 MBtu per hour, assuming maximum operating pressure in the St. Petersburg Lateral of 975 psig.

The Cane Island Lateral completed in 1993 is sized for the supply of natural gas at the ultimate plant development level (approximately 1,000 MW of combined cycle capacity) of the Cane Island site. However, subsequent to the completion of the lateral pipeline, a tap off serving the Intercession City Plant of Florida Power Corporation (FPC) has been completed from the Cane Island Lateral. This sublateral, installed in 1996, is an 8 inch diameter pipeline with an estimated flow capacity of 20 to 30 million cubic feet per day at present-day FGT mainline operating pressures. Under the contractual arrangements between KUA and FPC, the service to the Intercession City Plant is on an "as available" basis and is interruptible should KUA and FMPA require the gas supply for operation of the Cane Island facilities.

The existing infrastructure of the FGT system following completion of the Phase III expansion in February 1995 allows the flexibility to accommodate a certain amount of capacity expansion by an increase of mainline compression with minor looping of lines to alleviate bottlenecks. This expansion will be accomplished as part of the FGT Phase IV expansion program discussed below.

1A.3.3.4 Florida Gas Transmission Phase IV Expansion

On August 15, 1997, FGT initiated an "open season" for a proposed expansion of mainline transmission capability to serve new markets.[*] This initiative was structured to gauge potential demand for the prospective FGT Phase IV expansion project with an estimated in-service date of late 1999 or early 2000; however, depending upon market needs, it was indicated that a phased-in expansion at earlier dates may be possible.

FGT has indicated that the responses received from the August-September 1997 open season were not deemed to be firm and accurate to justify the formal implementation of the Phase IV expansion of the FGT system at that time. However, FGT continues to receive inquiries and hopes to formally file for Federal Energy Regulatory Commission (FERC) approvals of the Phase IV expansion program in late 1998 as requests for additional transmission services are firmed up. Under present planning scenarios, it is envisioned by FGT that this expansion will primarily consist of additional compression capability installed

[*]The term "open season" refers to the industry practice of conducting a survey of future market demands for transport of natural gas prior to the design and construction of new line construction or expansion projects on existing pipeline systems. The open-market survey is employed to "test the market" by requesting that potential shippers submit non-binding expressions of interest or requests for new or additional (incremental) firm transmission services or, in some cases, for the relinquishment from existing shippers of firm transmission capacity. This process allows the pipeline developer to ascertain the need for, the extent and nature of pipeline capacity expansion capacity volumes and the overall economic feasibility of the proposed project. The open season is conducted under defined ground rules to assure the integrity of the shipper's submissions and the non-discriminatory analysis of the responses.

in the Panhandle and West Leg portions of the pipeline system and line extensions of existing lateral branchlines. Looping of existing corridors to alleviate capacity constraints is not projected as being extensive. The Phase IV expansion of the FGT system should therefore be capable of implementation at a relatively low incremental cost impact to existing and prospective customers.

1A.3.3.5 Alternative Natural Gas Supply Pipelines for Peninsular Florida

Over the years a number of alternative schemes for pipeline delivery of natural gas to Peninsular Florida have been proposed to provide competition to the existing FGT system. The most notable of these initiatives is the "SunShine System" pipeline, proposed in 1993 by SunShine Pipeline Partners, a subsidiary of the Coastal Corporation, to provide natural gas from an interconnection to existing pipelines from Texas-Louisiana Gulf Coast production regions and from onshore gas processing plants located in the Mobile Bay production region. The interstate portion of the proposed system comprised approximately 143 miles of new pipeline extending from near Pascagoula, Mississippi, to delivery points in Escambia and Okaloosa Counties, Florida. A separate proposed intrastate pipeline extended from the Okaloosa delivery point eastward and then southward for a distance of about 502 miles to terminate at the Florida Power Corporation's Hines Energy Complex site northwest of Fort Meade (Polk County), Florida. The project included a 27 mile lateral line to enable deliveries to customers in the Pensacola (Escambia County) area.

The primary customer of the project was to have been Florida Power Corporation (FPC) which acquired an equity position and firm transport conditional commitment in the pipeline (January and February 1993). The project subsequently received preliminary (non-environmental) approvals for the intrastate and interstate pipelines from the Florida Public Service Commission and FERC, respectively.

The competitive threat to the established pipeline system was countered by FGT which reached agreement with FPC for gas transmission via the expanded FGT system. FPC subsequently withdrew as an equity partner in the SunShine Project (September 1994) and terminated the agreements for firm transmission service (February 1995). The project was canceled in April 1995.

The successor to the SunShine pipeline is the "Gulf Stream" pipeline which is also being promoted by the Coastal Corporation and ANR Pipeline. This pipeline would also originate in the Mobile Bay region, cross the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay) to service existing and prospective electric generation and industrial projects in south Florida. This project is in the development stage with the prognosis for ultimate completion uncertain. In any case, the proposed routing of the pipeline across peninsular Florida would appear to be too far to the south to provide economic service to the Cane Island site. Another proposal by Williams-Transco is also in the initial stage of development.

1A.3.3.6 Natural Gas Supply at the Cane Island Site

Based on discussions with FGT, the natural gas supply at the delivery point to the Cane Island lateral will be fully adequate in terms of quantity and delivery pressure to support the Cane Island Unit 3 facilities. In addition, natural gas transportation is sufficient to support the fuel requirements of the proposed Cane Island Unit 3 facilities.

1A.4.0 Consistency With Peninsular Florida Needs

The Florida Reliability Coordinating Council (FRCC) is the North American Reliability Council (NERC) Coordinating Council responsible for coordinating power supply reliability in Peninsular Florida. As part of their 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 PSC staff and utility members during annual workshops. The most recent planning summary conducted by FRCC is the, "1997 Ten-Year Plan State of Florida." Published during 1997, this Ten-Year Plan summarizes utility loads and resources, by type of capacity, through the year 2006. The summary also includes utility load forecast data and proposed generation expansion plans, retirements, and capacity re-rates. The following sections summarize the results of FRCC's reliability analysis in the determination of future capacity requirements for Peninsular Florida.

1A.4.1 Peninsular Florida Capacity and Reliability Needs

Table 1A.4-1 presents the peak demand and available capacity for Peninsular Florida for summer and winter as presented in the 1997 Ten-Year Plan State of Florida. The available capacity consists of existing capacity, capacity which has been certified under the Florida Electrical Power Plant Siting Act, and proposed capacity changes not requiring certification under the Florida Electrical Power Plant Siting Act as presented in the 1997 Ten-Year Plan State of Florida. Figures 1A.4-1 and 1A.4-2 present peak demands and available capacity from Table 1A.4-1 in graphical form.

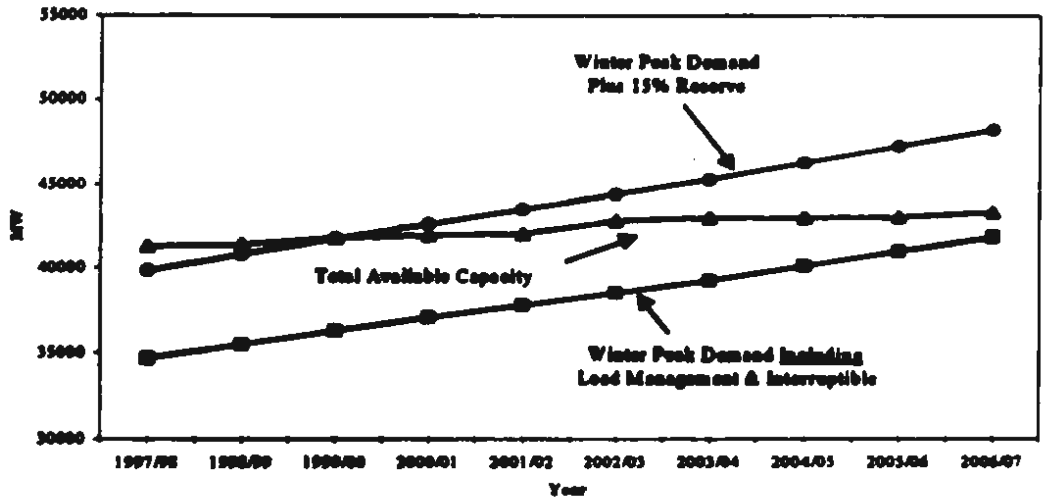
Table 1A.4-1 indicates that 689 MW of additional capacity is required in the winter for Peninsular Florida to maintain a 15 percent reserve margin beginning in 2000/01 and increasing to 4,808 MW by 2006/07. Additional capacity is required beginning in 2003 to maintain 15 percent reserve margin in the summer. Both needs are based on full load reductions for load management and interruptible load being implemented.

Cane Island Unit 3's capacity will help contribute to alleviating the capacity shortfall in Peninsular Florida and improve reliability beginning with its commercial operation on June 1, 2001.

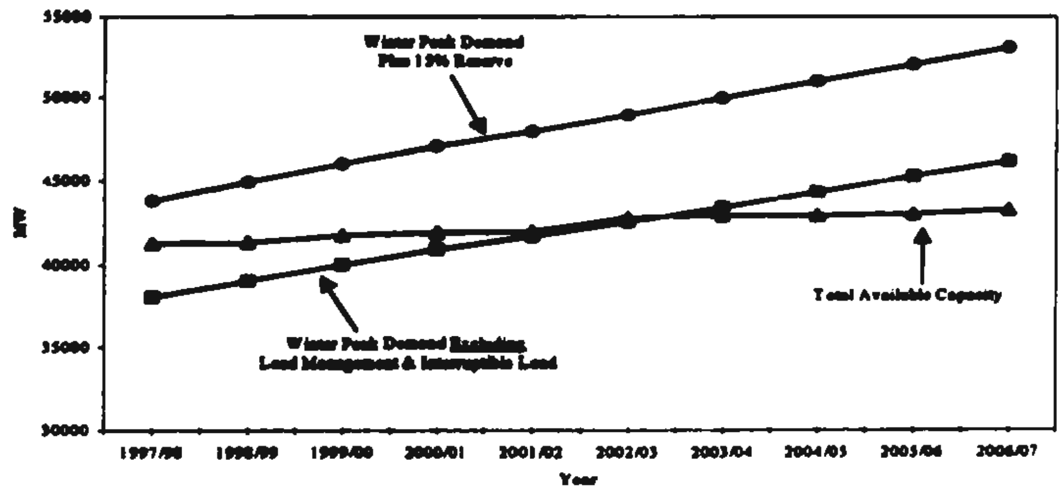
Table 1A.4-1
Peninsular Florida Peak Demand and Available Capacity

Calendar Year	Installed Capacity (MW)	Capacity Changes Not Requiring PPSA (MW)	Contracted Firm Interchange (net import) (MW)	Projected Firm Net to Grid from NUG (MW)	Total Available Capacity (MW)	Total Peak Demand (MW)	Reserve Margin w/o Exercising Load Manage and Int. (MW)	Reserve Margin w/o Exercising Load Manage and Int. % of peak	Load Management (MW)	Interruptible Load (MW)	Firm Peak Demand (MW)	Reserve Margin with Exercising Load Manage & Int. (MW)	Reserve Margin with Exercising Load Manage & Int. % of peak	Additional Required for 15% Reserves (MW)
10 Year Plan Summer Peak Demand														
1997	33110	60	1360	2416	38886	34566	4320	12.5%	1539	1159	31868	7018	22.0%	-
1998	33170	21	1311	2416	38918	35643	3275	9.2%	1629	1187	32826	6092	18.6%	-
1999	33191	325	1626	2331	39673	36172	3501	9.7%	1726	1241	33205	6468	19.5%	-
2000	33516	211	1714	2331	39972	37079	2893	7.8%	1843	1231	34005	5967	17.5%	-
2001	35727	64	1677	2331	39999	37894	2105	5.6%	1924	1232	34738	5261	15.1%	-
2002	35791	733	1666	2331	40721	38530	2191	5.7%	2010	1170	35350	5371	15.2%	-
2003	36534	224	1678	2331	40957	39197	1760	4.5%	2103	1168	35926	5031	14.0%	358
2004	36748	-9	1596	2331	40666	39691	975	2.4%	2162	1169	36359	4307	11.8%	1177
2005	36739	230	1607	2331	41107	40697	410	1.0%	2194	1163	37341	3766	10.1%	1833
2006	36969	275	1518	2331	41293	41386	-93	-0.2%	2224	1158	38003	3290	8.7%	2410
10 Year Plan Winter Peak Demand														
1997/98	36907	173	1723	2479	41282	38090	3192	8.4%	2281	1159	34650	6632	19.1%	-
1998/99	37080	18	1725	2554	41377	39091	2286	5.8%	2402	1210	35479	5898	16.6%	-
1999/00	37098	358	1728	2594	41778	40026	1752	4.4%	2533	1217	36276	5502	15.2%	-
2000/01	37436	236	1653	2594	41939	40962	977	2.4%	2658	1235	37068	4871	13.1%	689
2001/02	37682	90	1666	2594	42032	41737	295	0.7%	2773	1152	37812	4220	11.2%	1452
2002/03	37772	799	1655	2594	42820	42588	232	0.5%	2892	1147	38550	4270	11.1%	1513
2003/04	38571	256	1586	2594	43007	43467	-460	-1.1%	2996	1158	39313	3694	9.4%	2203
2004/05	38827	-13	1596	2594	43004	44374	-1370	-3.1%	3056	1145	40173	2831	7.0%	3195
2005/06	38814	156	1518	2594	43082	45304	-2222	-4.9%	3116	1140	41047	2035	5.0%	4122
2006/07	38970	273	1518	2594	43357	46188	-2831	-6.1%	3168	1137	41883	1474	3.5%	4808

10 Year Plan (1997): Winter Peak Demand
Including Load Management and Interruptible Load

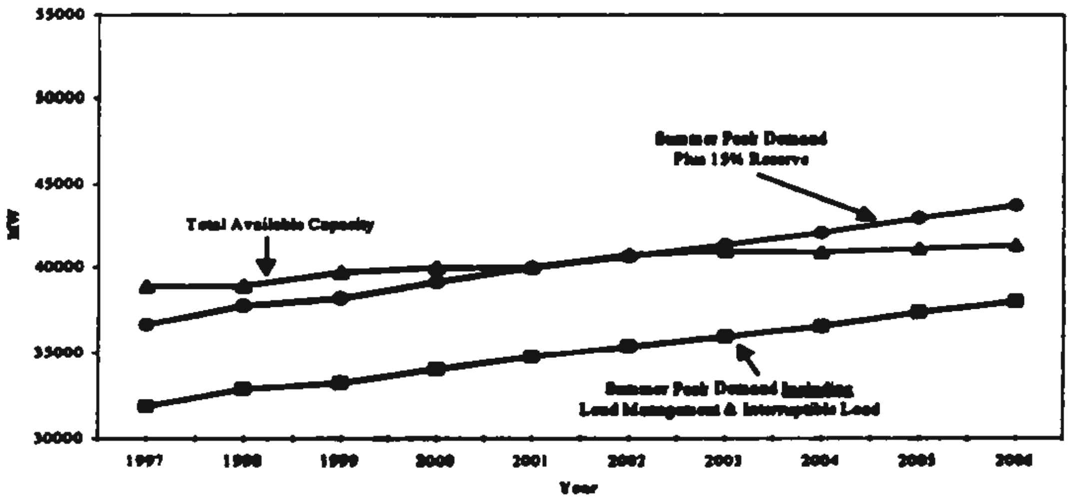


10 Year Plan (1997): Winter Peak Demand
Excluding Load Management and Interruptible Load

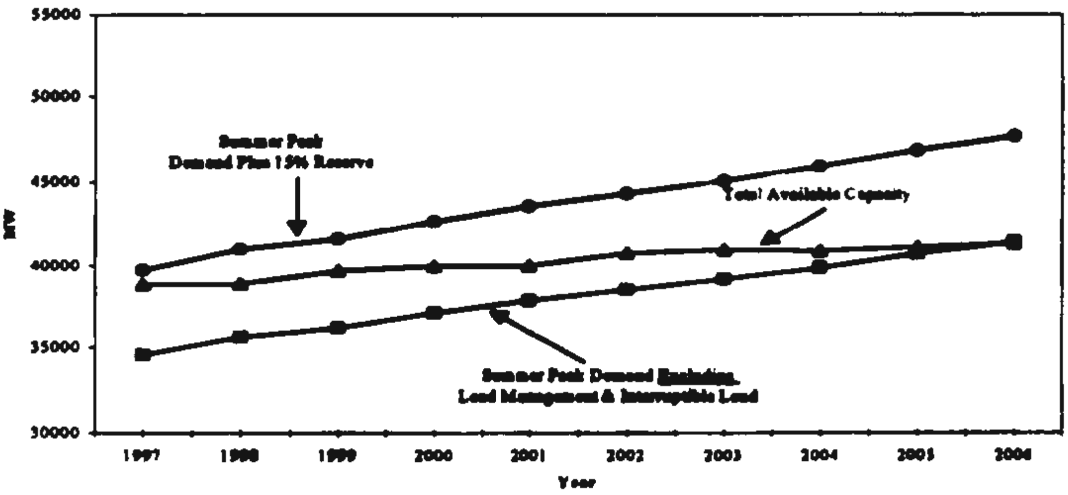


Peninsular Florida Capacity Reserves (Winter)
Figure 1A.4-1

10 Year Plan (1997): Summer Peak Demand
Including Load Management and Interruptible Load



10 Year Plan (1997): Summer Peak Demand
Excluding Load Management and Interruptible Load



Peninsular Florida Capacity Reserves (Summer)
Figure 1A.4-2

1A.5.0 Demand-Side Programs

Both KUA and FMPA consider conservation and demand-side management (DSM) an integral component in managing the efficiency of their electric systems and providing choice to their customers. Conservation and demand-side management programs for FMPA are generally administered by the individual All-Requirements Project member. Conservation programs were originally established under the Florida Energy Efficiency and Conservation Act (FEECA). Although neither KUA nor any of FMPA's All-Requirements Project members are currently classified as FEECA utilities, KUA and FMPA both are committed to conservation and load management programs.

Chapter 366.82, Fl. Stat. requires the Public Service Commission (PSC) to review and approve cost-effective utility conservation programs. In 1995, KUA performed a cost-effectiveness analysis for over 70 proposed DSM measures and submitted the results to the Public Service Commission (PSC). The results of the analysis indicated that DSM measures were not cost-effective. FMPA also regularly evaluates potential DSM programs to identify any which may call for implementation. In order to ensure their DSM program evaluations were current for this site certification, KUA and FMPA performed a new cost-effectiveness analysis using Cane Island 3 as the avoided unit of approximately 70 DSM programs using the Florida Integrated Resource Evaluator (FIRE). FIRE was originally developed by Florida Power Corporation. The results of the new analysis did not indicate any cost-effective DSM measures. More detailed discussion of the DSM penetration and existing conservation programs in place for KUA and FMPA are provided in Sections 1B.6.0 and 1C.6.0, respectively.

1A.5.1 Florida Integrated Resource Evaluator (FIRE) Results

The Florida Integrated Resource Evaluator uses avoided unit costs, DSM program costs, operations and maintenance costs, rebates/incentives and other input variables to calculate the incremental costs and incremental benefits of a DSM program. These incremental costs are used to perform three cost-effectiveness tests: the Rate Impact Test, the Total Resources Test, and the Participant Test. The DSM programs reviewed are listed in Table 1A.5-1, along with the results of the FIRE analysis.

Table 1A.5-1
FIRE Results

DSM Program SRC Code	DSM Program Description	Test: Rate Impact	Test: Total Resource Cost	Test: Participant Costs
New Construction				
RSC-1	High Efficiency Air Source Heat Pump	0.36	0.24	0.56
RSC-8A	Load Control for Residential Heat	0.00	0.01	8.61
RSC-8B	Load Control for Residential Heat	0.01	0.02	8.66
RSC-21A	High Efficiency Central AC	0.25	0.18	0.60
RSC-26A	DLC of Central AC	-0.30	-0.66	1.00
RSC-26B	DLC of Central AC	-0.30	-0.66	1.00
WH-10	DLC of Electric Water Heater	-0.22	-0.49	1.00
PP-3	DLC of Pool Pumps	-0.71	-0.72	1.00
SC-D-1	High Efficiency Chiller	0.62	9.99	28.50
SC-D-2	High Efficiency Chiller w/ASD	0.72	1.94	2.83
V-D-8	High Efficiency Motors - Chiller	0.40	1.47	8.92
V-D-9	High Efficiency Motors - DX AC	0.43	1.59	8.95
L-D-25	Compact Flourescent Lamps (15/18/27W)	0.70	0.55	0.00
L-D-26	Two Lamp Compact Flourescent (18W)	0.69	0.58	0.00
W-D-13	Heat Recovery Water Heater	0.57	1.44	3.28
C-D-19	Energy Efficient Electric Fryers	-0.07	-0.09	4.40
Existing Construction				
RSC-1	High Efficiency Air Source Heat Pump	0.35	0.25	0.60
RSC-5A	Reduced Duct Leakage	0.23	0.35	2.16
RSC-5B	Reduced Duct Leakage	0.23	0.35	2.16
RSC-8A	Load Control for Residential Heat	0.01	0.01	8.62
RSC-8B	Load Control for Residential Heat	0.01	0.01	8.62
RSC-10A	Ceiling Insulation (R0-R19)	0.42	0.51	1.37

Table 1A.5-1 (Continued) FIRE Results				
		Test		
DSM Program SRC Code	DSM Program Description	Rate Impact	Total Resource Cost	Participant Costs
RSC-10B	Ceiling Insulation (R0-R19)	0.40	0.46	1.27
RSC-11A	Ceiling Insulation (R11-R30)	0.32	0.26	0.65
RSC-11B	Ceiling Insulation (R11-R30)	0.25	0.18	0.49
RSC-17A	Low Emissivity	0.05	0.02	0.30
RSC-21A	High Efficiency Central AC	0.31	0.25	0.72
RSC-24A	High Efficiency Room AC	-0.05	-0.05	0.88
RSC-26A	DLC of Central AC	-0.49	-1.05	1.00
RSC-26B	DLC of Central AC	-0.29	-0.72	1.00
WH-7	DHW Pipe Insulation	0.05	0.05	1.00
WH-10	DLC of Electric Water Heater	-0.22	-0.49	1.00
PP-1	High Efficiency Pool Pumps	0.25	0.35	4.48
PP-3	DLC of Pool Pumps	-0.67	-0.69	1.00
SC-D-1	High Efficiency Chiller	0.65	10.03	27.29
SC-D-2	High Efficiency Chiller w/ASD	0.73	1.91	2.76
SC-D-4	High Efficiency Room AC Units	0.82	10.91	15.13
SC-D-8	2-Speed Motor for Cooling Tower	-0.22	-2.55	56.03
SC-D-9	Speed Control for Cooling Tower	0.72	2.31	5.03
SC-D-19	Roof Insulation - DX AC	0.17	0.56	4.75
SC-D-22	Window Film - Chiller	0.61	2.59	5.04
SC-D-23	Window Film - DX AC	0.47	1.48	3.70
V-D-1	Leak Free Ducts - DX AC	0.55	1.84	4.46
V-D-8	High Efficiency Motors - Chillers	0.58	1.56	6.01
V-D-9	High Efficiency Motors - DX AC	0.58	1.56	6.04
V-D-10	Separate Makeup Air/Exhaust Hoods - Chiller	0.53	0.03	0.05
V-D-11	Separate Makeup Air/Exhaust Hoods - DX AC	0.41	0.02	0.04

Table 1A.5-1 (Continued) FIRE Results				
		Test		
DSM Program SRC Code	DSM Program Description	Rate Impact	Total Resource Cost	Participant Costs
L-D-1	4' - 34W Flour. Lamps/Hybrid Ballasts (#1)	0.69	3.14	0.02
L-D-3	4' - 34W Flour. Lamps/Electronic Ballasts (#1)	0.68	2.56	0.02
L-D-5	8' - 60W Flour. Lamps/Electronic Ballasts (#1)	0.63	2.17	0.01
L-D-7	T8 Lamps/Electronic Ballasts (#1)	0.68	1.84	0.01
L-D-9	Refl/Delamp: Install 4' - 40W Flour. Lamps/ EE Ball	0.63	4.15	0.06
L-D-10	Refl/Delamp: Install 4' - 34 and 40W Flour. Lamps/EE	0.63	3.88	0.05
L-D-11	Refl/Delamp: Install 8' - 75W Flour. Lamps/EE Ball	0.64	3.30	0.03
L-D-12	Refl/Delamp: Install 8' - 60W Flour. Lamps/ EE Ball	0.63	3.16	0.03
L-D-21	High Pressure Sodium (70/100/150/250W)	0.63	0.87	0.00
L-D-23	High Pressure Sodium (35W)	0.69	0.35	0.00
L-D-25	Compact Flourescent Lamps (15/18/27W)	0.69	0.50	0.00
L-D-26	Two Lamp Compact Flourescent (18W)	0.63	0.23	0.00
R-D-4	Multiplex: Air-Cooled/Ambient and Mechanical Sub	0.80	1.41	0.00
R-D-5	Multiplex: Air-Cooled/External Liquid Suction HX	0.75	1.63	0.00
W-D-13	Heat Recovery Water Heater	0.57	1.43	3.29
W-D-14	DHW Heater Insulation	0.37	0.79	30.70
W-D-15	DHW Heat Trap	0.57	1.82	121.62
W-D-16	Low Flow Variable Flow Showerhead	0.52	2.44	255.52
C-D-19	Energy Efficient Electric Fryers	-0.07	-0.09	4.40

The DSM measures that correlate to the SRC codes listed in Table 1A.5-1 are based on the **Electricity Conservation and Energy Efficiency in Florida** study prepared by Synergic Resources Corporation for the Florida Energy Office.

1A.6.0 Supply-Side Alternatives

This Section presents a review of the conventional, advanced and renewable energy resources evaluated by KUA and FMPA 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 the most accurate resource planning evaluation. In addition, due to the nature of some technologies dependence 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 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, fuel, operations, and maintenance costs over the typical life expectancy of the unit, assuming municipal ownership and financing. Costs for advanced technologies and renewable energy sources are presented in 1998 dollars, and costs for conventional technologies are presented in 2001 dollars.

1A.6.1 Renewable Technologies

1A.6.1.1 Wind Energy Conversion

Wind power is growing significantly in the international market, but domestic growth in the United States has been slow. Worldwide installed wind power is over 5,000 MW, with around 1,700 MW in the U.S. Germany and India accounted for almost two-thirds of all new installations in 1996--nearly 900 MW. The U.S., on the other hand, lagged behind, adding only 41 MW of new wind capacity. In the last 10 years, the U.S. share of total world wind energy capacity has dropped from about 90 percent to 30 percent. Stagnation in the U.S. market can be attributed to the pending restructuring of the electric utility industry, which has made utility power planners hesitant to plan new capacity additions.

Utility scale wind energy systems consist of multiple wind turbines that range in size from 100 kW to 1,000 kW. Multiple turbines are used to supply the desired megawatt output. Reasonably sized installations may be 5 to 50 megawatts in size. Wind energy provides supplemental power when operating as a stand-alone resource with typical capacity factors of 15 to 40 percent, depending on 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. Table 1A.6-1 provides wind energy characteristics for a 10 MW wind farm with average yearly wind speed of 20 miles per hour.

1A.6.1.2 Solar

Solar energy consists of capturing the sun's energy and converting it to either thermal energy (solar thermal) or electrical energy (photovoltaics). Numerous options and techniques are used for this purpose.

1A.6.1.2.1 Solar Thermal. Solar thermal systems convert solar insolation to high temperature thermal energy, usually steam, which is then used to drive heat engines, turbine/generators, or other devices for electricity generation. More than 350 MW are currently generated by commercial solar thermal plants in the U.S. 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 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. They are parabolic trough, parabolic dish, and central receiver.

A measure of solar thermal plant efficiency is the ratio of net electric output to annual solar energy received by the collector field. The amount of solar energy received is a product of annual direct normal solar radiation, in kWh/m^2, multiplied by the total collector area. An 80 MW parabolic trough solar thermal plant is represented in Table 1A.6-2.

1A.6.1.2.2 Photovoltaics. 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 with atoms from an element with one more or less electrons 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

Table 1A.6-1
Wind Energy Conversion
Performance and Costs

Commercial Status	Commercial
Average Wind Speed (mph)	20
Performance:	
Power Capacity (MW_{rated})	10
Power Capacity ($MW_{average}$)	3.5
Energy Production (MWh/yr)	29,127
Capacity Factor (percent)	35
Costs:	
Capital Cost ($\$/kW_{rated}$)	1,130
Capital Cost ($\$/kW_{average}$)	3,220
O&M Costs:	
Fixed O&M ($\$/kW\text{-}yr_{average}$)	31
Variable O&M ($\$/MWh_{average}$)	5.0
Levelized Cost (cents/kWh)	3.8[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-2
Solar Thermal - Parabolic Trough
Performance and Costs

Commercial Status	Commercial
Duty Cycle	Supplemental
Performance:	
Power Capacity (MW)	80
Energy Production (MWh/yr)	252,288
Capacity Factor (percent)	36
Costs:	
Capital Cost ($/kW)	2,870 - 3,600
O&M Costs:	
Fixed O&M ($/kW-yr)	47
Variable O&M ($/MWh)	4.1
Levelized Cost (cents/kWh)	9.8 - 14.6[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

of physical connections, the current is gathered. Various currents and voltages can be supplied through series and parallel arrays of cells.

The DC current produced depends on the material involved and the intensity of the solar radiation incident on the cell. Most widely used today is the single crystal silicon cell. 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, which are inherently less efficient than single crystal solar cells, but also cheaper to produce. Gallium arsenide cells are among the most efficient solar cells today, with many other advantages, but are also expensive.

Another approach to producing solar cells that shows great promise is thin films. Commercial thin films today 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 easily manufactured on a large scale. Manufacturing lends itself to automation and the fabricated cells can be flexibly sized and incorporated into building components.

Current utility grid connected photovoltaic systems are generally below 1 megawatt in size, however, several larger projects ranging from 1 megawatt to 50 megawatts have been proposed. Recently, Greece funded 5 megawatts of photovoltaic power of a 50 MW proposed plant on the island of Crete.

Numerous variations in photovoltaic cells are available such as single crystalline silicon, polycrystalline, thin film silicon, etc. and several structure concepts are available (fixed-tilt, one-axis tracking, two-axis tracking). For representative purposes a fixed-tilt, single crystalline photovoltaic system is characterized in Table 1A.6-3.

1A.6.1.3 Wood Chip

Direct wood chip 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 expended through a turbine to produce electricity. Prior to combustion in the boiler, the wood chip fuel may require some processing to improve the physical and chemical properties of the feedstock. Furnaces used in the combustion of wood chips include spreader stoker-fired, suspension-fired, fluidized bed, cyclone and pile burners.

Table 1A.6-3
Utility-Scale Photovoltaics
Performance and Costs

Commercial Status	**Commercial**
Module Type	**Single Crystalline**
Array Type	**Fixed-tilt**
Duty Cycle	**Supplemental**
Performance:	
Module Efficiency (%)	**12.0**
Power Capacity (MW)	**10**
Energy Production (MWh/yr)	**17,520**
Capacity Factor (percent)	**20**
Costs:	
Capital Cost ($/kW$_{[illegible]}$)	**2,000**
Capital Cost ($/kW$_{[illegible]}$)	**10,000**
O&M Costs:	
Fixed O&M ($/kW-yr$_{[illegible]}$)	**14**
Variable O&M ($/MWh$_{[illegible]}$)	**2.0**
Levelized Cost (cents/kWh)	**8.4 - 13.0[1]**

(1) **California Energy Commission, <u>1996 Energy Technology Status Report</u>, adjusted to 199[illegible] dollars.**

The capacity of wood chip plants is usually less than 50 MW because of the large quantities and dispersed nature of the feedstock required. The stoker-fired grate is limited to the amount of fuel that can be handled. Wood chip 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 wood chip fuel compared to coal. Also, finding sufficient sources of fuel within a 100 mile radius may also limit the size of plant because of the transportation costs associated with low density wood chip fuel.

There are around 1,000 wood-fired plants in the country, with a typical size ranging from 10 to 25 MW. Only a third are operated to sell electricity, with the rest being owned and operated by the forest-products industry for self generation. Table 1A.6-4 provides typical characteristics of a 50 MW wood-fired combustion plant assuming spreader-stoker furnace technology using wet wood chips as fuel.

1A.6.1.4 Geothermal

The production of geothermal energy in the U.S. 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 2,900 megawatts of electricity (MWe) from geothermal energy, and direct applications have an installed capacity in excess of 2,100 thermal megawatts (MWt). Approximately 5,700 MWe are currently being generated in some 20 countries from geothermal energy, and there are 11,300 MWt of installed capacity worldwide for direct-heat applications at inlet temperatures above 95°F.

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. Four types of geothermal power conversion systems are in common use. They are dry steam, single-flash, double-flash, and binary cycle power plants. No known geothermal sources are located in the state of Florida. For representative purposes a 25 MW binary-cycle power plant is characterized in Table 1A.6-5. Capital costs of geothermal facilities can vary widely as the drilling of wells can cost as much as four million dollars and the number of wells drilled depends on success of finding the resource. Variable O&M cost will also include the replacement of production wells.

Table 1A.6-4 Wood Chip Combustion Performance and Costs	
Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	50
Net Plant HHV Heat Rate (Btu/kWh)	12,500 to 17,500
Energy Capacity (MWh)	260,000
Capacity Factor (percent)	60
Costs:	
Capital Cost ($/kW)	1,450 - 1,850
O&M Costs:	
Fixed O&M ($/kW-yr)	24 - 48
Variable O&M ($/MWh)	4.0 - 5.0
Levelized Cost (cents/kWh)	5.8 - 11.1[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-5
Geothermal
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25
Energy Capacity (MWh)	175,200
Capacity Factor (percent)	80
Costs:	
Capital Cost ($/kW)	2,000 - 4,000
O&M Costs:	
Fixed O&M ($/kW-yr)	105
Variable O&M ($/MWh)	7.2
Levelized Cost (cents/kWh)	3.4 - 12.1[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.1.5 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 cost have and are changing. 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.6-6 has typical ranges for performance and cost estimates.

1A.6.2 Waste Technologies

1A.6.2.1 Refuse to Energy Conversion

There are a wide variety of refuse types that have the potential to produce energy. The use of municipal solids waste, used tires, and sewage sludge will be addressed in this section. Economic feasibility of refuse to energy facilities is difficult to assess in general. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location.

1A.6.2.1.1 MSW to Energy Conversion. Converting refuse or municipal solids 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 primarily what will determine if a waste to energy facility is economically feasible.

The degree of refuse processing determines the method used to convert municipal solids waste to energy. Unprocessed refuse is typically combusted in a water wall furnace (mass burning). After only limited processing to remove non-combustible 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. Table 1A.6-7 has typical ranges for performance and costs.

Table 1A.6-6 Hydroelectric Performance and Costs	
Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	10 to 1,500+
Energy Capacity (MWh)	Resource dependent
Capacity Factor (percent)	Resource dependent
Costs:	
Capital Cost ($/kW)	1,300 - 5,200
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 30
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	3.3 - 6.3[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-7 Waste to Energy - Mass Burn Unit Performance and Costs	
Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	15,500
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,000 - 3,000
O&M Costs:	
Fixed O&M ($/kW-yr)	100 - 150
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	7.0 - 12.0[1 2]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.
(2) Excludes tipping fee credit.

1A.6.2.1.2 RDF to Energy Conversion. Refuse Derived Fuel (RDF) is preferred in many refuse to energy applications because it can be combusted in coal fired technologies. Spreader stoker-fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been utilized to generate steam from RDF. Fluidized bed combustors are often preferred for RDF to energy applications due to their high combustion efficiency, capability to handle RDF with minimal processing, and inherent ability to effectively reduce nitrous oxides 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.6-8 has typical ranges for performance and costs.

1A.6.2.1.3 Landfill Gas Energy Conversion. Previously 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 the landfill gas and either flare the gas or generate energy with it. The major constituents released from landfill gas wells are carbon dioxide and methane. The methane concentration is typically around 50 percent. To convert this clean burning low Btu gas to electricity, the gas is piped from wells, filtered, compressed, and used in internal combustion engine generation sets. Depending on the scale of the gas collection facility, it may be feasible to blend this gas with natural gas and generate power via a combustion turbine generator.

In general, landfills that have over one million tons of waste in place, a waste depth greater than 40 feet, more than 30 acres available for gas recovery, and the equivalent of 25+ inches of annual precipitation are sites at which landfill gas recovery is economically feasible. In many cases the payback period of landfill gas energy facilities is between 2 and 5 years. The capital costs will be highly dependent on the conversion technology and landfill characteristics. Table 1A.6-9 has typical ranges for performance and costs.

Table 1A.6-8 Waste to Energy - RDF 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 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,500 - 3,500
O&M Costs:	
Fixed O&M ($/kW-yr)	150 - 200
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	8.0 - 13.0[1,2]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.
(2) Excludes tipping fee credit.

Table 1A.6-9
Landfill Gas - IC Engine Unit
(Gas Collection/Processing Not Included)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500
Capacity Factor (percent)	60 - 75
Availability (percent)	93
Costs:	
Capital Cost ($/kW)	825
O&M Costs:	
Fixed O&M ($/kW-yr)	0.9[1]
Variable O&M ($/MWh)	6.7
Levelized Cost (cents/kWh)	2.0 - 4.0[2]

(1) Unstaffed site.
(2) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.2.2 Sewage Sludge to Energy Conversion

The disposal of sewage sludge is a significant environmental problem. The combustion of these materials in order to convert them into 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 performance problem, the low heating value of this waste has impeded the development of sludge combustion. Other waste to energy methods are currently being investigated that involve either digestion or fermentation 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.6.2.3 Used Tire 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) 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 10 percent has been utilized by eight utilities in the U.S. on a regular basis. In cyclone plants, the NO_x emissions and trace metal emissions have actually been reduced when burning TDF. Sulfur dioxide emissions did not change with the co-firing of 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.6-10. This plant has the flexibility to process MSW to RDF and co-fire up to 40 percent RDF with coal.

Table 1A.6-10
Multi-Fuel CFB
(~10 Percent TDF Co-Fire)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	11,000
TDF Tons per Day	100
Capacity Factor (percent)	60 - 75
Availability (percent)	85
Costs:	
Capital Cost ($/kW)	1,650
O&M Costs:	
Fixed O&M ($/kW-yr)	40
Variable O&M ($/MWh)	3.0
Levelized Cost (cents/kWh)	4.0 - 8.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.3 Advanced Technologies

1A.6.3.1 Brayton Cycles

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 that is a vapor cycle. Three of the Brayton cycles that are showing promise for advanced technologies and discussed below include: Humid Air cycle, Kalina cycle, and Cheng cycle.

1A.6.3.1.1 Humid Air. 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.6-11 presents typical performance and cost characteristics.

1A.6.3.1.2 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 non-isothermal 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 the 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.6-12 presents typical performance and cost characteristics.

Table 1A.6-11
Humid Air Turbine Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	410
O&M Costs:	
Fixed O&M ($/kW-yr)	7 - 9
Variable O&M ($/MWh)	0.10 - 0.60
Levelized Cost (cents/kWh)	3.3 - 4.8[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-12
Kalina Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 12
Variable O&M ($/MWh)	0.1 - 0.5
Levelized Cost (cents/kWh)	4.2 - 6.3[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.3.1.3 Cheng Cycle. The Cheng cycle, also known as 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. Several small cogeneration plants since 1984 have applied the Cheng cycle in California, Japan, Australia, and Europe. Table 1A.6-13 presents typical performance and cost characteristics.

1A.6.3.2 Advanced Coal Technologies

Coal continues to supply a large portion of the energy demand in the U.S. 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.6.3.2.1 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. Table 1A.6-14 presents typical performance and cost characteristics.

1A.6.3.2.2 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.6-15 presents typical performance and cost characteristics.

Table 1A.6-13
Cheng Cycle Power Plant
Performance and Costs

Commercial Status	**Development**
Performance:	
Typical Plant Capacity (MW)	**250 - 650**
Net Plant Heat Rate (Btu/kWh)	**6,500**
Capacity Factor (percent)	**60 - 75**
Costs:	
Capital Cost ($/kW)	**1,025**
O&M Costs:	
Fixed O&M ($/kW-yr)	**12**
Variable O&M ($/MWh)	**0.6**
Levelized Cost (cents/kWh)	**5.6 - 12.4[1]**

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-14
Supercritical Pulverized Coal Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	350 - 1,300
Net Plant Heat Rate (Btu/kWh)	9,300
Capacity Factor (percent)	60 - 75
Availability (percent)	78
Costs:	
Capital Cost ($/kW)	1,230
O&M Costs:	
Fixed O&M ($/kW-yr)	19 - 23
Variable O&M ($/MWh)	3.3
Levelized Cost (cents/kWh)	3.7 - 4.7[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-15 PCFB Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	80 - 350
Net Plant Heat Rate (Btu/kWh)	8,600 (6,700 2nd generation)
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,330 - 2,050
O&M Costs:	
Fixed O&M ($/kW-yr)	40 - 80
Variable O&M ($/MWh)	3.5
Levelized Cost (cents/kWh)	3.5 - 5.8[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.3.3 *Magnetohydrodynamics*

Magnetohydrodynamic (MHD) power generation converts the thermal energy of a high velocity ionized gas to electricity. 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 gases 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 non-sulfur containing potassium species. Particulate emissions can be controlled by electrostatic precipitator.

Currently, MHD power generation technology is still in the development stage. Estimates on operation, performance, costs, and availability are based primarily on conceptual designs. Although 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 is no commercial application of MHD technology that demonstrates that this improved performance is feasible. Table 1A.6-16 summarizes the characteristics of a conceptual 100 MW MHD plant. It is expected that MHD plant sizes will be 500 MW or greater for optimal economic feasibility.

Table 1A.6-16 Magnetohydrodynamic Combined Cycle Plant Conceptual Performance and Costs	
Commercial Status	Development/Conceptual
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	10,300
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,300 - 2,500
O&M Costs:	
Fixed O&M ($/kW-yr)	20 - 35
Variable O&M ($/MWh)	1.0 - 3.1
Levelized Cost (cents/kWh)	6.7 - 13.5

1A.6.3.4 Fuel Cells

Fuel cells are devices that can convert a hydrogen rich fuel 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. 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 10 MW in size. PAFC cogeneration facilities can attain efficiencies approaching 85 percent when the thermal energy from the fuel cell is utilized. Also, the potential development of fuel cell/gas turbine combined cycles could reach 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 cell remain one of the primary reasons for commercialization. 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. 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.6-17.

1A.6.3.5 Fusion

Theoretically the potential for fusion power is great. Energy is released when two light nuclei such as deuterium and tritium undergo fusion to form a 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 K is required to sustain a deuterium-tritium reaction.

Table 1A.6-17 Fuel Cell Power Plant Performance and Costs	
Commercial Status	Commercially Available
Performance:	
Plant Capacity (MW)	0.2
Net Plant Heat Rate (Btu/kWh)	9,980
Capacity Factor (percent)	85
Costs:	
Capital Cost ($/kW)	4,100
O&M Costs:	
Fixed O&M ($/kW-yr)	330
Variable O&M ($/MWh)	0.84
Levelized Cost (cents/kWh)	7.0 - 9.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

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 fission, the fusion power plant is not likely to undergo a uncontrolled melt-down situation. The minimal amount radioactive fusion waste does not emit strong radiation during its moderate half life of approximately 12 years.

Despite the attractive possibilities of fusion, it 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 U.S. The Princeton Tokamak Fusion Test Reactor has been decommissioned in the spring of 1997 due to cuts in federal funding of the program. Alternative basic research on various aspects of fusion continue, and the international effort to develop a viable fusion power facility is still significant. Nonetheless, it is likely to be well into the next century before fusion develops to the point of commercial viability.

1A.6.3.6 Ocean Wave Energy

Wave energy systems convert the kinetic and potential energy contained in the natural oscillations of ocean waves into electricity. There are a variety of proposed mechanisms for the utilization of this energy source, most of which are still in the demonstration or prototype testing stage. 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 the utilization of wave energy is the greatest for offshore/deep wave plants, but the technical barriers and associated costs are also considerably higher. Surge devices and oscillating water column devices are the primary technologies for converting wave energy. Both types of systems convert the oscillatory flow of air or water (driven by the waves) to power via a turbine.

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. The high capital costs of such systems have deterred the implementation of wave energy systems. Table 1A.6-18 presents typical performance and cost characteristics.

Table 1A.6-18
Ocean Wave Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	0.1 - 1.0
Net Plant Heat Rate (Btu/kWh)	N/A
Capacity Factor (percent)	25
Costs:	
Capital Cost ($/kW)	2,450
O&M Costs:	
Fixed O&M ($/kW-yr)	50 - 103
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	6.2 - 38.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.3.7 Ocean Tidal Energy

The conversion of ocean tidal cycle energy to electricity can be done through the creation of a dam and tidal basin. By opening a 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. The capacity factor of such a facility is around 24 percent. Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably from region to region. As a rule of thumb, a 16 foot tidal amplitude is considered the minimum amplitude for an energy conversion system to be considered economically feasible. In North America, the Northeast and Northwest coasts of Canada are generally considered the only regions where tidal energy plants would be economically feasible. Tidal amplitudes as high as 50 feet are experienced on the east coast of Canada in the Bay of Fundy.

Utilization of tidal energy for power generation has the environmental advantage of a zero emissions technology. At the same time, the environmental impact that the facility has on the coastline must be carefully evaluated. As with many developing technologies for energy utilization and conversion, high capital costs are the primary obstacle for widespread application. The economic viability of this option is highly dependent on the location chosen for application. Table 1A.6-19 presents typical performance and cost characteristics.

1A.6.3.8 Ocean Thermal Energy

The temperature of the ocean may differ up to 40 degrees from the surface to a depth of 3000 ft. The idea of utilizing this difference for energy production has existed for over a century. Ocean Thermal Energy Cycle (OTEC) concepts have been developed using two basic types of 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 seawater as the working fluid. The warm surface water is flashed to low-pressure steam, expanded in the turbine generator, and condensed by the deep cold water.

Table 1A.6-19
Ocean Tidal Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	18 - 240
Annual Energy Capacity (GWh)	35 - 500
Capacity Factor (percent)	20 - 25
Costs:	
Capital Cost ($/kW)	1,030 - 4,120
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 52
Variable O&M ($/MWh)	1.5 - 5.2
Levelized Cost (cents/kWh)	13.0 - 23.0

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. The best potential for OTEC sites are in tropical and sub-tropical areas because of the higher temperature difference between the surface and the deep water. Although the potential of utilizing this zero emissions conversion technology is attractive, the high capital costs are expected to delay implementation. There are also some environmental questions yet to be answered regarding the effect of high pumping flow rates and local temperature changes on the surrounding aquatic environment.

OTEC systems are still in the development stage. A few 50-200 kW demonstration systems are being designed or tested in Hawaii. Due in part to the low cost of fossil fuels which makes OTEC implementation less competitive, funding for OTEC research has been limited. Currently, new heat exchanger configurations are being tested for closed cycle OTEC systems which could potentially improve performance and efficiency of OTEC systems.

1A.6.4 Energy Storage Systems

1A.6.4.1 Pumped Storage

A pumped storage hydroelectric facility requires a reservoir/dam system similar to conventional hydroelectric facility. Excess energy is used to pump water from a lower reservoir to an upper reservoir above a dam. When this energy is required, the potential energy of the water in the upper reservoir is converted to electricity as the water flows through a turbine to the lower reservoir. Capital cost is the primary consideration in implementing this storage technology. With careful planning and construction, the environmental impact of this technology will be negligible. For this study, estimates of the cost and performance of a 30 MW pumped storage system has been provided. Table 1A.6-20 presents typical performance and cost estimates.

Table 1A.6-20 Pumped Storage Performance and Costs	
Commercial Status	Commercial
Performance:	
Power Capacity (MW)	30 (5 hour duration)
Energy Capacity (MWh)	150
Capacity Factor (percent)	20
Costs:	
Capital Cost ($/kW)	2,050
O&M Costs:	
Fixed O&M ($/kW-yr)	28
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	9.4 - 12.5[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.4.2 Battery Storage

A battery energy storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and a building to house these components. During the utility peak periods, the battery system can discharge ac power to the utility system for around 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 8 to 10 years. Currently, the only commercially available battery systems are lead-acid based systems. Research to develop better performing batteries such as sodium-sulfur and zinc-bromine batteries is currently underway. Commercially available lead-acid systems have currently been installed with capacities of up to 21 MW, 140 MWh. The overall efficiency of battery systems is on average 72 percent from charge to discharge. The cost and performance of a 5 MW (15 MWh) system is provided in Table 1A.6-21.

1A.6.4.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) systems store energy in the form of compressed air in an underground cavern. Air is compressed during off-peak hours, stored in an underground cavern and then used when needed by expanding the compressed gas through a turbogeneration system. In combustion technology applications, over half the energy produced by the turbine generator is required to drive the compressors. The ability to compress the working fluid during the off-peak hours is the advantage of the CAES system. During peak hours the compressed air from the cavern is extracted and preheated in the recuperator. Once heated, the air is combusted with oil or gas and the hot exhaust is expanded through the combustion turbine. The location of a CAES plant must be suitable for cavern construction. To utilize this storage method, a new plant will typically be designed around the CAES system requirements.

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. CAES units have a reputation for achieving good availability. Table 1A.6-22 shows the performance and cost characteristics of the compressed air energy storage.

Table 1A.6-21
Battery Energy Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Power Capacity (MW)	5 (3 hour duration)
Energy Capacity (MWh)	15
Capacity Factor (percent)	20
Costs:	
Capital Cost ($/kW)	2,500
O&M Costs:	
Fixed O&M ($/kW-yr)	13.5
Variable O&M ($/MWh)	310 (includes replacement)
Levelized Cost (cents/kWh)	12.0 - 14.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 1A.6-22
Compressed Air Energy Storage
Performance and Costs

Commercial Status	**Commercial**
Performance:	
Typical Plant Capacity (MW)	**25 - 300 MW**
Availability (percent)	**86**
Costs:	
Capital Cost ($/kW)	**1,230**
O&M Costs:	
Fixed O&M ($/kW-yr)	**8 - 20**
Variable O&M ($/MWh)	**6.0 - 12.0**
Levelized Cost (cents/kWh)	**6.0 - 6.5[1]**

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

1A.6.4.4 Fly Wheel 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 due to a high energy density (Wh/kg). They have a very long life cycle with low operating and maintenance costs. They also can transfer large amounts of energy quickly. 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 a flywheel to be economically viable for general purpose energy storage, the capital cost must be reduced, the performance must be enhanced with new materials and low friction bearings, and the motor/generator controls need to be enhunced to better utilize flywheel energy under the always changing flywheel speed. Current research is focusing on the development of magnetic bearings utilizing high temperature superconductor technology. At this point in flywheel development, the price per stored energy is significantly lower for conventional battery systems. Flywheels currently cannot compete against battery systems, particularly in the power industry.

1A.6.4.5 Super Conducting Magnetic Energy Storage

A superconducting magnetic energy storage (SMES) unit stores energy by allowing a current to pass through a "zero resistance" toriodal 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. Commercial SMES systems are available for eliminating power surges and dips in certain industries where elimination of these brief discontinuities is essential.

1A.6.5 Nuclear (Fission)

The environmental and safety issues (and associated costs) involved with producing power from nuclear reactors has kept new nuclear plants from being constructed in the U.S. Table 1A.6-23 provides a rough estimate of nuclear power plant costs.

Table 1A.6-23
Nuclear Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	>600 MW
Net Plant Heat Rate	10,500
Capacity Factor (percent)	65 - 80
Costs:	
Capital Cost ($/kW)	3,300
O&M Costs:	
Fixed O&M ($/kW-yr)	95
Variable O&M ($/MWh)	13.0
Levelized Cost (cents/kWh)	5.8 - 15.0

1A.6.6 Conventional Technologies

Several conventional capacity addition alternatives were selected for consideration. The size of the alternatives selected considered the need for capacity and the suitability of the Cane Island site for installation of the alternatives. The alternatives considered include specific alternatives that KUA and FMPA have studied in the past as well as generic alternatives. Conventional generating unit alternatives considered for capacity expansion included the following:

- Pulverized coal.
- Fluidized bed.
- Combined cycle.
- Simple cycle combustion turbine.

Combustion turbine based alternatives were based on the size and performance of specific machines, but were not intended to limit consideration to only those machines. There are a number of combustion turbines available from different manufacturers with similar sizes and performance characteristics. The pulverized coal and fluidized bed units are assumed to be the first units located at new undetermined sites. Combined cycle and simple cycle combustion turbines were assumed to be installed on the Cane Island site and to take advantage of existing infrastructure.

Performance and O&M cost estimates have been compiled for each capacity addition alternative. The estimates provide representative values for each generation alternative and show expected trends in performance and costs within a given technology as well as between technologies. Degradation is also included. Actual unit performance and availability will vary based on site conditions, regulatory requirements, and operation practices. Capital costs for conventional technology alternatives are in 2001 dollars.

1A.6.6.1 Performance Estimates

1A.6.6.1.1 Net Plant Output. Net plant output (NPO) which is equal to the net turbine output less auxiliary power, refers to the net generation of the plant, after all internal uses and losses, that is available for uses outside the plant.

1A.6.6.1.2 Equivalent Availability (EA). Equivalent availability is a measure of the capacity of a generating unit to produce power considering limitations such as equipment failures, repairs, 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.6.6.1.3 Equivalent Forced Outage Rate (EFOR). Equivalent forced outage rate is a reliability index which reflects the probability that a unit will 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.6.6.1.4 Planned Maintenance Outage. Estimates are provided for the time required each year to perform scheduled maintenance.

1A.6.6.1.5 Startup Fuel. Estimates for startup energy, where applicable, in millions of Btu, 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 operation conditions.

1A.6.6.1.6 Net Plant Heat Rate. Estimates for net plant heat rates are based on the higher heating value of the fuel. Heat rate estimates are provided for summer 95° F ambient) and ISO (59° F) conditions for combustion turbines and combined cycle units. Allowance for heat rate degradation over time because of aging has been included. 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, and local site conditions.

1A.6.6.1.7 Degradation. For steam plants, the performance degrades with time due to erosion, corrosion, and increased leakage. Similarly, the performance of simple cycle combustion turbines and combined cycle plants will degrade with time. Part of the degraded performance can be recovered by periodic maintenance and overhauls. However, some performance cannot be recovered. Approximations for performance degradation, which were applied to the new clean performance estimates of the combined cycle and simple cycle alterantives, included a 2 percent heat rate and 4 percent output degradation. A 2 percent heat rate degradation was assumed for the pulverized coal and fluidized bed alternatives. No capacity degradation was assumed.

1A.6.6.2 Cost Estimates

1A.6.6.2.1 Capital Costs. Capital costs were developed on the basis of the current competitive generation market. Indirect costs include the typical items of engineering, construction management, general indirect costs and contingency. In addition, other indirect costs including SCADA interface costs, spares, owner's engineer, permitting, training, and substation costs to integrate the unit into the Cane Island substation, in order to place the costs on a comparable basis with costs resulting from purchase power bids, were included. Indirect costs for the larger alternatives, the 501G simple cycle and combined cycle, the 1x1 501F , and the 2x1 7EA, include a transmission line interconnection to FPC's Intercession City Plant. Direct costs for the combined cycle alternatives include bypass stacks with dampers, along with continuous emissions monitoring equipment. Direct costs for all alternatives include a fuel oil storage tank. Costs for the coal units to be located at a new site include costs for a substation and land costs based on average typical site requirements, and a land cost of $2,000 per acre. Total capital cost is the summation of direct and indirect cost and interest during construction for commercial operation in 2001. The construction period is the time from start of construction to commercial operation. The construction period was used to estimate costs for interest during construction (IDC).

Based on discussions by the Department of Environmental Protection (DEP) in the City of Lakeland Electric and Water Utilities Technical Evaluation and Preliminary Determination for the C.D. McIntosh, Jr. Power Plant Unit 5, 501G combustion turbine, an SCR will be required for the 501G-series combustion turbines prior to 2002. Based on the DEP's determination, capital and operating costs for an SCR have been included for the 501G combustion turbine based alternatives for 2001. Beginning in 2002 these costs are not included in the economic evaluations since, based on the above DEP evaluation, the 501G combustion turbines will be capable of achieving BACT without the use of SCRs.

1A.6.6.2.2 O&M Costs. O&M estimates are based on a unit life of 25 years for combustion turbines and combined cycles, variable and fixed contingency of 20 percent, and baseload capacity factor (except simple cycle units). The fixed O&M analysis assumes that the fixed cost will remain constant over the life of the plant in real dollars. Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Fuel costs typically are determined separately and are not included in either fixed or variable O&M costs. The O&M costs presented in this report are typically referred to as nonfuel O&M costs. Variable O&M

costs include disposal of combustion wastes, consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation.

1A.6.6.2.3 Coal-Fueled O&M. O&M and performance estimates for the coal-fueled alternatives were based on the following assumptions.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Variable operations costs include an assumed lime cost of $95/ton for flue gas desulfurization (FGD) and limestone cost of $22/ton for the CFB, waste disposal which includes trucking to an onsite landfill, dozing and flattening (mobile reclaim equipment), and startup fuel oil. 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. Staffing estimates provided are based on recent utility experience with modern facilities.

An additional variable O&M cost of 0.73 $/MWh is included for the SCR, which includes NH_3 costs and catalyst replacement costs. For the SNCR, the additional variable O&M cost is approximately 0.52 $/MWh for NH_3 costs. The pulverized coal unit is assumed to require SCR, while the fluidized bed unit is assumed to require SNCR.

1A.6.6.2.4 Combined and Simple Cycle O&M. O&M and performance estimates for the combined cycle and simple cycle units were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors.
- Capacity and heat rate degradation of 4 and 2 percent, respectively, has been included in the performance estimates.
- Combustion turbine generator (CTG) maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at $38/man-hour for Westinghouse and $35/man-hour for General Electric (provided by manufacturers).
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost. These costs are included in the capital cost.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.

- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- Two additional staff are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle LM6000 and 7EA are based on a 5 percent capacity factor.
- O&M costs for the simple cycle 501G and 7FA are based on a 10 percent capacity factor.
- O&M costs for all the simple cycle combustion turbines are based on 200 starts per year.

1A.6.6.3 Pulverized Coal

A 250 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be the first unit at a undetermined new site in Central Florida. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 1A.6-24 presents the estimated cost and performance of the 250 MW pulverized coal unit.

1A.6.6.4 Fluidized Bed

A 250 MW atmospheric circulating fluidized bed unit (CFB) with selective noncatalytic reduction (SNCR) was selected as another solid fuel alternative. The CFB is capable of burning a wide range of fuels. For expansion planning purposes, the CFB is assumed to burn coal. Like the pulverized coal unit, the CFB is assumed to be the first unit at a undetermined new site in Central Florida. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 1A.6-25 presents the estimated cost and performance of the 250 MW CFB unit.

1A.6.6.5 Combined Cycle

Four combined cycle units were selected as generating unit alternatives:

- 1 x 1 General Electric 7EA (Table 1A.6-26)
- 2 x 1 General Electric 7EA (Table 1A.6-27)
- 1 x 1 Westinghouse 501FC (Table 1A.6-28)
- 1 x 1 Westinghouse 501G (Table 1A.6-29)

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. 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. SCRs are only included for the 501G. The units would be located at the Cane Island site and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

1A.6.6.6 Simple Cycle Combustion Turbine

Four simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric LM6000 (Table 1A.6-30)
- General Electric 7EA (Table 1A.6-31)
- Westinghouse 501G (Table 1A.6-32)
- General Electric 7FA (Table 1A.6-33)

The 7EA, 501G, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The LM6000 is an aeroderivative combustion turbine. The combustion turbines are dual fueled with specifications for performance and operating costs based on natural gas operation.

Table 1A.6-24
Estimated Cost and Performance of 250 MW Pulverized Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 $1,000	194,115
Indirect Capital Cost, 2001 $1,000	84,958
Total Capital Cost, 2001 $1,000	279,073[1]
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	30.96
Variable O&M Cost, 1998 $/MWh	4.31
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,750
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	240,749/10,157
75 Percent of Full Load	180,562/10,275
50 Percent of Full Load	120,374/10,967
25 Percent of Full Load	60,187/13,302

(1) Includes interest during construction.

Table 1A.6-25
Estimated Cost and Performance of 250 MW Fluidized Bed Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 2001 $1,000	180,415
Indirect Capital Cost, 2001 $1,000	81,710
Total Capital Cost, 2001 $1,000	262,125[1]
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	26.26
Variable O&M Cost, 1998 $/MWh	4.46
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	9
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	4,800
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	242,794/10,250
75 Percent of Full Load	182,095/10,353
50 Percent of Full Load	121,397/11,025
25 Percent of Full Load	60,698/13,295

(1) Includes interest during construction.

Table 1A.6-26 Generating Unit Characteristics 7EA 1 x 1 Combined Cycle		
Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	56,981	
Indirect Capital Cost, 2001 $1,000	20,923	
Total Capital Cost, 2001 $1,000	77,904[1]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	3.29	
Variable O&M Cost, 1998 $/MWh	2.37	
Equivalent Availability, percent	92.1	
Equivalent Forced Outage Rate, percent	3.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	59	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	109,939/8,114	124,166/7,849
79 Percent of Full Load	86,852/8,454	98,091/8,100
59 Percent of Full Load	64,864/9,219	73,258/8,738
35 Percent of Full Load	38,479/11,288	43,458/10,478

(1) Includes interest during construction.

Table 1A.6-27
Generating Unit Characteristics
7EA 2 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	95,069	
Indirect Capital Cost, 2001 $1,000	39,114	
Total Capital Cost, 2001 $1,000	134,184[1]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.24	
Variable O&M Cost, 1998 $/MWh	2.16	
Equivalent Availability, percent	94.1	
Equivalent Forced Outage Rate, percent	1.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	119	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	222,096/7,938	250,416/7,791
75 Percent of Full Load	166,572/8,258	187,812/8,025
50 Percent of Full Load	111,048/8,178	125,208/7,869
25 Percent of Full Load	55,524/9,865	62,604/9,309

(1) Includes interest during construction.

Table 1A.6-28
Generating Unit Characteristics
Westinghouse 1 x 1 501F Combined Cycle

Item		
Steam Pressure, psia	1,800	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 $1,000	83,622	
Indirect Capital Cost, 2001 $1,000	33,945	
Total Capital Cost, 2001 $1,000	117,567[1]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.08	
Variable O&M Cost, 1998 $/MWh	2.58	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	84	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	236,630/6,945	261,792/6,815
75 Percent of Full Load	175,106/7,483	196,344/7,141
52 Percent of Full Load	123,048/8,011	138,750/7,699
27 Percent of Full Load	63,890/10,474	73,302/9,894

(1) Includes interest during construction.

Table 1A.6-29
Generating Unit Characteristics
Westinghouse 1 x 1 501G Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2001 $1,000	107,386	
Indirect Capital Cost, 2001 $1,000	39,976	
Total Capital Cost, 2001 $1,000	147,363[1 2]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	1.95	
Variable O&M Cost, 1998 $/MWh	2.27[3]	
Equivalent Availability, percent	83.0	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	294,960/7,062	333,456/6,784
75 Percent of Full Load	221,220/7,437	250,092/7,083
50 Percent of Full Load	147,480/8,190	166,728/7,714
25 Percent of Full Load	73,740/10,788	83,364/9,967

(1) Includes interest during construction.
(2) After 2001, SCR is not included and total capital cost is reduced to $145,157 in 2001 dollars.
(3) After 2001, SCR is not included and variable O&M is reduced to $2.14/MWh in 1998 dollars.

Table 1A.6-30
Generating Unit Characteristics
General Electric LM6000 Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	16,210	
Indirect Capital Cost, 2001 $1,000	5,956	
Total Capital Cost, 2001 $1,000	22,165[1]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	5.45	
Variable O&M Cost, 1998 $/MWh	6.92	
Equivalent Availability, percent	95.8	
Equivalent Forced Outage Rate, percent	2.3	
Planned Maintenance Outage, weeks/y	1	
Startup Fuel (cold start), MBtu	6	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	33,360/9,893	41,664/9,417
75 Percent of Full Load	25,020/10,475	31,248/9,806
50 Percent of Full Load	16,680/11,639	20,832/10,650
25 Percent of Full Load	8,340/15,136	10,416/13,183

(1) Includes interest during construction.

Table 1A.6-31
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	22,527	
Indirect Capital Cost, 2001 $1,000	8,924	
Total Capital Cost, 2001 $1,000	31,451[1]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	3.32	
Variable O&M Cost, 1998 $/MWh	23.56	
Equivalent Availability, percent	95.6	
Equivalent Forced Outage Rate, percent	2.1	
Planned Maintenance Outage, weeks/y	1.25	
Startup Fuel (cold start), MBtu	12	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	72,432/12,335	81,552/11,959
75 Percent of Full Load	54,324/13,504	61,164/13,050
50 Percent of Full Load	36,216/15,844	40,776/15,300
25 Percent of Full Load	18,108/23,515	20,388/22,097

(1) Includes interest during construction.

Table 1A.6-32
Generating Unit Characteristics
Westinghouse 501G Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	51,871	
Indirect Capital Cost, 2001 $1,000	22,823	
Total Capital Cost, 2001 $1,000	74,694[1 2]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.13	
Variable O&M Cost, 1998 $/MWh	11.61[3]	
Equivalent Availability, percent	84.2	
Equivalent Forced Outage Rate, percent	13.3	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	18	
Construction Period, months	15	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	197,040/10,502	223,872/10,047
75 Percent of Full Load	147,780/11,377	167,904/10,854
50 Percent of Full Load	98,520/13,128	111,936/12,470
25 Percent of Full Load	49,260/18,757	55,968/17,322

(1) Includes interest during construction.
(2) After 2001, SCR is not included and total capital cost is reduced to $72,522 in 2001 dollars.
(3) After 2001, SCR is not included and variable O&M is reduced to $10.24/MWh in 1998 dollars.

Table 1A.6-33
Generating Unit Characteristics
General Electric 7FA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2001 $1,000	35,301	
Indirect Capital Cost, 2001 $1,000	13,457	
Total Capital Cost, 2001 $1,000	48,757[1]	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.47	
Variable O&M Cost, 1998 $/MWh	10.37	
Equivalent Availability, percent	94.5	
Equivalent Forced Outage Rate, percent	2.7	
Planned Maintenance Outage, weeks/y	1.5	
Startup Fuel (cold start), MBtu	35	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	95° F	59° F
100 Percent of Full Load	147,168/11,063	165,312/10,698
75 Percent of Full Load	110,376/12,030	123,984/11,546
50 Percent of Full Load	73,584/14,090	82,656/13,400
25 Percent of Full Load	36,792/20,339	41,328/19,122

(1) Includes interest during construction.

1A.6.7 Request for Proposals to Purchase Power

KUA and FMPA conducted a two-phase evaluation of purchased power alternatives based on bids received from a request for proposals for purchased power issued May 28, 1997. The comparison of purchase power bids included applicable transmission rates, transmission upgrade costs, and loss percentages. Certain nonprice items were also included in the evaluation including pricing terms and flexibility, supply availability for economy transactions, dispatchability, fuel risks, transmission path, commercial viability of technology, and potential environmental effects. Details of the RFP process for KUA and FMPA are presented in Sections 1B.9.0 and 1C.9.0, respectively.

1A.6.8 Supply-Side Screening

KUA and FMPA conducted individual screening analyses to determine the least cost alternative for capacity addition to their systems. The screening analysis was conducted in two phases. The first phase of the screening process, further described in Subsection 1A.6.8.1, was performed based on a broad-based comparison of the cost, commercial feasibility, and applicability of each generating technology.

The second phase screening analysis of the remaining generating alternatives was performed based on a comparison of the total cumulative present worth cost of each capacity addition alternative. EGEAS, an optimal generation expansion model, was used to determine the least cost cumulative present worth expansion plans for both utilities. The economic analysis included all cost, performance, and economic parameters listed in Sections 1A.3.0, 1B.4.0, and 1C.4.0. The second phase screening analyses are presented in Sections 1B.9.0 and 1C.9.0.

1A.6.8.1 Phase One Screening

1A.6.8.1.1 Renewable Technologies. Renewable technologies evaluated as capacity addition alternatives included wind energy, solar thermal and photovoltaics, wood chip fired, geothermal, and hydroelectric. Wind energy, solar thermal, and photovoltaics were deleted from consideration based on high capital costs (two to three times that of Cane Island 3) and low capacity factor. Wood chip fired generating alternatives were deleted based on high capital cost, environmental emission concerns, and lack of raw materials for baseload operation. Geothermal and hydroelectric generating alternatives were deleted based on high capital cost and lack of natural resources. Cost and performance data for these alternatives is presented in Tables 1A.6-1 through 1A.6-6.

1A.6.8.1.2 Waste Technologies. Waste energy technologies evaluated include mass burn units, Refuse Derived Fuel (RDF), landfill gas, sewage sludge and used tire fueled generating units. All waste technology alternatives were eliminated based on high capital costs and insufficient fuel supply availability. Cost and performance data for these alternatives is presented in Tables 1A.6-7 through 1A.6-10.

1A.6.8.1.3 Advanced Technologies. Advanced technologies evaluated include humid air turbine (HAT), Kalina and Cheng cycles, advanced coal technologies, magnetohydrodynamics, fuel cells, fusion, and ocean wave and tidal systems. Only fuel cell and supercritical coal technologies are considered commercially viable. However, prohibitive capital and operating costs eliminate them from further analysis. Cost and performance data for these alternatives is presented in Tables 1A.6-11 through 1A.6-19.

1A.6.8.1.4 Energy Storage Systems. Energy storage systems evaluated include pumped storage, battery storage, compressed air energy storage, flywheel storage, and super conducting magnetic energy storage. Energy storage systems were eliminated from further analysis based on low operating capacity factor and high capital and operating costs. In addition, a majority of these alternatives are considered experimental. Cost and performance data for these alternatives is presented in Tables 1A.6-20 through 1A.6-22.

1A.6.8.1.5 Nuclear. Nuclear power plants are capital intensive, which requires that large units be built to benefit from economies of scale. The high capital cost and licensing requirements of a nuclear facility eliminates it as an alternative. Cost and performance data for a typical nuclear power plant is presented in Tables 1A.6-23.

1A.6.8.1.6 Conventional Technologies. Conventional generating unit alternatives considered for capacity expansion include pulverized coal, fluidized bed, combined cycle and simple cycle combustion turbines. These alternatives were included in the second phase EGEAS screening analysis. Cost and performance data for these alternatives is presented in Tables 1A.6-24 through 1A.6-33.

1A.7.0 FMPP Need for Cane Island 3

KUA and the FMPA All Requirements Project are both members of the Florida Municipal Power Pool (FMPP) along with Orlando Utilities Commission (OUC) and the City of Lakeland Electric & Water (Lakeland). All of the generating units for each of the members are economically committed and dispatched by OUC to meet the combined loads of FMPP. Savings from the combined commitment and dispatch, over what each utility would have spent if they had met their loads individually with their own generation, are then shared among the Pool members by prescribed formulas. Thus, the addition of Cane Island 3 will not only reduce costs for KUA and FMPA, but will also reduce costs for OUC and Lakeland. To project the savings to FMPP from the addition of Cane Island 3, the PROSYM chronological production costing program was used to model FMPP with and without Cane Island 3. Load forecasts and generation expansion plans for the FMPP members were based on information contained in the 1997 Ten Year Site Plans.

FMPP is an energy pool only and requires the members to supply their own capacity. Thus, for the case without Cane Island 3, KUA and FMPA would still be required to install or obtain capacity in 2001, since without Cane Island 3, both KUA and FMPA could not maintain a 15 percent reserve margin. For evaluation purposes, it was assumed that KUA and FMPA would install a simple cycle General Electric 7FA and 7EA as described in Section 1A.6.0 for a total summer capacity of 220 MW, which nearly equals the summer capacity of Cane Island 3. Since these units are simple cycle combustion turbines, they would not require licensing under the Florida Electrical Power Plant Siting Act. Table 1A.7-1 presents the FMPP annual and cumulative present worth savings in total production costs. Annual costs listed include all system costs for 1997 through 2006. As shown in Table 1A.7-1, the projected cumulative present worth production cost savings to FMPP from the installation of Cane Island 3 is estimated to be $26,633,000 from only the first 6 years of operation.

Table 1A.7-1 FMPP Savings With Cane Island 3				
	Total Annual FMPP Production Cost		Total Annual FMPP Production Cost Savings	
	With Cane Island ($1000)	Without Cane Island ($1000)	Annual Savings ($1000)	Cumulative Present Worth Savings ($1000)
1997-2000	0	0	0	0
2001	260,970	267,314	6,344	5,403
2002	275,005	281,402	6,397	10,567
2003	287,186	293,575	6,389	15,455
2004	301,123	306,762	5,639	19,545
2005	309,142	312,936	3,794	23,131
2006	326,205	331,579	5,374	26,633
			Total CPW	26,633

1A.8.0 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 necessity of meeting environmental requirements has cost and performance impacts on the facility. The Clean Air Act requirements have the greatest impact on the power plant's cost and performance.

1A.8.1 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}). NO_x and SO_2 contribute to the formation of acid rain. 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 sulphur 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 is less than existing emissions.

General discussion of the Unit 3 construction, operating, and acid rain permitting requirements associated with the Clean Air Act, is given below. However, a more detailed discussion of the Unit 3 environmental impacts and permitting requirements is given in Volumes 2 through 5 of this Site Certification Application. Additionally, the compliance strategy for KVA and FMPA for sulfur dioxide emissions is detailed in Volumes 1B and 1C.

1A.8.2 Authority to Construct

The Cane Island Power Park is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. An authority to construct (ATC) permit must be obtained prior to the construction of Unit 3. 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, VOC, CO, and PM/PM_{10}. Unit 3 will achieve BACT for NO_x through the use of dry low NO_x combustors which will limit the NO_x emissions to 12 to 15 ppm while firing natural gas. When firing No. 2 oil, water injection will be used to limit NO_x emissions to 42 ppm. Unit 3 will achieve BACT for CO, VOCs, and PM/PM_{10} through the use of good combustion control practices. Limited operation while firing No. 2 oil (approximately 30 days per year) will keep Unit 3 below the threshold level for SO_2.

1A.8.3 Title V Operating Permit

Along with the ATC, the Cane Island Power Park will be required to obtain an operating permit under Title V of the Clean Air Act. All three units of the Cane Island Power Park will ultimately be included in a single Title V permit. Requirements under the Title V permit for Unit 3 will require similar emissions control and operations to those required under the ATC BACT determination.

1A.8.4 Title IV Acid Rain Permit

In addition to the construction and operating permit requirements of the Cane Island Power Park, the regulations implementing the Acid Rain provisions of the Clean Air Act amendments require that electric utility units obtain acid rain permits. Unit 3 will be a Phase II unit requiring SO_2 allowances for emissions. Volumes 1B and 1C present KUA's and FMPA's plans for supplying the SO_2 allowances necessary for operation of Unit 3. The acid rain permit requires the installation of continuous emissions monitoring equipment (CEM) and fuel flowmeters, which are included in the design and cost of Unit 3.

Appendix 1A.9.1

Analysis of Utility Fuel Prices in the South Atlantic Region

Analysis of Utility Fuel Prices in the South Atlantic Region

Prepared for: Kissimmee Utility Authority

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Note: The short-term distillate and natural gas price forecasts were prepared at the end of September 1997. The long-term forecasts represent DRI's latest long-term fuel price analysis, which was prepared in April 1997. For the natural gas concepts that appear in both the short and long-term forecasts (Henry Hub and Gulf Coast), the long-term forecasts have been updated with the latest short-term analysis through 1999. The other forecasts are not directly comparable between the short and long term since they do not represent the same concept (e.g., distillate spot prices compared with delivered price to utilities) and they were not prepared contemporaneously. The long-term forecasts of prices to South Atlantic utilities are all directly comparable.

Forecast Highlights

Distillate

- Distillate fuel prices rose sharply at the end of 1996, but have since declined significantly in 1997. The key factors causing the 1996 price run-up, including uncertainty over Iraqi oil exports and very short inventories, are gone, and distillate prices have largely followed the downward trend in crude prices since the beginning of the year. The price of distillate (New York Harbor spot cargoes) has declined from a high of 72.0 cents per gallon in November 1996 to 52.3 cents in September, over a 27% drop.

- In the short term, prices will rise moderately, supported by both slightly firming crude prices and seasonal demand. Current distillate inventories are above historically average levels and about 20% above the low levels of last year at this time, so the acute stock shortages of last year and the resulting strong prices should not be repeated this heating season. The price of distillate (New York Harbor spot cargoes) will rise to 56.6 cents per gallon by this December, 8% above September's level but 19% below last December's level.

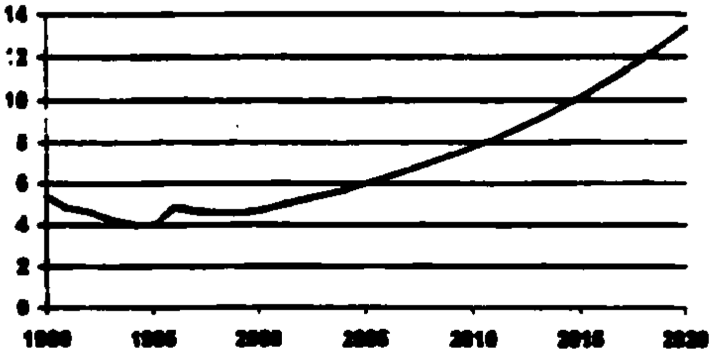
- In the long-term, distillate prices are determined primarily by the price of crude oil. DRI's forecast is that real crude prices will decline moderately through 2000. Strong non-OPEC production, weak OECD demand, and the eventual full reintroduction of Iraqi crude will allow average real crude prices to decline to about $17.00 per barrel in 2000. Real distillate prices will also decline over the same period, with nominal prices remaining essentially flat. The price of distillate fuel oil to utilities in the South Atlantic region will fall slightly from $4.84 per MMBtu (83.1 cents per gallon) in 1996 to $4.69 per MMBtu (80.5 cents per gallon) in 2000.

- After 2000, world oil prices will increase moderately in real terms. As production from mature non-OPEC regions wanes, non-OPEC exploration and production costs will increase and OPEC's market share will gradually grow. Real crude prices will increase at about 1.0% per year through 2020, to just over $25.00 per barrel. Distillate prices will also follow this trend, reaching $13.37 per MMBtu ($2.30 per gallon) in nominal terms for utilities in the South Atlantic region by 2020.

- In 1996, total distillate fuel demand was 3.4 million barrels per day (b/d). This represented 18.4% of total petroleum consumption, and distillate fuel is second only to gasoline in petroleum product demand. The transportation sector is the dominant consumer of distillate fuel, with diesel fuel and marine and rail distillate accounting for 63.3% of total distillate fuel demand. The balance is consumed by the industrial, residential, commercial, and electric utility sectors, with utilities consuming just 44,000 b/d (1.3% of the total).

- Over the forecast period, total distillate fuel demand will grow by 1.0% per year, reaching 4.3 million b/d by 2020. The transportation sector will remain the dominant consumer of distillate fuel and will realize the greatest volume increase in total distillate demand. For the stationary sectors, competition from natural gas will play a key role in shifting demand. Distillate demand in the residential and commercial sectors will decline, industrial consumption will increase slightly, and demand from electric power generators will increase strongly, although the total volume will remain small (340,000 b/d). The growth in demand for distillate fuel by electricity generators (including industrial cogenerators) is due in large part to its use as a back-up fuel for gas-fired units.

Distillate Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Natural Gas

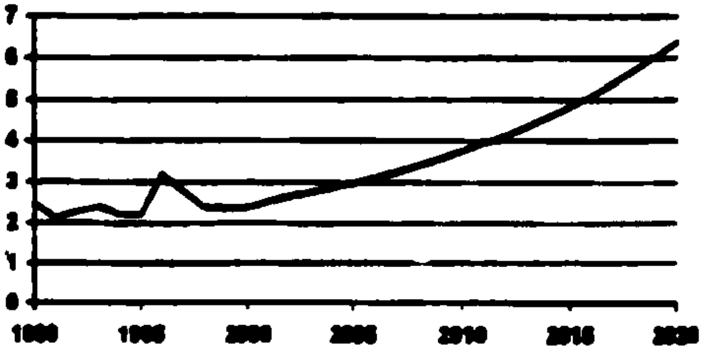
- Natural gas prices in early 1997 exceeded $4 per MMBtu compared to prices above $3 in 1996. However, prices weakened significantly in March and April before rebounding in May and June. Gas markets will remain very volatile until the new pipeline projects are completed. Natural gas prices have again reached the $3 level in late September 1997. This is evidence of the volatility that has prevailed in markets over the past two years. The current forecast is based upon normal weather, which in combination with adequate storage and a normal output from nuclear stations, presages moderate prices over this winter. Either abnormal weather or severe nuclear outages could trigger substantially higher prices this winter.

- Natural gas supply increases are expected to be at least adequate and possibly excessive by 2000. First, reserve additions have exceeded production in each of the past two years in the United States. Also, by 2000, pipeline capacity additions of 5 to 10 Bcf/day from Canada, the Rocky Mountains and the deep Gulf of Mexico have the potential to create a "gas bubble" even though gas demand is projected to grow by up to 7 Bcf/day. Thus natural gas prices are expected to weaken as new supply sources are added to the U.S. market.

- Swift demand growth will absorb the new supplies and gas markets will return to a better balance after 2000. For 1997, demand growth was absent in the first half but is expected to increase significantly for the second half to average 2% for the year. DRI expects demand growth for 1997 to 2000 to average about 1.9 Bcf/day per year.

- The price of natural gas to electric generators in the South Atlantic region was $3.18 per MMBtu in 1996. This was the highest average price of all regions, and 10% above the national average. Over the forecast period, increased fuel competition and pipeline capacity expansions will allow the gap with other regions to narrow considerably, especially with other regions in the East. For much of the forecast period, the average price of natural gas to utilities in the South Atlantic region will be about 7% above the national average, and this will fall to just 4% by 2020.

Natural Gas Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Coal

- Expirations of many above market long-term coal contracts set in the late 1970s and 1980s have forced down the cost of delivered coal to utilities. As these contracts expire and are replaced by agreements that track the spot market price, the average delivered price will continue to decline.

- Deregulation and consolidation of the railroad industry have dramatically reduced transportation costs. Many onlookers in the nascent power-marketing industry are expecting the same type of improvements on the mining side of the coal supply business, as consolidation and realignment continues there as well. However, that amount of flexibility in the production process has yet to be seen.

- As utility fuel purchasers increase their spot purchases or supplies from fuel marketers, price volatility will increase, spurring more robust risk-mitigating strategies.

- Under the competing goals to lower costs and mitigate price risk in a volatile marketplace, utility fuel purchasers are increasingly relying upon a flexible purchasing approach. This includes using various types of coal (either low-sulfur or high-sulfur) with bundled emission allowances; increasing spot purchases in conjunction with shorter term contracts containing price adjustment clauses; and purchasing coal through multiple delivery routes as rail systems increasingly become integrated and reliable.

- As eastern utilities switching from high-sulfur Northern Appalachian and Ohio basin coal move to lower-sulfur coal, Central Appalachian low-sulfur coal will experience continued strong demand, suppressing movements towards dramatic price declines.

- Coastal power plants and those with easy rail access to port facilities are the plants best able to use the international coal market as an optimal supply source for low-sulfur coal that meets emission limits. As rail transportation systems become more centralized and reliable, the import of coal farther inland will become feasible.

Coal Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)

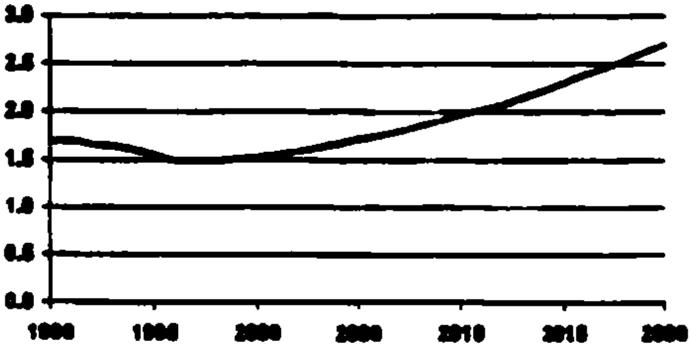


Table A-1

Short-Term Forecast of
Distillate Fuel Prices
New York Harbor Spot Cargoes and
Tampa, Florida Posted Prices
(Cents per Gallon)

Month	New York	Tampa
1996	56.0	65.3
Jan	60.2	58.7
Feb	62.2	61.5
Mar	63.2	64.1
Apr	58.2	61.8
May	51.2	59.1
Jun	56.3	58.8
Jul	60.0	61.7
Aug	67.3	68.9
Sep	72.0	74.0
Oct	68.7	71.5
Nov	72.8	71.7
Dec	68.8	70.5
1997		
Jan	68.8	70.5
Feb	60.8	64.7
Mar	54.6	57.8
Apr	55.8	57.3
May	55.6	58.8
Jun	51.9	54.6
Jul	52.7	54.9
Aug	53.6	56.5
Sep	52.3	54.9
Forecast		
Oct	53.6	55.8
Nov	55.8	57.1
Dec	56.6	58.3
1998		
Jan	56.6	55.8
Feb	54.4	54.6
Mar	54.2	56.1
Apr	52.8	53.9
May	52.0	55.4
Jun	50.7	54.4
Jul	51.5	52.9
Aug	53.2	54.6
Sep	53.6	55.8
Oct	56.4	57.4
Nov	56.7	58.0
Dec	58.0	57.7

Table A-2

Long-Term Forecast of
Distillate Fuel Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

Year	South Atlantic
1983	4.22
1984	4.60
1985	3.98
1986	4.84
Forecast	
1987	4.62
1988	4.56
1989	4.55
2000	4.88
2001	4.93
2002	5.16
2003	5.42
2004	5.80
2005	6.01
2006	6.22
2007	6.64
2008	7.00
2009	7.37
2010	7.76
2011	8.18
2012	8.63
2013	9.10
2014	9.61
2015	10.14
2016	10.71
2017	11.32
2018	11.96
2019	12.64
2020	13.37

Table B-1

Short-Term Forecast of Natural Gas Prices Henry Hub and Gulf Coast Spot (Dollars per MMBtu)

Month	Henry Hub	Gulf Coast
1996		
Jan	3.42	3.25
Feb	2.40	2.33
Mar	2.94	2.81
Apr	2.70	2.68
May	2.21	2.15
Jun	2.38	2.28
Jul	2.68	2.57
Aug	2.30	2.22
Sep	1.83	1.72
Oct*	1.86	1.75
Nov	2.78	2.63
Dec	3.90	3.73
1997		
Jan	4.00	3.84
Feb	2.95	2.79
Mar	1.78	1.68
Apr	1.86	1.77
May	2.16	2.04
Jun	2.31	2.24
Jul	2.16	2.07
Aug	2.18	2.11
Sep	2.55	2.46
Forecast		
Oct	3.20	3.13
Nov	2.80	2.71
Dec	3.14	3.02
1998		
Jan	3.21	3.08
Feb	2.41	2.30
Mar	2.11	2.01
Apr	2.13	2.04
May	2.07	2.00
Jun	2.19	2.11
Jul	2.14	2.07
Aug	2.03	1.96
Sep	2.05	1.96
Oct	2.21	2.13
Nov	2.24	2.15
Dec	2.62	2.50

Table B-2

**Long-Term Forecast of
Gulf Coast and Henry Hub
Spot Natural Gas Prices
Delivered To Pipeline
(Dollars per MMBtu)**

Year	Henry Hub	Gulf Coast
1993	2.11	2.06
1994	1.89	1.83
1995	1.64	1.57
1996	2.81	2.80
	Forecast	
1997	2.60	2.49
1998	2.28	2.19
1999	2.20	2.11
2000	2.12	2.03
2001	2.14	2.08
2002	2.28	2.19
2003	2.38	2.27
2004	2.42	2.34
2005	2.51	2.43
2006	2.61	2.53
2007	2.71	2.63
2008	2.85	2.77
2009	2.97	2.88
2010	3.15	3.07
2011	3.32	3.24
2012	3.48	3.41
2013	3.66	3.58
2014	3.88	3.80
2015	4.07	3.99
2016	4.30	4.22
2017	4.57	4.48
2018	4.78	4.70
2019	5.08	5.00
2020	5.40	5.31

Table B-3

Long-Term Forecast of
Natural Gas Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

Year	South Atlantic
1993	2.42
1994	2.30
1995	2.22
1996	3.18
Forecast	
1997	2.78
1998	2.39
1999	2.38
2000	2.40
2001	2.54
2002	2.67
2003	2.77
2004	2.87
2005	2.98
2006	3.11
2007	3.26
2008	3.41
2009	3.58
2010	3.78
2011	3.96
2012	4.13
2013	4.36
2014	4.57
2015	4.83
2016	5.11
2017	5.40
2018	5.71
2019	6.04
2020	6.38

Table C-1

Long-Term Forecast of
Coal Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

Year	South Atlantic
1993	1.64
1994	1.60
1995	1.55
1996	1.40
Forecast	
1997	1.50
1998	1.50
1999	1.51
2000	1.53
2001	1.56
2002	1.60
2003	1.64
2004	1.69
2005	1.72
2006	1.76
2007	1.81
2008	1.86
2009	1.91
2010	1.97
2011	2.03
2012	2.08
2013	2.15
2014	2.22
2015	2.30
2016	2.38
2017	2.46
2018	2.53
2019	2.62
2020	2.70

Appendix 1A.9.1

Analysis of Utility Fuel Prices in the South Atlantic Region

Analysis of Utility Fuel Prices in the South Atlantic Region

Prepared for: Kissimmee Utility Authority

Table of Contents

Note: The short-term distillate and natural gas price forecasts were prepared at the end of September 1997. The long-term forecasts represent DRI's latest long-term fuel price analysis, which was prepared in April 1997. For the natural gas concepts that appear in both the short and long-term forecasts (Henry Hub and Gulf Coast), the long-term forecasts have been updated with the latest short-term analysis through 1999. The other forecasts are not directly comparable between the short and long term since they do not represent the same concept (e.g., distillate spot prices compare with delivered price to utilities) and they were not prepared contemporaneously. The long-term forecasts of prices to South Atlantic utilities are all directly comparable.

Forecast Highlights

Distillate

- Distillate fuel prices rose sharply at the end of 1996, but have since declined significantly in 1997. The key factors causing the 1996 price run-up, including uncertainty over Iraqi oil exports and very short inventories, are gone, and distillate prices have largely followed the downward trend in crude prices since the beginning of the year. The price of distillate (New York Harbor spot cargoes) has declined from a high of 72.0 cents per gallon in November 1996 to 52.3 cents in September, over a 27% drop.

- In the short term, prices will rise moderately, supported by both slightly firming crude prices and seasonal demand. Current distillate inventories are above historically average levels and about 20% above the low levels of last year at this time, so the acute stock shortages of last year and the resulting strong prices should not be repeated this heating season. The price of distillate (New York Harbor spot cargoes) will rise to 56.6 cents per gallon by this December, 8% above September's level but 19% below last December's level.

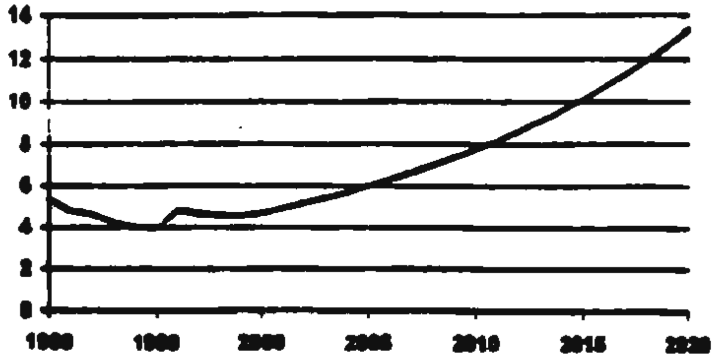
- In the long-term, distillate prices are determined primarily by the price of crude oil. DRI's forecast is that real crude prices will decline moderately through 2000. Strong non-OPEC production, weak OECD demand, and the eventual full reintroduction of Iraqi crude will allow average real crude prices to decline to about $17.00 per barrel in 2000. Real distillate prices will also decline over the same period, with nominal prices remaining essentially flat. The price of distillate fuel oil to utilities in the South Atlantic region will fall slightly from $4.84 per MMBtu (83.1 cents per gallon) in 1996 to $4.69 per MMBtu (80.5 cents per gallon) in 2000.

- After 2000, world oil prices will increase moderately in real terms. As production from mature non-OPEC regions wanes, non-OPEC exploration and production costs will increase and OPEC's market share will gradually grow. Real crude prices will increase at about 1.0% per year through 2020, to just over $25.00 per barrel. Distillate prices will also follow this trend, reaching $13.37 per MMBtu ($2.30 per gallon) in nominal terms for utilities in the South Atlantic region by 2020.

- In 1996, total distillate fuel demand was 3.4 million barrels per day (b/d). This represented 18.6% of total petroleum consumption, and distillate fuel is second only to gasoline in petroleum product demand. The transportation sector is the dominant consumer of distillate fuel, with diesel fuel and marine and rail distillate accounting for 63.3% of total distillate fuel demand. The balance is consumed by the industrial, residential, commercial, and electric utility sectors, with utilities consuming just 44,000 b/d (1.3% of the total).

- Over the forecast period, total distillate fuel demand will grow by 1.0% per year, reaching 4.3 million b/d by 2020. The transportation sector will remain the dominant consumer of distillate fuel and will realize the greatest volume increase in total distillate demand. For the stationary sectors, competition from natural gas will play a key role in shifting demand. Distillate demand in the residential and commercial sectors will decline, industrial consumption will increase slightly, and demand from electric power generators will increase strongly, although the total volume will remain small (340,000 b/d). The growth in demand for distillate fuel by electricity generators (including industrial cogenerators) is due in large part to its use as a back-up fuel for gas-fired units.

Distillate Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Natural Gas

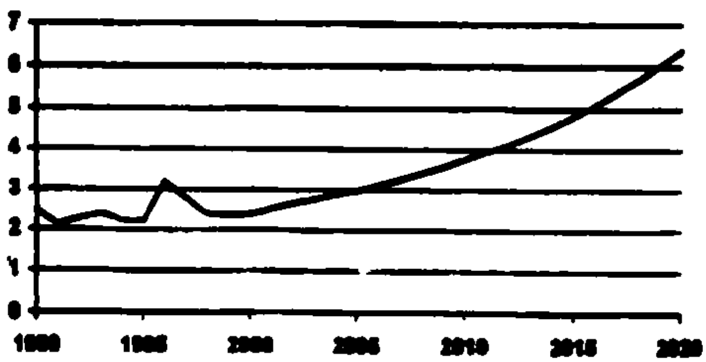
- Natural gas prices in early 1997 exceeded $4 per MMBtu compared to prices above $3 in 1996. However, prices weakened significantly in March and April before rebounding in May and June. Gas markets will remain very volatile until the new pipeline projects are completed. Natural gas prices have again reached the $3 level in late September 1997. This is evidence of the volatility that has prevailed in markets over the past two years. The current forecast is based upon normal weather, which in combination with adequate storage and a normal output from nuclear stations, presages moderate prices over this winter. Either abnormal weather or severe nuclear outages could trigger substantially higher prices this winter.

- Natural gas supply increases are expected to be at least adequate and possibly excessive by 2000. First, reserve additions have exceeded production in each of the past two years in the United States. Also, by 2000, pipeline capacity additions of 5 to 10 Bcf/day from Canada, the Rocky Mountains and the deep Gulf of Mexico have the potential to create a "gas bubble" even though gas demand is projected to grow by up to 7 Bcf/day. Thus natural gas prices are expected to weaken as new supply sources are added to the U.S. market.

- Swift demand growth will absorb the new supplies and gas markets will return to a better balance after 2000. For 1997, demand growth was absent in the first half but is expected to increase significantly for the second half to average 2% for the year. DRI expects demand growth for 1997 to 2000 to average about 1.9 Bcf/day per year.

- The price of natural gas to electric generators in the South Atlantic region was $3.18 per MMBtu in 1996. This was the highest average price of all regions, and 16% above the national average. Over the forecast period, increased fuel competition and pipeline capacity expansions will allow the gap with other regions to narrow considerably, especially with other regions in the East. For much of the forecast period, the average price of natural gas to utilities in the South Atlantic region will be about 7% above the national average, and this will fall to just 4% by 2020.

Natural Gas Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)



Coal

- Expirations of many above market long-term coal contracts set in the late 1970s and 1980s have forced down the cost of delivered coal to utilities. As these contracts expire and are replaced by agreements that track the spot market price, the average delivered price will continue to decline.

- Deregulation and consolidation of the railroad industry have dramatically reduced transportation costs. Many onlookers in the nascent power-marketing industry are expecting the same type of improvements on the mining side of the coal supply business, as consolidation and realignment continues there as well. However, that amount of flexibility in the production process has yet to be seen.

- As utility fuel purchasers increase their spot purchases or supplies from fuel marketers, price volatility will increase, spurring more robust risk-mitigating strategies.

- Under the competing goals to lower costs and mitigate price risk in a volatile marketplace, utility fuel purchasers are increasingly relying upon a flexible purchasing approach. This includes using various types of coal (either low-sulfur or high-sulfur) with bundled emission allowances; increasing spot purchases in conjunction with shorter term contracts containing price adjustment clauses; and purchasing coal through multiple delivery routes as rail systems increasingly become integrated and reliable.

- As eastern utilities switching from high-sulfur Northern Appalachian and Ohio basin coal move to lower-sulfur coal, Central Appalachian low-sulfur coal will experience continued strong demand, suppressing movements towards dramatic price declines.

- Coastal power plants and those with easy rail access to port facilities are the plants best able to use the international coal market as an optional supply source for low-sulfur coal that meets emission limits. As rail transportation systems become more centralized and reliable, the impact of coal farther inland will become feasible.

Coal Prices
Electric Power Industry - South Atlantic Region
(Dollars per MMBtu)

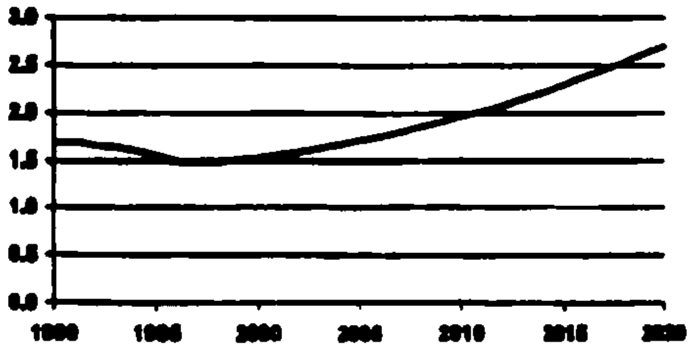


Table A-1

Short-Term Forecast of Distillate Fuel Prices New York Harbor Spot Cargoes and Tampa, Florida Posted Prices (Cents per Gallon)

Month	New York	Tampa
1996	55.0	56.3
Jan	60.2	60.7
Feb	62.2	61.5
Mar	63.2	64.1
Apr	65.2	61.8
May	51.2	59.1
Jun	55.3	56.8
Jul	60.0	61.7
Aug	67.3	68.9
Sep	72.0	74.0
Oct	69.7	71.6
Nov	72.8	71.7
Dec	69.8	70.5
1997		
Jan	68.8	70.5
Feb	60.8	64.7
Mar	54.6	57.6
Apr	56.6	57.3
May	55.5	56.8
Jun	51.9	54.6
Jul	52.7	54.9
Aug	53.6	56.8
Sep	52.3	54.8
Forecast		
Oct	53.9	55.8
Nov	55.8	57.1
Dec	56.6	58.3
1998		
Jan	55.6	58.8
Feb	54.4	54.9
Mar	54.2	56.1
Apr	52.8	53.9
May	52.0	55.4
Jun	50.7	54.4
Jul	51.6	52.9
Aug	53.2	54.8
Sep	53.8	56.8
Oct	56.4	57.4
Nov	56.7	58.0
Dec	58.0	57.7

Table A-5

Long-Term Forecast of
Distillate Fuel Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

Year	South Atlantic
1993	4.22
1994	4.00
1995	3.96
1996	4.84
Forecast	
1997	4.82
1998	4.56
1999	4.55
2000	4.69
2001	4.93
2002	5.10
2003	5.42
2004	5.66
2005	6.01
2006	6.32
2007	6.64
2008	7.00
2009	7.37
2010	7.78
2011	8.16
2012	8.63
2013	9.10
2014	9.61
2015	10.14
2016	10.71
2017	11.32
2018	11.96
2019	12.64
2020	13.37

Table B-1

Short-Term Forecast of
Natural Gas Prices
Henry Hub and Gulf Coast Spot
(Dollars per MMBtu)

Month	Henry Hub	Gulf Coast
1996		
Jan	3.42	3.25
Feb	2.40	2.33
Mar	2.94	2.81
Apr	2.70	2.58
May	2.21	2.15
Jun	2.38	2.28
Jul	2.66	2.57
Aug	2.30	2.22
Sep	1.83	1.72
Oct	1.85	1.75
Nov	2.76	2.63
Dec	3.90	3.73
1997		
Jan	4.00	3.84
Feb	2.96	2.79
Mar	1.78	1.69
Apr	1.86	1.77
May	2.15	2.04
Jun	2.31	2.24
Jul	2.18	2.07
Aug	2.18	2.11
Sep	2.56	2.48
	Forecast	
Oct	3.20	3.13
Nov	2.80	2.71
Dec	3.14	3.02
1998		
Jan	3.21	3.08
Feb	2.41	2.30
Mar	2.11	2.01
Apr	2.13	2.04
May	2.07	2.00
Jun	2.19	2.11
Jul	2.14	2.07
Aug	2.03	1.96
Sep	2.05	1.98
Oct	2.21	2.13
Nov	2.24	2.16
Dec	2.62	2.50

Table B-2

**Long-Term Forecast of
Gulf Coast and Henry Hub
Spot Natural Gas Prices
Delivered To Pipeline
(Dollars per MMBtu)**

Year	Henry Hub	Gulf Coast
1993	2.11	2.05
1994	1.89	1.83
1995	1.84	1.67
1996	2.81	2.80
	Forecast	
1997	2.60	2.48
1998	2.28	2.19
1999	2.20	2.11
2000	2.12	2.03
2001	2.14	2.09
2002	2.29	2.19
2003	2.38	2.27
2004	2.42	2.34
2005	2.51	2.43
2006	2.61	2.53
2007	2.71	2.63
2008	2.86	2.77
2009	2.97	2.90
2010	3.15	3.07
2011	3.32	3.24
2012	3.48	3.41
2013	3.68	3.59
2014	3.86	3.80
2015	4.07	3.99
2016	4.30	4.22
2017	4.57	4.48
2018	4.79	4.70
2019	5.08	5.00
2020	5.40	5.21

Table B-3

Long-Term Forecast of
Natural Gas Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)

Year	South Atlantic
1993	2.42
1994	2.20
1995	2.22
1996	3.18
Forecast	
1997	2.78
1998	2.38
1999	2.38
2000	2.40
2001	2.54
2002	2.67
2003	2.77
2004	2.87
2005	2.98
2006	3.11
2007	3.26
2008	3.41
2009	3.58
2010	3.78
2011	3.96
2012	4.13
2013	4.36
2014	4.57
2015	4.83
2016	5.11
2017	5.40
2018	5.71
2019	6.04
2020	6.38

Table C-1

**Long-Term Forecast of
Coal Prices
Electric Power Industry
South Atlantic Region
(Dollars per MMBtu)**

Year	South Atlantic
1983	1.84
1984	1.80
1985	1.65
1986	1.49
Forecast	
1987	1.49
1988	1.50
1989	1.51
2000	1.53
2001	1.56
2002	1.60
2003	1.64
2004	1.68
2005	1.72
2006	1.76
2007	1.81
2008	1.86
2009	1.91
2010	1.97
2011	2.03
2012	2.09
2013	2.15
2014	2.22
2015	2.30
2016	2.38
2017	2.46
2018	2.53
2019	2.62
2020	2.70