Florida Electrical Power Plant Siting Act
Need for Power Application

Greenland Energy Center
Combined Cycle Conversion Project

JEA®

Building Community®

September 2008

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Abbreviations and Acronyms

ac	Alternating Current
ACH	Air Changes per Hour
ACI	Activated Carbon Injection
AEO2008	Annual Energy Outlook 2008
ALA	American Lung Association
ASD	Adjustable Speed Drive
B&V	Black & Veatch
Bcf	Billion Cubic Feet
BGEM	BG Energy Merchants
BGLS	BG LNG Services
BIG	Biomass Investment Group
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCS	Carbon Capture and Sequestrations
CEMS	Continuous Emissions Monitoring System
CDD	Cooling Degree Day
CFB	Circulating Fluidized Bed
CFL	Compact Fluorescent Lamp
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COG	Cogenerator
CO_2	Carbon Dioxide
CO_3	Carbonate
Constellation	Constellation Energy Commodities Group, Inc.
COP	Coefficient of Performance
COS	Carbonyl Sulfide
CPP	Critical Peak Pricing
CPWC	Cumulative Present Worth Costs
CTG	Combustion Turbine Generator
d	Day
dc	Direct Current
DCIS	Distributed Control and Information System
DEIS	Draft Environmental Impact Statement

DEP	Department of Environmental Protection
DLC	Direct Load Control
DLN	Dry Low NO_x
DR	Demand Response
DSM	Demand-Side Management
DWP	Deep Water Port
DWPA	Deep Water Port Application
EIA	Energy Information Administration
EPC	Engineering, Procurement, and Construction
EMS	Energy Management Systems
FAC	Florida Administration Code
FCR	Fixed Charge Rate
FDEP	Florida Department of Environmental Protection
FGD	Fuel Gas Desulfurization
FGS	Floridian Natural Gas Storage Company, LLC
FGT	Florida Gas Transmission Company
FMPA	Florida Municipal Power Agency
FNGA	Florida Natural Gas Association
FPL	Florida Power & Light Company
FPSC	Florida Public Service Commission
FPUC	Florida Public Utilities Company
FRCC	Florida Regional Reliability Council
FRSG	Florida Reserve Sharing Group
GE	General Electric
GEC	Greenland Energy Center
GHG	Greenhouse Gas
GSLD	General Service Large Demand
Gulfstream	Gulfstream Natural Gas System
GWh	Gigawatt-Hour
HDD	Heating Degree Day
HERS	Home Energy Rating Systems
HDMC	High-Deliverability, Multi-Cycle
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure

HPC	High-Pressure Compressor
HPT	High-Pressure Turbine
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilating, and Air Conditioning
IAS	Integral Aqua Systems
IDC	Interest During Construction
IP	Intermediate-Pressure
ITS	Integrated Transmission System
kV	Kilovolts
kW	Kilowatts
LED	Light Emitting Diode
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LP	Low-Pressure
LPC	Low-Pressure Compressor
LPT	Low-Pressure Turbine
MARAD	Maritime Administration
MBtu	Million British Thermal Units
MBtu/d	Million British Thermal Units per Day
Mcf	Million Cubic Feet
mcf	Thousand Cubic Feet
MEAG	Municipal Electric Authority of Georgia
mgd	Million Gallons per Day
Mmt	Million Metric Ton
msl	Mean Sea Level
MVA	Megavolt-Ampere
MW	Megawatts
NEFBA	Northeast Florida Builders Association
NEL	Net Energy for Load
NEMA	National Electrical Manufacturers Association
NERC	North American Electric Reliability Corporation
NEMS	National Energy Modeling System
NGA	Natural Gas Act
NO_x	Oxides of Nitrogen
NPPD	Nebraska Public Power District

NRLM	Nonroad, Locomotive, and Marine
O&M	Operations and Maintenance
O_2	Oxygen
Petcoke	Petroleum Coke
PGS	Peoples Gas System
PPA	Power Purchase Agreement
ppm	Parts Per Million
ppmvd	Parts Per Million Volumetric Dry
PPSA	Florida Electrical Power Plant Siting Act
PRB	Powder River Basin
PSC	Public Service Commission
PSD	Prevention of Significant Deterioration
psig	Pounds per Square Inch Gauge
PV	Photovoltaic
QF	Qualifying Facility
REC	Renewable Energy Credit
RFP	Request for Proposal
RIM	Ratepayer Impact
rpm	Revolutions per Minute
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SeaCoast	SeaCoast Gas Transmission, LLC
SESH	Southeast Supply Header, LLC
Sierra Club	Sierra Club of Northeast Florida
SJRPP	St. Johns River Power Park
SJWMD	St. Johns Water Management District
SNG	Southern Natural Gas
SO_2	Sulfur Dioxide
SPP	Small Power Producer
SRV	Shuttle and Regasification Vessel
STG	Steam Turbine Generator
Summitt Blue	Summitt Blue Consulting, LLC
SWG	Stability Working Group
Tcf	Trillion Cubic Feet
T&D	Transmission and Distribution

TEA	The Energy Authority
TECO	TECO Energy, Inc.
TRC	Total Resource Cost
TWG	Transmission Working Group
ULSD	Ultra-Low Sulfur Diesel
UNF	University of North Florida
UPS	Unit Power Sales
VFD	Variable Frequency Drive

1.0 Executive Summary

JEA submits this Need for Power Application in support of a proposed conversion of two natural gas fired simple cycle combustion turbines to a 2x1 combined cycle configuration at the Greenland Energy Center (GEC) generating station in Duval County, Florida. The analyses summarized below and discussed throughout this Application demonstrate that the combined cycle conversion is needed to meet the growing electrical demands of JEA's customers in the most cost-effective manner.

1.1 The Applicant

JEA's electric service area covers all of Duval County and portions of Clay and St. Johns counties, serving a total of approximately 400,000 customers. JEA owns and operates three generating plants and all transmission and distribution facilities. A fourth power plant, the St. Johns River Power Park (SJRPP), is owned jointly by JEA and the Florida Power & Light Company (FPL); it is operated by JEA. JEA and FPL are also joint owners of Unit 4 at Georgia Power Company's coal fired Robert W. Scherer Plant (Plant Scherer), which is located in Macon, Georgia. In addition, JEA produces 1.2 megawatts (MW) using landfill gas produced by the Girvin Road Landfill. JEA's total available summer net capacity is 3,370 MW, and its total available winter net capacity is 3,620 MW.

1.2 The Proposed GEC Combined Cycle Conversion

The proposed GEC combined cycle conversion will result in a high-efficiency, natural gas fueled combined cycle unit, consisting of two combustion turbines and two heat recovery steam generators (HRSGs) that will drive a steam turbine generator. The new unit will have a net output rating of 522 MW at average ambient temperature conditions. All of the generation capacity from the unit will be committed for sale to JEA's customers. The proposed GEC combined cycle conversion is needed to meet energy and capacity needs of JEA's customers.

1.3 The Power Plant Siting Act Process

The Florida Electrical Power Plant Siting Act (PPSA), Chapter 403, Part II, Florida Statutes, provides a "centrally coordinated, one-stop licensing process" for power plant projects. The PPSA provides a centralized process to ensure that all affected state and local agencies review a project before the Siting Board, consisting of the Governor and Cabinet, takes final action on the site certification application. The Florida Public

Service Commission's (FPSC) need determination is a critical step in the PPSA certification process. Along with the reports submitted by the Florida Department of Environmental Protection (DEP) and other agencies, the Commission's need determination allows the Siting Board to balance "the increasing demand for electrical power plants with the broad interests of the public."

1.4 The Commission's Need Determination

Section 403.519(3), Florida Statutes, sets forth the following criteria that the Commission must consider in making need determinations:

- The need for electric system reliability and integrity.
- The need for adequate electricity at a reasonable cost.
- The need for fuel diversity and supply reliability.
- Whether the proposed plant is the most cost-effective alternative available.
- Whether renewable energy sources and technologies, as well as conservation measures, are utilized to the extent reasonably available.
- Whether there are conservation measures taken by, or reasonably available to, the applicant or its members that might mitigate the need for the proposed plant.

The Legislature did not assign the weight this Commission is to give each of these factors. Rule 25-22.081, Florida Administrative Code, sets forth specific information that each Need for Power Application must include to allow the Commission to address the statutory factors. The required information is summarized below and discussed in detail throughout this Application.

1.5 The Need for the GEC Combined Cycle Conversion

JEA's capacity needs are projected to continuously increase. As discussed in Section 12.0 of this Need for Power Application, by the summer of 2012, JEA's reserve margin decreases to 9.6 percent, or 167 MW below the capacity required to continue to reliably serve JEA's customers and maintain a 15 percent reserve margin. By the summer of 2013, the need for additional capacity to maintain a 15 percent reserve margin will increase to 242 MW. The need for additional capacity reflects the impact of interruptible and curtailable loads. A number of JEA's capacity and power purchase contracts are expiring, or nearing the end of their lifetime. By providing capacity necessary to meet JEA's growing needs, the GEC combined cycle conversion will contribute to the reliability and integrity of JEA's electric system.

1.6 Analysis of Generating (Supply-Side) Alternatives

As discussed in Section 13.0 of this Application, JEA has evaluated several supply-side technologies, either as alternatives to the GEC combined cycle conversion or as capacity resource options for installation following the proposed combined cycle conversion. As part of that analysis, JEA evaluated renewable technologies, conventional technologies, and emerging technologies. Based on the results of production cost modeling of multiple economic scenarios, JEA identified the GEC combined cycle conversion as the most cost-effective alternative to meet the need for additional capacity.

Although not subject to the Commission's "Bid Rule," JEA has issued numerous requests for proposals (RFP). The evaluations of the RFP responses indicated that none of the responses would be a cost-effective alternative to the GEC combined cycle conversion. As a result of these RFPs and other initiatives, JEA is evaluating renewable projects that may eventually be integrated into JEA's generating system.

1.7 Analysis of Non-Generating (Demand-Side) Alternatives

JEA's 2005 Demand-Side Management (DSM) plan was approved by the FPSC on September 1, 2004. Upon reviewing the plan, the FPSC determined that there were no cost-effective conservation measures available for use by JEA, so the FPSC established and approved zero DSM and conservation goals for JEA's residential and commercial/industrial sectors through 2014 (Docket No. 040030-EG). Nevertheless, JEA has voluntarily continued its historical programs, because it had determined that these programs were in the overall best interest of its customers.

Furthermore, in June 2006, JEA contracted with Summit Blue Consulting, LLC (Summit Blue), an independent firm that specializes in DSM program evaluation and development, to identify potential DSM programs for JEA. As part of this effort, Summit Blue and JEA developed an aggressive DSM portfolio that has been approved and funded by JEA's Board. Even with the energy and demand savings projected for the new DSM portfolio, however, the Greenland Energy Center combined cycle conversion is still needed to meet JEA's capacity requirements.

1.8 Integrated Fuel and CO_2 Emissions Allowance Cost Projections

Although no carbon dioxide (CO_2) regulatory programs have been adopted, in light of continuing discussion of potential CO_2 regulation, this Application presents additional economic analyses that incorporate a range of CO_2 emissions allowance cost estimates, and associated fuel forecasts, developed by the U.S. Department of Energy's Energy Information Agency (EIA). These analyses demonstrate that the GEC combined cycle conversion is JEA's most cost-effective alternative, even assuming a carbon-regulated environment and a range of costs associated with CO_2 emissions allowances.

Fuel and emissions allowance costs are interrelated. Therefore, fuel and CO_2 emissions allowance cost projections included in this Application are fully integrated. That is, the EIA price projections consider fuel supply and demand in tandem with potential CO_2 emissions allowance costs, along with numerous other market influences, to develop fully integrated fuel and CO_2 emissions allowance cost projections.

1.9 Most Cost-Effective Alternative

After extensive economic comparisons to other generating unit and nongeneration alternatives, the GEC combined cycle conversion was determined to be the most cost-effective alternative to meet JEA's needs. Under the reference case, the expansion plan with the GEC is approximately $122.6 million lower in cumulative present worth costs (CPWC) than the plan without the GEC combined cycle conversion.

1.10 Adverse Consequences If the GEC is Not Built

Delaying the conversion of GEC would result in reduced reliability and higher costs to JEA's customers. If the proposed combined cycle conversion is delayed, JEA's summer reserve margin will fall to 9.6 percent in 2012, which is 167 MW below JEA's 15 percent reserve margin criterion. The impact of delaying the conversion of GEC to combined cycle configuration by 1 year (to 2013) and instead installing alternative capacity to maintain reserve margin requirements in the summer of 2012 would be an increase in CPWC of approximately $36.7 million.

The capacity deficit in the summer of 2012 represents a significant portion of the capacity that will be provided by the conversion of GEC to combined cycle. With a reserve margin below 15 percent in 2012, JEA's system will be exposed to decreased reliability and increased costs if the GEC combined cycle conversion is delayed and no additional generating capacity is installed in its place.

1.11 Conclusion

The proposed GEC combined cycle conversion will ensure that JEA has an adequate supply of power to serve its customers' needs at a reasonable cost. The detailed economic analyses presented in this Need for Power Application demonstrate that the GEC combined cycle conversion is the most cost-effective alternative to meet JEA's power supply needs. The addition of cost-effective natural gas generation will further diversify JEA's fuel mix. The project will also enhance fuel diversity and supply reliability by utilizing multiple natural gas supply options. JEA already utilizes reasonably available DSM programs and renewable resources. Even with potential demand and energy reductions that could be achieved from additional conservation and renewable energy initiatives, the GEC combined cycle conversion is the least-cost alternative to reliably meet JEA's power supply needs.

2.0 Introduction

This Application demonstrates the need for the GEC combined cycle conversion under Section 403.519 Florida Statutes. The GEC facility will consist of two simple cycle 7FA combustion turbine units that are currently under development for commercial operation in 2010 and are proposed to be converted to a 2x1 combined cycle configuration by June 2012.

Section 3.0 provides a description of JEA and its existing facilities. This general overview of the system includes JEA's generating plants and electric bulk systems, existing purchase power agreements (PPAs), JEA's involvement with The Energy Authority (TEA), existing power sales agreements, unit retirements anticipated during the planning horizon, operating and spinning reserve requirements, JEA's Clean Power Program, and JEA's transmission system.

Section 4.0 provides the economic parameters and assumptions used throughout the Application.

Section 5.0 presents the JEA load forecast, which indicates the continued load growth that necessitates the GEC combined cycle conversion.

Section 6.0 demonstrates the availability of natural gas to provide a reliable fuel supply for the GEC, thus maintaining the integrity and reliability of JEA's system.

Section 7.0 presents the fuel price projections used in the economic evaluations. The fuel price projections are based on the US Department of Energy's Energy Information Administration's Annual Energy Outlook 2008 (AEO2008) projections and also include projections of CO_2 emissions allowance prices.

Section 8.0 discusses the available natural gas transportation system to serve the GEC and demonstrates that the natural gas transportation system will provide reliable delivery of natural gas to the GEC site.

Section 9.0 describes the GEC combined cycle conversion and provides the capital cost estimate, operating cost estimates, and estimated performance parameters for the combined cycle. Section 9.0 demonstrates that the GEC combined cycle will be designed and constructed so that it will operate reliably and efficiently and maintain the integrity of JEA's system.

Section 10.0 describes the evaluations conducted to demonstrate that interconnection of the GEC combined cycle conversion will not have an adverse impact on the transmission system. The Florida Regional Reliability Council (FRCC) has approved the interconnection of GEC combined cycle to the transmission system.

Section 11.0 discusses the reliability criteria used by JEA.

Section 12.0 demonstrates JEA's need for additional capacity by applying the 15 percent reserve margin to JEA's load forecast and comparing the capacity requirements to JEA's existing generating resources.

Section 13.0 describes the conventional and emerging generating unit alternatives that were compared to the GEC combined cycle conversion and used in expansion plans to provide JEA's capacity needs beyond those supplied by the GEC combined cycle conversion.

Section 14.0 describes JEA's Request for Proposals (RFP) process to identify renewable (wind and solar) resources that may be available, and demonstrates that JEA is utilizing available renewable energy sources and technologies to the extent reasonably available.

Section 15.0 describes JEA's existing conservation and demand-side management (DSM) programs and discusses the expanded DSM portfolio being developed by JEA.

Section 16.0 describes the methodology used to evaluate the cost-effectiveness of the GEC combined cycle conversion.

Section 17.0 presents the results of the economic analyses conducted. These analyses demonstrate that the GEC combined cycle conversion is JEA's least-cost alternative under a wide range of scenarios. The GEC combined cycle conversion is JEA's least-cost alternative, even with the addition of renewables and conservation and DSM.

Section 18.0 presents the cost and reliability impacts of delaying the GEC combined cycle conversion.

Section 19.0 demonstrates that JEA can readily finance the addition of the GEC combined cycle conversion.

3.0 Description of Existing System

This section provides details related to JEA's existing generating facilities, PPAs, power sales, planned unit retirements, spinning and operating reserve requirements, JEA's clean power portfolio, and JEA's transmission system.

3.1 JEA Structure

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. The JEA electric service area covers all of Duval County and portions of Clay and St. Johns counties within Florida. JEA's service area covers approximately 900 square miles and serves more than 400,000 customers.

JEA's generation system consists of three financially separate components: the electric system, the bulk power system SJRPP Units 1 and 2, and the bulk power system Robert W. Scherer Electric Generating Plant (Scherer Unit 4). The total summer net capacity of the electric system, SJRPP, and Scherer Unit 4 is 3,370 MW, and the total available winter net capacity is 3,620 MW.

3.2 JEA Electric System

JEA solely owns and operates three generating plants: the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), and the Brandy Branch Generating Station (Brandy Branch). In addition, JEA owns and operates methane-fueled internal combustion engine generators located at the City of Jacksonville's Girvin Road Landfill (Girvin Road). SJRPP is owned jointly by JEA and FPL; it is operated by JEA. JEA and FPL are also joint owners of Unit 4 at Georgia Power Company's coal fired Robert W. Scherer Plant (Scherer), which is located in Macon, Georgia. JEA ownership interest in SJRPP and Scherer are structured as separate JEA bulk power supply systems. Details of the existing facilities are described in the following subsections and are summarized in Table 3-1.

In addition to the units presented in Table 3-1, JEA is planning to add two 7FA simple cycle combustion turbine units at the new Greenland Energy Center site in Jacksonville, Florida. These new combustion turbine units are expected to be in commercial operation by the summer of 2010 and are proposed to be converted to combined cycle in 2012.

Table 3-1
Existing Generating Facilities

Plant Name	Unit Number	Unit Type	Fuel Type Primary	Alt.	Fuel Transport Primary	Alt.	Commercial Service (Mo/Yr)	Gen Max Nameplate (kW)	Net MW Capacity Summer	Net MW Capacity Winter	Ownership
Kennedy											
	3	GT	FO2		WA	TK	7/1973	68,600	51	63	Sole
	7	GT	NG	FO2	PL	WA	6/2000	203,800	150	191	Sole
Northside											
	1	ST	PC	BIT	WA	RR	11/1966[1]	350,000	293	293	Sole
	2	ST	PC	BIT	WA	RR	3/1972[1]	350,000	293	293	Sole
	3	ST	NG	FO6	PL	WA	7/1977	563,700	524	524	Sole
	3-6	GT	FO2		WA	TK	1/1975	248,400	212	246	Sole
Brandy Branch											
	1	CT	NG	FO2	PL	TK	5/2001	203,800	150	191	Sole
	2	CT	NG	FO2	PL	TK	5/2001	203,800	150	191	Sole
	3	CT	NG	FO2	PL	TK	11/2001	203,800	150	191	Sole
	4	ST	NG	FO2	PL	TK	1/2005	268,400	201	223	Sole
Girvin Landfill	1-4	IC	LFG		PL		6/1997	1.2	1.2	1.2	Sole
St. Johns River Power Park											
	1	ST	BIT/PC		RR	WA	3/1987	679,600	501[2]	510[2]	Joint
	2	ST	BIT/PC		RR	WA	5/1988	679,600	501[2]	510[2]	Joint
Scherer	4	A	SUB	BIT	RR	RR	2/1989	846,000[4]	194[3]	194[3]	Joint
JEA System Total[4]									**3,370**	**3,620**	

[1]Northside steam Units 1 and 2 were repowered as CFBs and returned to service in May 2002 and February 2002, respectively.
[2]Net capacity reflects JEA's 80 percent ownership of Power Park. Nameplate is original nameplate of the unit.
[3]Nameplate and net capacity reflect JEA's 23.64 percent ownership in Scherer 4.
[4]Numbers may not add up due to rounding.

3.2.1 Kennedy Generating Station

The Kennedy Generating Station is located in JEA's urban load center and is interconnected to the 69 kV transmission system. Kennedy Generating Station consists of a simple cycle General Electric (GE) 7FA dual fuel (gas/oil) capable combustion turbine generator (CTG) unit (Kennedy CT 7) that was placed in commercial operation in June 2000, and one oil fueled CTG (Kennedy CT 3) that was placed in commercial operation in the summer of 1973. The total summer net capacity at the Kennedy Generating Station is 201 MW, and the total winter net capacity is 254 MW.

3.2.2 Northside Generating Station

The Northside Generating Station is located in JEA's north district load center, just north of the west-to-east portion of the St. Johns River. The total summer net capacity of Northside Generating Station is 1,322 MW, and the total winter net capacity is 1,355 MW. Northside Generating Station consists of two petroleum coke (petcoke) and coal fired circulating fluidized bed (CFB) steam turbine generator (STG) units (Northside steam Units 1 and 2), one dual fuel (gas/oil) STG unit (Northside steam Unit 3), and four oil fired CTG units (Northside CTs 3, 4, 5, and 6).

Northside steam Unit 1 was originally placed in service in November 1966 as an oil fired STG. The steam unit was repowered as a CFB and returned to service in May 2002, and has a net 293 MW capacity for summer and winter. Northside steam Unit 2 was originally placed in service in March 1972 as an oil fired STG. The steam unit was repowered as a CFB and returned to service in February 2002, and has a net 293 MW capacity for summer and winter. Limestone is blended with petcoke and coal for sulfur dioxide (SO_2) removal for Northside steam Units 1 and 2.

Northside steam Unit 3 was originally placed in service in July 1977 and has a net 524 MW capacity for summer and winter. Northside steam Unit 3 is a unit capable of burning residual oil (1.8 percent sulfur) and natural gas. Northside Unit 3 has received approximately 1,500 kilowatts (kW) of landfill gas on an as-available basis by pipeline from the closed City of Jacksonville North Landfill since 1999.

Northside CTs 3 through 6 were placed in service in late 1974 through early 1975, as distillate-fired CTGs. The total summer net capacity of these four CT units is 212 MW, and the total winter net capacity is 246 MW.

Northside steam Unit 1 and CTs 3 through 6 are interconnected to the 138 kV transmission system. Northside steam Unit 2 and steam Unit 3 are interconnected to the 230 kV transmission system.

3.2.3 Brandy Branch Generating Station

The Brandy Branch Generating Station is located in JEA's northwest district load center. Brandy Branch consists of three dual fuel (gas/oil) GE 7FA CTG units (Brandy Branch CT 1, 2, and 3) and one STG unit (Brandy Branch STG 4); CTs 1 and 2 were placed in commercial operation in May 2001, and CT 3 was placed in commercial operation in November 2001. Brandy Branch is interconnected with the 230 kV system.

Heat recovery steam generators (HRSGs) were added to Brandy Branch CTs 2 and 3 to provide heat input for Brandy Branch steam Unit 4, and the CTs and steam turbine currently operate in combined cycle configuration. The CTs can be operated with steam bypass to the condenser. An HRSG was installed on each CT exhaust, which recovers energy to produce the steam that powers the STG. The steam turbine, STG 4, has a summer net capacity of 201 MW, including supplemental duct firing capacity. STG 4's winter net capacity is 223 MW, which includes supplemental duct firing capacity. With supplemental duct firing, the overall combined cycle (CT 2, CT 3, and STG 4) operation has a net summer capability of 501 MW and a net winter capacity of 605 MW. The total summer net capacity of Brandy Branch Generating Station is 651 MW, and the total winter net capacity is 796 MW.

3.2.4 Girvin Road Landfill

JEA owns and operates three internal combustion engine generators located at the City of Jacksonville's Girvin Road Landfill. This facility was placed into service in July 1997 and is fueled by gas produced by the landfill. The facility originally had four generators. Since that time, gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility.

3.3 JEA Electric Bulk Systems

3.3.1 SJRPP

The SJRPP generating station is located in JEA's north district load center, adjacent to and northeast of the Northside Generating Station. SJRPP consists of two pulverized bituminous coal and petcoke fired steam electric generating units (SJRPP 1 and 2). SJRPP 1 began commercial operation in March 1987, and SJRPP 2 followed in May 1988. SJRPP is jointly owned by JEA and FPL, with JEA maintaining an 80 percent ownership interest in the facility. JEA is currently entitled to 50 percent (equal to 626 MW net summer and 637.5 MW net winter) of the facility capacity. JEA has sold its remaining 30 percent (equal to 376 MW net summer and 382.5 MW net winter) ownership interest of the facility capacity to FPL. Based on the terms and conditions of the sales agreement, the total amount of energy that FPL can take under the agreement is limited. For the purpose of modeling in this Application, the term of the FPL-SJRPP sale is assumed to end on March 31, 2016. After the terms of the energy sales agreement are satisfied, JEA will be entitled to its full 80 percent ownership share of SJRPP, representing a summer net capacity of 1,002 MW and a winter net capacity of 1,020 MW.

3.3.2 Scherer Plant

The Scherer Plant is located near Forsyth, Georgia. Scherer Unit 4, a pulverized coal fired steam electric generator, is jointly owned by JEA and FPL. JEA has a 23.6 percent ownership interest in Unit 4 (equal to 200 MW net) and proportionate ownership interests in associated common facilities and an associated coal stockpile. JEA purchased 150 MW of Scherer Unit 4 in July 1991 and purchased an additional 50 MW on June 1, 1995. The output of Scherer 4 is available to JEA via Georgia Power Company transmission services delivered to the Georgia/Florida transmission interface. JEA's joint ownership in the 500 kV transmission lines from the Duval Substation to the Georgia/Florida interface completes the transmission path into JEA's service territory. Scherer Unit 4 has a net summer and winter capacity of 846 MW.

3.4 JEA Purchased Power

3.4.1 Southern Company

JEA contracted with Southern Company for the purchase of 207 MW of coal fired capacity and energy from June 1995 through May 2010 (Southern Unit Power Sales [UPS] Purchase). These capacity obligations of Southern Company are firm, subject only to the availability of the units involved (Miller Units 1 through 4 and Scherer Unit 3). The capacity and energy are priced according to the specific cost of the units allocated to JEA. In addition, JEA occasionally purchases economy interchange power from Southern Company over and above the Southern UPS Purchase. JEA has exercised its rollover rights to retain the transmission rights for this capacity even after the expiration of the UPS Purchase.

3.4.2 Constellation Energy Commodities Group, Inc

JEA contracted with Constellation Energy Commodities Group, Inc. (Constellation) for peaking capacity of 75 MW, 150 MW, and 150 MW for the winter seasons 2008, 2009, and 2010, respectively. This system capacity is in Georgia and will be delivered to the Georgia/Florida interconnection. From this point of interconnection, JEA is responsible for delivery to its own territorial load.

3.4.3 Qualifying Facilities

JEA continues to encourage and evaluate opportunities for cogeneration. Cogeneration facilities reduce the demand on JEA's system and/or provide additional system capacity. JEA purchases power from four customer-owned qualifying facilities (QFs), as defined in the Public Utilities Regulatory Policy Act of 1978. These have a total installed summer peak capacity of 17 MW and a winter peak capacity of 19 MW. JEA purchases energy from these QFs on an as-available (non-firm) basis. Due to the non-firm nature of the purchases, these resources are not relied upon for capacity planning purposes.

Table 3-2 summarizes JEA's customers with QFs that are located within JEA's service territory.

Table 3-2
JEA Service Territory Qualifying Facilities

Cogenerator Name	Unit Type	In-Service Date	Net Capacity(1) – MW	
			Summer	Winter
Anheuser-Busch	COG(2)	April 1988	8	9
Baptist Hospital	COG	October 1982	7	8
Ring Power Landfill	SPP(3)	April 1992	1	1
St Vincent's Hospital	COG	December 1991	1	1
		Total	17	19

(1)Net generating capacity, not net generation sold to JEA.
(2)Cogenerator.
(3)Small Power Producer.

3.5 The Energy Authority

JEA is a member of The Energy Authority (TEA), which actively trades energy with a large number of counterparties throughout the United States. TEA is generally able to acquire capacity and energy from other market participants when any of its members, including JEA, require additional resources. TEA has reserved firm transmission rights across the Georgia Integrated Transmission System (ITS) to the Florida/Georgia border. Therefore, capacity from generating units located in Georgia should provide similar levels of reliability as the capacity available within Florida.

At this time, TEA has no active firm purchases on behalf of JEA. However, since its inception, TEA has purchased capacity and energy on behalf of JEA for seasonal periods. Typically, TEA acquires necessary short-term purchases the season before the additional energy is needed (based on market conditions), identifies a number of potential suppliers within Florida and Georgia, selects the best offer, and enters into PPAs with the supplier and JEA. TEA's ability to acquire capacity and/or energy, along with TEA's firm transmission rights across the Georgia ITS, give JEA assurance that short-term market purchases are viable.

3.6 Power Sales

3.6.1 Florida Public Utilities Company Sale

JEA furnishes wholesale power to Florida Public Utilities Company (FPUC) for resale in the city of Fernandina Beach in Nassau County, north of Jacksonville. JEA has provided FPUC's power requirements for many years, and under the current 10 year renewal term, JEA is contractually committed to supply power to FPUC from January 1, 2008, through December 31, 2017. FPUC's historical loads are embedded in JEA's historical loads for the purpose of developing the load forecast used throughout the GEC Need for Power Application. JEA expects that the contract to sell power to FPUC will be renewed upon its expiration. Therefore, FPUC's load will be treated as JEA's native load and will be served by JEA's resources throughout the 20 year evaluation period considered in this Application.

3.6.2 FPL-SJRPP Sale

As noted previously, JEA has sold 30 percent (equal to 376 MW net summer and 382.5 MW net winter) of the SJRPP capacity to FPL. Based on the terms and conditions of the sales agreement, the total amount of energy that FPL can take under the agreement is limited. For the purpose of modeling in this Application, the term of FPL-SJRPP sale is assumed to end on March 31, 2016.

3.7 Unit Retirements

Over the planning horizon considered in this Application, the only existing unit that is planned for retirement is Kennedy CT 3, with retirement planned during the first quarter of 2009. The following subsections discuss JEA's generating fleet with regard to unit age and possible future maintenance activities to help ensure continued reliable operation.

3.7.1 Steam Turbine Units

JEA owns all or part of six steam units: Northside 1, Northside 2, Northside 3, SJRPP 1, SJRPP 2, and Scherer 4.

Northside 1 and Northside 2 were originally commissioned in 1966 and 1972, respectively, as heavy oil-fired units. As noted above, both units were repowered with coal and petcoke fired CFB boilers in 2002The 2002 repowering is expected to prolong the original design life of these units, allowing them to remain operational throughout the 20 year evaluation period considered in this Application.

The Northside 3 steam unit was originally commissioned in 1977. A recent condition assessment has shown that the unit is in typical condition for the type, age, and operating mode of the unit. A major maintenance plan has been developed to preserve reliability and availability of the unit through the 20 year evaluation period considered in this Application. It is expected that currently pending environmental regulations could be applicable to the unit and may necessitate either modified operating practices, major upgrades, or economic retirement. JEA will continue to evaluate future plans for this unit as pending environmental regulations are brought forth.

SJRPP Unit 1 was commissioned in 1987 and SJRPP Unit 2 was commissioned in 1988. These units are well within their original design life, and there is no prospect for their retirement throughout the 20 year evaluation period considered in this Application.

Scherer Unit 4 was commissioned in 1989. This unit is well within its original design life, and there is no prospect for its retirement throughout the 20 year evaluation period considered in this Application.

3.7.2 Combustion Turbine Units

JEA currently has three types of combustion turbines distributed between the Northside, Kennedy and Brandy Branch Stations.

Kennedy Station has one nominal 182 MW GE 7FA gas fired (with distillate backup) combustion turbine, commissioned in 2000 and designated as Kennedy CT 7. An additional gas fired (with distillate oil backup) 7FA designated as Kennedy CT 8 is under construction with a scheduled commercial operation date of March 2009. No major repairs or upgrades beyond those dictated by unit starts and operating hours are planned. Kennedy Station also has one operating 54.3 MW Westinghouse distillate oil-fired CT designated as Kennedy CT 3, which was commissioned in 1973, and is scheduled for retirement in 2009 (contingent on the successful commercial operation of Kennedy CT 8).

Northside Station was constructed with four distillate oil-fired GE Frame 7 CTs with a nominal capacity of 52.4 MW each. All four units were commissioned from late 1974 through early 1975 and designated as Northside CT 3, 4, 5, and 6. These units are late in their planned life cycle and could require increased O&M, additional capital expenditures, or possibly retirement within the term of this planning cycle. No additional major repairs or upgrades beyond those dictated by unit starts and operating hours are currently planned and the units are not assumed to retire during the 20 year evaluation period in this Application.

Brandy Branch Station was constructed with three gas fired (with distillate oil backup) GE 7FA CTs with a nominal capacity of 182 MW each. All three units were commissioned as simple-cycle units in 2001 and designated as Brandy Branch CT 1, 2, and 3. Subsequently, Units 2 and 3 were converted to a 2 x 1 combined-cycle configuration in 2005. All three units are well within their design life cycles throughout the 20 year evaluation period considered in this Application. No major repairs or upgrades beyond those dictated by unit starts and operating hours are planned.

3.8 JEA Operating and Spinning Reserve Requirements

JEA is a member of the FRCC and party to the Florida Reserve Sharing Group (FRSG) agreement. The FRSG participants collectively share contingency reserves within the FRCC region to meet the individual participant's obligations to comply with reliability standards and requirements. FRCC members collectively carry operating reserves to cover the loss of at least the single largest unit of the participant's generator resources. When an FRSG participant requests operating reserves, the reserve capacity is immediately scheduled by all other FRSG participants and the requesting participant may hold this operating reserve for up to 30 minutes.

JEA is currently obligated to maintain operating reserves of 82.5 MW. Approximately 20.6 MW of the 82.5 MW must be spinning reserve. The remaining 61.9 MW reserve requirement can be met by quick start units.

3.9 JEA Clean Power Portfolio

Since 1999, JEA has worked closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled Clean Power Action Plan. The Clean Power Action Plan has an Advisory Panel that is composed of participants from the Jacksonville community, including representatives from the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Although the Clean Power Action Plan does not speak directly to CO_2 emissions, projects undertaken by JEA pursuant to the Plan have reduced JEA's CO_2 emissions.

JEA has made considerable progress towards the goals set forth in the Clean Power Action Plan through installation of clean power systems, PPAs, legislative and public education activities, and research into and development of clean power technologies. In particular, JEA has conducted a number of generation efficiency improvements, such as turbine upgrades, which increase the output of generating units without increasing the amount of fuel burned or the amount of CO_2 emitted. As further discussed in the following subsections, JEA has also undertaken several renewable energy projects as part of the Clean Power Program including installation of solar photovoltaic (PV), solar thermal, landfill and wastewater treatment biogas capacity, and wind. As discussed in Section 14, JEA continues to evaluate new renewable energy initiatives and opportunities, including biomass generation and participating in ongoing research efforts to promote development of renewable energy technologies.

Over the past several years, JEA has received several awards for its clean power program, including a Sierra Club Clean Power Award in 2005 for its voluntary commitment to increasing the use of solar, wind, and other renewable or green power sources.

3.9.1 Solar and the Solar Incentive Program

JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provides cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued in favor of the solar water heating program, which provides more cost-effective CO_2 reduction. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. JEA also offers incentives for the installation of solar water heaters. To date, the program has resulted in over 500 incentives, or approximately 1.6 MW of capacity savings.

3.9.2 Landfill Gas and Biogas

Since 1997, JEA has owned and operated internal combustion engine generators fueled by landfill gas produced by the City of Jacksonville's Girvin Road landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The facility uses biogas produced by the wastewater treatment plant to fuel the 800 kW generator. JEA has received approximately 1,500 kW of landfill gas from the North Landfill, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a PPA with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date for completion of the facility is late 2008.

3.9.3 Wind

As part of its ongoing effort to utilize more sources of renewable energy, in 2004 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet state or federal environmental requirements.

3.10 JEA Transmission and Interconnections

The JEA transmission system consists of 728 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kilovolts (kV), 138 kV, 230 kV, and 500 kV.

The 500 kV transmission lines are jointly owned by JEA and FPL and complete the path from FPL's Duval substation (to the west of JEA's system) to the Florida interconnect at the ITS. Along with JEA and FPL, Progress Energy Florida and the City of Tallahassee each also own transmission interconnections with the Georgia ITS. JEA's first contingency import entitlement over these transmission lines is 1,228 MW out of 3,600 MW.

The 230 kV and 138 kV transmission system provides a backbone around JEA's service territory, with one river crossing in the north and no river crossings in the south, leaving an open loop. The 69 kV transmission system extends from JEA's core urban load center to the northwest, northeast, east, and southwest to fill in the area not covered by the 230 kV and 138 kV transmission backbone.

JEA owns and operates three 230 kV tie-lines terminating at FPL's Duval substation in Duval County, one 230 kV tie-line terminating at Beaches Energy's

Sampson substation (FPL metered tie-line) in St. Johns County, one 230 kV tie-line terminating at Seminole Electric Cooperative's Black Creek substation in Clay County, and one 138 kV tie-line terminating at Beaches Energy's Penman Road substation.

JEA also owns and operates a 138 kV transmission loop that extends from the 138 kV backbone, north to the Nassau substation, where JEA delivers wholesale power to FPUC for resale within the City of Fernandina Beach, Nassau County, Florida.

3.11 JEA Transmission System Considerations

JEA continues to evaluate and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually assesses, in compliance with North American Electric Reliability Corporation (NERC) and FRCC standards, the needs and options for increasing the capability of the transmission system.

JEA performs system assessments using JEA's published Transmission Planning Process in conjunction with and as an integral part of the FRCC's published Regional Transmission Planning Process which facilitates coordinated planning by all transmission providers, owners, and stakeholders with the FRCC Region. FRCC's members include investor owned utilities, cooperative utilities, municipal utilities, a federal power agency, power marketers, and independent power producers. The FRCC Board of Directors has the responsibility to ensure that the FRCC Regional Transmission Planning Process is fully implemented. The FRCC Planning Committee, which includes representation by all FRCC members, directs the FRCC Transmission Working Group, in conjunction with the FRCC Staff, to conduct the necessary studies to fully implement the FRCC Regional Transmission Planning Process. The FRCC Regional Transmission Planning Process meets the principles of the FERC Final Rule in Docket No. RM05-25-000 (1) coordination, (2) openness, (3) transparency, (4) information exchange, (5) comparability, (6) dispute resolution, (7) regional coordination, (8) economic planning studies, and (9) cost allocation for new projects.

4.0 Economic Parameters

This section presents the economic parameters and methodology used to evaluate the economics of the GEC combined cycle conversion as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period.

4.1 Inflation and Escalation Rates

The general inflation rate, construction cost escalation rate, fixed operations and maintenance (O&M) escalation rate, and nonfuel variable O&M escalation rate are each assumed to be 2.5 percent.

4.2 Municipal Bond Interest Rate

The tax exempt municipal bond interest rate is assumed to be 5.0 percent.

4.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to the tax exempt municipal bond interest rate of 5.0 percent.

4.4 Interest During Construction Interest Rate

The interest during construction rate, or IDC, is assumed to be 5.0 percent.

4.5 Levelized Fixed Charge Rate

The fixed charge rate, or FCR, represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year FCR.

Different generating technologies are assumed to have different economic lives and, therefore, different financing terms. Simple cycle combustion turbines are assumed to have a 20 year financing term, while natural gas fired combined cycle units are assumed to be financed over 25 years. Given the various economic lives and corresponding financing terms, different levelized FCRs were developed. All levelized FCR calculations assume the 5.0 percent tax exempt municipal bond interest rate, a 2.0 percent bond issuance fee, an assumed 0.50 percent annual property insurance cost, and a debt service reserve fund equal to 100 percent of the average annual debt service requirement earning interest at an interest rate equal to the bond interest rate of 5.0 percent. The resulting 20 year FCR is 8.972 percent, and the 25 year FCR is 7.915 percent.

5.0 Forecast of Electrical Demand and Consumption

5.1 Load Forecast

This section describes the methodology used to develop the peak demand and net energy for load forecasts for JEA for the years 2008 through 2027 and presents the resulting forecasts.

5.1.1 JEA Historical Peak Demand

The forecast of peak demand requires projecting both the summer and winter peaks. JEA has historically experienced annual peaks in both the summer and winter periods. Table 5-1 indicates that between 1998 and 2007, the system peak occurred seven times during the winter period and three times in the summer period.

Table 5-1 indicates that from 1998 to 2007, the winter peak demand increased from 1,938 MW to 2,722 MW, which is an average annual growth rate of 3.85 percent. The 1998 summer peak demand level was 2,338 MW, and the 2007 summer peak was 2,897 MW. The average annual growth rate for the summer peak demand was 2.41 percent.

Table 5-1
Historical JEA Peak Demand (with FPUC)

Year	Winter (MW)	Summer (MW)
1998	1,938	2,338
1999	2,403	2,427
2000	2,478	2,380
2001	2,666	2,389
2002	2,590	2,562
2003	3,083	2,535
2004	2,668	2,539
2005	2,860	2,815
2006	2,919	2,835
2007	2,722	2,897
Average Annual Percent Change 1998-2007	3.85%	2.41%

5.1.2 JEA Peak Demand Forecast

To forecast peak demand, JEA has developed a regression analysis technique that utilizes SAS and Excel software. JEA develops a forecast of total load, including interruptible and curtailable customers, and then subtracts these customers to derive an estimate of firm demand only.

The peak demand forecast is driven by temperature and time-series data. The forecasting process involves the collection of historical hourly system load data and daily temperature data. Since the historical system peak has occurred on non-holiday weekdays, JEA has found that the most accurate historical forecasting method involves removing the data for weekends and holidays from the historical database. To further eliminate historical data that would tend to understate peak demand levels, summer load data was further reduced if a day was a summer rain day and if the 5:00 p.m. load is lower than the 3:00 p.m. load. Since JEA demand peaks in the late afternoon during the summer, the highest value between 2:00 p.m. and 8:00 p.m. was identified as the daily peak for the remaining summer days. For winter days, the daily peak occurs early in the morning because of heating requirements. To eliminate historical data that would tend to distort the analysis, daily load data was removed if a cold front moved in and caused the 11:00 a.m. load to be higher than the load between 1:00 a.m. and 11:00 a.m.

After the summer and winter data were adjusted, as described previously, a regression analysis was conducted to forecast the summer and winter peaks. The forecast temperature used in the regression was 97° F (summer) and 25° F (winter) where the winter seasonal extreme for a year was the lowest temperature during the months of December, January, and February, and the summer seasonal extreme was the highest temperature during the months of July, August, and September.

The results of the summer and winter peak demand forecasts are shown in Table 5-2 for total peak demand, non-firm demand, and firm peak demand. During the 20 year forecast period, total summer peak demand is forecast to increase at an average annual growth rate of 1.88 percent. The annual growth rate in summer firm peak demand is 1.94 percent. Total winter peak demand is forecast to increase at an average annual growth rate of 2.06 percent. The annual growth rate in winter firm peak demand is 2.14 percent. The winter and summer non-firm demand values are projected to remain constant at 133 MW and 117 MW, respectively.

Table 5-2 indicates that the total JEA peak demand in 2008 is projected to be 3,079 MW in the winter, compared to a summer total peak demand of 2,941 MW. In the final year of the forecast, the 2027 total winter peak demand is projected to be 4,537 MW, compared to 4,187 MW during the summer period. A similar pattern holds for the firm peak demand projections. The firm winter peak demand is projected to increase from 2,946 MW in 2008 to 4,404 MW in 2027, and the firm summer peak demand is projected to increase from 2,824 MW in 2008 to 4,070 MW in 2027. These projections assume that the FPUC load (refer to Section 3.0) will continue to be served through the end of the study period.

In addition to a base case forecast, JEA performed a forecast that incorporates the effects that extreme or moderate temperatures could have on peak demand (Extreme and Moderate Condition forecasts). The temperatures used for the winter season were 7° F and 32° F for the Extreme and Moderate forecasts, respectively. The temperatures used for the summer season were 103° F and 93° F for the Extreme and Moderate forecasts, respectively. The Extreme and Moderate peak demand forecasts for the summer and winter seasons are presented in Table 5-3.

Table 5-2
JEA Peak Demand Forecast (with FPUC)

Year	Total Peak Demand		Non-Firm Demand		Firm Peak Demand	
	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
2008	3,079	2,941	133	117	2,946	2,824
2009	3,155	3,007	133	117	3,022	2,890
2010	3,232	3,072	133	117	3,099	2,955
2011	3,309	3,138	133	117	3,176	3,021
2012	3,386	3,204	133	117	3,253	3,087
2013	3,462	3,269	133	117	3,329	3,152
2014	3,539	3,335	133	117	3,406	3,218
2015	3,616	3,400	133	117	3,483	3,283
2016	3,693	3,466	133	117	3,560	3,349
2017	3,770	3,531	133	117	3,637	3,414
2018	3,846	3,597	133	117	3,713	3,480
2019	3,923	3,662	133	117	3,790	3,545
2020	4,000	3,728	133	117	3,867	3,611
2021	4,077	3,794	133	117	3,944	3,677
2022	4,153	3,859	133	117	4,020	3,742
2023	4,230	3,925	133	117	4,097	3,808
2024	4,307	3,990	133	117	4,174	3,873
2025	4,384	4,056	133	117	4,251	3,939
2026	4,461	4,121	133	117	4,328	4,004
2027	4,537	4,187	133	117	4,404	4,070
Average Annual Percent Change	2.06%	1.88%	0.00%	0.00%	2.14%	1.94%

Table 5-3
JEA Moderate and Extreme Peak Demand Forecast (with FPUC)

Year	Moderate Case[1]				Extreme Case[2]			
	Winter Total (MW)	Winter Firm (MW)	Summer Total (MW)	Summer Firm (MW)	Winter Total (MW)	Winter Firm (MW)	Summer Total (MW)	Summer Firm (MW)
2008	2,897	2,764	2,808	2,691	3,244	3,111	3,019	2,902
2009	2,970	2,837	2,871	2,754	3,326	3,193	3,086	2,969
2010	3,042	2,909	2,934	2,817	3,408	3,275	3,154	3,037
2011	3,114	2,981	2,997	2,880	3,490	3,357	3,221	3,104
2012	3,186	3,053	3,060	2,943	3,572	3,439	3,288	3,171
2013	3,258	3,125	3,122	3,005	3,655	3,522	3,355	3,238
2014	3,331	3,198	3,185	3,068	3,737	3,604	3,422	3,305
2015	3,403	3,270	3,248	3,131	3,819	3,686	3,489	3,372
2016	3,475	3,342	3,311	3,194	3,901	3,768	3,556	3,439
2017	3,547	3,414	3,374	3,257	3,983	3,850	3,624	3,507
2018	3,619	3,486	3,437	3,320	4,065	3,932	3,691	3,574
2019	3,692	3,559	3,500	3,383	4,147	4,014	3,758	3,641
2020	3,764	3,631	3,563	3,446	4,229	4,096	3,825	3,708
2021	3,836	3,703	3,625	3,508	4,312	4,179	3,892	3,775
2022	3,908	3,775	3,688	3,571	4,394	4,261	3,959	3,842
2023	3,980	3,847	3,751	3,634	4,476	4,343	4,027	3,910
2024	4,052	3,919	3,814	3,697	4,558	4,425	4,094	3,977
2025	4,125	3,992	3,877	3,760	4,640	4,507	4,161	4,044
2026	4,197	4,064	3,940	3,823	4,722	4,589	4,228	4,111
2027	4,269	4,136	4,003	3,886	4,766	4,633	4,295	4,178
Average Annual Percent Change	2.06%	2.14%	1.88%	1.95%	2.05%	2.12%	1.87%	1.94%

[1]Based on a 32° F low winter temperature and a 93° F high summer temperature.
[2]Based on a 7° F low winter temperature and a 103° F high summer temperature.

5.1.3 JEA Historical Net Energy for Load

JEA's historical NEL requirements are shown in Table 5-4. NEL is defined as the energy generated and purchased minus off-system sales. From 1998 through 2007, the annual average growth rate in NEL on the JEA system was 2.12 percent. This growth rate was lower than the growth rate in JEA's winter and summer peak demand during the same period. Total NEL requirements during the period increased from 11,470 GWh in 1998 to 13,854 GWh in 2007.

Table 5-4
Historical JEA Net Energy for Load Requirements
(with FPUC)

Year	Actual NEL (GWh)
1998	11,470
1999	11,782
2000	12,190
2001	12,322
2002	12,983
2003	13,204
2004	13,243
2005	13,696
2006	13,811
2007	13,854
Average Annual Percent Increase	2.12%

5.1.4 JEA Net Energy for Load Forecast

The NEL forecast was developed on a monthly and annual basis as a function of time and heating and cooling degree-day data. Inputs into the forecast include energy production, JEA territory sales, off-system sales, and heating and cooling degree-days. The JEA forecast modeling methodology separately accounts for and projects the temperature-dependent and non-temperature-dependent energy requirements over time, then combines these components to derive the system total NEL forecast. The temperature-dependent NEL is modeled as a function of parameter estimates for historical and projected heating degree-days (HDDs) and cooling degree-days (CDDs). The HDD and CDD parameter estimate projections were based on the 1985 through 2006 historical averages.

The NEL forecast for JEA is shown in Table 5-5. The NEL is forecast to increase at an average annual growth rate of 2.08 percent during the 2008 through 2027 forecast period. NEL is forecast to increase from 14,701 GWh in 2008 to 21,726 GWh in 2027. These projections assume that the FPUC load (refer to Section 3.0) will continue to be served through the end of the study period.

Table 5-5
JEA Forecasted Net Energy for Load
(with FPUC)

Year	NEL (GWh)
2008	14,701
2009	15,016
2010	15,367
2011	15,717
2012	16,106
2013	16,418
2014	16,768
2015	17,119
2016	17,511
2017	17,820
2018	18,170
2019	18,520
2020	18,916
2021	19,222
2022	19,572
2023	19,922
2024	20,321
2025	20,623
2026	21,324
2027	21,726
Average Annual Percent Increase	2.08%

As previously discussed, in addition to the base NEL forecast JEA prepares an Extreme Condition forecast and a Moderate Condition forecast. The Extreme Condition forecast is based on the maximum HDDs and CDDs, by month, since 1985. The Moderate Condition forecast is based on the minimum HDDs and CDDs, by month, since 1985.

Results of these alternative forecasts are shown in Table 5-6. Under the Extreme Condition forecast, the total NEL would increase from 16,003 GWh in 2008 to 23,132 GWh in 2027, yielding an average annual growth rate of 1.96 percent. Under the Moderate Condition forecast, the total NEL would increase from 14,000 GWh in 2008 to 20,346 GWh in 2027, yielding an average annual growth rate of 1.99 percent.

Table 5-6
JEA Net Energy for Load--Moderate and Extreme Cases
(with FPUC)

Year	Moderate Forecast[1] (GWh)	Extreme Forecast[2] (GWh)
2008	14,000	16,003
2009	14,301	16,345
2010	14,636	16,722
2011	14,972	17,099
2012	15,347	17,515
2013	15,644	17,853
2014	15,980	18,230
2015	16,315	18,607
2016	16,693	19,026
2017	16,988	19,361
2018	17,323	19,738
2019	17,659	20,115
2020	18,040	20,538
2021	18,331	20,870
2022	18,667	21,247
2023	19,002	21,623
2024	19,387	22,049
2025	19,675	22,378
2026	20,010	22,755
2027	20,346	23,132
Average Annual Percent Change	1.99%	1.96%

[1]Based on minimum HDDs and CDDs, by month, since 1985.
[2]Based on maximum HDDs and CDDs, by month, since 1985.

6.0 Natural Gas Availability

This section discusses the availability of natural gas based on information from the US Energy Information Administration (EIA) and other sources as described in this section. Due to projected increases in natural gas production and imports of liquefied natural gas (LNG), natural gas supplies are projected to meet projected demand in the United States. There are also several new natural gas storage and pipeline projects that will help facilitate reliable delivery of natural gas to the Southeast region. For these and other reasons, the GEC will have a reliable supply of natural gas.

6.1 Domestic Natural Gas Production and Imports

The fuel price projections presented in Section 7.0 for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US EIA Annual Energy Outlook 2008 (AEO 2008). AEO 2008 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO 2008 are based on results from the EIA's National Energy Modeling System (NEMS). NEMS is a computer based, energy-economy modeling system of US energy markets. It projects the production, imports, conversion, consumption, and prices of energy.

According to the AEO 2008 reference case, total domestic US natural gas production, including supplemental natural gas supply, is projected to increase from 19.24 trillion cubic feet (Tcf) in 2008 to peak at 20.04 Tcf in 2022, before slightly declining to 19.44 Tcf in 2030. The overall projected trend in domestic natural gas production between 2008 and 2030 reflects a shift in sources of domestic supply from large fields in Alaska and the Gulf of Mexico to newer but smaller sources.

A large proportion of the lower 48 onshore conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total onshore production within the lower 48 US states will decline from 15.49 Tcf in 2008 to 13.95 Tcf by 2030. This reduced overall production will be due in part to the decrease in onshore conventional natural gas production in the lower 48 states, which the AEO 2008 reference case predicts will decrease from 5.09 Tcf in 2008 to 3.23 Tcf in 2030.

Given the decline in conventional sources, the incremental production of lower 48 onshore natural gas is projected to come primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. The increased role of unconventional resources was evident as more than half of the increase in natural gas production between the first-quarter of 2007 and the first-quarter of 2008 came from

Texas, where supplies grew by an exceptionally high 15 percent. Other contributing regions included Wyoming (with growth of 9 percent), Oklahoma (with 6 percent growth), and Louisiana (with 4 percent growth). Even natural gas production from the offshore Gulf of Mexico, which had been declining for years, increased 2 percent from first-quarter 2007 to first-quarter 2008. The startup last year of production from the deepwater Independence Hub, with wells in 9,000 feet of water, alone added about 1 percent to lower 48 states production while production in the rest of the states as a whole increased by 8 percent from first-quarter 2007 to first-quarter 2008.

Of the unconventional resources for domestic natural gas, shales seem particularly promising. As can be seen on Figure 6-1, shale formations in the lower 48 states are large and widely distributed. They contain huge resources of natural gas that are just starting to be fully developed. Production from the Barnett Shale field in Texas, alone, contributes more than 6 percent of production to the lower 48 states. Considerable natural gas resources also remain in the offshore Gulf of Mexico, especially in the deep waters.

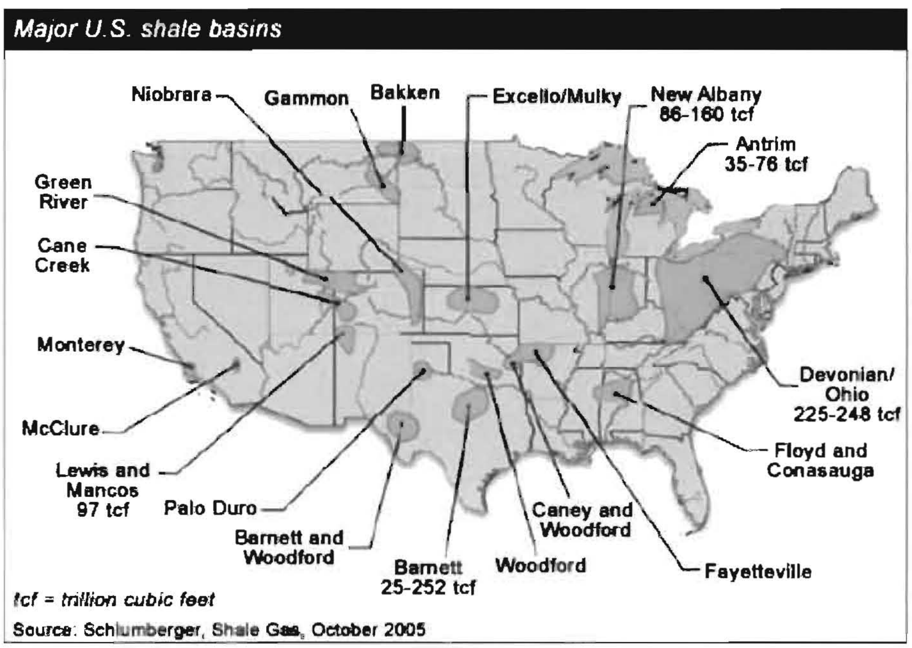

Figure 6-1
Major US Shale Basins
(Source: www.eia.doe.gov)

The Alaska pipeline is expected to be an even more significant source of domestic natural gas. It will begin to transport gas to the lower 48 States in 2020, when the pipeline is expected to be completed. The projected total amount of natural gas produced in Alaska remains around 0.41 Tcf from 2008 until it spikes to 1.19 Tcf in 2020 with the pipeline completion, and then doubles its production to 2.0 Tcf in 2021 as the pipeline goes fully online. Production remains at that approximate level, ending at 2.01 Tcf in 2030. Figure 6-2 indicates domestic sources of gas supply.

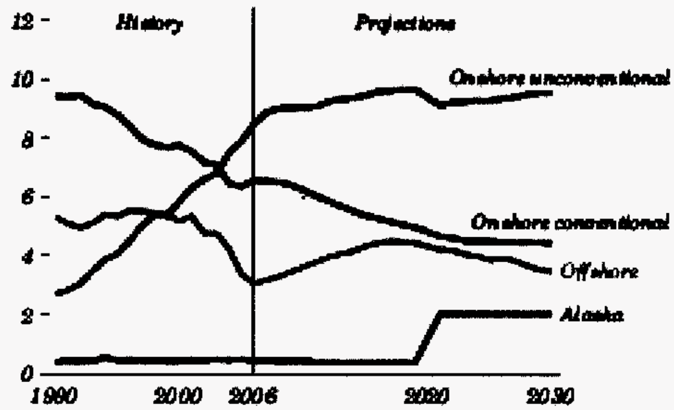

Figure 6-2
Domestic Sources of Gas Supply (Tcf per year)
(Source: www.eia.doe.gov)

While not domestic sources of natural gas, Canada and Mexico's supplies are closely linked to the US via pipeline. Net pipeline imports of natural gas from these two countries are projected to decrease from 2.95 Tcf in 2008 to 0.33 Tcf in 2030 in the AEO 2008 reference case. However as described later in this section, total net imports of LNG to the United States in the AEO 2008 reference case are expected to increase from 0.90 Tcf in 2008 to 2.8 Tcf in 2030, as other countries begin to export more LNG to the United States.

6.2 Liquefied Natural Gas

LNG is natural gas that has been cooled to -260° F at atmospheric pressure, the point at which natural gas condenses to a liquid. When natural gas is converted to a liquid (i.e., LNG), its volume is reduced by a ratio of 600 to 1, allowing considerably more natural gas to be stored and shipped in its liquid form. The LNG is stored in double-walled tanks at atmospheric pressure and shipped aboard specially designed LNG storage vessels.

Upon the vessel's arrival at an LNG receiving facility, the LNG is pumped onshore in its liquid state. It is then stored in permanent double-walled tanks, or is heated, vaporized, and regulated for temperature and pressure, and delivered as natural gas into a pipeline network. The former method provides the greatest flexibility in terms of where the LNG is stored until needed, acting similar in nature to deliveries from natural gas storage. In the latter instance, the gas must be received and used as a supplemental baseload supply.

6.2.1 Liquefied Natural Gas in North America

The United States is one of the world's leading importers of LNG. In 2007, the US LNG imports totaled 770,812 Tcf. These imports were sourced from six countries: Trinidad and Tobago, Egypt, Equatorial Guinea, Nigeria, Qatar, and Algeria. According to the reference case, net imports of LNG are expected to increase by an annual value of 5.4 percent between 2008 and 2030. In terms of actual volume, LNG imports will rise from 0.90 Tcf in 2008 to 2.84 Tcf in 2030. LNG receiving terminal capacity is anticipated to also increase from 1.5 Tcf in 2006 to 5.2 Tcf in 2009 (with no further increase through 2030) in order to accommodate this growth.

Currently, the United States maintains four onshore LNG terminals: Distrigas Facility in Everett, Massachusetts; Dominion Cove Point LNG in Lusby, Maryland; Southern LNG in Elba Island, Georgia; and Trunkline LNG in Lake Charles, Louisiana. The United States also has one offshore LNG terminal, the Gulf Gateway Energy Bridge. These existing energy terminals are shown on Figure 6-3.

The Distrigas facility is owned by Suez, North America and receives the largest volume of any onshore terminal in the United States at 184 billion cubic feet (Bcf). The sustainable daily capacity of the Distrigas facility is approximately 725 million cubic feet (Mcf). By comparison, the Dominion Cove Point LNG facility received 117 Bcf in 2006, and plans are in place to expand the regasification capability of the facility to 657 Bcf per year by late 2008. StatoilHydro, Shell, and BP currently share the capacity rights to the Dominion Cove Point LNG facility.

Southern LNG and Trunkline LNG received 147 Bcf and 144 Bcf of LNG, respectively, in 2006. The United Kingdom based BG Group owns the capacity rights to the Southern and Trunkline LNG facilities. Both facilities have undergone recent expansions and plans are in place to further expand each facility. El Paso Corporation, which owns Southern LNG, has formulated a plan to increase its regasification capacity from the current 1.2 Bcf per day (Bcf/d) to 2.1 Bcf/d by 2010, as well as constructing new pipeline connections to access new markets. The Southern Union Company owns Trunkline LNG, which maintains a regasification capacity of 1.8 Bcf/d. Currently, the sendout capacity of the Trunkline LNG facility is 0.3 Bcf/d, but plans are in place to increase the sendout capacity to 2.1 Bcf/d by 2009.

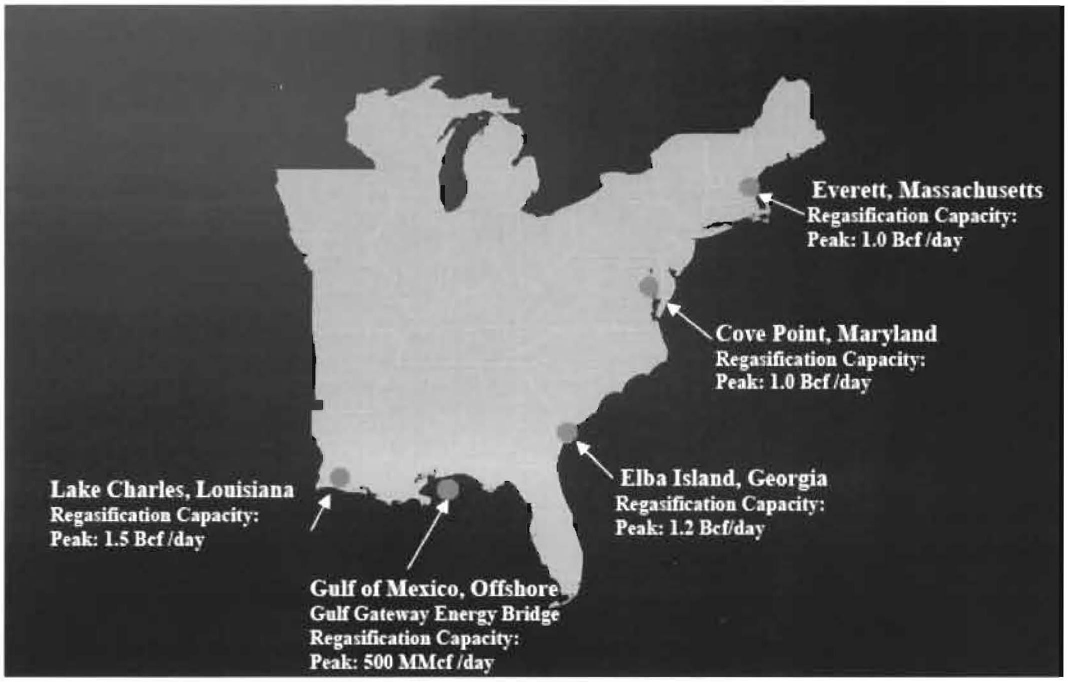

Figure 6-3
Current US LNG Import Terminals
(Source: www.eia.doe.gov)

6.2.2 Existing LNG Importing Countries for North America

LNG imports to the United States were generally not competitive with domestic supplies of natural gas and pipeline imports from Canada through the 1980s and 1990s, resulting in low levels of these imports during these decades. However, higher natural gas prices in the United States in recent years have attracted larger volumes of LNG imports to this country, including a record US total in 2007 equaling 771 Bcf of natural gas in gaseous form.

Deliveries of LNG from Trinidad and Tobago account for the majority of LNG imports to the United States. The Atlantic LNG facility located in Port Fortin, Trinidad and Tobago, now produces nearly 700 Bcf a year. In recent years, several African countries, including Egypt, Nigeria, and Algeria, also have been suppliers of LNG to the United States.

Growth in LNG imports to US markets is expected to come from new trading partners, one of which is Equatorial Guinea, where Marathon Oil Corporation has begun operation of an LNG plant. This plant, located on Bioko Island, has recently begun deliveries to the United States. In total, Trinidad and Tobago supplied 451 Bcf of LNG to the United States in 2007. This was 59 percent of the total LNG imported by the United States for the year.

Algeria, which was formerly the largest exporter of LNG supply to the United States, exported a total 17 Bcf of LNG in 2006. This was a drastic reduction from the 97 Bcf of LNG it exported to the US in 2005. In 2007, that trend reversed, with Algeria supplying 75 Bcf, or 10 percent of the US annual LNG import.

Egypt began exporting LNG to the United States in 2005. During 2005, Egypt exported a total of 73 Bcf to the United States. In 2006, Egypt increased LNG exports to the United States by 47 Bcf, or 64.8 percent, for a total of 120 Bcf. This amount dropped slightly to 115 Bcf in 2007.

Nigeria increased LNG exports to the United States from 8 Bcf in 2005 to 57 Bcf in 2006 after increasing the liquefaction capacity on the Bonny Island facility. Its exports to the United States increased significantly to 95 Bcf in 2007, equivalent to 12 percent of the overall supply in the United States. Figure 6-4 shows the leading LNG exporters to the United States, by volume and percent.

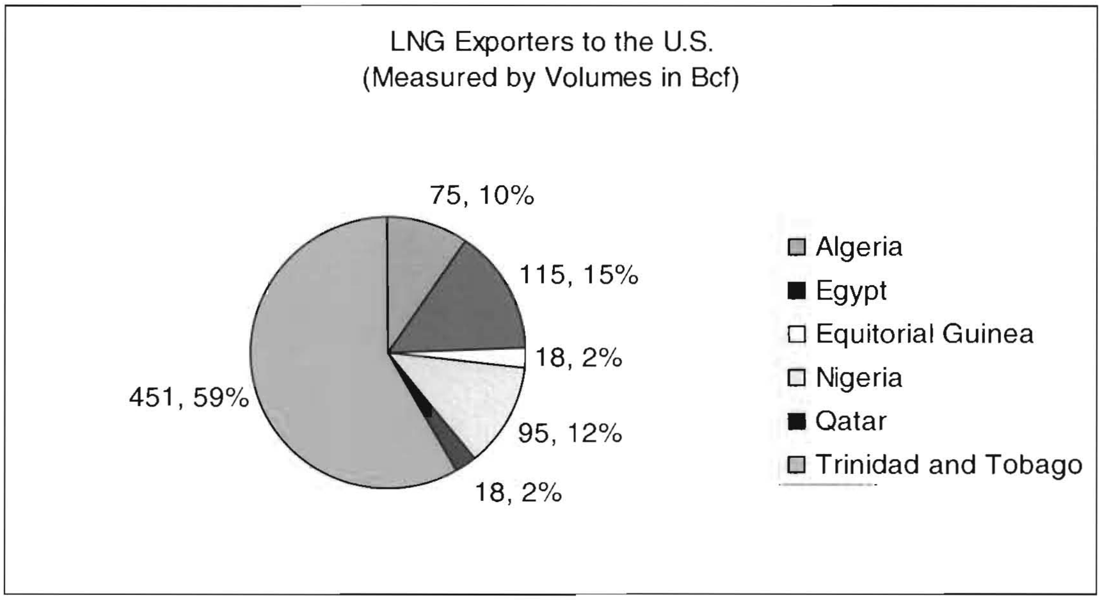

Figure 6-4
Top LNG Exporters to the United States in 2007
(Source: www.eia.doe.gov)

6.2.2.1 Potential LNG Importing Countries for North America. International LNG trade has grown rapidly in recent years as new export facilities have started operations in several countries. In 2006, 13 countries exported natural gas in the form of LNG to 17 importing countries. International trade equaled more than 7.5 Tcf of natural gas in 2006. By the end of 2010, there will likely be five additional exporting countries for a total of 18 LNG source countries, although not all will be consistent suppliers of LNG to the United States.

LNG has the potential to be exported from countries with large, proven natural gas reserves and relatively high reserves-to-production ratios. Some countries meeting these criteria include the Republic of Peru, Republic of Venezuela, Azerbaijan Republic, Republic of Kazakhstan, Islamic Republic of Iran, Republic of Iraq, State of Kuwait, State of Qatar, United Arab Emirates (also known as Al Imarat al-Arabiyah al-Muttahidah), Republic of Yemen, Federal Republic of Nigeria, and the Independent State of Papua New Guinea.

However, not all of these countries are exporters of natural gas as LNG due to domestic need, inaccessibility to international natural gas trade and infrastructure, geopolitics, and lack of capital or technological investment. As largely populated countries such as the People's Republic of China and the Republic of India enter the international LNG market, the need to overcome these particular barriers, while further discovering and exploring accessible, proven natural gas reserves, is evident.

As traditional, economically viable oil and gas fields deplete, exploration and discovery have reached out to the furthest ends of the earth. The Arctic Ocean, long regarded as international territory, has experienced a recent rush for claims by not only Russia, but Denmark (via territory Greenland), Norway, the United States, and Canada.

The Antarctic landmass, traditionally used for research, has also seen a recent surge of land and maritime claims, most recently by the United Kingdom. Argentina, Australia, Chile, France, New Zealand, Norway, and the United Kingdom all claim portions of the great landmass, although the United States does not recognize any of these claims. Along with Russia, the United States has reserved the right to make claims in the future on the southern-most continent.

Currently, natural gas supplies are expected to arrive to the United States from the Snohvit LNG project in Norway through a contract with StatoilHydro ASA. In the Middle East, Qatar, the largest LNG exporter in the world, is expected to begin regular deliveries to the United States in the next couple of years. New supplies are expected to come online in Yemen by early 2009, with much of the LNG projected to be delivered to US markets.

6.2.2.2 Future LNG Import Terminals in North America. Projected growth in the demand for LNG has resulted in companies adding LNG receiving capacity in the United States. Five LNG import terminals currently operate in the United States. Four of these have recently been expanded. EIA expects additional new terminals to be operational in the next 2 years, increasing import capacity from 4.7 Bcf/d at the end of 2006 to over 11 Bcf/d at the end of 2008. It is projected that the regasified natural gas sendout capacity of onshore facilities could grow to more than 10 Bcf/d by the middle of 2010, with about half of this sendout capacity coming from new terminals.

6.2.2.2.1 Freeport LNG Terminal. One of these terminals is the Freeport LNG terminal on Quintana Island, Texas. It is nearing completion and will mark the first new onshore terminal in the United States in more than 25 years. Operations are expected to begin in 2008 with deliverability of 1.5 Bcf/d. The terminal is owned by a partnership of Michael S. Smith and ConocoPhillips, Cheniere Energy, Dow Chemical, and Contango Oil and Gas companies. ConocoPhillips has contracted for 500 Mcf/d of the capacity until mid-2009 and 1 Bcf/d thereafter; Dow Chemical, 500 Mcf/d; and Mitsubishi Corp., 150 Mcf/d for 17 years starting in 2009. Freeport LNG has also received approval from the FERC to expand the terminal's regasification capacity to 4.0 Bcf/d, which would make it the largest regasification terminal in the United States.

6.2.2.2.2 Sabine Pass Terminal. Cheniere Energy, Incorporated, is nearing completion of its new Sabine Pass LNG terminal in Cameron Parish, Louisiana. That facility will have 2.6 Bcf/d of sendout capacity. Total S.A. has reserved 1 Bcf/d of capacity for 20 years, while Chevron Corp. has reserved 700 Mcf/day for 20 years. Sabine Pass operations began in March 2008, and Cheniere Energy has received permission from FERC to expand the LNG terminal to 4.0 Bcf/d.

6.2.2.2.3 Cameron LNG Terminal. Sempra Energy's Cameron LNG facility on Lake Charles, Louisiana, is under construction with an expected initial capacity of 1.5 Bcf/d and an estimated operation date of late 2008. Italy's Eni SpA has agreed to purchase 0.6 Bcf/d of capacity at the facility for 20 years, while Algeria's Sonantrach, Suez North America, and Merrill Lynch Commodities are nearing final capacity arrangements. While the first phase of construction is ongoing, Sempra has initiated regulatory applications for a second phase of construction that would increase regasification capacity to about 2.7 Bcf/d by 2010.

6.2.2.2.4 Golden Pass LNG Terminal. ExxonMobil has received approval from FERC and has begun construction of its Golden Pass project near Sabine Pass, Texas. In the first phase of operations, Golden Pass, majority owned by Qatar Petroleum, will have the capacity to deliver up to 1 Bcf/d into the pipeline grid. It will likely be employed for receiving LNG from Qatar starting in 2009. ExxonMobil has signed contracts of agreement with Qatar for 2 Bcf/d of supply starting in 2009.

6.2.2.2.5 Florida LNG Supply Options. Recognizing pipeline transportation limitations, there are four viable options to supply Florida directly with LNG. These four options are: (1) Gulf LNG Clean Energy Project; (2) Elba Island with deliveries to Florida Gas Transmission Company (FGT) via the Cypress pipeline; (3) the Calypso Project; and (4) the Port Dolphin Project. The first two projects are onshore LNG storage facilities that either exist (Elba Island) or are under construction. The latter two are deepwater port facilities that will gasify LNG onboard the delivering vessel. The Gulf LNG Clean Energy Project and the Dolphin Port Project are still obtaining the necessary permits and certifications. The following subsections discuss each of these projects.

6.2.2.2.5.1 Gulf LNG Clean Energy Project. The Gulf LNG Clean Energy Project is jointly owned. El Paso Corporation owns 50 percent of the facility. The remaining 50 percent is shared by The Crest Group, consisting of Houston-based investors, with a 30 percent ownership in the project, and Sonangol USA with 20 percent. Sonangol is the state-owned national oil company of Angola, responsible for the development of Angola's hydrocarbon resources.

The project received its FERC certificate in February 2007 and is currently under construction. The terminal includes the construction of two 160,000 cubic meter storage tanks with a combined capacity of 6.6 Bcf, 10 high pressure submerged combustion vaporizers; and 5 miles of 36 inch pipeline. The pipeline will connect the terminal to Gulfstream, Destin Pipeline, FGT, and Transco. The terminal is expected to be placed into service in late 2011 at an estimated cost of $1.1 billion.

6.2.2.2.5.2 Elba Island. Southern LNG plans to expand its Elba Island facilities in order to supply new gas to growth markets in the Southeastern United States. Specifically, it plans to further expand its Elba Island LNG receiving terminal in Savannah, Georgia. Southern LNG also proposes to construct, own, and operate a new 190 mile interstate natural gas pipeline, Elba Express.

Construction has already begun on the significant expansions to the Elba Island LNG terminal. The expansion will add 8.4 Bcf of total storage capacity at the facility. The expansion will take place in two phases. Phase I of the project will add one 200,000 cubic meter storage tank that holds 1,250,000 barrels. The new tank will be complete by mid-year of 2010 and will add approximately 4.2 Bcf of LNG storage capacity to the terminal. Maximum sendout capacity will be 0.405 Bcf/d. Phase I of the project will also include modifying the north and south docks to accommodate new larger vessels and to facilitate simultaneous unloading of two ships.

Phase II of the project will add an additional 200,000 cubic meter (1,250,000 barrel) storage tank. This tank will add approximately 4.2 Bcf storage capacity to the terminal in 2012 and increase sendout by 0.495 Bcf/d. The LNG for the expansion will be transported by ship from gas rich regions outside of the United States. Southern LNG's facilities at Elba Island will vaporize the LNG and inject the natural gas into Southern's existing pipeline.

6.2.2.2.5.3 The Calypso System. Calypso LNG LLC (a subsidiary of SUEZ Energy International) is proposing the development of a submerged buoy system known as a "Deep Water Port" (DWP) located off the southeastern coast of Florida. The Calypso DWP will serve as an offshore delivery point for connection to specially built LNG tankers. The LNG tankers will vaporize stored LNG and send it through the buoy system into the FERC-permitted Calypso US Pipeline, which will transport the natural gas onshore to deliver to the FGT system. When the offloading system is not in use, it will reside approximately 120 feet under the ocean surface. The DWP will consist of two buoys approximately 2.6 miles apart.

According to Suez Energy International, the Calypso Pipeline will be capable of delivering over 1 Bcf of natural gas per day, which represents approximately 25 percent of Florida's peak demand on a hot summer day.

The Maritime Administration (MARAD) and the US Coast Guard (USCG) announced in the Federal Register on November 2, 2007, the availability of the Draft Environmental Impact Statement (DEIS) for the Calypso LNG LLC, Calypso Natural Gas Deep Water Port (Calypso) license application (DWPA). The application describes a project that would be located in the federal waters of the Outer Continental Shelf in the OCS NG 17–06 (Bahamas) lease area, approximately 8 to 10 miles off the east coast of Florida to the northeast of Port Everglades, in a water depth of 800 to 950 feet.

USCG and MARAD have 240 days from the date of the Notice of Application to hold one or more public license hearings in the adjacent coastal state of Florida. The Governor of Florida must approve, approve with conditions, or deny the DWPA license within 45 days of the last DWPA public hearing. If the Governor does not act within 45 days, approval will be conclusively presumed. Approval or denial of the license application by MARAD must occur not more than 90 days after the last public hearing.

6.2.2.2.5.4 Port Dolphin Energy. Port Dolphin Energy LLC, a wholly owned US subsidiary of the Norwegian based company Hoegh LNG AS, is also proposing development of a deep water port. The proposed project would consist of two submerged unloading and mooring buoys to receive an average of up to 800 Mcf/d of natural gas from LNG Shuttle and Regasification Vessels (SRVs), which are oceangoing LNG vessels designed to regasify the LNG onboard and deliver natural gas to a subsea pipeline. The DWP would be connected to a subsea pipeline that would bring the regasified natural gas from the offshore terminal to Port Manatee in Tampa Bay. The pipeline is planned to interconnect with the Gulfstream Natural Gas System and the facilities of TECO Energy, Inc. (TECO). The proposed offshore terminal would be located approximately 28 miles from the coast. Initial average daily throughput will be approximately 400 million British thermal units per day (MBtu/d) of natural gas will have a capacity of 800 MBtu/d of natural gas with peak delivery capacity of approximately 1.2 Bcf/d of natural gas.

Port Dolphin filed its DWPA with the USCG in March 2007 and expects the approval process for the Deepwater Port License and its associated permits will take approximately 18 months. Construction of the proposed project would consist of two phases with operations of Port Dolphin beginning in the second quarter of 2011.

6.3 Natural Gas Reserves

The United States had 211,085 Bcf of dry natural gas proven reserves as of December 31, 2006, the highest level since 1976. Proven reserves of natural gas increased by 3 percent from 2005 to 2006.

Texas led the nation in natural gas reserves additions in 2006 with a 9 percent increase in dry gas proven reserves, due to rapid development of Barnett Shale reservoirs in the Newark East Field. Advances in horizontal drilling and hydraulic fracturing technology, as well as relatively high natural gas prices, supported this development. Alaska and Utah were second and third for dry natural gas proven reserves additions in 2006, respectively. The total US reserves additions replaced 136 percent of 2006 dry gas production as illustrated on Figure 6-5.

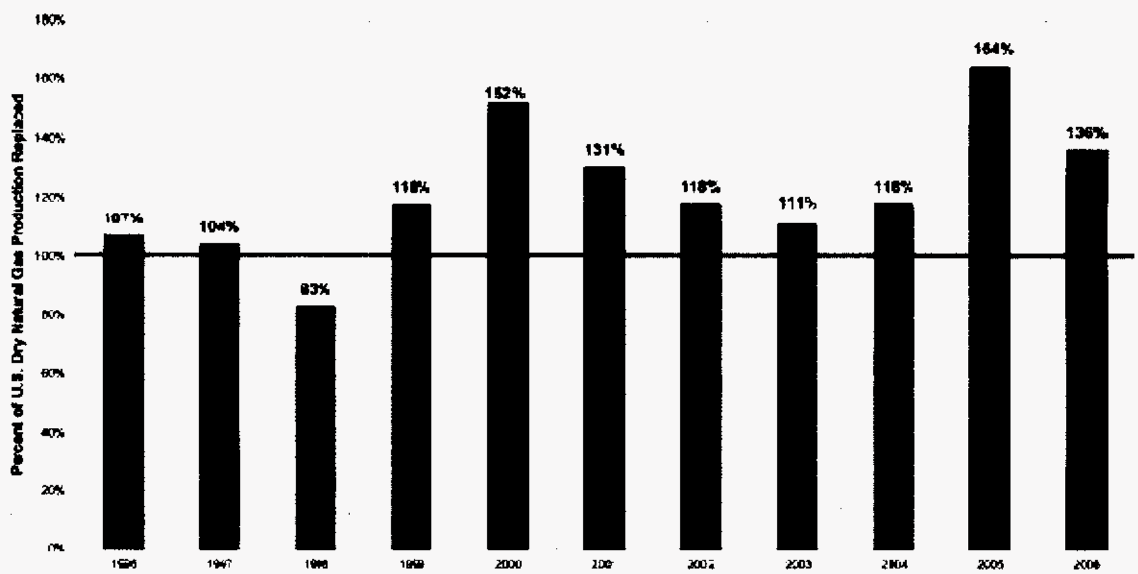

Figure 6-5
Replacement of Dry Natural Gas Productions by Reserve Additions 1996 - 2006
(Source: www.eia.dov.gov)

The proven reserves by state are shown on the map on Figure 6-8. Eight areas accounted for 81 percent of the nation's dry natural gas proven reserves, which amounts to about 171,000 Bcf. The highest concentration of natural gas reserves, as well as the highest potential production of natural gas, clusters around the Gulf Coast states. Strong potential exists in transporting natural gas reserves on the Transco Pipeline into the FRCC region making the necessary connection onto the Gulfstream Pipeline. Figure 6-6 illustrates the proven natural gas reserves in North America.

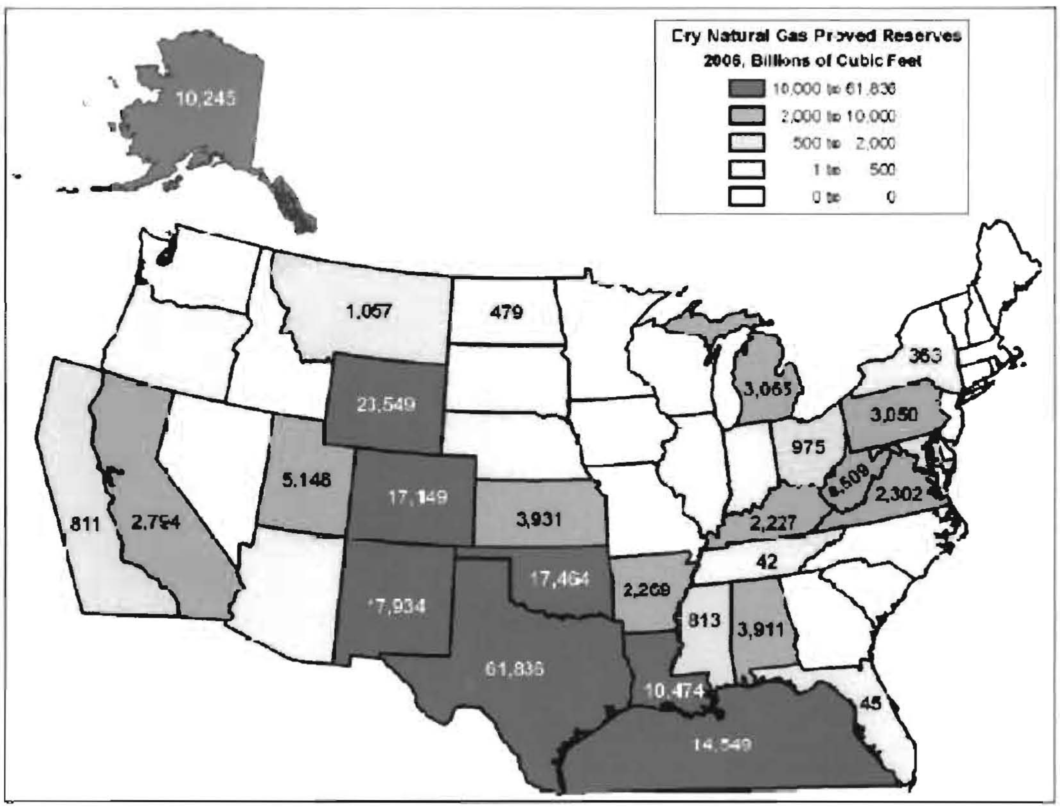

Figure 6-6
Dry Natural Gas Proven Reserves
(Source: www.eia.dov.gov)

6.4 Natural Gas Demand

In the AEO 2008 reference case, total natural gas consumption is projected to increase from 23.12 Tcf in 2008 to a peak value of 23.83 Tcf in 2016, followed by a decline to 22.72 Tcf in 2030.

The projected path of total natural gas consumption depends almost entirely on the amount consumed in the electric power sector. In the AEO 2008 reference case, natural gas consumption for electricity generation in the power sector declines from current levels to 5.0 Tcf in 2030, as a result of a projected increase in natural gas prices that begins after 2016. Consumption of natural gas in the residential, commercial, and industrial sectors is influenced not only by fuel prices but also by economic trends. Fuel price assumptions have a smaller effect on natural gas consumption because fuel substitution options are limited and stocks of equipment that use natural gas have relatively slow turnover rates.

6.5 Natural Gas Storage

Natural gas storage facilities are being developed along the Gulf Coast in numerous locations. The southeastern states of the United States accounted for over 38,000 miles of pipeline mileage in 2007, with the State of Florida accounting for approximately 5,000 miles of pipeline. The total Florida pipeline capacity is served by four companies: FGT, GulfSouth Pipeline, Gulfstream Natural Gas System, and Southern Natural Gas (SNG). These four interstate pipelines provide reliable and adequate natural gas transportation capacity into Florida and, along with the existing and proposed natural gas storage facilities, will provide adequate transportation and storage capacity for the Florida market.

6.5.1 Existing Natural Gas Storage Facilities Near Florida

As shown on Figure 6-7, a number of natural gas storage facilities have been built or expanded in recent years. These provide immediate benefits to the Florida market because of their respective locations, and the three most recent additions are described in the following subsections.

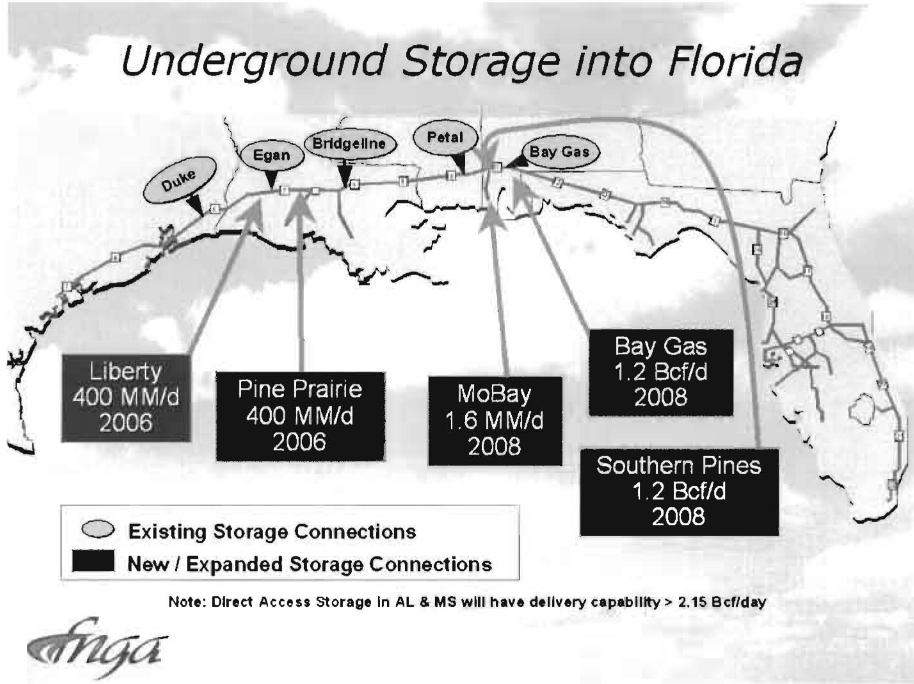

Figure 6-7
Underground Storage into Florida
(Source: www.floridagas.org)

6.5.1.1 Southern Pines Energy Center. Southern Pines Energy Center is being developed in Mississippi as a FERC-regulated natural gas storage facility. The project site has the capability to develop up to five 8 Bcf caverns for a total working gas capacity of 40 Bcf. Currently, the project is constructing a 16 Bcf multi-cycle natural gas storage facility consisting of two underground storage caverns, each capable of storing up to 8 Bcf each. The first cavern entered commercial operation May 1, 2008, and the second is scheduled for commercial operation later in the year. A third cavern is planned for 2008 with commercial operation in 2010.

The natural gas storage facilities will include the following:

- Three salt caverns capable of storing 24 Bcf in an underground salt-dome (with the capability of constructing two additional caverns for a total of five caverns and 40 Bcf of storage capacity).
- Aboveground facilities with 48,000 horsepower of compression for the three storage caverns and with 1.6 Bcf/d of maximum withdrawal capability and 0.8 Bcf/d of maximum injection capability. This configuration enables Southern Pines to cycle its working gas capacity a maximum of 12 times per year, thus providing its customers with the ultimate flexibility to quickly balance operational flows and meet peaking demands.

- Southern Pines will initially have direct interconnects to three existing interstate pipelines, Destin Pipeline Company, FGT, and Transcontinental Gas Pipeline Corporation. An interconnection with the Southeast Supply Header is scheduled for service in second quarter 2008 as that pipeline is constructed.

Figure 6-8 presents a map of the Southern Pines Energy Center.

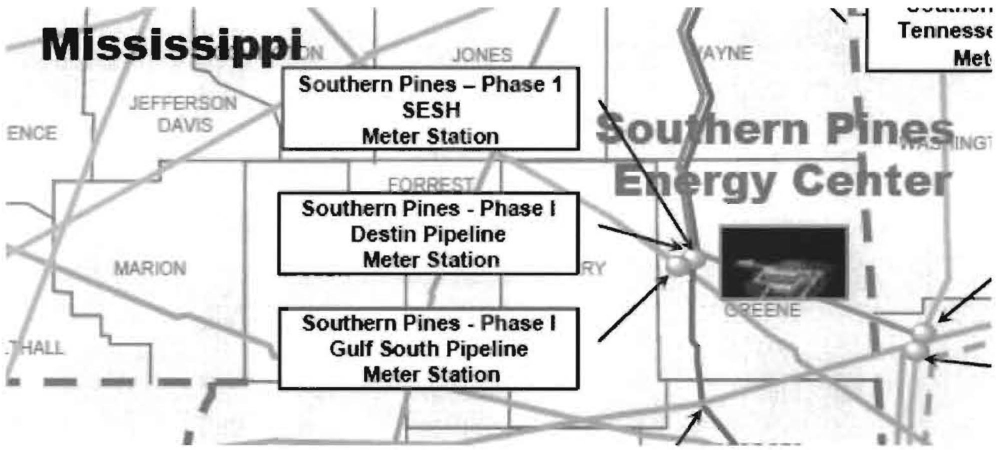

Figure 6-8
Southern Pines Energy Center
(Source: www.sgr-holdings.com)

6.5.1.2 MoBay Storage Hub, LLC. MoBay Storage Hub, LLC, will provide high-deliverability, multi-cycle (HDMC) gas storage services to the Southeast market. Located at the confluence of major market and supply area pipeline systems, MoBay would initially connect with four major interstate pipelines systems serving the Southeast and Northeast markets. Currently, the combined pipeline takeaway capacity at MoBay is 6.9 Bcf/d to the east and 3.9 Bcf/d to the west. MoBay would be the most southeasterly HDMC storage facility in the United States. The proposed MoBay compressor station will be located directly adjacent to Gulfstream Station 410 in Mobile County, Alabama. Working gas capacity will be 50 Bcf with maximum injection and withdrawal capability of 1 Bcf/d.

Figure 6-9 illustrates the relative proximity of the MoBay Storage Hub to the relative gas pipeline interconnections.

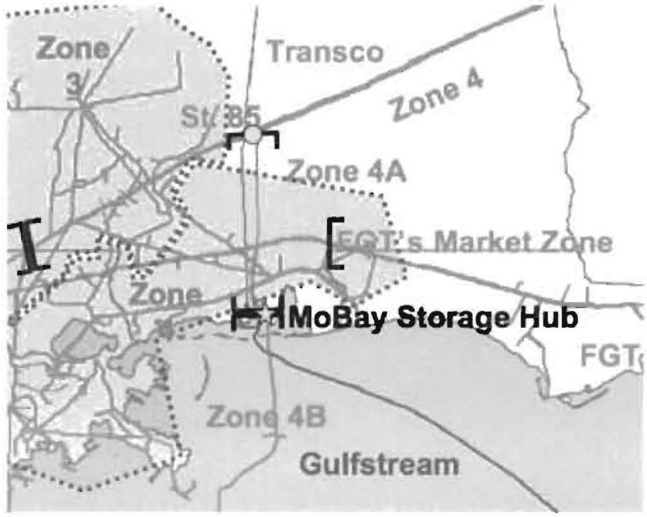

Figure 6-9
MoBay Storage Hub
(Source: www.falcongasstorage.com)

6.5.1.3 Bay Gas Storage. Bay Gas Storage is owned by EnergySouth Midstream, Inc., based in Houston, Texas. Bay Gas began the operation of its third underground natural gas storage cavern in April 2008. The new cavern increases total working gas capacity by 5.4 Bcf, bringing total working gas capacity to 11.4 Bcf at the McIntosh, Alabama facility.

In concert with bringing Cavern 3 in service, Bay Gas Storage will begin salt cavern leaching of its fourth underground storage cavern in McIntosh. The development of the company's fourth cavern is the first phase of a planned 10 Bcf expansion that will include a fifth cavern at the south Alabama facility. Cavern 4 has an expected in-service date of the first quarter of 2010 and will add 5 Bcf of total working gas capacity. A map of the facility is shown below on Figure 6-10.

Figure 6-10
Bay Gas Storage Facility
(Source: www.esmidstream.com)

6.5.2 *Floridian Natural Gas Storage Company*

The Floridian Natural Gas Storage Company LLC (FGS) facility is expected to be located in an industrial area near Indiantown in Martin County, Florida. The FGS facility will ultimately consist of two aboveground liquid natural gas storage tanks each capable of storing up to 4 Bcf of natural gas, refrigeration compressors to cool the gas, and regasification equipment. Natural gas will be delivered to and from FGS using both the FGT and Gulfstream natural gas pipeline systems. FGS is expected to begin commercial operation in mid-2011.

FGS will be regulated by the FERC. In October 2007, FGS filed an abbreviated application pursuant to Section 7(c) of the Natural Gas Act (NGA) and Parts 157 and 284 of FERC's regulations for a certificate of public convenience and necessity to construct and operate the FGS project; a blanket certificate to perform certain routine activities and operations; and a blanket certificate to provide open access storage services. The proposed project is currently under FERC review with a target decision date of October 23, 2008. The addition of downstream storage facilities will effectively increase the capacities of the FGT/Gulfstream systems.

6.6 Southeast Supply Header

The Southeast Supply Header, LLC (SESH) is a joint venture between subsidiaries of CenterPoint Energy, Inc. and Spectra Energy. The 270 mile, 36 inch and 42 inch diameter pipeline has an estimated capacity of 1 Bcf/d. The pipeline will extend from the Perryville Hub in northeastern Louisiana to Gulfstream in southern Mobile County, Alabama, and will have two interconnects with FGT, the combination of which will have a capacity of 1.5 Bcf/d.

SESH will link the onshore natural gas supply basins of east Texas and northern Louisiana to Southeast markets now predominantly served by offshore natural gas supplies from the Gulf of Mexico. This pipeline will give customers an important alternative to offshore supply, which can be vulnerable to weather related disruptions. Figure 6-11 illustrates a map of the SESH route.

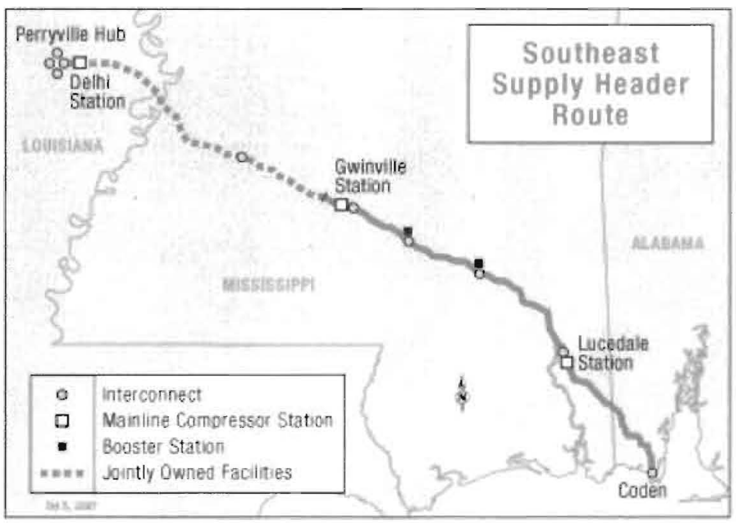

Figure 6-11
Southeast Supply Header Route Pipeline

6.7 Summary of Natural Gas Availability

As discussed throughout this section, the AEO 2008 reference case identifies growth trends in the supply and consumption of natural gas in the United States. Although conventional production in the lower 48 states will decline slightly by 2030, many sources of natural gas will continue to be available and new sources will come online, ensuring a reliable supply of natural gas. These sources of domestic natural gas production will be increasingly unconventional, and from sources that are both onshore and offshore. Of these, Alaska and the lower 48 states are forecast to not only maintain, but also increase, their production. Specifically, Alaskan natural gas production is expected to increase to almost five times its present level, from 0.41 Tcf in 2008 to 2.01 Tcf in 2030. The lower 48 states offshore production is also expected to increase by approximately 6 percent, from 3.28 Tcf in 2008 to 3.47 Tcf in 2030. While this additional gas supply may not be delivered directly to the Southeast US, it will displace the use of natural gas elsewhere in the United States, allowing more gas to be delivered to the Southeast. Imports of natural gas into the United States will also continue, and the amount of imported LNG is projected to increase by over threefold from 0.90 Tcf in 2008 to 2.84 Tcf in 2030.

Not only will access to supplies of LNG improve, so will the infrastructure to support natural gas storage and delivery. The United States has sufficient natural gas reserves, and these reserves are consistently being replaced as existing natural gas reserves have been consumed. In order to better facilitate this process, existing natural gas storage facilities have recently been or are planned to be expanded. New storage facilities are also being constructed, and projects are under way to better provide natural gas to the pipelines that serve the Southeast US. This construction will allow for better management of gas volumes and increases in reliability of supply.

7.0 Fuel and CO_2 Emissions Allowance Price Projections

This section discusses the methodology used to develop projections for the prices of natural gas, distillate and residual fuel oils, and coal specific to the FRCC region that is considered in this Application. In addition to the reference case price projections, high and low price projections have been developed. The analyses presented throughout this Application also consider projections of emissions allowance prices. Development of emissions allowance price projections are also presented in this section.

7.1 Importance of Fully Integrated Fuel and Emissions Allowance Price Projections

The fuel and emissions allowance price projections considered throughout this Application (whether for the reference case, high case, low case, or the case in which existing and potential new emissions such as carbon dioxide, or CO_2, are treated as regulated emissions) represent fully integrated forecasts. That is, fuel price supply and demand are considered in tandem with potential costs associated with regulation of various emissions, along with numerous other market influences to develop fully integrated projections of fuel and emissions allowance prices. This is important for all scenarios considered, but especially so when considering the potential impacts associated with acquiring any allowances for existent regulated emissions and considering the potential impacts of the regulation of CO_2.

Regulations of emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_x), and mercury (Hg) are reflected in each fuel price projection considered throughout this Application. While there is currently no State or Federal regulation of CO_2 emissions, several bills to regulate emissions of CO_2 (and other GHGs) have been proposed to the 110th US Congress. As such, this Application considers potential regulation of CO_2 emissions as outlined in Sections 7.7 and 7.8.

7.2 Description of 2008 US Energy Information Administration Annual Energy Outlook Reference Case

The fuel price projections for natural gas, fuel oil, and coal used in this Application were developed based on those included in the US EIA Annual Energy AEO2008. AEO2008 presents projections of energy supply, demand, and prices through 2030. The projections presented within AEO2008 are based on results from the EIA's NEMS. NEMS is a computer based, energy-economy modeling system of US energy markets and projects the production, imports, conversion, consumption, and prices of energy, subject to a variety of assumptions related to macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, technology characteristics, and demographics. The discussion of the fuel price projections presented within this section is intended to be an overview of the AEO2008 and, therefore, focuses on the more salient aspects of AEO2008 and elaborates on relevant conclusions and projections. The AEO2008 in its entirety can be found at http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2008).pdf, while documentation on NEMS can be found at http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model%20documentation.

7.2.1 Consideration of State and Federal Legislation and Regulations in AEO2008

Analyses developed by the EIA are required to be policy-neutral. Therefore, the projections in AEO2008 generally are based on Federal and State laws and regulations in effect on or before December 31, 2007 (with few exceptions). As stated in AEO2008, the potential impacts of pending or proposed legislation, regulations, and standards – or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself – are not reflected in the projections.

AEO2008 considered the potential impacts of both the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), although both rules were recently vacated by the District of Columbia Circuit Court of Appeals. The vacatur of CAIR happened during publication of the AEO2008 (July 11, 2008) while CAMR was vacated too late for EIA to remove the CAMR provisions from its analysis. CAIR was adopted to limit emissions of SO_2 and NO_x from power plants in 29 states and the District of Columbia, while CAMR was adopted to limit emissions of Hg from power plants throughout the United States. Both CAIR and CAMR are represented as regional cap-and-trade programs in AEO2008, because the document was developed prior to final decisions being made regarding the structure of state programs and participation in regional trading programs contemplated in CAIR and CAMR.

In light of the recent vacatur of CAIR and CAMR, the economic analyses presented in Section 17.0 do not include costs for SO_2 or NO_x allowances under CAIR or Hg allowances under CAMR. In any event, CAIR and CAMR allowance costs would not have been significant for the proposed combined cycle unit due to the inherently low SO_2, NO_x and Hg emission rates associated with natural gas-fired generation, particularly as compared to other fuel types.

7.3 AEO2008 Reference Case FRCC Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2008 Reference Case forecast prices for natural gas and fuel oil delivered to the FRCC region are presented in Table 7-1[1]. Forecasts of prices for High Sulfur Eastern Interior and Powder River Basin (PRB) coal delivered to the Georgia/Florida region are presented in Table 7-2[2]. The fuel price projections shown in Tables 7-1 and 7-2 are presented in constant 2006 dollars per MBtu. For the economic analysis presented in Section 19.0 of this Application, the fuel price projections were converted from those shown in Tables 7-1 and 7-2 to nominal dollars per MBtu by applying the 2.5 percent general inflation rate.

The natural gas price projections presented in Table 7-1 represent the AEO2008 projections for delivered natural gas to the FRCC region and do not include any usage charges or any other costs for firm or interruptible intrastate natural gas transportation. Discussion of how such costs were considered and factored into the economic analysis is presented in Section 19 of this Application.

Table 7-2 only presents forecast prices for coal delivered to the Georgia/Florida region from the Eastern Interior and PRB coal production region. Although the EIA provided forecast prices for coals from other production regions, this Application only considers coal delivered from the Eastern Interior and the PRB. The analyses presented throughout this Application assumes that PRB coal will continue to be burned in the existing Scherer plant, while Eastern Interior coal is assumed to be burned in the existing SJRPP and Northside units.

Although SJRPP and Northside have historically utilized coal from international sources (including Latin America), the characteristics of Eastern Interior coal are relatively comparable to the characteristics of the Latin American coal that has been used in the SJRPP and Northside units. AEO2008 does not include projections of the price of international coal for delivery to the United States. Given the similarities in coal characteristics and the capability of the SJRPP and Northside units to burn Eastern Interior coal, consideration of Eastern Interior coal is appropriate for the comparative economic analyses presented throughout this Application.

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[1] Regional fuel price projections, such as those shown in Table 7-1 for FRCC, are not included in the AEO2008 report itself, but are available on the EIA Web site as *Supplemental Tables* (http://www.eia.doe.gov/oiaf/aeo/supplement/supref.html). The FRCC fuel price projections corresponding to the AEO2008, from which the data in Table 7-1 were extracted, are presented in Supplemental Table 69.

[2] Supplemental Table 69 to the AEO2008, referenced previously, only presents forecasts of prices for coal delivered to the FRCC region on a composite basis (i.e., a single coal price forecast, with no differentiation between coal type/production region). EIA was able to provide forecast prices for coal delivered to the Georgia/Florida region from various coal production regions upon request. These projections are factored into the overall modeling and analysis used to generate the coal price projections shown in Supplemental Table 69 to the AEO2008.

Table 7-1
Annual Energy Outlook 2008 Reference Case Price Projections
Forecast of Natural Gas and Fuel Oil Delivered to the
Florida Reliability Coordinating Council Boundary(1)

Year	Natural Gas (2006 $/MBtu) (2)	Distillate Fuel Oil (2006 $/MBtu) (3)	Residual Fuel Oil (2006 $/MBtu)
2008	7.53	17.05	10.08
2009	7.83	14.50	11.13
2010	7.44	13.83	10.33
2011	7.17	13.13	9.78
2012	7.23	12.43	9.14
2013	6.88	11.73	8.61
2014	6.64	11.45	8.36
2015	6.47	10.88	7.80
2016	6.40	10.45	7.36
2017	6.41	10.46	7.35
2018	6.46	10.60	7.46
2019	6.51	10.75	7.60
2020	6.42	10.86	7.70
2021	6.31	10.96	7.80
2022	6.44	11.07	7.87
2023	6.49	11.27	8.04
2014	6.60	11.50	8.23
2025	6.73	11.72	8.40
2026	6.78	11.95	8.57
2027	6.87	12.13	8.60
2028	7.09	12.35	8.78
2029	7.17	12.60	8.87
2030	7.30	12.83	9.04

(1) Based on data presented in Supplemental Table 69 to the AEO2008 Reference Case.
(2) Natural gas price projections do not include usage charges or firm or interruptible transportation charges within the State. These costs are accounted for in the economic analysis as discussed in Section 16.0 of this Application.
(3) Distillate fuel oil price projections reflect the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004, which requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 parts per million (ppm) starting mid-2007. NRLM also establishes a new ultra-low sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010.

Table 7-2
Annual Energy Outlook 2008 Reference Case Price Projections
Forecast of High Sulfur Eastern Interior and
Low Sulfur Powder River Basin Coal Delivered to the Georgia/Florida Region(1)

Year	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006 $/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006 $/MBtu)
2008	2.27	1.88
2009	2.38	1.97
2010	2.49	2.07
2011	2.52	2.08
2012	2.53	2.05
2013	2.52	2.06
2014	2.53	2.06
2015	2.51	2.05
2016	2.52	2.04
2017	2.52	2.04
2018	2.50	2.05
2019	2.52	2.07
2020	2.51	2.08
2021	2.51	2.08
2022	2.54	2.09
2023	2.55	2.10
2014	2.57	2.11
2025	2.59	2.12
2026	N/A	2.13
2027	N/A	2.14
2028	N/A	2.16
2029	N/A	2.17
2030	N/A	2.18

(1) Based on data received directly from the EIA.

7.4 AEO2008 High and Low Price Case Natural Gas, Fuel Oil, and Coal Price Projections

The AEO2008 includes various cases in addition to the reference case. Each of these cases incorporates various changes to the reference case assumptions. Of the various cases considered by the EIA as part of AEO2008, two cases have been carried forward to the analyses considered in this Application in addition to the reference case – the High Price Case and the Low Price Case. Both the High Price Case and the Low

Price Case rely on assumptions consistent with the reference case with the exception of assumptions related to crude oil and natural gas resources. The High Price Case reflects more pessimistic assumptions related to these resources while the Low Price Case reflects more optimistic assumptions. Both the High Price and Low Price cases are fully integrated NEMS simulations, consistent with the reference case.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2008 High Price Case are presented in Table 7-3. For comparison purposes, the AEO2008 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-3. Figures 7-1 through 7-4 present graphical comparisons of the High Price Case and Reference Case price projections shown in Table 7-3.

The natural gas, fuel oil, and coal price projections corresponding to the AEO2008 Low Price Case are presented in Table 7-4. For comparison purposes, the AEO2008 Reference Case price projections for natural gas, fuel oil, and coal are also presented in Table 7-4. Figures 7-5 through 7-8 present graphical comparisons of the Low Price Case and Reference Case price projections shown in Table 7-4.

The price projections in Tables 7-3 and 7-4 (and corresponding Figures 7-1 through 7-8) are not specific to the FRCC region. The following section discusses the methodology used to develop high and low fuel price projections specific to FRCC.

7.5 FRCC High and Low Fuel Price Projections

As discussed in Section 7.4, AEO2008 included High Price Case and Low Price Case fuel price projections. Both the High and Low Price case projections were developed on a national basis and are, therefore, not specific to the FRCC region. Adjustments were made to the High Price Case and Low Price Case natural gas, fuel oil, and coal price projections in order to develop high and low fuel price projections specific to the FRCC region. The following subsections discuss the methodology used to develop the FRCC-specific high and low fuel price projections and present the resulting annual natural gas, fuel oil, and coal price projections. Consideration of any additional intrastate transportation costs is discussed in Section 16.0.

7.5.1 High Fuel Price Projections for FRCC

7.5.1.1 High Natural Gas Prices. In order to develop natural gas price projections for the FRCC region based on the AEO2008 High Price Case, the AEO2008 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-3. The annual transportation differentials between natural gas delivered to the FRCC region and

Table 7-3
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

Year	Natural Gas - Henry Hub (2006$/MBtu)		Fuel Oil - Electric Power (2006 cents/gallon) Distillate		Fuel Oil - Electric Power (2006 cents/gallon) Residual		Coal - Average Minemouth (2006$/MBtu)	
	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case	High Price Case	Reference Case
2008	7.23	7.23	240.7	240.7	157.2	157.2	1.28	1.28
2009	7.40	7.35	204.3	197.6	148.5	149.3	1.29	1.29
2010	7.28	6.90	203.1	189.0	146.6	141.5	1.28	1.28
2011	7.00	6.56	206.0	179.2	148.9	134.2	1.26	1.25
2012	7.01	6.37	209.4	169.1	155.5	127.5	1.25	1.22
2013	6.92	6.16	211.4	159.8	156.9	121.8	1.23	1.20
2014	6.85	5.99	217.1	156.1	161.2	117.9	1.22	1.18
2015	6.92	5.87	221.6	148.0	164.6	110.9	1.20	1.17
2016	7.02	5.82	226.5	142.3	168.6	105.2	1.21	1.16
2017	7.12	5.89	234.7	142.5	175.3	105.5	1.19	1.15
2018	7.16	5.97	242.5	144.5	179.9	107.7	1.19	1.14
2019	7.24	6.05	248.1	146.6	184.7	110.1	1.19	1.14
2020	7.08	5.95	254.3	148.3	190.5	112.3	1.20	1.14
2021	6.95	5.82	261.6	149.8	197.9	114.2	1.20	1.14
2022	7.01	5.95	264.3	151.6	201.5	115.7	1.21	1.15
2023	7.10	6.08	266.7	154.5	204.3	118.5	1.21	1.15
2024	7.28	6.25	269.3	157.9	208.3	121.1	1.21	1.16
2025	7.39	6.39	266.9	160.8	206.9	123.4	1.22	1.16
2026	7.64	6.56	268.7	164.4	210.7	126.4	1.22	1.16
2027	7.94	6.61	272.7	167.0	214.5	128.1	1.23	1.17
2028	8.19	6.86	277.7	169.9	218.4	131.0	1.25	1.18
2029	8.33	7.06	281.9	173.4	221.8	133.1	1.25	1.18
2030	8.43	7.22	286.5	176.2	226.6	135.3	1.28	1.19

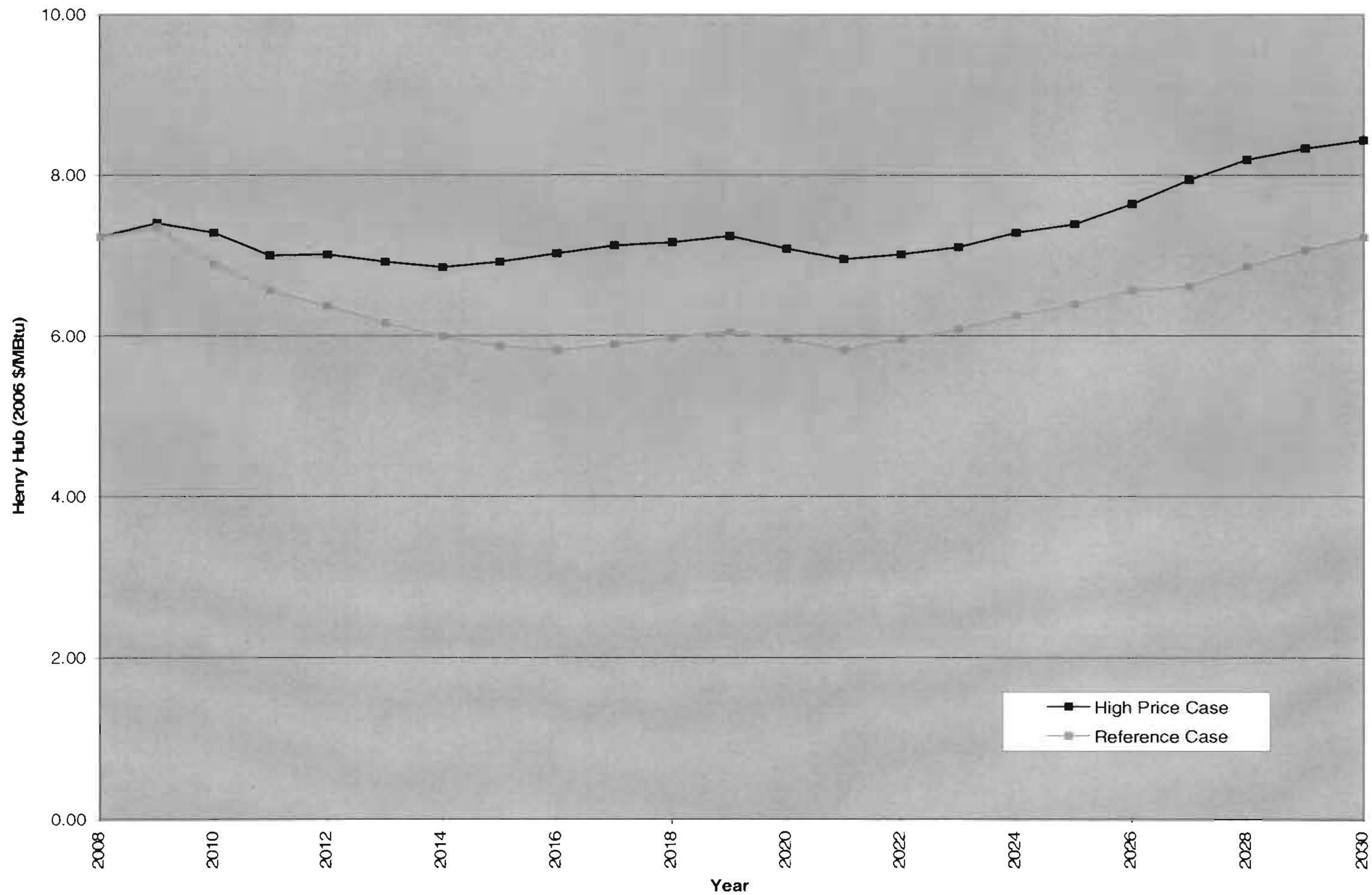


Figure 7-1
Comparison of Natural Gas Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

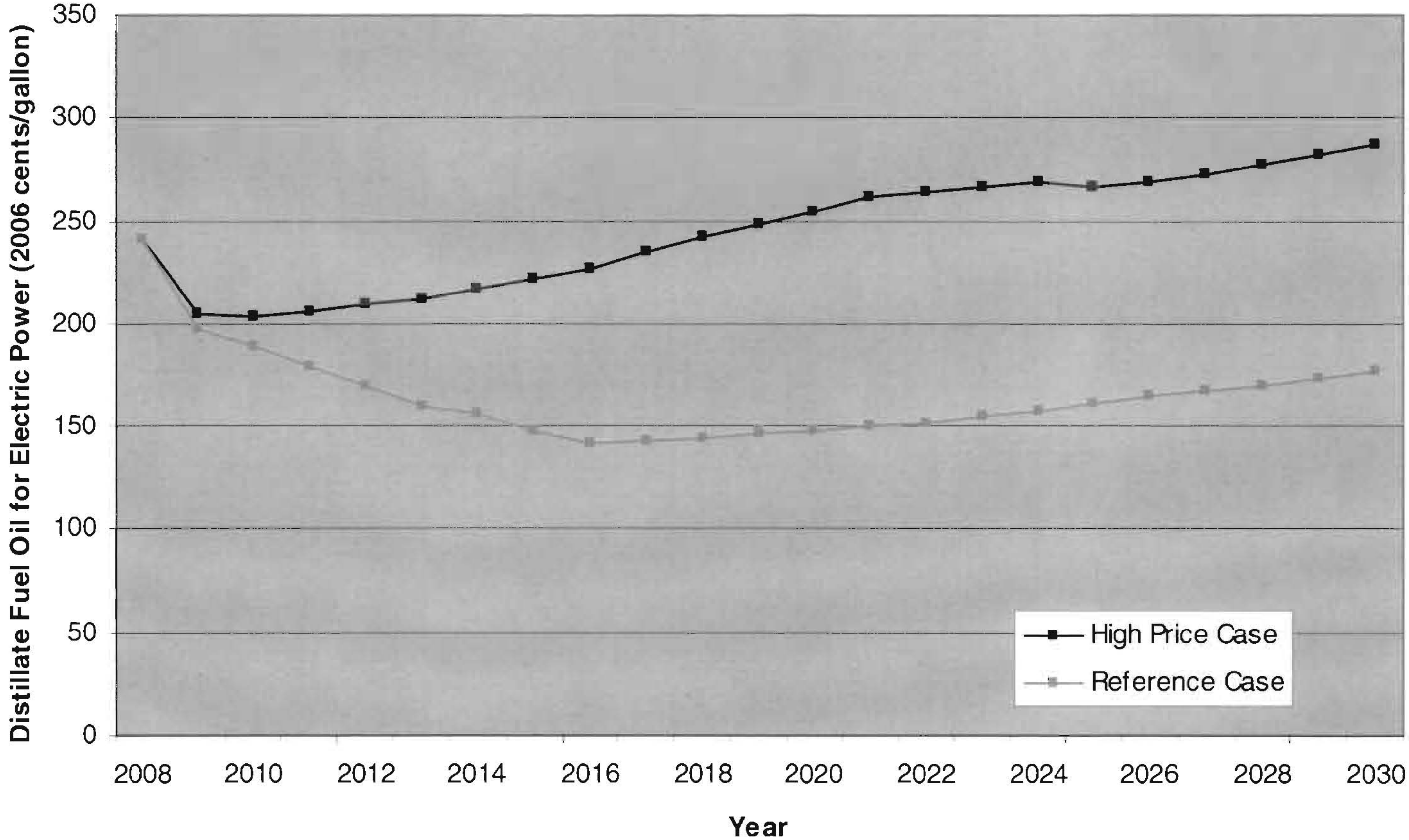


Figure 7-2
Comparison of Distillate Fuel Oil Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

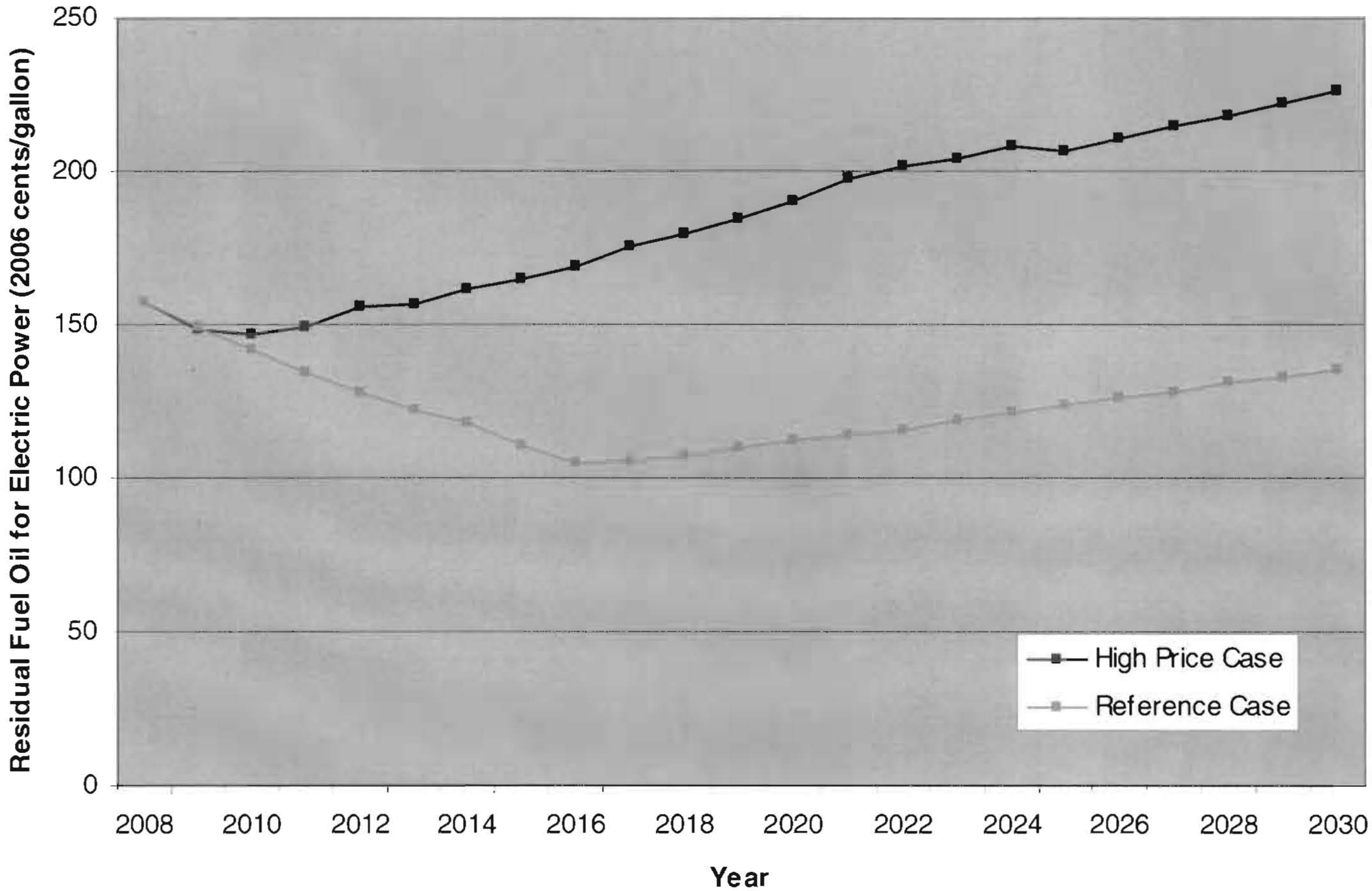


Figure 7-3
Comparison of Residual Fuel Oil Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

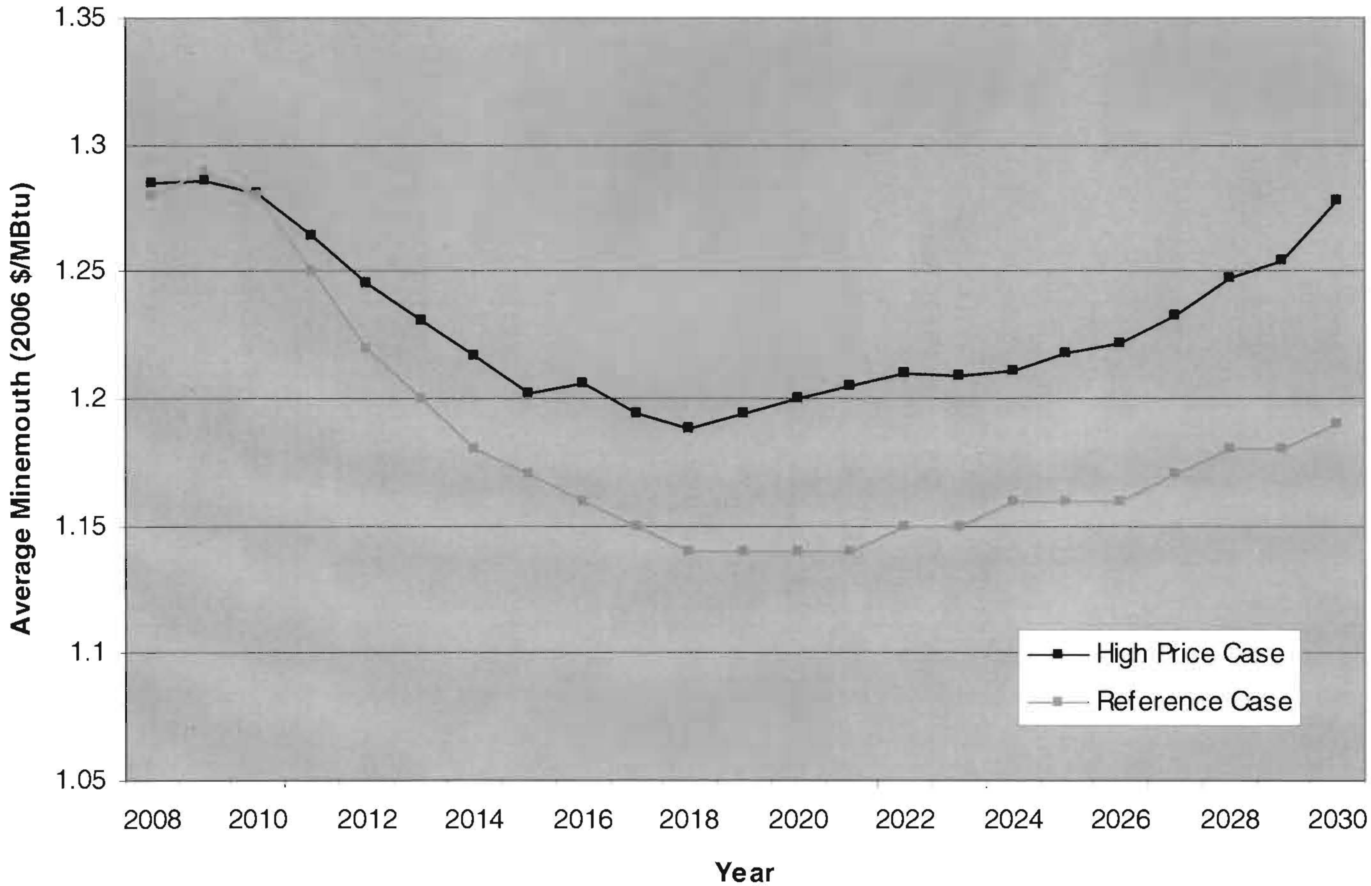


Figure 7-4
Comparison of Coal Price Projections
AEO2008 High Price Case and AEO2008 Reference Case

Table 7-4
Natural Gas, Fuel Oil, and Coal Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

	Natural Gas - Henry Hub (2006$/MBtu)		Fuel Oil - Electric Power (2006 cents/gallon)				Coal - Average Minemouth (2006$/MBtu)	
			Distillate		Residual			
Year	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case	Low Price Case	Reference Case
2008	7.23	7.23	240.7	240.7	157.2	157.2	1.28	1.28
2009	7.22	7.35	198.6	197.6	148.6	149.3	1.28	1.29
2010	6.61	6.90	178.6	189.0	132.8	141.5	1.27	1.28
2011	6.20	6.56	164.7	179.2	120.7	134.2	1.24	1.25
2012	5.92	6.37	150.5	169.1	110.9	127.5	1.21	1.22
2013	5.60	6.16	136.9	159.8	98.7	121.8	1.18	1.20
2014	5.34	5.99	123.6	156.1	86.4	117.9	1.17	1.18
2015	5.05	5.87	110.8	148.0	76.2	110.9	1.14	1.17
2016	4.83	5.82	98.0	142.3	66.0	105.2	1.12	1.16
2017	4.90	5.89	97.9	142.5	65.9	105.5	1.11	1.15
2018	4.97	5.97	97.3	144.5	65.5	107.7	1.09	1.14
2019	5.08	6.05	97.7	146.6	66.0	110.1	1.09	1.14
2020	5.01	5.95	98.1	148.3	66.4	112.3	1.09	1.14
2021	4.91	5.82	98.5	149.8	67.6	114.2	1.08	1.14
2022	4.99	5.95	98.8	151.6	67.8	115.7	1.08	1.15
2023	5.17	6.08	99.3	154.5	68.6	118.5	1.08	1.15
2024	5.30	6.25	100.0	157.9	70.4	121.1	1.08	1.16
2025	5.42	6.39	101.1	160.8	71.3	123.4	1.09	1.16
2026	5.55	6.56	102.5	164.4	72.0	126.4	1.10	1.16
2027	5.65	6.61	105.2	167.0	72.9	128.1	1.10	1.17
2028	5.78	6.86	108.4	169.9	74.3	131.0	1.11	1.18
2029	5.86	7.06	109.8	173.4	75.4	133.1	1.11	1.18
2030	6.00	7.22	111.2	176.2	76.1	135.3	1.12	1.19

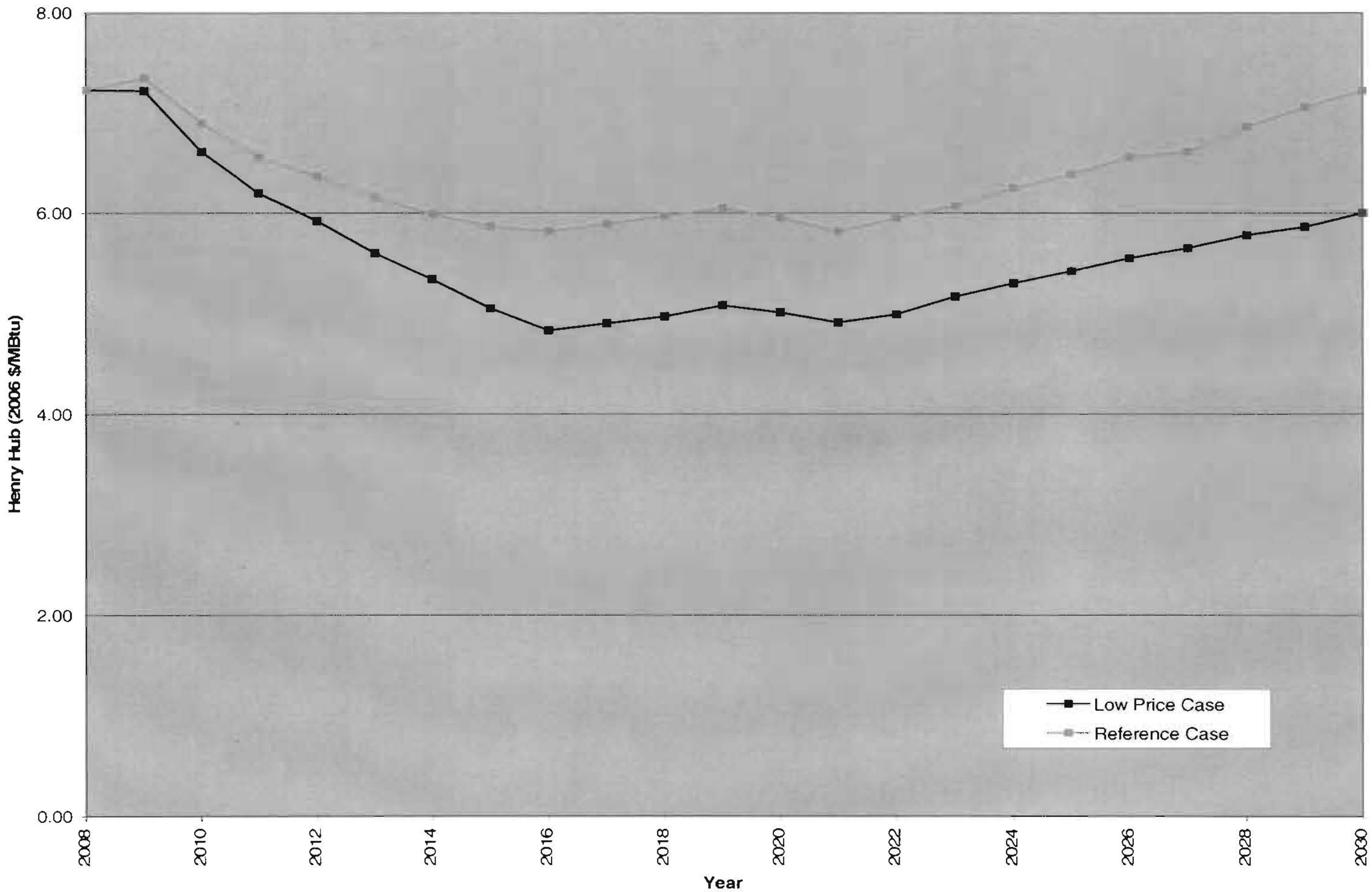


Figure 7-5
Comparison of Natural Gas Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

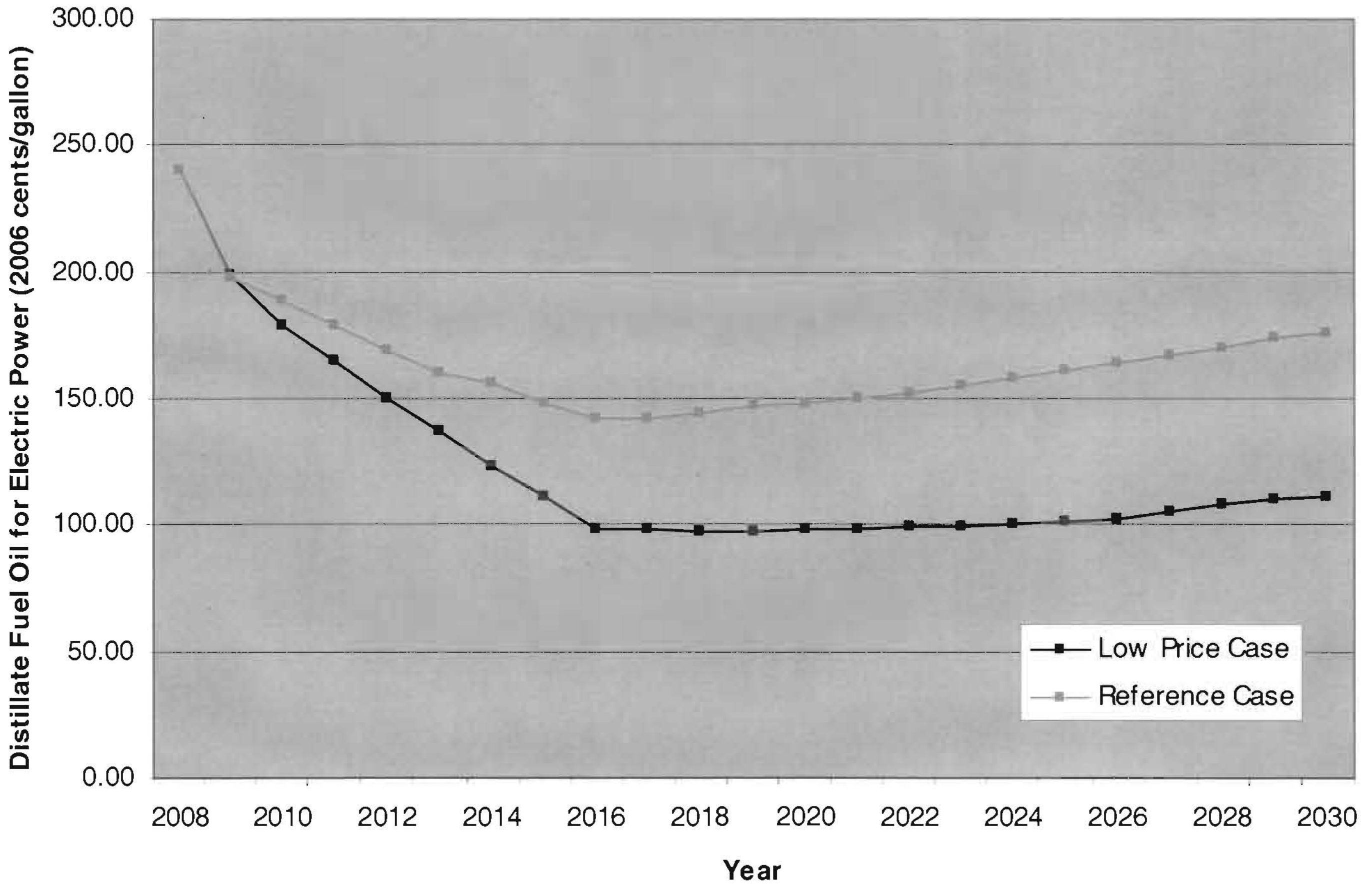


Figure 7-6
Comparison of Distillate Fuel Oil Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

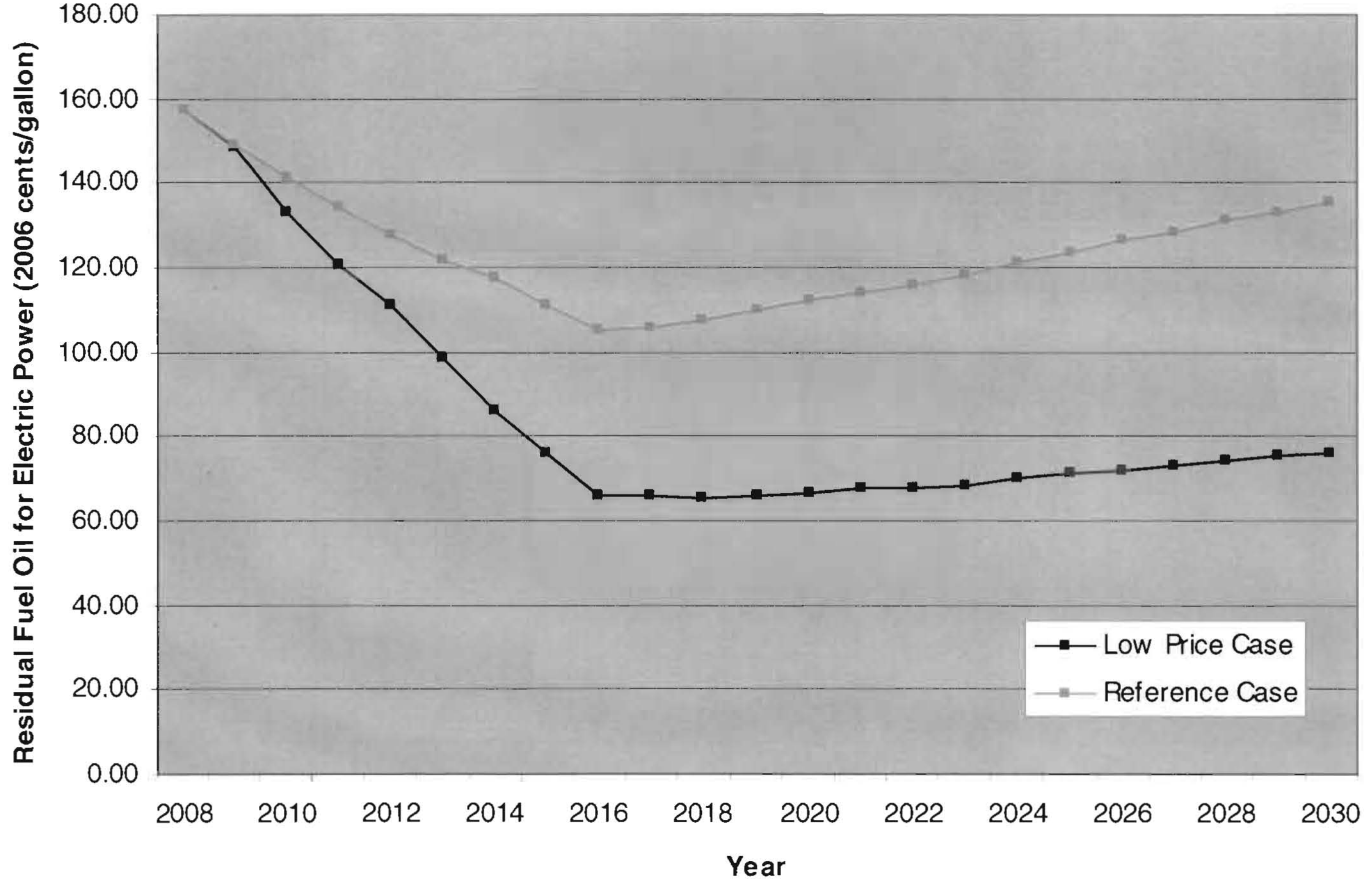


Figure 7-7
Comparison of Residual Fuel Oil Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

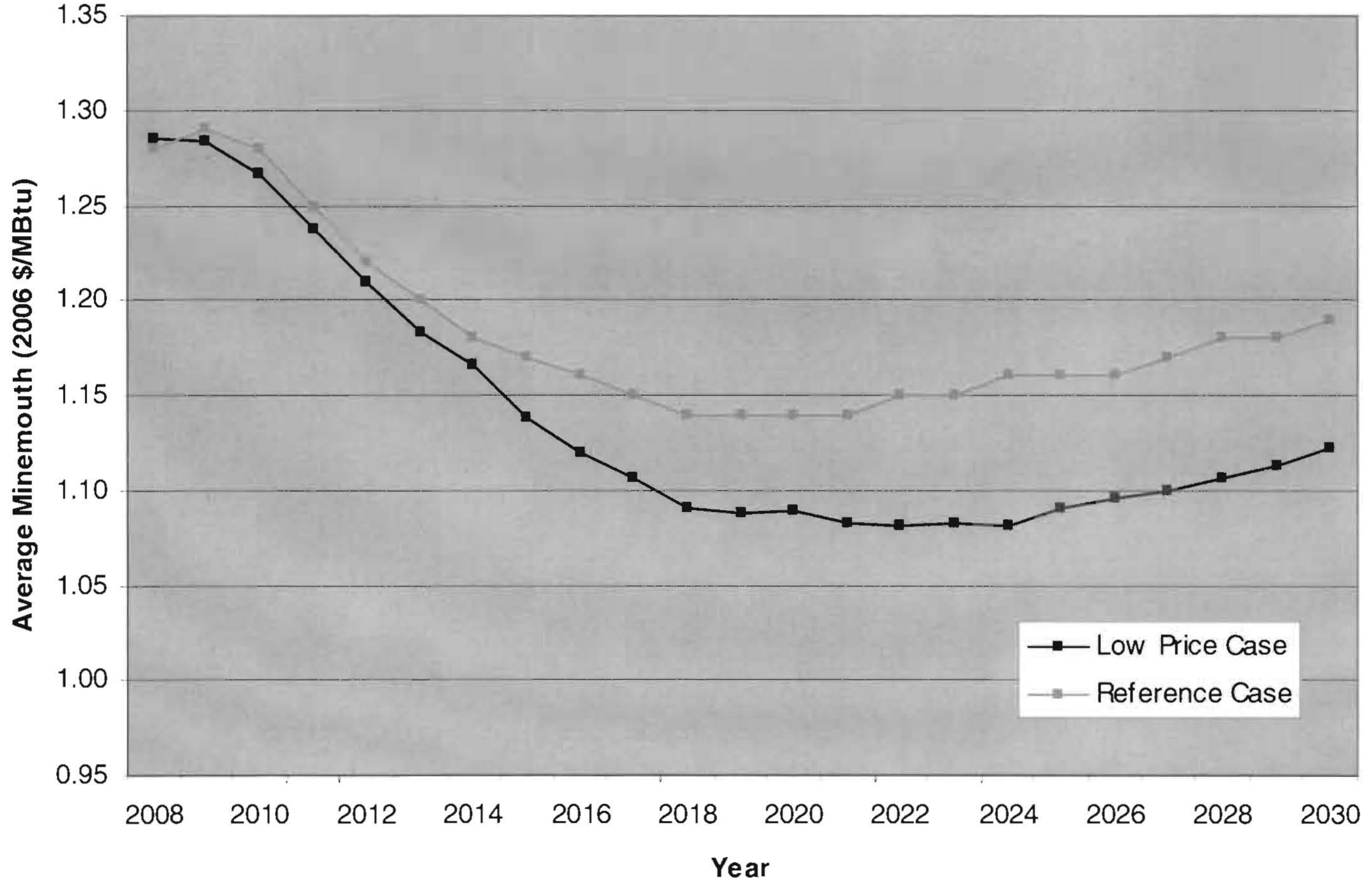


Figure 7-8
Comparison of Coal Price Projections
AEO2008 Low Price Case and AEO2008 Reference Case

natural gas at Henry Hub derived from the reference case were held constant and added to the AEO2008 High Price Case Henry Hub natural gas price projections shown in Table 7-3. The resulting high natural gas price projections specific to the FRCC region are presented in Table 7-5.

7.5.1.2 High Distillate and Residual Fuel Oil Prices. High price projections for distillate and residual fuel oil specific to the FRCC region were developed by first converting the AEO2008 High Price and AEO2008 Reference Case projections presented in Table 7-3 from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2008 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-3) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2008 High Price Case projections shown in Table 7-3 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting high distillate and residual fuel oil price projections specific to the FRCC region are presented in Table 7-5.

7.5.1.3 High Eastern Interior and Powder River Basin Coal Prices

The AEO2008 Reference Case Eastern Interior and PRB minemouth coal prices (annual dollars per ton)[3] were divided by the respective heat content of the coal from these regions (MBtu per ton)[4] resulting in reference case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

The AEO2008 Reference Case average minemouth coal prices for the United States were subtracted from the AEO2008 High Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the High Case average US minemouth coal prices. This annual differential was applied to the reference case minemouth prices specific to Eastern Interior and PRB described above to yield annual high case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) to represent the cost for delivering Eastern Interior and PRB coal from the minemouth to the FRCC region was calculated by taking the difference between the annual reference case Eastern Interior and PRB minemouth prices and the AEO2008 Reference Case Eastern Interior and PRB coal prices delivered to the FRCC Region. This annual delivery adder was applied to the high case Eastern Interior and PRB coal minemouth prices resulting in the high price case

[3] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[4] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

projections for Eastern Interior and PRB coal delivered to the FRCC region, which are presented in Table 7-5.

7.5.2 Low Fuel Price Projections for FRCC

7.5.2.1 Low Natural Gas Prices. In order to develop natural gas price projections for the FRCC region based on the AEO2008 Low Price Case, the AEO2008 Reference Case natural gas price projections were analyzed to determine the annual differential between the FRCC-specific natural gas price projections presented in Table 7-1 and the Reference Case Henry Hub natural gas price projections presented in Table 7-4. The annual transportation differentials between natural gas delivered to the FRCC region and natural gas at Henry Hub derived from the reference case were held constant and added to the AEO2008 Low Price Case Henry Hub natural gas price projections shown in Table 7-4. The resulting low natural gas price projections specific to the FRCC region are presented in Table 7-6.

7.5.2.2 Low Distillate and Residual Fuel Oil Prices. Low price projections for distillate and residual fuel oil specific to the FRCC region were developed by first converting the AEO2008 Low Price and AEO2008 Reference Case projections presented in Table 7-4 from cents per gallon to dollars per MBtu. The conversions were made by using the heat contents for distillate (138,690 Btu per gallon) and residual (149,690 Btu per gallon) used by the EIA. The annual transportation differentials for distillate and residual fuel oil between the AEO2008 Reference Case for the FRCC region (presented in Table 7-1) and for electric power usage in the United States as a whole (presented in Table 7-4) were determined. These annual transportation differentials for distillate and residual fuel oil were added to the AEO2008 Low Price Case projections shown in Table 7-4 (after being converted to dollars per MBtu using the heat contents referenced previously). The resulting low distillate and residual fuel oil price projections specific to the FRCC region are presented in Table 7-6.

7.5.2.3 Low Eastern Interior and Powder River Basin Coal Prices. The AEO2008 Reference Case Eastern Interior and PRB minemouth coal prices (annual dollars per ton)[5] were divided by the respective heat content of the coal from these regions (MBtu per ton)[6] resulting in reference case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

[5] http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_113.xls
[6] Table 71, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/coal.pdf

Table 7-5
Annual Energy Outlook 2008 High Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (2006$/MBtu)[2]	Distillate Fuel Oil (2006$/MBtu)	Residual Fuel Oil (2006$/MBtu)	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006$/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006$/MBtu)
2008	7.53	17.05	10.08	1.89	2.27
2009	7.88	14.98	11.07	1.97	2.38
2010	7.81	14.85	10.67	2.07	2.49
2011	7.61	15.06	10.76	2.10	2.54
2012	7.86	15.33	11.02	2.08	2.55
2013	7.65	15.45	10.96	2.08	2.55
2014	7.50	15.85	11.26	2.09	2.56
2015	7.53	16.18	11.39	2.08	2.55
2016	7.60	16.52	11.59	2.08	2.56
2017	7.64	17.11	12.01	2.09	2.57
2018	7.65	17.67	12.29	2.10	2.55
2019	7.70	18.06	12.59	2.12	2.57
2020	7.55	18.50	12.92	2.14	2.57
2021	7.44	19.03	13.39	2.14	2.57
2022	7.49	19.20	13.60	2.15	2.60
2023	7.50	19.36	13.77	2.16	2.61
2024	7.63	19.53	14.05	2.16	2.63
2025	7.74	19.37	13.97	2.18	2.65
2026	7.86	19.47	14.21	2.19	2.67
2027	8.20	19.76	14.38	2.21	2.70
2028	8.41	20.13	14.62	2.23	2.73
2029	8.44	20.43	14.80	2.24	2.76
2030	8.51	20.78	15.13	2.27	2.80

(1) Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (High Price Case), Table 13 (Reference Case), Table 13 (High Price Case), Table 15 (Reference Case), and Table 15 (High Price Case) in the AEO2008.

(2) Natural gas price projections do not include usage charges or intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 16.0 of this Application.

Table 7-6
Annual Energy Outlook 2008 Low Case Price Projections
Forecast of Natural Gas, Fuel Oil, and Central Appalachian Coal Delivered to the Florida Reliability Coordinating Council[1]

Year	Natural Gas (2006$/MBtu)[2]	Distillate Fuel Oil (2006$/MBtu)	Residual Fuel Oil (2006$/MBtu)	High Sulfur Eastern Interior (2.64 lb S/MBtu) (2006$/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu) (2006$/MBtu)
2008	7.53	17.05	10.08	1.89	2.27
2009	7.69	14.57	11.08	1.97	2.38
2010	7.15	13.08	9.75	2.07	2.48
2011	6.81	12.08	8.88	2.10	2.51
2012	6.78	11.09	8.04	2.08	2.51
2013	6.33	10.08	7.07	2.08	2.51
2014	5.99	9.10	6.26	2.09	2.51
2015	5.66	8.20	5.48	2.08	2.48
2016	5.41	7.25	4.74	2.08	2.47
2017	5.42	7.25	4.70	2.09	2.48
2018	5.45	7.20	4.64	2.10	2.45
2019	5.54	7.22	4.66	2.12	2.46
2020	5.48	7.24	4.63	2.14	2.46
2021	5.41	7.26	4.69	2.14	2.45
2022	5.47	7.27	4.66	2.15	2.47
2023	5.57	7.29	4.70	2.16	2.48
2024	5.66	7.33	4.84	2.16	2.50
2025	5.76	7.41	4.91	2.18	2.52
2026	5.77	7.49	4.95	2.19	2.55
2027	5.92	7.68	4.91	2.21	2.57
2028	6.00	7.92	5.00	2.23	2.59
2029	5.97	8.02	5.01	2.24	2.62
2030	6.08	8.15	5.08	2.27	2.64

(1) Based on data presented in Supplemental Table 69 (Reference Case), Table 12 (Reference Case), Table 12 (Low Case), Table 13 (Reference Case), Table 13 (Low Price Case), Table 15 (Reference Case), and Table 15 (Low Price Case) in the AEO2008.

(2) Natural gas price projections do not include any usage charges of intrastate firm or interruptible transportation charges. These costs are accounted for in the economic analysis as discussed in Section 16.0 of this Application.

The AEO2008 Low Case average minemouth coal prices for the United States were subtracted from the AEO2008 Reference Case average minemouth coal prices for the United States (each of which are presented in Table 7-3) to give an annual differential from the Reference Case to the Low Case average US minemouth coal prices. This annual differential was applied to the reference case minemouth prices specific to Eastern Interior and PRB described above to yield annual low case minemouth prices specific to Eastern Interior and PRB coal on a dollar per MBtu basis.

An annual delivery adder (dollar per MBtu basis) to represent the cost for delivering Eastern Interior and PRB coal from the minemouth to the FRCC region was calculated by taking the difference between the annual reference case Eastern Interior and PRB minemouth prices and the AEO2008 Reference Case Eastern Interior and PRB coal prices delivered to the FRCC region. This annual delivery adder was applied to the low case Eastern Interior and PRB coal minemouth prices resulting in the low price case projections for Eastern Interior and PRB coal delivered to the FRCC region, which are presented in Table 7-6.

7.6 EIA Analysis of Senate Bill 2191

Several bills to regulate emissions of GHGs (including CO_2, methane, NO_x, and fluorinated gas) have been proposed to the 110th US Congress. In response to a request from Senators Joseph Lieberman and John Warner, the US EIA developed an analysis entitled *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner ClimateSecurity Act of 2007*, which was published in April 2008. The following subsections discuss this analysis and summarize the conclusions EIA arrived at regarding projected CO_2 emission allowance prices and associated impacts to the price of natural gas.

As of the date that this Application was prepared, *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* was one of three published analyses by the EIA of proposed legislation to regulate CO_2. The other two analyses were published by the EIA in January 2008 and April 2007, titled *Energy Market and Economic Impacts of S.1766, the Low Carbon Economy Act of 2007*, and *Energy Market and Economic Impacts of S.280, the Climate Stewardship and Innovation Act of 2007*, respectively. The CO_2 emission allowance prices and corresponding natural gas price projections presented in the EIA's analysis of S.2191 are higher than those presented in the EIA's analysis of S.1766 and the EIA's analysis of S.280, and the price projections presented in S.2191 utilize the most advanced forecasting models. Therefore, the EIA's analysis of S. 2191 was selected for consideration in this Application.

7.6.1 Overview of the Proposed Climate Security Act of 2007 (S.2191)

The *Climate Security Act of 2007* was introduced to the 110th US Congress as S.2191 on October 18, 2007, by Senators Lieberman (for himself, Senator Warner, Senator Harkin, Senator Coleman, Senator Dole, Senator Collins, Senator Cardin, Senator Klobuchar, and Senator Casey). The legislative intent of S.2191 is as follows:

> **(1)To establish the core of a federal program that will reduce United States greenhouse gas emissions substantially enough between 2007 and 2050 to avert the catastrophic impacts of global climate change; and (2) to accomplish that purpose while preserving robust growth in the United States economy, creating new jobs, and avoiding the imposition of hardship on United States citizens.**

As proposed, S.2191 would place a declining cap on US emissions of five primary GHGs (CO_2, methane, NO_x, sulfur hexafluoride, and perfluorocarbons - which the bill denotes as type I GHGs) and on US emissions of the sixth primary GHG (hydrofluorocarbons - which the bill denotes as Type II GHG) .

The annual GHG emission targets set forth in S.2191, measured in units of CO_2 equivalents, are summarized below. According to the EIA, The Title I caps decline gradually from 5,775 million metric tons (mmt) CO_2-equivalent in 2012 (7 percent below 2006 emission levels), to 3,860 mmt in 2030 (39 percent below 2006 levels), and 1,732 mmt in 2050 (72 percent below 2006 levels).

- For calendar years beginning after 2011 – 5,775 mmt, reduced by the amount of emissions of GHG in calendar year 2012 from noncovered entities.
- For calendar years beginning after 2029 – 3,860 mmt, reduced by the amount of emissions of GHG in calendar year 2030 from noncovered entities.
- For calendar years beginning after 2049 – 1,732 mmt, reduced by the amount of emissions of GHG in each such calendar year from noncovered entities.

Under S.2191, individual covered entities must submit allowances equal to their emissions, but their CO_2 emissions are not otherwise limited. Entities could buy and sell allowances, or bank allowances for future use. Under limited conditions, covered entities could also borrow allowance credits against future emissions reductions. Additionally, there are various alternative means of compliance including the following:

- Submitting tradable allowances from another nation's market in GHG emissions.
- Submitting a registered net increase in sequestration.
- Submitting a GHG emissions reduction (other than a registered net increase in sequestration).

- Submitting credits related to assisting developing countries achieve sustainable development and contribute to reducing their GHG emissions.

7.6.2 EIA Analysis of S.2191 – Overview and Summary of Results[7]

In developing its analysis of S.2191, EIA ran each of the policy cases described below through its integrated NEMS program. NEMS is developed and maintained by the EIA's Office of Integrated Analysis and Forecasting to provide projections of domestic energy-economy markets in the long term and perform policy analyses requested by decision makers in various US government agencies (including the White House, Congress, and offices within the US Department of Energy, among others). NEMS is the modeling tool used by EIA in developing its AEO2008. For the S.2191 analysis EIA made adjustments to the AEO2008 Reference Case that are delineated in Appendix C of the *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007.* The adjustments encompass assumptions related to the treatment of ethanol and biodiesel, offshore wind technology, corn and biomass feedstock, interregional transmission cost structure, and biomass electricity generation.

The use of NEMS allows for a fully integrated analysis of potential GHG emission allowance prices and energy demand. As stated in EIA's analysis of S.2191:

> **NEMS endogenously calculates changes in energy-related CO_2 emissions in the analysis cases. The cost of using each fossil fuel includes the costs associated with the GHG allowances needed to cover the emissions produced when they are used. The adjustments influence energy demand and energy-related CO_2 emissions. The GHG allowance price also determines the reductions in the emissions of other GHGs and from international offsets based on abatement cost relationship. With emission allowance banking, NEMS solves for the time path of permit prices such that cumulative emissions match the cumulative emissions target without requiring allowance borrowing and with price escalation consistent with the average cost of capital to the electric power sector.**

The EIA analysis of S.2191 includes several various policy cases and projections of associated CO_2 emissions allowance prices. The policy cases considered by EIA in the analysis of S.2191 are described as follows:

- **S.2191 Core Case** – represents the primary policy case.
- **S.2191 No International Offsets Case** – assumes offsets from international sources are not available.

[7] Refer to *Energy Market and Economic Impacts of S.2191, the Lieberman-Warner Climate Security Act of 2007* for additional detail regarding the various policy cases and the analysis as a whole.

- **S.2191 High Cost Case** – is similar to the S.2191 Core Case except that the costs of nuclear, coal with carbon capture and sequestration (CCS), and biomass generating technologies are assumed to be 50 percent higher than in the Core Case.
- **S. 2191 Limited Alternatives Case** – represents an environment where the deployment of key technologies, including nuclear, fossil with CCS, and various renewables, is held to their reference case level through 2030, as are imports of LNG.
- **S. 2191 Limited/No International Case** – combines the assumptions from the S. 2191 Limited Alternatives and S. 2191 No International Offset Cases.

The following tables and figures summarize results of the evaluations of the five policy cases considered by EIA in its analysis of S.2191. Tables 7-7 through 7-10 present projections of annual natural gas, distillate fuel oil, residual fuel oil, and coal prices, respectively, for use in the electric power sector for each of the five policy cases, as well as the corresponding annual price projections presented in the AEO2008 Reference Case. The annual natural gas price projections are presented in constant 2006 dollars per mcf, the distillate and residual fuel oil prices are presented in constant 2006 cents per gallon, and the annual coal price projections are presented in constant 2006 dollars per MBtu. Annual natural gas and coal price projections are presented beginning in 2012, which is the initial year of CO_2 emissions regulations contemplated in S.2191. It is important to note that the price projections for the five policy cases presented in Tables 7-7 through 7-10 include the cost of CO_2 emission allowances, while no such costs are included in the annual price projections for the AEO2008 Reference Case. Table 7-11 presents projections of annual CO_2 emissions allowance prices for each of the five policy cases, in constant 2006 dollars per metric ton CO_2 equivalent, beginning in 2012. Figure 7-9 through Figure 7-13 present graphical depictions of the data in Tables 7-7 through 7-112, respectively. Analysis of Tables 7-7 through 7-11 (supplemented by Figures 7-9 through 7-13) shows that projected impacts on natural gas prices and corresponding CO_2 emission allowance price projections differ depending upon the policy cases considered in the EIA analysis of S.2191.

Table 7-7
Natural Gas Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 \$/mcf – Electric Power Sector, Including Cost of CO_2
Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	$6.67	$7.52	$7.75	$7.95	$9.60	$10.09
2013	$6.42	$7.36	$7.57	$7.81	$9.19	$9.39
2014	$6.23	$7.27	$7.52	$7.81	$9.05	$9.54
2015	$6.10	$7.21	$7.49	$7.81	$9.02	$9.73
2016	$6.05	$7.16	$7.53	$7.92	$8.84	$10.08
2017	$6.10	$7.23	$7.70	$8.16	$8.60	$10.43
2018	$6.15	$7.33	$7.93	$8.47	$8.33	$10.77
2019	$6.21	$7.48	$8.16	$8.86	$8.10	$11.28
2020	$6.11	$7.52	$8.30	$9.04	$8.06	$11.68
2021	$5.97	$7.49	$8.45	$9.27	$8.09	$12.05
2022	$6.09	$7.66	$8.73	$9.65	$8.32	$12.66
2023	$6.18	$7.88	$9.03	$10.07	$8.62	$13.27
2024	$6.31	$8.09	$9.32	$10.50	$8.85	$13.78
2025	$6.44	$8.25	$9.61	$10.94	$9.13	$14.23
2026	$6.56	$8.48	$10.00	$11.51	$9.47	$14.96
2027	$6.62	$8.76	$10.38	$12.01	$9.91	$15.66
2028	$6.85	$9.07	$10.79	$12.58	$10.45	$16.41
2029	$6.99	$9.51	$11.21	$13.26	$11.02	$17.31
2030	$7.13	$9.95	$11.75	$13.95	$11.64	$18.24

Table 7-8

Distillate Fuel Projections for AEO2008 Reference Case and EIA Analysis of S.2191 (Delivered 2006 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	169.06	185.57	190.03	192.94	216.40	218.59
2013	159.80	177.63	182.62	186.05	205.23	205.86
2014	156.14	173.53	179.13	182.80	199.66	202.46
2015	148.02	166.79	172.73	177.03	194.61	199.33
2016	142.27	162.32	168.72	173.89	188.13	197.97
2017	142.47	164.66	171.34	176.54	185.24	202.81
2018	144.46	169.39	176.08	181.69	184.58	209.65
2019	146.65	172.73	179.97	185.85	184.37	216.29
2020	148.32	175.76	184.14	191.02	186.77	223.94
2021	149.79	179.63	188.64	196.69	191.43	231.44
2022	151.59	184.25	193.47	202.40	196.34	239.16
2023	154.47	188.68	199.16	207.64	202.78	248.09
2024	157.92	194.45	204.81	214.11	208.44	257.93
2025	160.77	198.69	210.26	221.31	215.51	265.87
2026	164.44	204.90	216.37	227.84	224.12	276.04
2027	166.97	212.07	223.84	235.50	231.97	287.03
2028	169.89	219.08	231.84	243.78	241.83	299.27
2029	173.43	227.82	239.29	251.80	250.97	311.27
2030	176.22	236.82	247.24	261.44	261.07	324.78

Table 7-9
Residual Fuel Projections for AEO2008 Reference Case and EIA Analysis of S.2191 (Delivered 2006 Cents/Gallon – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	127.47	145.08	150.05	154.40	182.69	180.81
2013	121.77	144.11	148.57	151.86	172.83	172.20
2014	117.85	143.57	149.37	154.00	171.59	170.48
2015	110.86	138.88	145.01	150.18	168.06	169.08
2016	105.19	134.59	141.34	146.68	163.68	171.19
2017	105.50	138.68	146.02	150.73	161.01	178.65
2018	107.69	143.97	151.74	157.21	161.71	187.08
2019	110.05	150.62	157.86	164.61	163.47	194.73
2020	112.32	154.69	161.71	168.81	166.39	202.56
2021	114.21	161.09	167.52	175.39	173.15	210.39
2022	115.70	161.76	171.69	180.90	176.61	220.42
2023	118.46	168.59	177.10	187.53	183.60	232.15
2024	121.14	175.47	184.35	196.16	190.33	243.21
2025	123.44	180.75	190.87	203.72	197.92	253.68
2026	126.36	187.12	197.13	210.23	206.04	264.74
2027	128.13	193.89	206.09	220.02	213.77	278.11
2028	130.99	201.69	215.09	227.89	222.73	292.77
2029	133.09	209.34	222.18	235.62	232.85	305.70
2030	135.33	218.13	234.40	248.32	246.59	319.67

Table 7-10
Coal Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/MBtu – Electric Power Sector, Including Cost of CO_2
Allowances for S.2191 Cases)

Year	AEO 2008 Reference Case	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	$1.78	$3.39	$3.82	$4.18	$6.35	$6.61
2013	$1.76	$3.47	$3.93	$4.32	$6.16	$6.21
2014	$1.75	$3.58	$4.08	$4.48	$6.21	$6.42
2015	$1.74	$3.69	$4.22	$4.66	$6.29	$6.74
2016	$1.72	$3.82	$4.39	$4.85	$6.21	$7.10
2017	$1.72	$3.97	$4.58	$5.07	$5.95	$7.47
2018	$1.71	$4.13	$4.78	$5.30	$5.66	$7.88
2019	$1.71	$4.31	$5.01	$5.54	$5.41	$8.33
2020	$1.72	$4.49	$5.24	$5.83	$5.51	$8.81
2021	$1.72	$4.67	$5.49	$6.13	$5.77	$9.32
2022	$1.72	$4.88	$5.77	$6.46	$6.07	$9.85
2023	$1.73	$5.11	$6.07	$6.81	$6.37	$10.46
2024	$1.73	$5.34	$6.39	$7.17	$6.71	$11.11
2025	$1.74	$5.60	$6.73	$7.60	$7.06	$11.81
2026	$1.74	$5.87	$7.11	$8.02	$7.47	$12.55
2027	$1.75	$6.15	$7.51	$8.47	$7.90	$13.34
2028	$1.76	$6.46	$7.94	$8.96	$8.38	$14.21
2029	$1.77	$6.82	$8.41	$9.50	$8.87	$15.11
2030	$1.78	$7.21	$8.91	$10.07	$9.40	$16.11

Table 7-11
CO_2 Emission Allowance Price Projections from EIA Analysis of S.2191
(2006 \$/Metric Ton CO_2 Equivalent)

Year	S. 2191 Core	S. 2191 High Cost	S.2191 Limited Alternatives	S. 2191 No International Offsets	S. 2191 Limited No International Offsets
2012	$16.88	$21.47	$25.05	$48.47	$50.62
2013	$18.13	$23.06	$26.90	$46.77	$47.25
2014	$19.47	$24.77	$28.89	$47.75	$49.84
2015	$20.91	$26.60	$31.03	$48.83	$53.53
2016	$22.46	$28.57	$33.32	$48.23	$57.49
2017	$24.12	$30.68	$35.79	$45.54	$61.75
2018	$25.90	$32.95	$38.44	$42.65	$66.32
2019	$27.82	$35.39	$41.28	$40.27	$71.23
2020	$29.88	$38.01	$44.34	$41.53	$76.50
2021	$32.09	$40.82	$47.62	$44.60	$82.16
2022	$34.46	$43.84	$51.14	$47.91	$88.24
2023	$37.01	$47.09	$54.93	$51.45	$94.77
2024	$39.75	$50.57	$58.99	$55.26	$101.78
2025	$42.69	$54.31	$63.36	$59.35	$109.31
2026	$45.85	$58.33	$68.05	$63.74	$117.40
2027	$49.24	$62.65	$73.08	$68.46	$126.09
2028	$52.89	$67.28	$78.49	$73.52	$135.42
2029	$56.80	$72.26	$84.30	$78.96	$145.44
2030	$61.01	$77.61	$90.54	$84.81	$156.20

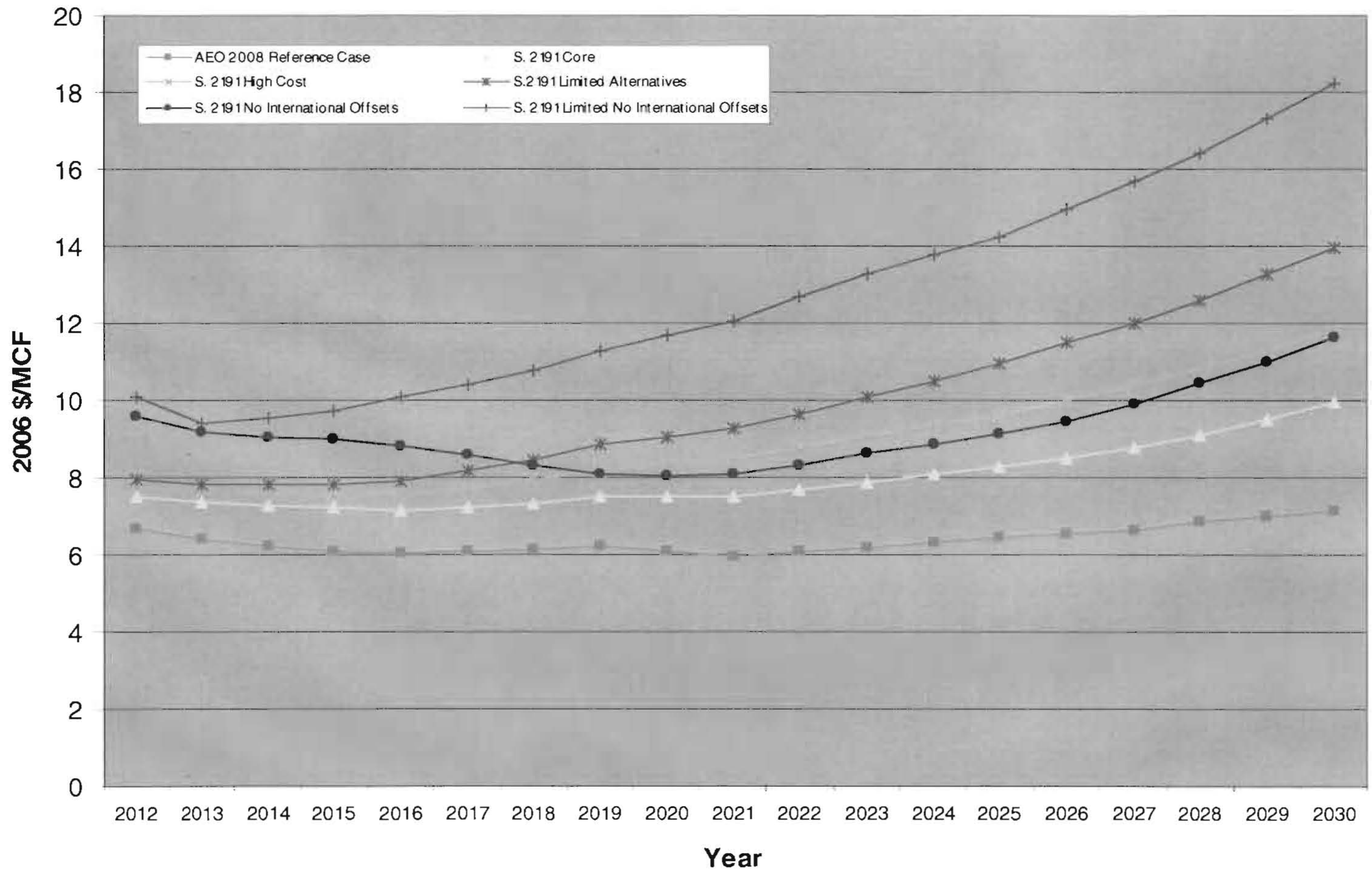


Figure 7-9
Natural Gas Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/mcf – Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

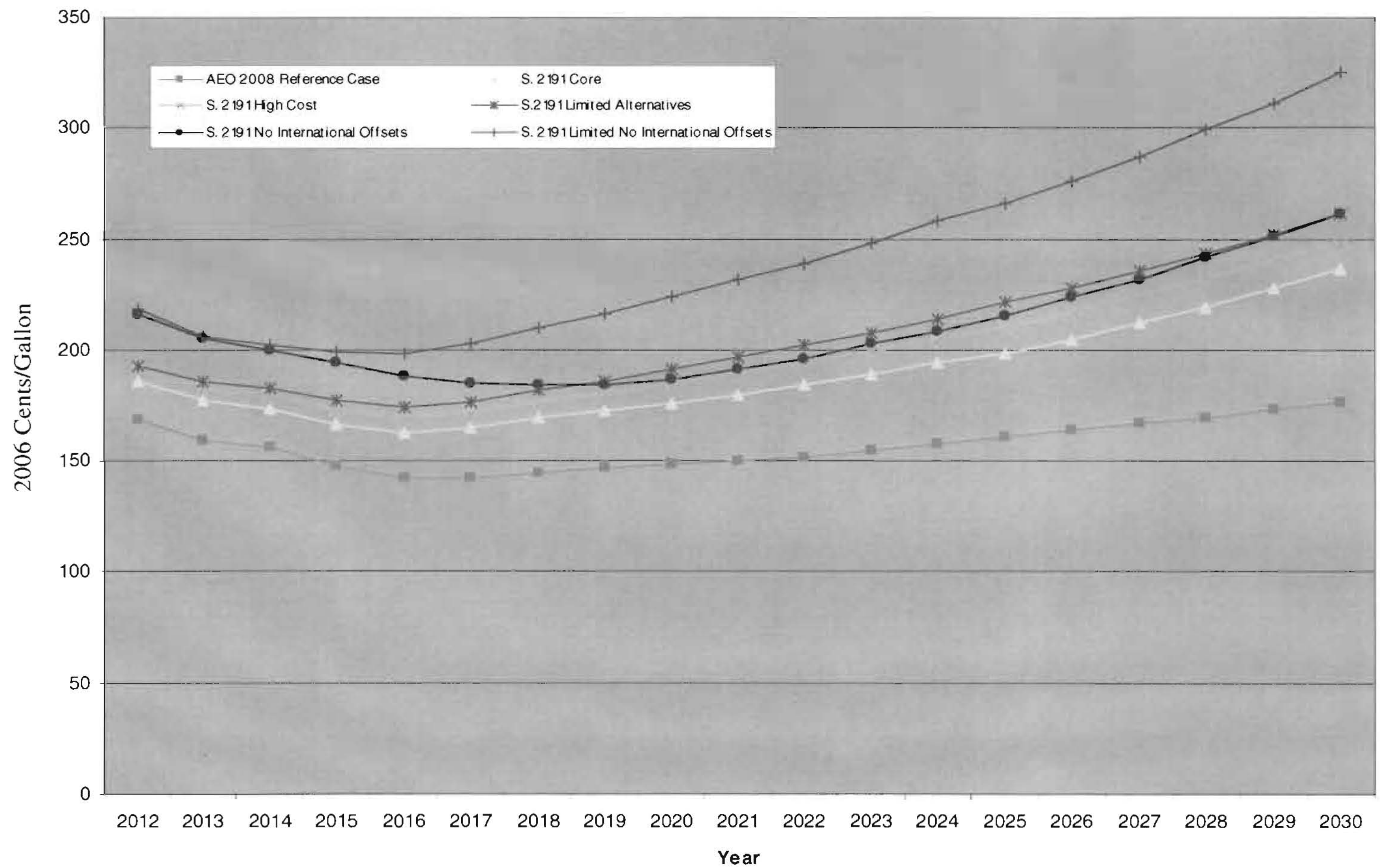


Figure 7-10
Distillate Fuel Oil Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 Cents/Gallon– Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

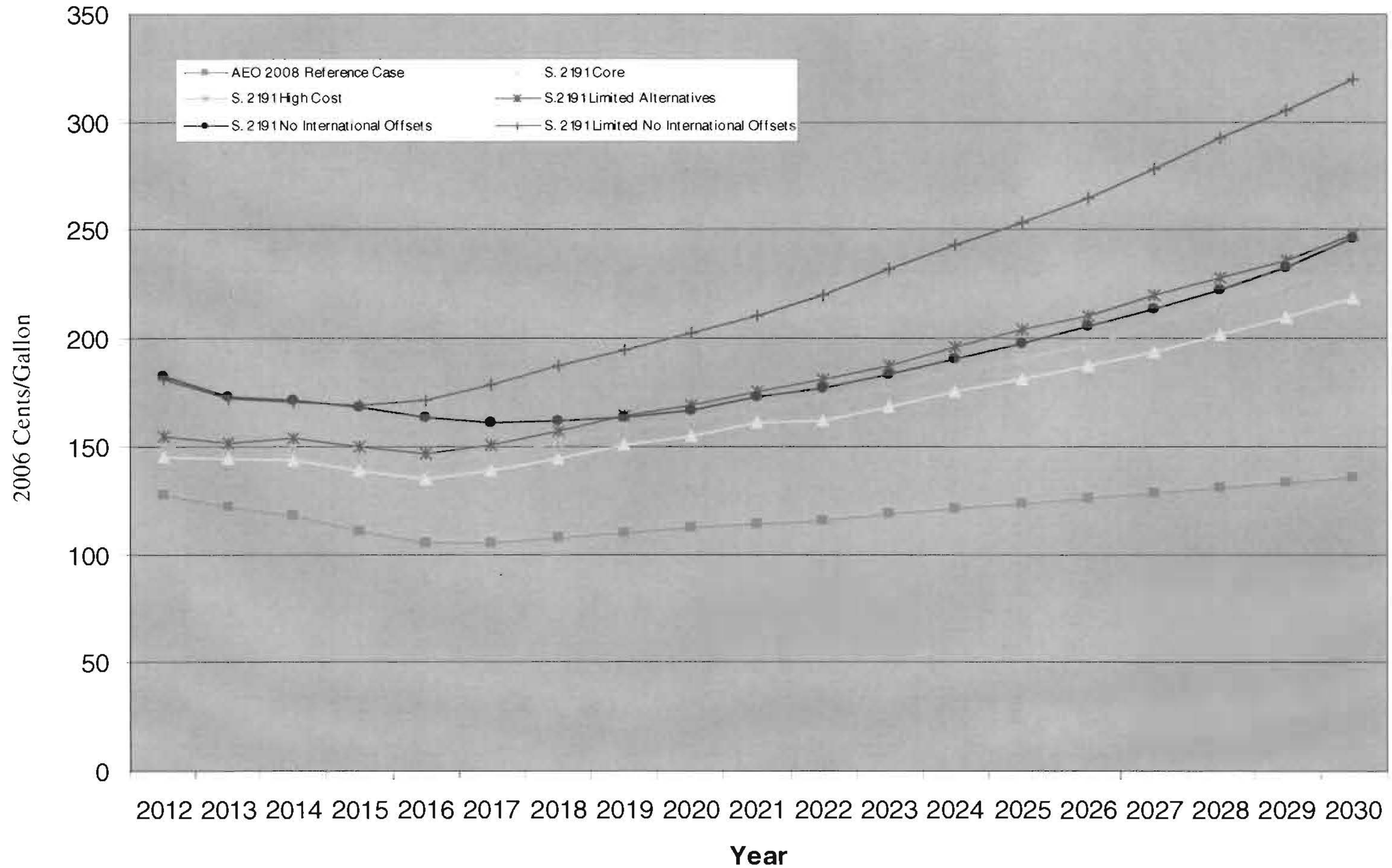


Figure 7-11
Residual Fuel Oil Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 Cents/Gallon– Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

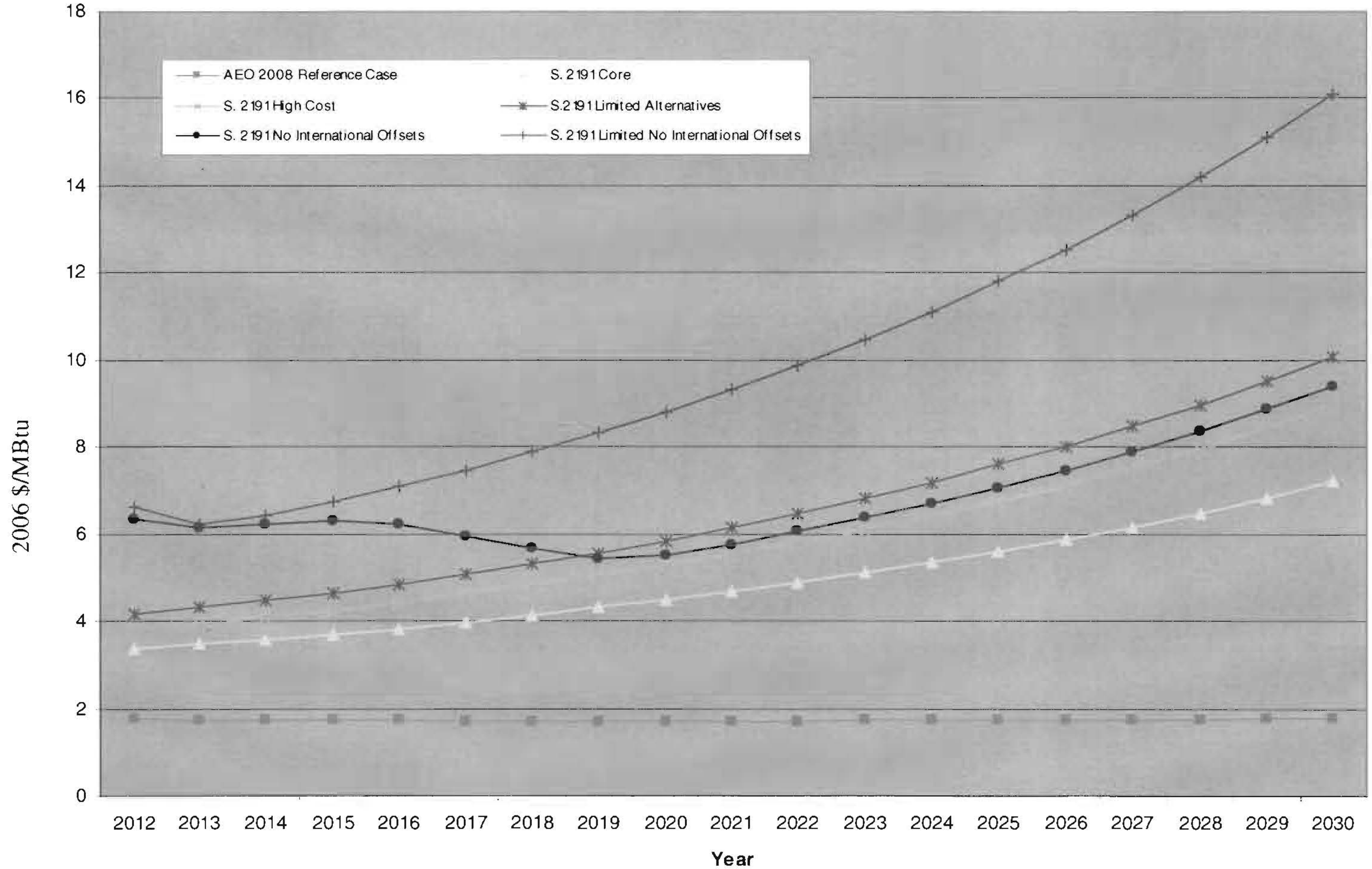


Figure 7-12
Coal Price Projections for AEO2008 Reference Case and EIA Analysis of S.2191
(Delivered 2006 $/MBtu– Electric Power Sector, Including Cost of CO_2 Allowances for S.2191 Cases)

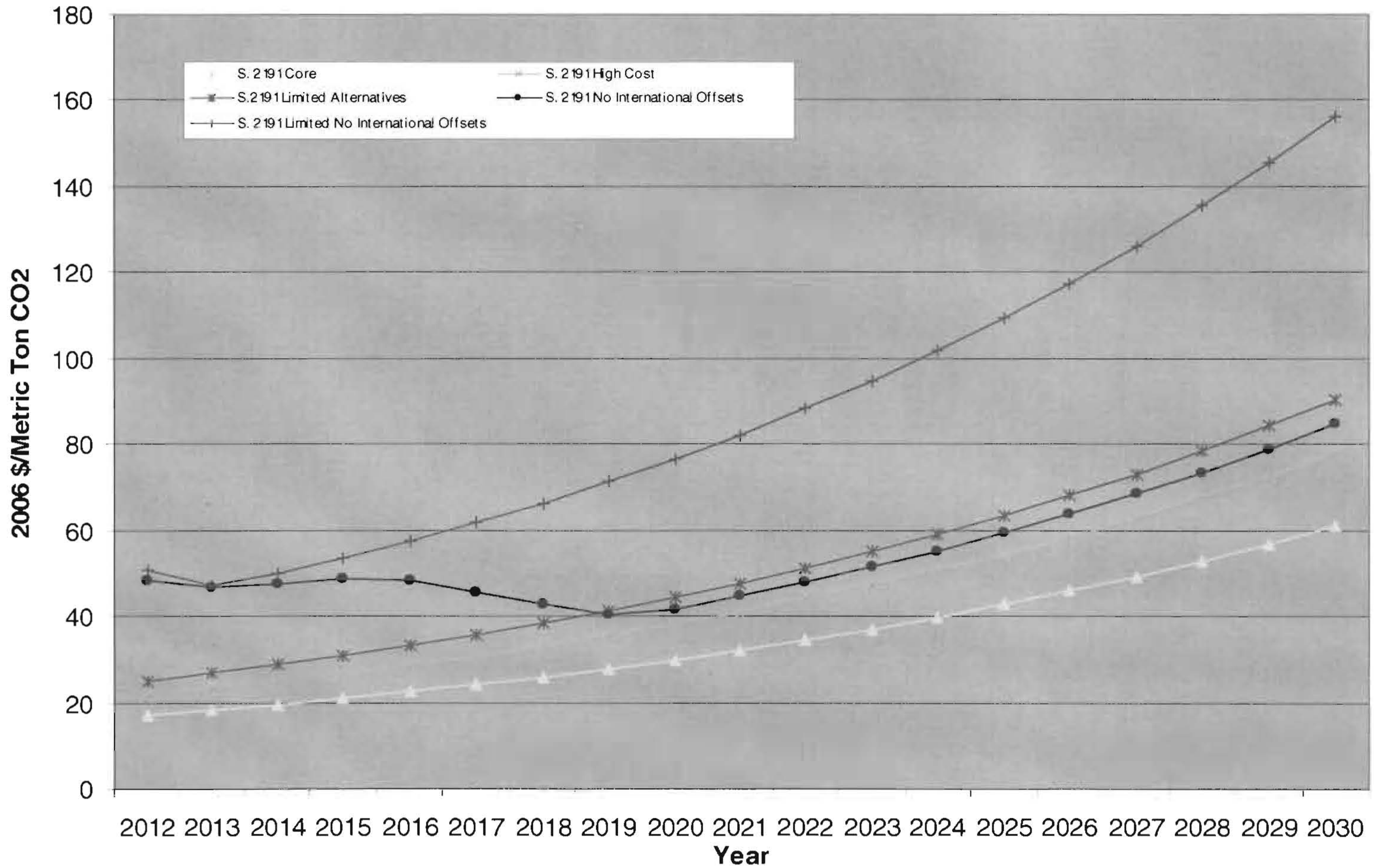


Figure 7-13
CO_2 Emission Allowance Price Projections from EIA Analysis of S.2191 (2006 \$/Metric Ton CO_2 Equivalent)

7.7 Consideration of EIA Analysis of Senate Bill 2191

As discussed in Section 7.6, the *Climate Security Act of 2007* was introduced to the 110th US Congress as S.2191 on October 18, 2007, by Senators Lieberman (for himself, Senator Warner, Senator Harkin, Senator Coleman, Senator Dole, Senator Collins, Senator Cardin, Senator Klobuchar, and Senator Casey). The EIA's analysis of S.2191 included projections of natural gas, fuel oil, and coal prices, along with projected prices for emissions of CO_2, for five various policy cases involving different assumptions related to the structure of how S.2191 may be implemented if ultimately enacted by Congress. The fuel price projections, as well as the CO_2 emissions allowance price projections, for each of the five policy cases are presented throughout Section 7.6. The EIA's consideration of S.2191 Core Case as being representative of the primary policy case resulted in the selection of the S.2191 Core Case for further analysis in this Application.

The natural gas, fuel oil, and coal price projections for the S.2191 Core Case presented in Section 7.6 include the annual costs of CO_2 emissions allowance prices, consistent with the presentation of data in EIA's analysis of S.2191. Table 7-12 presents the natural gas, fuel oil, and coal price projections from the S.2191 Core Case excluding the annual costs of CO_2 emissions allowance prices as projected by the EIA.

Also presented in Table 7-12 are projections of natural gas, fuel oil, and coal prices including the EIA's projected annual costs of CO_2 emissions allowances for the S.2191 Core Case. It should be noted that these natural gas and fuel oil price projections differ from those presented in Section 7.6 as the natural gas, fuel oil, and coal prices presented in Table 7-12 are in constant 2006 dollars per MBtu, while those presented in Section 7.6 are presented in constant 2006 dollars per mcf for natural gas and constant 2006 cents per gallon for fuel oil.

Table 7-12
S. 2191 Core Case Natural Gas, Fuel Oil, and Coal Price Projections
Compared to Non-Adjusted Fuel Price Forecasts (2006 $/MBtu)

	Natural Gas		Distillate Fuel Oil		Residual Fuel Oil		Coal	
Year	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances	Including Costs of CO_2 Emission Allowances	Excluding Costs of CO_2 Emission Allowances
2012	7.31	6.30	13.38	12.15	9.69	8.36	3.39	1.78
2013	7.16	6.07	12.81	11.48	9.63	8.20	3.47	1.75
2014	7.07	5.90	12.51	11.09	9.59	8.06	3.58	1.73
2015	7.01	5.76	12.03	10.50	9.28	7.63	3.69	1.71
2016	6.96	5.61	11.70	10.06	8.99	7.22	3.82	1.69
2017	7.03	5.57	11.87	10.11	9.26	7.36	3.97	1.68
2018	7.13	5.56	12.21	10.32	9.62	7.58	4.13	1.67
2019	7.28	5.58	12.45	10.42	10.06	7.87	4.31	1.67
2020	7.31	5.49	12.67	10.49	10.33	7.98	4.49	1.66
2021	7.29	5.32	12.95	10.60	10.76	8.23	4.67	1.63
2022	7.45	5.34	13.28	10.76	10.81	8.09	4.88	1.61
2023	7.66	5.38	13.60	10.90	11.26	8.35	5.11	1.60
2024	7.87	5.41	14.02	11.11	11.72	8.59	5.34	1.58
2025	8.03	5.37	14.33	11.20	12.08	8.71	5.60	1.55
2026	8.25	5.37	14.77	11.42	12.50	8.89	5.87	1.53
2027	8.52	5.42	15.29	11.69	12.95	9.07	6.15	1.48
2028	8.83	5.47	15.80	11.93	13.47	9.31	6.46	1.45
2029	9.25	5.63	16.43	12.27	13.98	9.51	6.82	1.43
2030	9.68	5.77	17.08	12.61	14.57	9.76	7.21	1.41

7.7.1 S.2191 Core Case Fuel Prices Delivered to the FRCC Region

Projections of natural gas, fuel oil, and coal prices to the FRCC region considering the potential impacts of CO_2 regulations, consistent with the EIA S.2191 Core Case, were developed for analysis in this Application. In order to develop such fuel price forecasts for natural gas and fuel oil, the AEO2008 Reference Case fuel prices delivered to the US electric power sector were analyzed and compared to the corresponding S.2191 Core Case fuel price projections presented in Table 7-12 (excluding the costs of CO_2 emissions allowances, which are accounted for elsewhere in the economic analysis included in this Application). Annual absolute differentials between the AEO2008 Reference Case fuel price projections and corresponding fuel price projections from the S. 2191 Core Case were calculated for natural gas, distillate and residual fuel oil. The annual absolute differentials were applied to the natural gas, distillate and residual fuel oil price projections for the FRCC Region shown in Tables 7-1 and 7-2 to develop projections of fuel prices delivered to the FRCC region that reflect the potential impact of S.2191 related to regulation of emissions of CO_2 (consistent with the EIA S.2191 Core Case). A similar method to calculate the impact of S.2191 on coal price projections was utilized. The only variation in the calculation is that the AEO2008 Reference Case fuel price projections for coal and the S.2191 Core Case price projections for coal were applied to both the Eastern Interior coal and the PRB coal. The AEO2008 Reference Case price projections for coal and the S.2191 Core Case price projections for coal were utilized as an average coal price indicator and, therefore, applied to both regions without differentiation. The resulting projections of fuel prices for 2012 through 2030, in constant 2006 dollars per MBtu, specific to the FRCC region are presented in Table 7-13. Prior to 2012, the natural gas, fuel oil, and coal price projections presented in Tables 7-1 and 7-2 remain unaffected as the analysis assumes that CO_2 regulations will begin in 2012.

Table 7-13
Forecast of Fuel Prices Delivered to FRCC Considering
Potential Impact of S.2191 (EIA S.2191 Core Case)
(2006 $/MBtu)

Year	Natural Gas	Distillate Fuel Oil	Residual Fuel Oil	High Sulfur Eastern Interior (2.64 lb S/MBtu)	Low Sulfur Powder River Basin (0.35 lb S/MBtu)
2012	$7.04	$12.39	$8.99	$2.53	$2.05
2013	$6.70	$11.69	$8.67	$2.52	$2.05
2014	$6.48	$11.28	$8.54	$2.51	$2.04
2015	$6.29	$10.70	$8.02	$2.48	$2.02
2016	$6.13	$10.25	$7.55	$2.48	$2.01
2017	$6.04	$10.30	$7.67	$2.48	$2.00
2018	$6.03	$10.50	$7.84	$2.46	$2.01
2019	$6.05	$10.60	$8.12	$2.47	$2.03
2020	$5.96	$10.65	$8.18	$2.45	$2.02
2021	$5.83	$10.76	$8.40	$2.41	$1.99
2022	$5.86	$10.90	$8.23	$2.43	$1.98
2023	$5.85	$11.03	$8.47	$2.42	$1.97
2024	$5.87	$11.23	$8.73	$2.41	$1.96
2025	$5.84	$11.33	$8.86	$2.41	$1.93
2026	$5.77	$11.51	$9.02	$2.41	$1.92
2027	$5.85	$11.78	$9.11	$2.41	$1.87
2028	$5.90	$12.03	$9.34	$2.41	$1.85
2029	$6.00	$12.37	$9.49	$2.41	$1.83
2030	$6.14	$12.74	$9.76	$2.41	$1.81

7.7.2 Carbon Dioxide Emissions Allowance Prices

EIA's projected CO_2 emission allowance prices corresponding to the S.2191 Core Case are presented in Table 7-14. EIA developed its projections of CO_2 emissions allowance prices in constant 2006 dollars per metric ton, which are shown in the second column of Table 7-14 and match those presented previously in Section 7.6 (Table 7-11). The annual CO_2 emission allowance price projections in constant 2006 dollars per short ton are shown in the third column of Table 7-14.

Table 7-14
Projected CO_2 Emission Allowance Prices
EIA S.2191 Core Case

Year	2006$/Metric Ton	2006$/Short Ton
2012	16.88	15.31
2013	18.13	16.44
2014	19.47	17.66
2015	20.91	18.97
2016	22.46	20.37
2017	24.12	21.88
2018	25.90	23.50
2019	27.82	25.24
2020	29.88	27.10
2021	32.09	29.11
2022	34.46	31.26
2023	37.01	33.58
2024	39.75	36.06
2025	42.69	38.73
2026	45.85	41.60
2027	49.24	44.67
2028	52.89	47.98
2029	56.80	51.53
2030	61.01	55.34

8.0 Natural Gas Transportation

Florida's natural gas transportation system is highly reliable and interconnected. Several areas of the system are also undergoing planned expansions. For these reasons, natural gas transportation capacity will be more than adequate to meet the needs of the GEC. As described later in this section, the combustion turbines on this site will be served by the SeaCoast Gas Transmission, LLC (SeaCoast) intrastate pipeline via the GEC Lateral (the distribution lateral to the GEC site) being developed by Peoples Gas System (PGS). Therefore, the necessary natural gas transportation infrastructure will already be in place at the GEC site to accommodate the combined cycle conversion. The PGS natural gas transportation supply system, along with additional natural gas pipeline systems that serve the State of Florida as a whole, are discussed in this section.

8.1 Peoples Gas System

PGS is one of four business units of TECO Energy, an S&P 500 energy company headquartered in Tampa, Florida. PGS is Florida's largest natural gas distribution utility serving more than 320,000 commercial, industrial, and residential customers. PGS has long-term agreements with FGT, Gulfstream Natural Gas System, LLC (Gulfstream), and SNG for natural gas transportation into Florida.

PGS serves as Jacksonville's natural gas distribution company and provides commercial and residential gas service to the Jacksonville area through its pipeline system. In addition, JEA has existing agreements with PGS to receive natural gas delivery service through the local gas distribution system to its generating units. Figure 8-1 illustrates the Florida counties served by PGS.

8.1.1 Existing PGS in Jacksonville Area

JEA and PGS have a successful history of working together to ensure reliable natural gas deliveries to JEA generating units. JEA and PGS are joint owners of a portion of the natural gas pipeline network in the Jacksonville area including the pipelines that serve the Northside Generating Station and the Brandy Branch Generating Station. PGS owns the pipeline system that serves the Kennedy Generating Station and JEA's Buckman Street Wastewater facility.

8.1.2 Planned PGS Expansion

The JEA-PGS working relationship has resulted in several ongoing projects. PGS is currently improving gas delivery capability to JEA's Kennedy Generating Station. Installation of additional pipe and the uprating of existing pipeline infrastructure will allow JEA to operate Kennedy CT 7 and Kennedy CT 8 simultaneously. PGS is constructing a lateral to add natural gas service to SJRPP. In addition, PGS is constructing a natural gas pipeline (the GEC Lateral) to serve the GEC simple cycle combustion turbines prior to the combined cycle conversion.

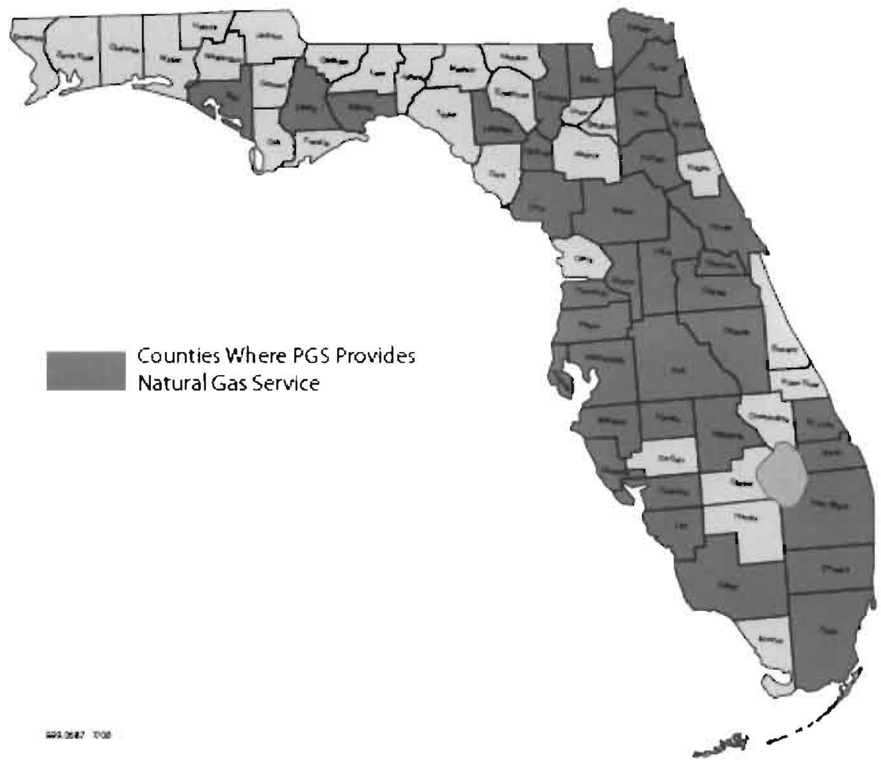


Figure 8-1
Florida Counties Served by PGS

PGS is in the process of engineering a 16 inch diameter delivery lateral that will extend from the proposed SeaCoast Pipeline in Clay County to the GEC site. JEA will receive natural gas from both the SNG and FGT systems through the SeaCoast Pipeline to the GEC Lateral for delivery to GEC. The SeaCoast Pipeline will initially extend from the point of interconnection of SNG and FGT located near Jacksonville to the commencement of the GEC Lateral in Clay County.

Several lateral routes extending from the mainline to the GEC site are being considered; the lateral is likely to utilize a tie-in point near Highway 315 in Clay County, approximately 27 miles south of the FGT/SNG interconnect. Depending on the final route, the proposed lateral will extend a length of approximately 31 to 36 miles through Clay, St. Johns, and Duval counties with a majority of the pipe co-located alongside highway and power line corridors.

8.2 Florida Gas Transmission Company

FGT, a subsidiary of Citrus Corporation (Citrus Corp.), operates a 5,000 mile natural gas pipeline system that extends from south Texas to south Florida with a current mainline capacity of 2.1 Bcf/d. FGT offers natural gas transportation service for third parties. Citrus Corp. is 50 percent owned by Southern Union Company (NYSE:SUG) and 50 percent owned by El Paso Corporation (NYSE:EP). The FGT system is illustrated in Figure 8-2.

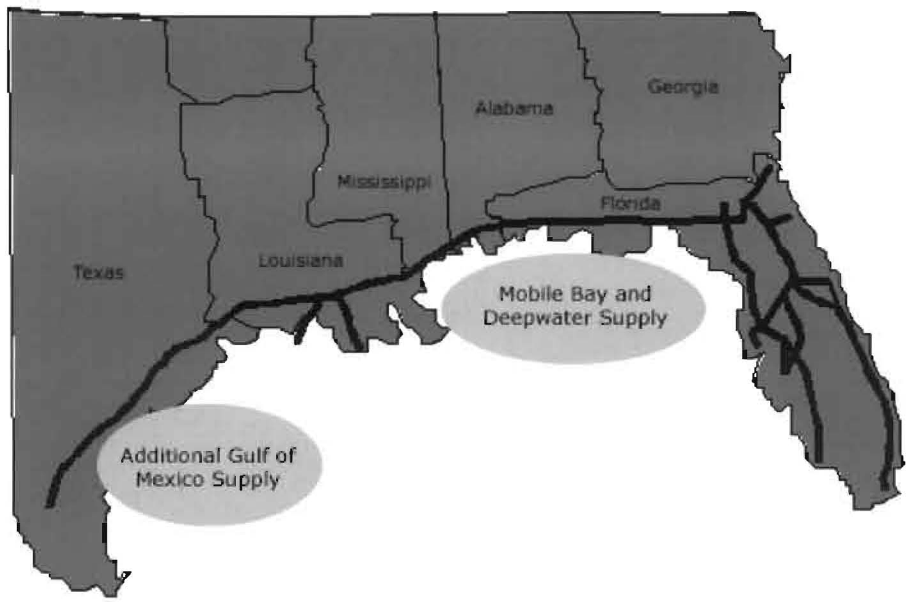


Figure 8-2
FGT System
(Source: http://www.crosscountryenergy.com/about/fgt.shtml)

8.2.1 Existing FGT System

The FGT pipeline system transports natural gas to cogeneration facilities, electric utilities, independent power producers, municipal generators, and local distribution companies through a 5,000 mile natural gas pipeline that extends from south Texas to south Florida. It delivers 2.1 Bcf of natural gas per day to more than 240 delivery points, consisting of more than 50 natural gas fired electric generation facilities. FGT's total receipt point capacity is in excess of 3.0 Bcf/d and includes interconnects with 10 interstate and 10 intrastate pipelines to facilitate receiving supplies of natural gas into its pipeline system. The pipeline has extensive access to diverse natural gas supplies, including the offshore Gulf of Mexico region.

The pipeline enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the primary pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns in a southeasterly direction 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, and Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through eastern Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

FGT has completed numerous system expansions since its initial Phase III expansion in 1995. The following is a summary of the projects that were of sufficient significance to warrant a "phase" designation:

- Phase IV expansion project completed in May 2001. This project consisted of approximately 205 miles of various diameter pipelines, additional compression totaling 48,570 horsepower, and four new delivery points (including three new measurement stations) in the states of Mississippi, Alabama, and Florida. The Phase IV expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 272,000 MBtu/d at an estimated cost of $268 million.
- Phase V expansion project completed in May 2003. This project consisted of approximately 166 miles of pipeline and 133,000 horsepower of compression, including three new compressor stations, to its existing system in the states of Mississippi, Alabama, and Florida. The Phase V expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 428 Mcf/d at an estimated cost of $452 million.
- Phase VI expansion project completed in November 2003. This project consisted of approximately 33 miles of pipeline and 18,600 horsepower of compression to its existing system in the states of Louisiana, Mississippi, Alabama, and Florida. The Phase VI expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 121 Mcf/d at an estimated cost of $100 million.
- Phase VII expansion project construction completed in May 2007, with modifications to a compressor station completed in December 2007. This project added approximately 33 miles of pipeline and 9,800 horsepower of compression to FGT's existing Florida system. The Phase VII expansion added incremental mainline capacity to FGT's existing pipeline system of approximately 160 Mcf/d at an estimated cost of $104 million. This

expansion provides access to an additional natural gas supply from the SNG LNG Elba Island LNG import terminal near Savannah, Georgia.

8.2.2 Market Area Pipeline Interconnections

FGT's pipeline system has three pipeline interconnections that are capable of making natural gas deliveries within the state of Florida. FGT has two interconnections with Gulfstream: one interconnection in Osceola County and the other in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into FGT's system in its market area of central Florida. SNG also has an interconnection with FGT in Clay County near Jacksonville. This interconnection allows for the delivery of natural gas off of the SNG system, the majority of which comes from SNG's Elba Island LNG import terminal in Savannah, Georgia.

8.2.3 Planned FGT System Expansions

As presented previously in the summary of system expansions, FGT has continuously added pipeline capacity to increase its ability to offer firm transportation service into the state of Florida and to meet the growing demand for natural gas within the state. FGT conducted an Open Season ending on February 15, 2008, for a proposed Phase VIII expansion project. On February 11, 2008, FGT announced that FPL had agreed to become the anchor shipper of a proposed natural gas pipeline expansion project through a 25 year service agreement for 400 Mcf/d of capacity. FGT is in the regulatory approval process for construction of the proposed Phase VIII system expansion at an estimated cost of $2 billion to provide approximately 800 Mcf/d of increased natural gas capacity to Florida. The proposed Phase VIII expansion includes construction of approximately 500 miles of additional large diameter pipeline and the installation of approximately 170,000 horsepower of additional compression. The Phase VIII expansion will increase the capacity of FGT's mainline facilities from the Mobile Bay, Alabama, area to southern Florida to provide additional firm transportation service capacity throughout Florida. Pending regulatory approvals, FGT is anticipating a spring 2011 in-service date for the project. The FPL commitment will help ensure that the Phase VIII expansion will be built, filling 50 percent of the incremental capacity that is planned.

The FGT Phase VIII Expansion will increase gas deliverability into Florida in the time frame necessary to support operation of the units at the GEC site. FGT plans to file a FERC certificate by the fall of 2008 and expects FERC approval by February 2009. The target in-service date for the project is spring 2011.

8.3 Gulfstream Natural Gas System, LLC

Gulfstream is a joint development between Williams and Spectra Energy. The Gulfstream system consists of a 691 mile pipeline that was placed in service in May 2002; the pipeline is illustrated on Figure 8-3.

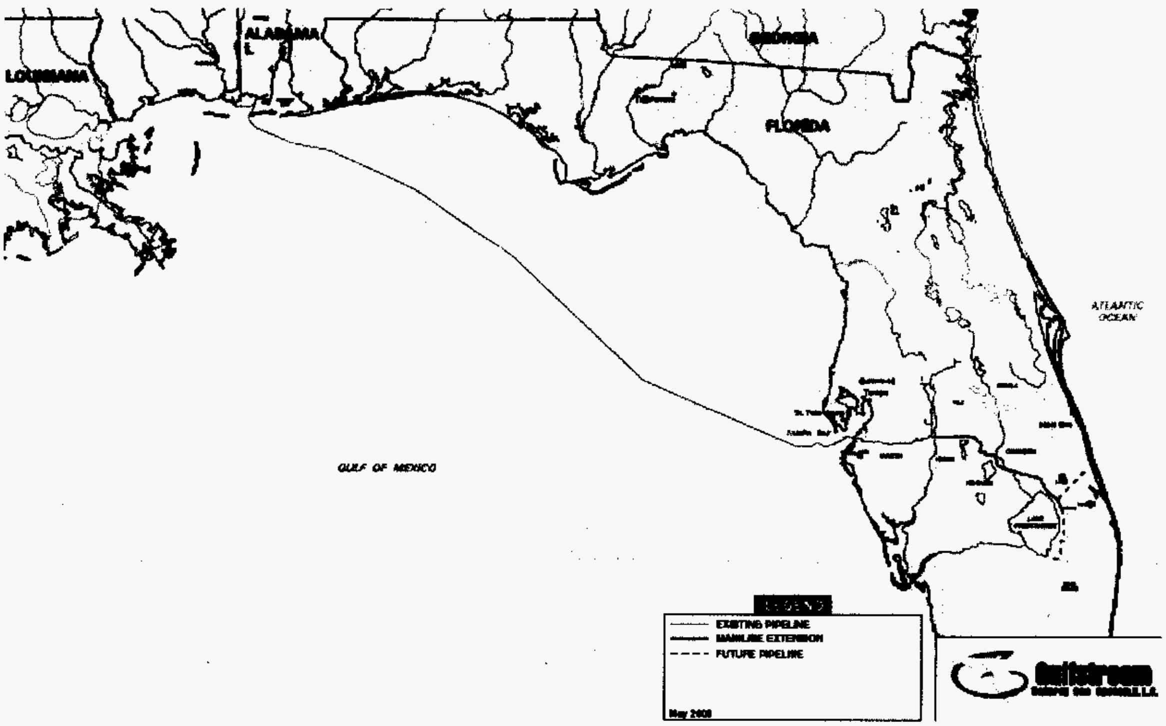


Figure 8-3
Gulfstream System
(Source: http://www.gulfstreamgas.com/images/gulfstream05_03.pdf)

8.3.1 Existing Gulfstream System

The Gulfstream pipeline originates near Pascagoula, Mississippi and Mobile, Alabama, and crosses the Gulf of Mexico with more than 430 miles of 36 inch diameter pipeline to Manatee County, Florida. Once onshore, 240 miles of 30 inch to 36 inch diameter pipeline crosses Manatee, Hardee, Polk, Osceola, Highlands, Okeechobee, and Martin counties in Florida. Gulfstream can serve customers on both the east and west coasts of Florida, as well as in the interior of the peninsula. The Gulfstream system went into service with a capacity of 1.1 Bcf/d of gas. The initial subscribed capacity was less than 200 MBtu/s, leaving approximately 900 MBtu/d of capacity available for new and existing industrial and electric generation customers in central and southern Florida. Gulfstream currently does not have any direct interconnections that would allow it to serve the GEC site.

Gulfstream has undertaken several system extensions/expansions since its initial in-service date of May 2002. These system expansions were designed to connect Gulfstream to facilities that were more remote from its initial routing. These project expansions are as follows:

- The Phase II extension of the Gulfstream pipeline was placed into service in February 2005. The 110 mile extension was designed to provide 350,000 dekatherms per day of firm natural gas transportation service for FPL's Martin and Manatee power plant expansions. The new pipeline traverses five counties: Polk, Hardee, Highlands, Okeechobee, and Martin.
- FERC approved commencement of service for the Phase III project in August 2008. The Phase III project extends the Gulfstream pipeline approximately 35 miles south from Martin to Palm Beach County (approximately 8.8 miles in Martin County and approximately 26.2 miles in Palm Beach County). This volume commitment used the remaining available system capacity.
- The Phase IV expansion project is scheduled for completion in January 2009. The Phase IV project will add compression and extend the pipeline to a new market, increasing Gulfstream's mainline capacity from 1.1 Bcf/d to 1.255 Bcf/d by early 2009. The Phase IV expansion project will include construction of approximately 17.5 miles of 20 inch diameter pipeline, connecting the existing Gulfstream pipeline to Progress Energy's Bartow Generating Station. It will also include the installation of an additional 45,000 horsepower of compression for service by January 2009: 15,000 horsepower at an existing compressor station in Coden, Alabama, and 30,000 horsepower at a new station in Manatee County, Florida. The Phase IV expansion project will increase Gulfstream's system capacity by approximately 155,000 MBtu/d to a total of 1.25 Bcf/d.

8.3.2 Market Area Pipeline Interconnections

Gulfstream's pipeline system has two pipeline interconnections that are capable of delivering natural gas within the state of Florida. FGT has two interconnections with Gulfstream: one in Osceola County and one in Hardee County. Both of these interconnections offer delivery of Gulf Coast supplies directly into Gulfstream's system via displacement in the system's market delivery area of central Florida.

8.3.3 Planned Gulfstream System Expansions

Gulfstream conducted an Open Season from June 1 to August 31, 2007, to gauge market interest in an expansion of its existing natural gas pipeline system to serve

Florida's rapidly growing natural gas market. Based on the response received by Gulfstream, Gulfstream's "G2" expansion is expected to provide approximately 500,000 to 1,000,000 MBtu/d of incremental firm transportation service to the west side of Florida beginning in 2012. The expansion will provide access to supplies from new shale production areas located primarily in north Texas and Arkansas as well as reserves located onshore and offshore in the Gulf Coast area. Facilities will include a combination of compression, pipe looping, and necessary onshore facilities.

8.4 Southern Natural Gas

SNG is a natural gas pipeline company headquartered in Birmingham, Alabama. It is a subsidiary of El Paso Corporation. The company transports more than 3 Bcf of natural gas per day during peak periods through approximately 8,000 miles of pipeline in the southeast. SNG owns and operates the Elba Island LNG regasification facility near Savannah, Georgia. Elba has approximately 4 Bcf of storage capacity and 440 Mcf/d of sendout capacity. The facility is currently being expanded to approximately 7.3 Bcf of storage capacity and a sendout capacity of 800 Mcf/d. Figure 8-4 shows the SNG natural gas transportation system.

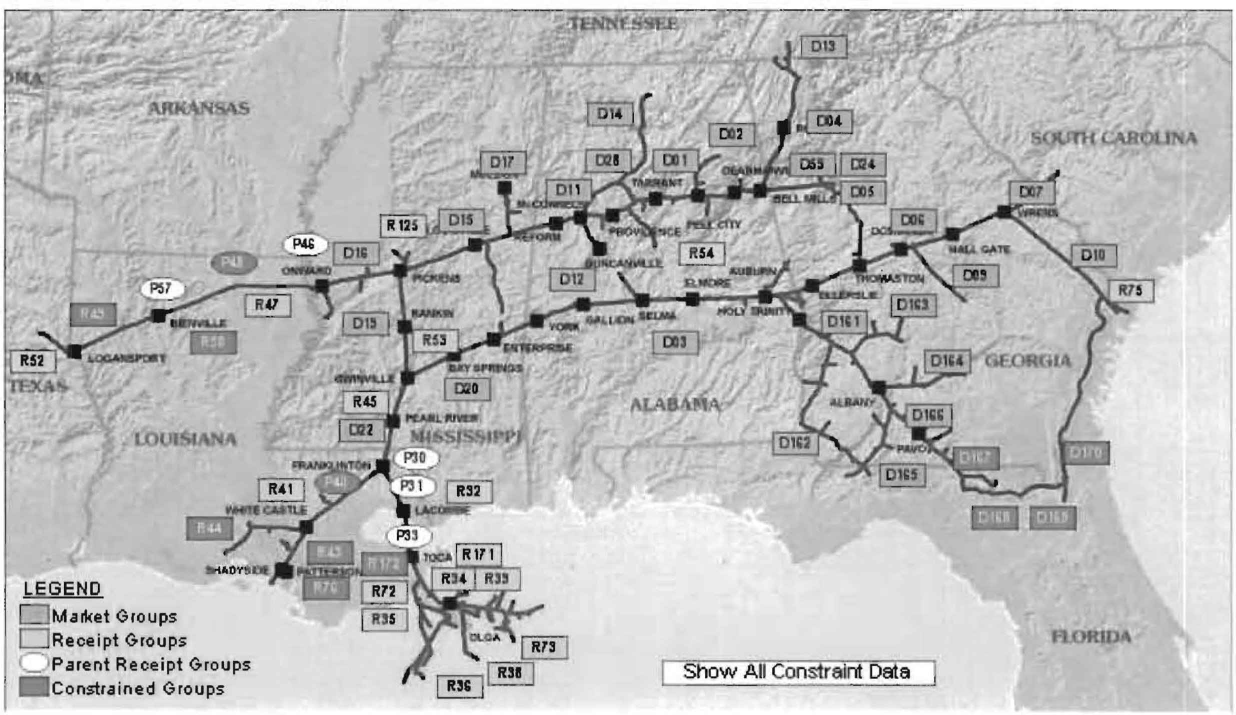


Figure 8-4
SNG System
(Source: http://premier.sonetpremier.com/snghomepage)

8.4.1 Cypress Pipeline

The Cypress pipeline is a specific section of the SNG system. This pipeline was placed into service on May 1, 2007. The new pipeline provided an incremental 220,000 MBtu/d of takeaway capacity from Elba Island, SNG's LNG facility near Savannah, Georgia. From Elba Island, the 167 mile, 24 inch pipeline extends the SNG system into southern Georgia and northern Florida and interconnects with the FGT system near Jacksonville, Florida.

The Phase 2 expansion project included the addition of 10,350 horsepower of compression at the new compressor station in Glynn County, Georgia. Phase 2 went into service in May 2008 and increased the capacity an additional 116 MBtu/d from 220,000 MBtu/d up to a total of 336,000 MBtu/d. The Cypress pipeline is illustrated on Figure 8-5.

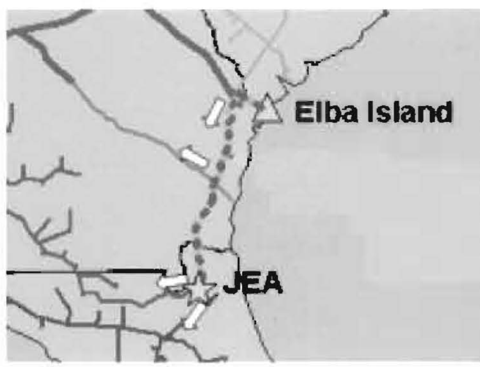


Figure 8-5
Cypress Pipeline
(Source: http://www.elpaso.com/cypresspipeline/default.shtm)

8.4.2 Planned Cypress Pipeline Expansions

There is currently one more planned expansion of the Cypress pipeline. The Phase 3 expansion project will consist of approximately 10 miles of 30 inch diameter pipeline, the addition of 10,350 horsepower of compression at the new compressor station in Liberty County, Georgia, and an additional 10,350 horsepower of compression at the new compressor station in Nassau County, Florida. Phase 3 is scheduled for completion by May 2010. Phase 3 will increase the capacity an additional 164,000 MBtu/d from 336,000 MBtu/d up to a total of 500,000 MBtu/d.

8.5 BG Group

BG Group is an energy production and distribution company headquartered near London, England. The company has established itself as the leading importer of LNG in the United States. In 2006, it was responsible for approximately 50 percent of the US

LNG imports. In 2004, BG LNG Services (BGLS), a wholly owned subsidiary of BG Group, began marketing regasified LNG from Elba Island after assuming responsibility for 446 Mcf/d of terminal capacity and long-term LNG supply from El Paso in late 2003. Additionally, BGLS maintains a long-term commitment for firm transportation on SNG to allow delivery of Elba's regasified LNG through the SNG's Cypress pipeline into the Florida market near Jacksonville.

In 2005, SNG announced plans to expand the total terminal capacity to just over 2 Bcf/d, of which BG Group currently has 0.57 Bcf/d. BGLS agreed with SNG that it will, by the start of 2014, increase its share of capacity to 1.17 Bcf/d.

JEA has a long-term contract extending through May 31, 2021, with BG Energy Merchants (BGEM), a subsidiary of BGLS, for the supply of natural gas delivered to Jacksonville. BGEM markets natural gas to intermediary and end use customers. In 2006, BGEM's marketing activities in the United States met 1.3 percent of the daily US gas demand (data source: EIA). Figure 8-6 shows the Elba Island Express Pipeline.

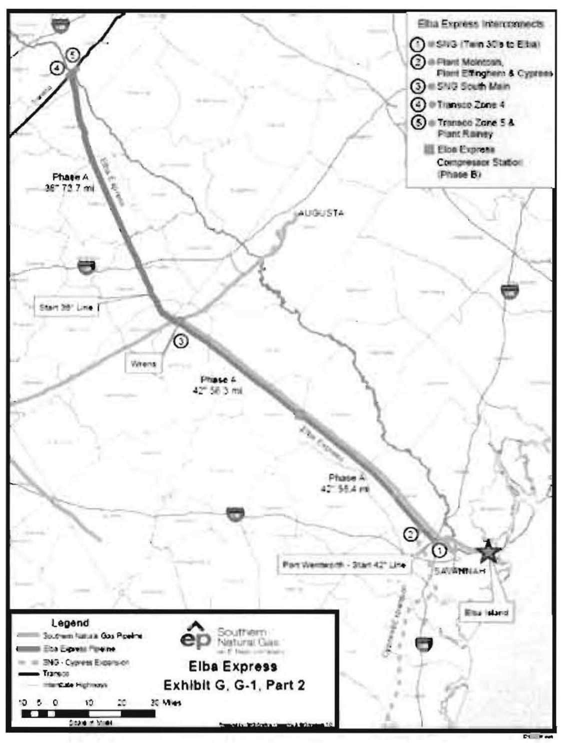


Figure 8-6
Elba Express Pipeline
(Source: www.elba3.com)

8.6 Southeast Supply Header

The SESH project is an ongoing, nonconventional domestic project that will further enhance the supply of natural gas into the State of Florida. The project will provide transportation of onshore supplies in east Texas and northern Louisiana into the Southeast US, which is normally served by offshore supplies from the Gulf of Mexico. The SESH project will provide an alternative to offshore supplies and improve the overall reliability of natural gas supply.

SESH and SNG will co-own the first 115 miles of the pipeline from the Perryville Hub to an interconnection with SNG in Mississippi. The SESH pipeline will also interconnect with Gulfstream and FGT. The SESH pipeline will connect the Florida market area with two new unconventional natural gas production basins – the Barnett Shale in east Texas and the Bossier Sands in north Louisiana. The Barnett Shale formation is estimated to extend from Dallas, Texas, to west of Ft. Worth, Texas, and to contain as much as 30 Tcf of natural gas reserves. Natural gas production from the Barnett Shale and Bossier Sand reservoirs has become economically viable due to higher natural gas prices and improvements in hydraulic fracturing and horizontal drilling.

8.7 Availability of Natural Gas Transportation Capacity

As discussed throughout this section, the Florida natural gas transportation system has become increasingly diverse and interconnected. Natural gas transportation providers have a long history of expanding the system to meet the needs of Florida's natural gas transportation customers. With all of the proposed natural gas supply expansion projects under way, JEA is confident that adequate natural gas transportation capacity will be available to provide reliable service for the GEC.

Although not all of the natural gas transportation infrastructure discussed previously in this section is interconnected directly to the GEC site, the entire infrastructure system plays an important role in providing reliable natural gas supplies to the State of Florida, as natural gas is sourced from geographically diverse locations. Ongoing domestic projects and increased imports of LNG will also contribute to sufficient availability of natural gas to serve the needs of GEC and JEA's other natural gas fired generating units. JEA is uniquely situated to obtain conventional natural gas supplies for the US Gulf, nonconventional supplies from SESH, and LNG sourced from Elba Island.

9.0 Project Overview

9.1 Description of Project

The GEC combined cycle conversion will consist of converting the two simple cycle GE 7FA combustion turbines planned for operation by the summer of 2010 at the GEC site in Jacksonville, Florida, to a 2x1 combined cycle configuration. The 2x1 GEC combined cycle will have a nominal net output rating of 522 MW at average ambient temperature conditions. Consideration will be made for installing future units at the site through space allocation. In general, consideration will be given to installing facilities required to support future units at the site when appropriate.

The GEC combined cycle will be dual fueled with natural gas as the primary fuel and ULSD fuel oil as a backup fuel. The combined cycle power plant will include HRSGs provided with natural gas-fired supplemental duct burners to increase power generation and a steam turbine bypass to the condenser to allow for simple cycle operation.

9.1.1 Mode of Operation

Subject to final approval by the Siting Board and the Florida Department of Environmental Protection (FDEP), GEC will be permitted for unlimited operation on natural gas and up to 500 hours per year on ULSD in combined cycle mode. GEC will have full steam bypass capability, allowing the combustion turbine units to operate in simple cycle mode.

9.1.2 Combustion Turbine Generator

The CTGs will be GE Model PG 7241 (FA) enhanced combustion turbines with dry low NO_x (DLN) combustors and modulating inlet guide vanes. The CTGs will be installed outdoors and will include the following major features:

- Dual fuel firing system using natural gas or ULSD.
- DLN combustion system for pipeline gas firing.
- Direct connected generator with static excitation.
- Acoustic enclosure for turbine.
- Inlet air filter system with silencers.
- Lube oil systems.
- Static starting system.
- Water injection system for NO_x reduction when firing fuel oil.
- Fire detection/CO_2 fire protection systems.

- Mark VI control system with remote work stations.
- Off-line water wash system.
- Package electrical and electronics control compartments.
- Natural gas heating for maintaining the fuel gas temperature at the CTG manufacturer's recommended margin above hydrocarbon dew point temperature.

9.1.3 Heat Recovery Steam Generators

The HRSGs will be installed outdoors and will utilize exhaust heat from the combustion turbines to generate steam for use in driving the STG. The HRSGs are expected to be natural circulation, three-pressure, reheat units with supplemental duct firing by pipeline gas to increase unit output. Nominal cycle operating pressure will be 1,800 pounds per square inch gauge (psig). SCR for NO_x emission control is expected to be included within each HRSG. Each HRSG will discharge to an exhaust stack. A stack damper will be included to minimize heat loss during shutdowns. Two 100 percent capacity boiler feedwater pumps will be included for each HRSG.

9.1.4 Steam Turbine Generator

The steam turbine is expected to be a tandem-compound single reheat condensing turbine operating at 3,600 revolutions per minute (rpm). The steam turbine will have one HP section with a nominal 1,800 psig throttle pressure, one IP section, and one low-pressure (LP) section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring and control systems will be utilized. A surface condenser will be provided for condensing steam from the turbine exhaust and will utilize a recirculating cooling tower system for cooling. The condenser will be designed for full steam flow bypass around the steam turbine. A synchronous generator will be direct coupled to the steam turbine. Generator suppliers' standard auxiliary equipment; supervisory, monitoring, and control systems; and static excitation system will be utilized. The steam turbine will be installed indoors with a fully enclosed turbine building.

A standby power diesel engine generator will be provided to maintain the plant in a ready condition if the transmission interconnection and, therefore, plant auxiliary power is lost. The standby power engine generator will use ULSD as fuel.

9.1.5 Cooling Tower

A multiple cell, mechanical draft, counterflow water cooling tower will be used for plant cooling. The cooling tower will be installed on a reinforced concrete basin that will include a pump intake structure housing two 50 percent capacity circulating water pumps and one 100 percent capacity auxiliary cooling water pump. A circulating water chemical feed system also will be included. The cooling tower will be equipped with drift eliminators.

9.1.6 Air Quality Control

GEC will be subject to FDEP's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology for emissions of various pollutants. GEC will minimize air pollutant emissions by using the most efficient and pollutant-preventing generating technology. This concept has been incorporated with the selection of a combined cycle process utilizing advanced combustion turbines. Compared to simple cycle generating plants, combined cycle units have higher efficiency and, therefore, generate more electrical output (megawatts) per unit of fuel consumed. As a result, air pollutant emissions per megawatt output are minimized. Pollution prevention is also incorporated through the use of clean fuels that minimize emissions of SO_2 and particulate matter. In addition, advanced DLN combustion technology will be used to minimize NO_x emissions while ensuring that emissions of carbon monoxide (CO) and volatile organic compounds (VOCs) are within accepted limits. Moreover, SCR will be installed in each HRSG to further reduce NO_x emissions when operating in combined cycle mode. Taken together, these design features will make GEC one of the most efficient and lowest polluting power plants in the state of Florida.

9.1.7 Control System

GEC will be designed for control through a plant distributed control and information system (DCIS). A GE Mark VI control system for turbine control will also be included. The DCIS operator control stations will be located in the main plant control room that will be in a new Administration/Control/Maintenance Building.

9.1.8 Water Use

Water for cooling tower makeup is expected to be reclaimed water (treated wastewater). Reclaimed water is expected to be supplied from JEA via a pipeline adjacent to the plant site. If needed, municipal water will be used for backup cooling water makeup supply. Cooling water makeup water flow will vary depending upon the plant load and operating conditions.

Service water, potable water, demineralizer water makeup, and fire water will be supplied from the JEA municipal water system. Water will be stored onsite in a fire water/service water storage tank. GEC will include a site fire protection system consisting of a fire/service water storage tank, in addition to the municipal water supplied hydrant system, one diesel engine driven fire water pump, a site hydrant system, and deluge systems as required. A CO_2 fire suppression system will be provided for each CTG as provided in the CTG manufacturer's standard scope of supply.

A new demineralizer system will be installed to provide demineralized water for combustion turbine water injection for NO_x control when firing fuel oil and for steam cycle makeup. Two 800,000 gallon demineralized water storage tanks will be provided for a total capacity of approximately 40 hours of storage/makeup capacity under maximum demineralized water demand conditions.

9.1.9 Project Process Wastewaters

There will be four major sources of wastewater: sanitary waste, oil/water separator effluent, cooling tower blowdown, and treated chemical wastewaters. Cooling tower blowdown will be reblended into the JEA reclaimed water distribution system. All other wastewaters will be routed via the adjacent force main to the JEA municipal wastewater treatment plant.

9.1.10 Storm Water Management

A complete storm water management system will be developed for the site. Storm water system design will be in accordance with FDEP, St. Johns Water Management District (SJWMD), and Duval County requirements. Storm water runoff will be collected in an onsite detention pond for percolation into the ground water.

9.1.11 Transmission Interconnection

GEC will be interconnected to JEA's 230 kV transmission system. The CTGs and STG will each connect to separate 18 kV/230 kV generator step-up (GSU) transformers. The CTGs and the STG will each have generator breakers. Auxiliary power will be provided by auxiliary transformers connected to each unit's 18 kV power.

9.1.12 Site Design Conditions

Table 9-1 presents the conceptual site design conditions for the GEC site.

Table 9-1
Conceptual Design Conditions for the Project Site

Condition	Value or Range	Reference
Maximum Temperature	103° F	Weatherbase Web site
Minimum Temperature	7° F	Weatherbase Web site
Average Temperature	69° F	Weatherbase Web site
Wind Loading	Basic Wind Speed: 130 miles per hour (mph), (3 second gust), Occupancy Category IV, Importance Factor: 1.15, Exposure Category C	ASCE 7-05, with applicable addenda
Seismic Loading	Occupancy Category: IV, Seismic Design Category: C, Site Soil Classification (stiff soil): D, Mapped 1 Second Spectral Response Acceleration (S1), g: .06, Mapped Short-Term (0.25 sec) Spectral Response Acceleration (Ss), g: 0.15	ASCE 7-05
Site Elevation	Nominal 30.0 feet above mean sea level (msl)	
Location	Outdoors	

9.1.13 Site Arrangement

Figure 9-1 is a conceptual drawing that shows the arrangement and locations of the major equipment for each unit at the GEC site.

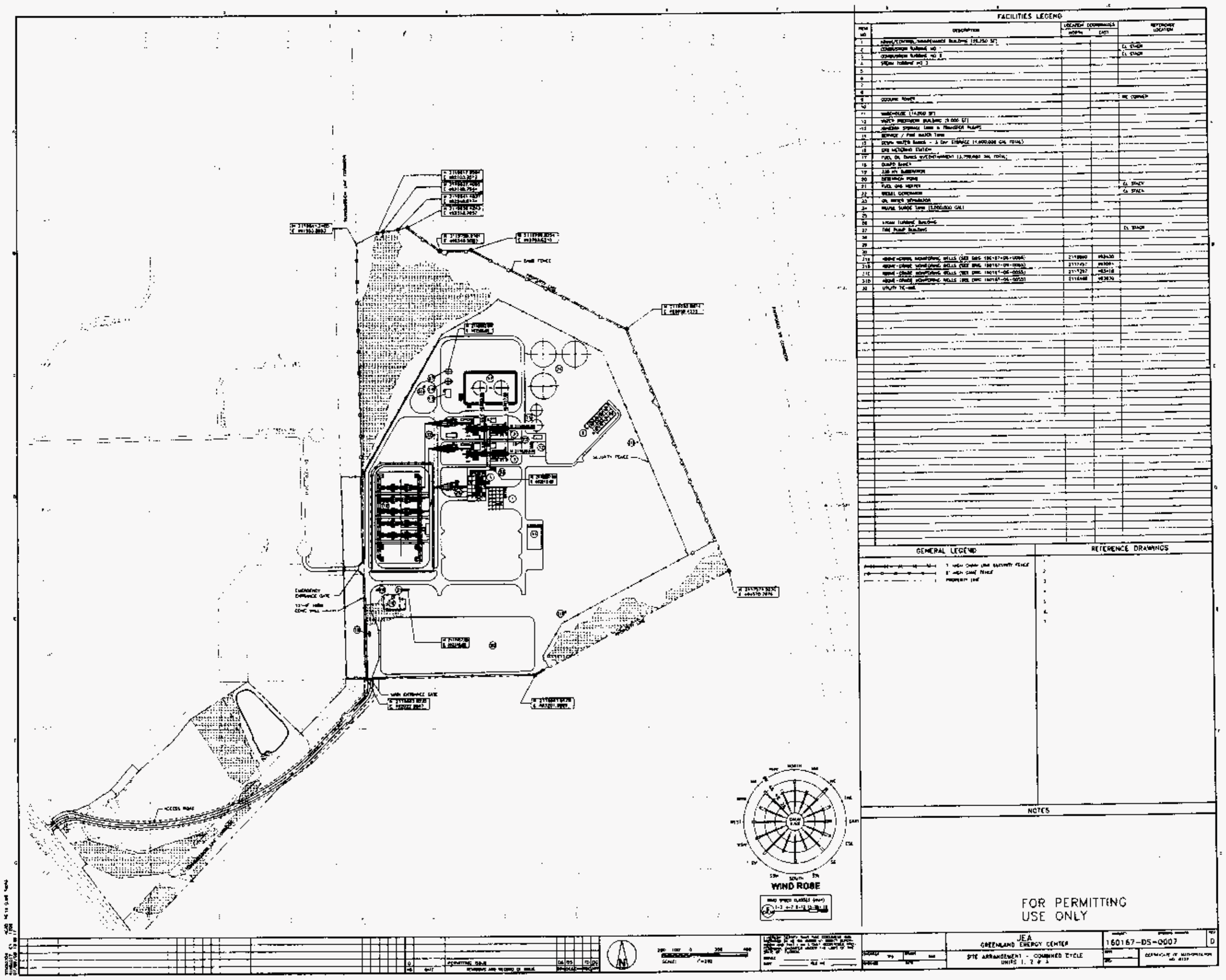


Figure 9-1
Conceptual Site Arrangement Drawing

9.1.14 Overall One-Line Diagram

Figure 9-2 is a conceptual electrical one-line diagram that shows the arrangement of the electrical interconnections to the existing transmission system and electrical power distribution for GEC.

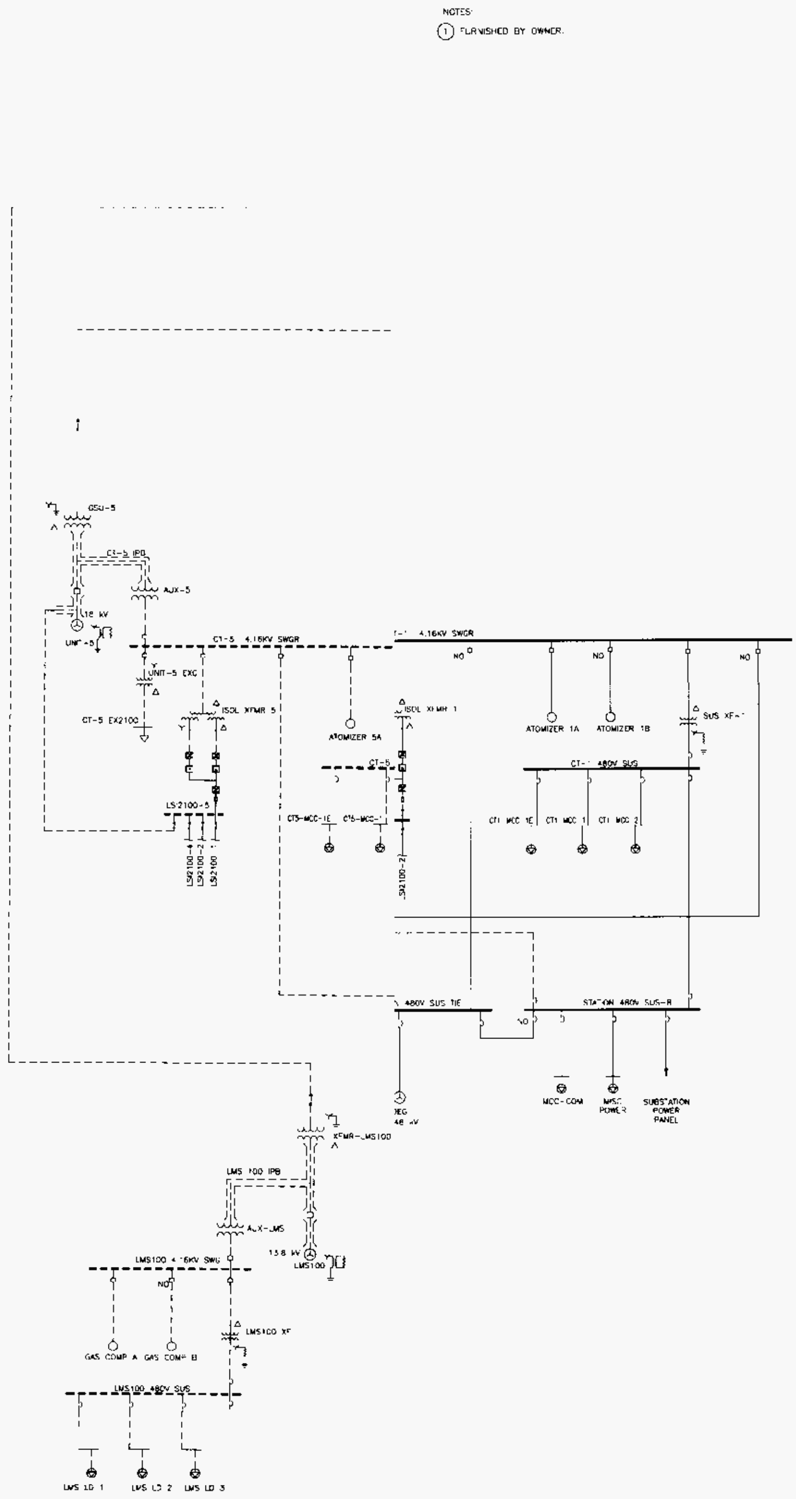
9.1.15 Cycling Design Features

GEC will include several design features for cycling load operation. The STG will be selected in combination with the HRSGs to provide a reasonable design throttle pressure to ensure satisfactory cycling operation. Because the unit is going to be designed for cycling operation, a nominal throttle pressure of 1,800 psig will be used for design purposes. In comparison to a higher design throttle pressure such as 2,400 psig, a 1,800 psig operating pressure allows reduced wall thicknesses in HRSG drums and piping, thereby reducing thermal stresses and allowing reduced warm-up times. This reduces overall startup time and increases ramp rates when changing loads.

HRSG design for cycling operation will include nozzle arrangement and connections, use of full penetration welds, separation of headers, and use of higher strength drum and header materials to enable thinner wall construction to reduce stress from temperature gradients. HRSG design will also include a stack damper for heat retention, automated vent and drain valves to control pressure and drain condensate during shutdowns and startups, and 100 percent bypass systems to enable steam/turbine temperature matching.

9.1.16 Ammonia Systems

Ammonia will be required for use in the SCR process for NO_x control. Vaporized ammonia is injected into the combustion turbine exhaust gases prior to passage through the catalyst bed, which is installed in the HRSGs. The onsite ammonia system will include unloading facilities, aqueous ammonia storage tank, forwarding system, and vaporizing facilities. Aqueous ammonia will be used and will be delivered to the GEC site by tanker trucks, which include integral unloading pumps. The aqueous ammonia will be stored as a liquid in a nominal 20,000 gallon tank, which provides for two full tanker truck deliveries. The liquid ammonia will be forwarded to the HRSGs, vaporized, and injected upstream of the catalyst.


NOTES:
1 FURNISHED BY OWNER.
GSU-5
CT-5 IPB
AUX-5
CT-5 4.16KV SWGR
UNIT-5 EXC
ISOL XFMR 5
CT-5 EX2100
LS2100-5
ATOMIZER 5A
ATOMIZER 1A
ATOMIZER 1B
480V SUS TIE
STATION 480V SUS-B
MCC-COM
SUBSTATION POWER PANEL
XFMR-LMS100
LMS100 IPB
AUX-LMS
LMS100 4.16KV SWG
LMS100 XF
GAS COMP A
GAS COMP B
LMS100 480V SUS
LMS LD 1
LMS LD 2
LMS LD 3

9.1.17 Capability for Future Expansion

The GEC site will have the capability for the future installation of combined cycle and simple cycle units. The site layout and infrastructure will support the future installation of an identical combined cycle power plant and future peaking unit capacity, for an ultimate certification capacity of approximately 1,300 MW.

It is anticipated that the site will be cleared and developed, including the storm water detention pond, for ultimate build out of future units during the construction of the initial simple cycle combustion turbines at GEC. It is also anticipated that most offsite facilities will be sized for ultimate build out including the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

9.2 Fuel Supply

The primary fuel for GEC will be natural gas, while the backup fuel will be ULSD fuel oil. Natural gas will be delivered to the GEC site through the SeaCoast Pipeline and a distribution lateral utilizing firm transportation service from SeaCoast. The initial phase of the SeaCoast pipeline will extend from interconnections with FGT and SNG Cypress Lateral, near Jacksonville, Florida, to the interconnection between the SeaCoast Pipeline and PGS located in Clay County, Florida. The lateral will extend from the SeaCoast–PGS interconnection to the inlet of the meter located at GEC. SeaCoast's interconnection with both FGT and SNG will allow JEA to utilize a diverse natural gas supply portfolio. It is anticipated that adequate natural gas pressure will be available with no need for the addition of gas compressors.

9.2.1 Natural Gas Transportation, Delivery, and Metering

Natural gas will be delivered to the GEC site by SeaCoast via the GEC Lateral and will be regulated, metered, and conditioned onsite. The pipeline to the site will be sized for ultimate site capacity. Carbon steel pipe with cathodic protection will be installed underground from the main pipeline to the site. A new meter run and natural gas conditioning equipment is included. The natural gas conditioning equipment includes a fuel gas scrubber, two coalescing gas filters, and a dew point control fuel gas heater.

9.2.2 Fuel Oil Storage and Handling

A complete fuel oil unloading, storage, and supply system will be installed. Two 1,875,000 gallon tanks will be installed that will provide a minimum 5 days of full load operation at minimum ambient conditions for GEC. The tanks will be single wall design fabricated from carbon steel and will be installed inside a dike containment area. Normal fuel oil delivery will be by truck. A truck unloading system will be installed including truck connections. Fuel oil forwarding skids will be included to transfer fuel oil from the storage tanks to the CTGs. Two 100 percent capacity electric motor driven pumps will be included for each skid and the skids will be installed outdoors on concrete pads near the new fuel oil storage tanks.

9.3 Capital Cost

The capital cost estimate is based on the conversion of the two GE 7FA simple cycle combustion turbines at GEC to a 2x1 combined cycle configuration. The construction cost includes direct costs for purchased equipment and materials, construction contract costs, and indirect costs. The direct construction cost estimate is based on site development for the ultimate capacity and also sizing interconnecting pipelines for the ultimate capacity. Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services. All direct costs include escalation to spring 2012 commercial operation.

Construction costs are based on an engineering, procurement, and construction (EPC) contracting philosophy. Construction is assumed to be performed based on a 50 hour work week, with some 60 hour work weeks. Local labor craft rates that include payroll, payroll taxes, and benefits were used in developing the estimated construction costs. Construction indirects and construction equipment costs are included in the construction and service contracts portion of the estimate.

Indirect costs associated with construction are included in the base cost estimate. General indirect costs include all necessary services required for checkouts, testing services, and commissioning. Insurance for builder's risk and general liability are included. Contractor engineering, contractor field construction management, technical direction, contingency, profit, equipment transportation costs, startup, and commissioning are also included.

Table 9-2 provides a summary of the capital cost estimate for the GEC combined cycle conversion. Financing fees are not included in the estimate. These are estimated separately and included in the economic evaluations using the assumptions presented in Section 4.0.

Table 9-2
GEC 2x1 Combined Cycle Conversion
In-Service Capital Cost Estimate
(000s)

Cost Item Descriptions	Total Cost
Major Procurements	
STG	41,000
HRSGs	60,000
Subtotal	101,000
EPC	
Civil/Structural Engineered Materials/Equipment	4,753
Mechanical Engineered Materials/Equipment	23,190
Electrical Engineered Materials/Equipment	6,141
Control Engineered Materials/Equipment	656
Chemical Engineered Materials/Equipment	3,100
Civil/Structural Construction	9,973
Mechanical/Chemical Construction	16,409
Electrical/Control Construction	1,121
Service Contracts and Construction Indirects	12,700
Startup Spare Parts	1,083
Field Management	14,080
Engineering	14,218
Overhead and Profit	35,856
Subtotal	143,280
Total Direct Costs	244,280
Owner/Other Cost Items	
Balance of Owner's Costs	41,346
Contingency	22,977
Escalation to Summer 2012 Commercial Operation	69,167
IDC	40,805
Subtotal	174,295
Project Total Cost	418,575

9.4 Operating and Maintenance Cost

O&M costs include fixed and variable costs. Fixed costs are independent of plant operation while variable costs are directly related to the plant operation. The O&M cost estimates were based on the following assumptions:

- Primary fuel is natural gas.
- Potable water will be provided by JEA, cooling tower makeup water will be provided by JEA as reclaimed water, and service water will be provided by JEA's municipal water supply. JEA's municipal water supply will also provide an emergency source of makeup water.
- A full-time plant staff of 22 personnel consisting of a plant manager, three administrative staff, and 18 O&M personnel.
- An operating profile consisting of up to 300 starts per year, weekly starts during the summer months, and daily starts during the non-summer months with an average capacity factor ranging from 20 to 95 percent.

9.4.1 Fixed O&M Costs

Fixed costs include labor, payroll burden, fixed routine maintenance, and administration costs. The incremental fixed O&M costs associated with the GEC combined cycle conversion are estimated to be $3.38 million per year in 2008 dollars.

9.4.2 Nonfuel Variable O&M

Nonfuel variable O&M costs include consumables, chemicals, lubricants, water, and major inspections and overhauls. Major inspection and overhaul costs can be covered under long-term service agreements with the turbine manufacturer, or each overhaul can be subcontracted to the turbine supplier or a third party maintenance provider. Because the plant is not staffed to fully perform these major inspections, it is assumed that these will be subcontracted to the turbine supplier or a third party O&M provider. Nonfuel variable O&M costs vary as a function of plant generation. The incremental nonfuel variable O&M costs associated with the GEC combined cycle conversion are estimated to be $2.28 million per year in 2008 dollars. The estimated nonfuel variable O&M costs assume operation on natural gas.

9.5 Heat Rate

Based on the heat balances developed for the project, Table 9-3 presents a summary of the estimated performance for the GEC combined cycle. Nonrecoverable performance degradation factors of 2.7 percent for output and 1.5 percent for heat rate have been included in the estimated performance.

Table 9-3
Estimated Greenland Energy Center
Estimated Combined Cycle Performance

Performance Point	Net Plant Output (kW)	Net Plant Heat Rate (Btu/kWh, Higher Heating value[HHV])
95° F, Full Load with Supplemental Firing	491,346	7,280
24° F, Full Load with Supplemental Firing	562,423	7,159
69° F, Full Load with Supplemental Firing	522,190	7,136
69° F, Full Load without Supplemental Firing	490,314	7,019
69° F, 2 CTGs at 80% Load without Supplemental Firing	405,420	7,226
69° F, 2 CTGs at 50% Load without Supplemental Firing	284,534	7,908
69° F, 1 CTG at 100% Load without Supplemental Firing	240,136	7,165
69° F, 1 CTG at 80% Load without Supplemental Firing	197,091	7,432
69° F, 1 CTG at 50% Load without Supplemental Firing	134,644	8,355

9.6 Emissions

The estimated emissions for the GEC combined cycle are presented in Table 9-4. The estimated emissions include operation of SCR and DLN burners.

9.7 Availability

Equivalent availability is a measure of the capacity of a generating unit to produce power considering operational limitations such as equipment failures, repairs, routine maintenance, and scheduled maintenance activities. Equipment outages and forced outages are not predictable and, as a result, a forced outage of 4 percent is assumed for each year. Scheduled outages will be determined by the hours of operation and number of starts. The CTG maintenance program typically consists of combustion inspections, hot gas path inspections, and major overhauls. Typical durations for these outages have been assumed as follows: 7 days for a combustion inspection, 14 days for a hot gas path inspection, and 25 days for a major overhaul. Based on the expected operating profile for the plant, the equivalent availability for GEC is estimated to be 94 percent. On average, 7 maintenance days per year and a 4 percent forced outage rate have been assumed.

Table 9-4
Greenland Energy Center Combined Cycle Estimated Emissions (1)

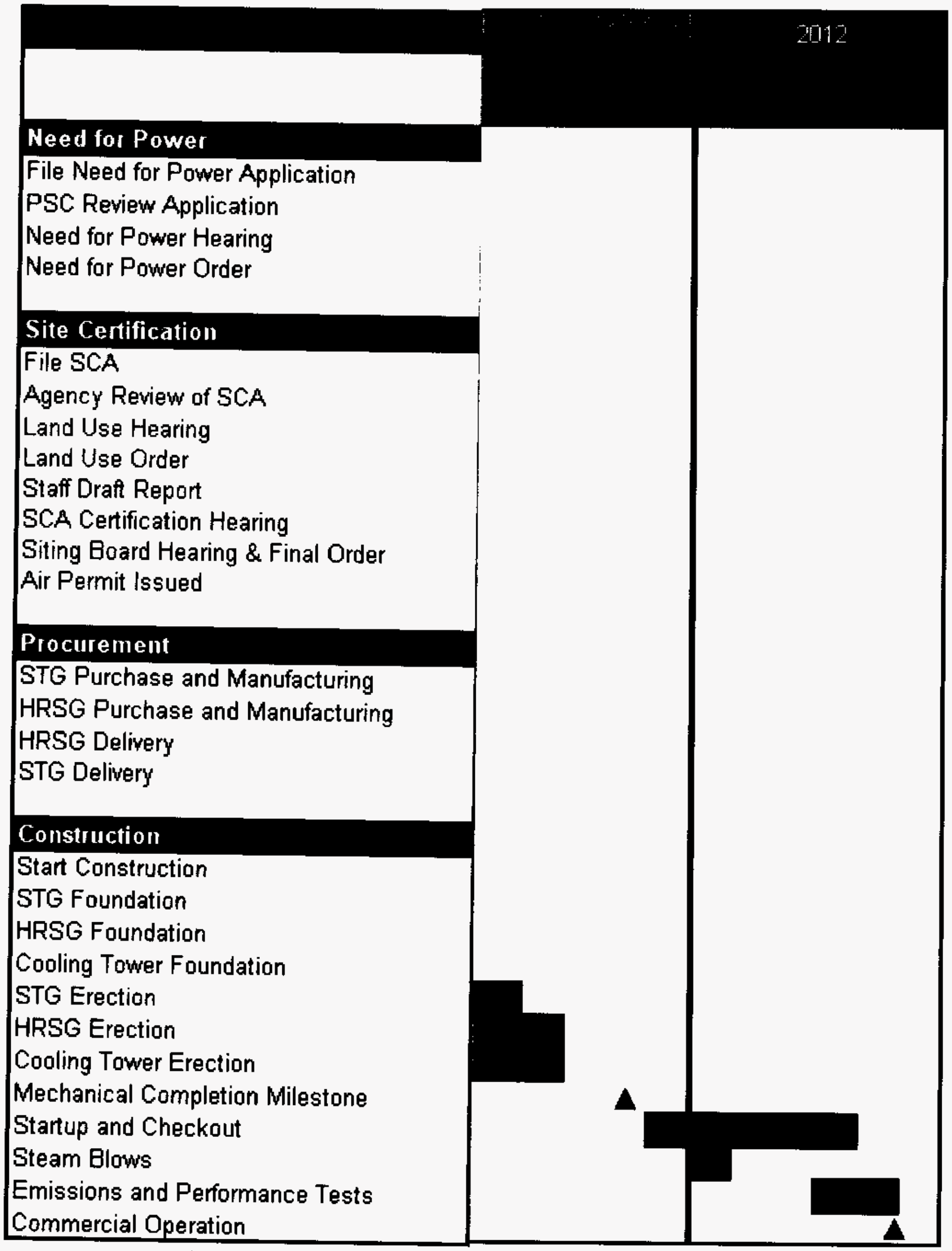
NO_x, parts per million volumetric dry (ppmvd) at 15% Oxygen (O_2)	2.0
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0004
Hg, lb/MBtu	Negligible
CO_2, lb/MBtu	114.8 lb/MBtu
CO, ppmvd at 15% O_2	7.6
CO, lb/MBtu	0.0166

(1)Emissions are at full load at average ambient conditions, reflect operation on natural gas, and include the effects of SCR and DLN burners.

9.8 Schedule

The GEC combined cycle conversion is planned for commercial operation beginning in June 2012. In order to achieve the planned commercial operation date, detailed engineering activities will be required in advance of the June 2010 start of initial construction. These activities are planned to commence during the first quarter of 2009. Similarly, procurement activities such as specification, equipment proposal solicitation, and contract negotiation for the STG and HRSGs, which are all long lead equipment items, will occur starting in 2008 to allow for delivery of this equipment to support the schedule. A schedule of these activities is provided on Figure 9-3.

Figure 9-3
Schedule of Combined Cycle Conversion Construction Activities


2012
Need for Power
File Need for Power Application
PSC Review Application
Need for Power Hearing
Need for Power Order
Site Certification
File SCA
Agency Review of SCA
Land Use Hearing
Land Use Order
Staff Draft Report
SCA Certification Hearing
Siting Board Hearing & Final Order
Air Permit Issued
Procurement
STG Purchase and Manufacturing
HRSG Purchase and Manufacturing
HRSG Delivery
STG Delivery
Construction
Start Construction
STG Foundation
HRSG Foundation
Cooling Tower Foundation
STG Erection
HRSG Erection
Cooling Tower Erection
Mechanical Completion Milestone
Startup and Checkout
Steam Blows
Emissions and Performance Tests
Commercial Operation

10.0 Transmission System Impacts

The GEC facility will be interconnected with the existing JEA system. The proposed interconnection and integration of GEC have been evaluated by the FRCC Transmission Working Group (TWG) and Stability Working Group (SWG). This evaluation concluded that the project is reliable and adequate, with no adverse impact on the FRCC transmission system. The remainder of this section describes the GEC interconnection, as well as the FRCC transmission study.

10.1 Description of Interconnection

The GEC is located near the Greenland Substation in Duval County, Florida. The addition of the simple cycle units in June 2010 will necessitate the following upgrades to the transmission system:

- Loop existing Greenland – Center Park 230 kV line into GEC.
- Loop existing Greenland – SE Jax 230 kV line into GEC.

10.2 System Impact Analysis

The FRCC study evaluated whether the addition of the GEC may cause any thermal overloads and voltage limitations, instability or inadequately damped response to system disturbances, or short-circuit concerns. The following previously planned and committed projects by JEA and FPL were already identified as necessary to support the area reliability under certain contingencies assessed using the NERC standards TPL-001, TPL-002, and TPL-003.

- Upgrade Greenland – GEC 230 kV circuit 1 from 637 megavolt-ampere (MVA) to 668 MVA by the summer of 2010.
- Upgrade Hasting – Elkton 115.kV line from 73 MVA to 149 MVA by the summer of 2010 or earlier.
- Upgrade St. Johns – Elkton 115 kV from 73 MVA to 180 MVA by the summer of 2010.
- Construct GEC – Nocatee – Bartram 230 kV by the summer of 2015 (presently scheduled for 2012).
- Bartram – Switzerland 230 kV will be rated 668 MVA by the summer of 2012 when Bartram Substation is constructed.

The TWG reviewed the results of the steady-state single contingency analysis. The results identified incremental system impacts under certain single and double contingency events due to the addition of the GEC. JEA, FPL, and Florida Municipal Power Agency (representing Beaches Energy System, Inc.) addressed these incremental impacts by providing corrective action plans that included either post-contingency operating procedures (remedial action plans) or additional system improvements.

For the installation of the GEC simple cycle combustion turbines, JEA identified and committed to one additional project to further improve the reliability of the bulk electric system: Re-conductor Center Park – Neptune 138 kV from 155 MVA to 289 MVA by the summer of 2010 or earlier. The GEC simple cycle combustion turbines and the combined cycle conversion project will result in the deferral of several major transmission system projects due to its favorable location in the southern part of JEA's transmission system.

In addition to the steady-state analysis, the SWG reviewed the dynamic simulations showing a stable response at peak load levels for normally cleared and delayed cleared three-phase faults in the vicinity of GEC. The results indicate that there are no grid stability concerns with the addition of the GEC.

A review of the short-circuit analysis has shown that there are no short-circuit concerns with the addition of the GEC.

Based upon the review and analysis conducted by the TWG and SWG, the FRCC has determined that the proposed interconnection and integration of the GEC to serve JEA's native load is reliable, adequate, and does not adversely impact the reliability of FRCC transmission system.

11.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand and to maintain an additional margin of capacity should unforeseen events result in higher system demand and/or lower than anticipated availability of capacity. This section discusses the reliability criteria used by JEA.

11.1 Reserve Sharing Requirements

Section 25-6.035 of the Florida Administration Code (FAC) requires that Florida utilities maintain a minimum 15 percent planned reserve margin for purposes of equitable sharing of energy reserves. The investor owned utilities in the State of Florida have entered into a stipulation to maintain 20 percent reserve margins, while the municipal utilities in the State generally maintain reserve margins of no less than 15 percent.

11.2 Reserve Margin Requirements

JEA uses a minimum 15 percent reserve margin in both the summer and the winter. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. JEA plans to maintain its seasonal reserve margins for firm load obligations (reflecting the load reductions associated with interruptible and curtailable loads). The reserve margin is calculated as follows:

$$\frac{\text{System Net Capacity - System Firm Peak Demand (After Interruptible/Curtailable Load)}}{\text{System Firm Peak Demand (After Interruptible/Curtailable Load)}}$$

11.2.1 Demand Response Considerations

Special consideration needs to be given to the portion of planned reserve requirements that can be covered by demand response (DR). Because DR grows as a portion of planned reserves, the frequency that DR is exercised increases. Depending upon the nature of the DR, increased frequency of its use can result in customer dissatisfaction, even to the extent that they leave the DR program, which can further exasperate reserve issues. Progress Energy Florida encountered this situation a few years ago, when many customers left their direct load control program.

JEA recently completed a review of its Planning Reserve Policy and determined that up 7.5 percent of JEA's forecast firm demand (half of its planning reserve margin) can be met by demand response programs. As a point of comparison, the FRCC's *2008 Summer Assessment* indicated that on a statewide basis, load management and interruptible loads were expected to account for approximately 6.6 percent of the FRCC Region's 2008 summer firm peak demand. JEA's Planning Reserve Policy regarding non-firm load (i.e., demand response) is consistent with the non-firm load proportion of the firm peak demand for the FRCC Region as a whole.

11.2.2 Renewable Considerations

The inclusion of significant amounts of renewable energy that are neither dispatchable nor controllable may impact system reliability. Solar and wind are primary examples of this type of renewable resources. Currently, JEA is not anticipating adding wind capacity to its system, but is actively pursuing the addition of solar PV capacity. As the amount of capacity that JEA receives from renewable resources that are neither dispatchable nor controllable increases, the associated impact on system reliability will need to be evaluated.

12.0 Capacity Requirements

JEA adheres to a minimum 15 percent reserve margin in both the summer and winter seasons. The planning reserve margin covers uncertainties in extreme weather, forced outages for generators, and uncertainty in load projections. JEA plans to maintain this 15 percent reserve margin only for firm load obligations. Interruptible load and curtailable load are considered in developing projections of firm peak demand for which the 15 percent reserve margin is calculated.

To determine JEA's need for capacity, a forecast of system peak demand was developed for the summer and winter seasons and was compared against net system capacity. The forecast system peak demand through 2027 is presented in Section 5.0. The net system capacity includes existing generation resources, existing system purchases, system sales, firm capacity additions, and planned unit retirements. JEA's existing system, including PPAs, planned unit retirements, and planned unit additions, are discussed in Section 3.0. Relevant changes to JEA's existing system that impact the future capacity requirements presented in this section are summarized as follows:

- JD Kennedy Unit 3 is assumed to be retired in March 2009.
- Planned unit additions include JD Kennedy CT 8 in 2009 and the two GEC simple cycle combustion turbines in 2010.
- Existing purchases include 207 MW from Southern Company through May 31, 2010, and winter purchases from Constellation in 2008 through 2010.
- For purposes of this Application, summer purchases have been added in 2008 through 2011 to maintain reserve margin requirements prior to the time of the Greenland Energy Center combined cycle conversion.
- Existing sales include 383 MW (winter) and 376 MW (summer) from the SJRPP units to FPL. Based on the terms and conditions of the sales agreement the total amount of energy that FPL can take under the agreement is limited. For the purpose of modeling in this Application, the term of the FPL-SJRPP sale is assumed to end on March 31, 2016.

The reliability levels for the summer base case and the winter base case (based on the changes to JEA's available generating capacity described above) are presented in Tables 12-1 and 12-2, respectively. The tables show that JEA's capacity will fall below its required 15 percent reserve margin in the summer of 2012. At that time, JEA's reserve margin decreases to 9.6 percent, or 167 MW below the level required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The deficit continues to increase and by the summer of 2015 the reserve margin is 3.0 percent, or 393 MW below the capacity required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The summer reserve margin increases in the summer of 2016 because of the projected end of the SJRPP sale to FPL; however, the reserve margin is still below the capacity required to maintain the 15 percent required reserve margin.

In the winter of 2012/13, JEA's reserve margin decreases to 12.7 percent, or 77 MW below the capacity required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The deficit continues to increase and by the winter of 2015/16 the reserve margin is 5.4 percent, or 342 MW below the capacity required to maintain the 15 percent reserve margin (including reducing the level of firm load by the impact of interruptible and curtailable loads). The winter reserve margin increases in the winter of 2016/17 because of the projected end of the SJRPP sale to FPL; however, the reserve margin is still below the capacity required to maintain the 15 percent required reserve margin.

Table 12-1
Projected Reliability Levels – Summer/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements [4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2008	3,367	216	(376)	0	0	3,207	2,941	2,824	9.0%	13.5%	(176)	(41)
2009	3,367	216	(376)	(51)	150	3,306	3,007	2,890	9.9%	14.4%	(152)	(18)
2010	3,367	9	(376)	(51)	434	3,383	3,072	2,955	10.1%	14.5%	(150)	(16)
2011	3,367	9	(376)	(51)	434	3,383	3,138	3,021	7.8%	12.0%	(226)	(91)
2012	3,367	9	(376)	(51)	434	3,383	3,204	3,087	5.6%	9.6%	(301)	(167)
2013	3,367	9	(376)	(51)	434	3,383	3,269	3,152	3.5%	7.3%	(377)	(242)
2014	3,367	9	(376)	(51)	434	3,383	3,335	3,218	1.4%	5.1%	(452)	(317)
2015	3,367	9	(376)	(51)	434	3,383	3,400	3,283	-0.5%	3.0%	(527)	(393)
2016	3,367	9	0	(51)	434	3,759	3,466	3,349	8.5%	12.3%	(227)	(92)
2017	3,367	9	0	(51)	434	3,759	3,531	3,414	6.4%	10.1%	(302)	(167)
2018	3,367	0	0	(51)	434	3,750	3,597	3,480	4.3%	7.8%	(386)	(252)
2019	3,367	0	0	(51)	434	3,750	3,662	3,545	2.4%	5.8%	(462)	(327)
2020	3,367	0	0	(51)	434	3,750	3,728	3,611	0.6%	3.9%	(537)	(403)
2021	3,367	0	0	(51)	434	3,750	3,794	3,677	-1.1%	2.0%	(613)	(478)
2022	3,367	0	0	(51)	434	3,750	3,859	3,742	-2.8%	0.2%	(688)	(553)
2023	3,367	0	0	(51)	434	3,750	3,925	3,808	-4.5%	-1.5%	(763)	(629)
2024	3,367	0	0	(51)	434	3,750	3,990	3,873	-6.0%	-3.2%	(839)	(704)
2025	3,367	0	0	(51)	434	3,750	4,056	3,939	-7.5%	-4.8%	(914)	(780)
2026	3,367	0	0	(51)	434	3,750	4,121	4,004	-9.0%	-6.4%	(990)	(855)
2027	3,367	0	0	(51)	434	3,750	4,187	4,070	-10.4%	-7.9%	(1,065)	(930)

[1] Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2010.

Table 12-2
Projected Reliability Levels – Winter/Base Case

Year	2008 Net Generating Capacity (MW)	Purchases [2] (MW)	Sales [3] (MW)	Net Firm Planned Capacity Retirements[4] (MW)	Net Firm Capacity Additions [5] (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin [1]		Excess/(Deficit) to Maintain 15% Reserve Margin	
							Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)	Before Int. and Load Mgt. (%)	After Int. and Load Mgt. (%)	Before Int. and Load Mgt. (MW)	After Int. and Load Mgt. (MW)
2007/08	3,621	291	(383)	0	0	3,529	3,079	2,946	14.6%	19.8%	(11)	142
2008/09	3,621	366	(383)	0	0	3,604	3,155	3,022	14.2%	19.3%	(24)	129
2009/10	3,621	366	(383)	(63)	191	3,733	3,232	3,099	15.5%	20.4%	16	169
2010/11	3,621	9	(383)	(63)	567	3,751	3,309	3,176	13.4%	18.1%	(54)	99
2011/12	3,621	9	(383)	(63)	567	3,751	3,386	3,253	10.8%	15.3%	(142)	11
2012/13	3,621	9	(383)	(63)	567	3,751	3,462	3,329	8.3%	12.7%	(230)	(77)
2013/14	3,621	9	(383)	(63)	567	3,751	3,539	3,406	6.0%	10.1%	(319)	(166)
2014/15	3,621	9	(383)	(63)	567	3,751	3,616	3,483	3.7%	7.7%	(407)	(254)
2015/16	3,621	9	(383)	(63)	567	3,751	3,693	3,560	1.6%	5.4%	(495)	(342)
2016/17	3,621	9	0	(63)	567	4,134	3,770	3,637	9.7%	13.7%	(201)	(48)
2017/18	3,621	0	0	(63)	567	4,125	3,846	3,713	7.3%	11.1%	(298)	(145)
2018/19	3,621	0	0	(63)	567	4,125	3,923	3,790	5.2%	8.8%	(386)	(233)
2019/20	3,621	0	0	(63)	567	4,125	4,000	3,867	3.1%	6.7%	(474)	(321)
2020/21	3,621	0	0	(63)	567	4,125	4,077	3,944	1.2%	4.6%	(563)	(410)
2021/22	3,621	0	0	(63)	567	4,125	4,153	4,020	-0.7%	2.6%	(651)	(498)
2022/23	3,621	0	0	(63)	567	4,125	4,230	4,097	-2.5%	0.7%	(739)	(586)
2023/24	3,621	0	0	(63)	567	4,125	4,307	4,174	-4.2%	-1.2%	(828)	(675)
2024/25	3,621	0	0	(63)	567	4,125	4,384	4,251	-5.9%	-2.9%	(916)	(763)
2025/26	3,621	0	0	(63)	567	4,125	4,461	4,328	-7.5%	-4.7%	(1,004)	(851)
2026/27	3,621	0	0	(63)	567	4,125	4,537	4,404	-9.1%	-6.3%	(1,092)	(940)

[1] Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
[2] Assumes UPS purchase through May 2010.
[3] Assumes FPL contract to purchase 30 percent of SJRPP ends on March 31, 2016.
[4] Retirement of JD Kennedy CT 3 in March 2009.
[5] Addition of JD Kennedy CT 8 in March 2009 and GEC CTs 1 and 2 in June 2010.

13.0 Supply-Side Alternatives

This section presents the conventional and emerging supply-side technologies that were considered by JEA. Estimated performance characteristics, emissions profiles, capital and operating costs, availability, and construction schedules are presented.

13.1 Conventional and Emerging Technologies

The conventional and emerging generating options that were evaluated as potential sources of future capacity for JEA are discussed in this section. In addition to a general description, a summary of projected performance, emissions, capital cost, O&M costs, construction schedules, scheduled maintenance requirements, and forced outage rates have been developed for each option.

Cost and performance estimates have been developed for several conventional self-build generation technologies that are proven, commercially available, and widely used in the power industry. Additionally, cost and performance estimates were developed for the LMS100 simple cycle combustion turbine, which may be considered an emerging technology. An emerging technology is a technology that cannot be considered conventional for various reasons, as discussed further in this section.

Although the combustion turbines and the combined cycle alternatives discussed herein assume a specific manufacturer (GE) and specific models (e.g., aeroderivative and frame combustion turbines), doing so is not intended to limit the alternatives considered solely to GE models. Rather, such assumptions were made to provide indicative cost, output, and performance data. Several manufacturers offer similar generating technologies with similar attributes, and the data presented in this analysis should be considered indicative of comparable technologies across a wide array of manufacturers.

Building additional coal or nuclear generation by 2012 is not feasible due to permitting constraints and construction lead times, and therefore.solid fuel generating facilities have not been included as generating unit alternatives. In addition, nuclear units are not included beyond the potential opportunities to participate in future nuclear generating units (as described in Section 16.4) because of the large size of the nuclear units and the need to have another entity develop and manage the projects.

The capital cost estimates developed include both direct and indirect costs. An allowance for possible general owner's cost items, as summarized in Table 13-1, has been included in the cost estimates.

Table 13-1
Possible Owner's Costs

Project Development	Owner's Contingency
• Site selection study • Land purchase/rezoning for Greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	• Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • HRSG materials, supplies, and parts • BOP equipment/tools • Rolling stock • Plant furnishing and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property **Utility Interconnections** • Natural gas service • Natural gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer
Plant Startup/Construction Support • Owner's site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of natural gas not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Financing (included in fixed charge rate, but not in direct capital cost)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

13.1.1 Generating Alternatives Assumptions

13.1.1.1 General Capital Cost Assumptions. Unless otherwise discussed for each site, the following general assumptions were applied in developing the cost and performance estimates:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, laydown, and staging.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site(s).
- The LMS100 is assumed to have standard SCR. The LM6000 and 7FA simple cycle combustion turbines will have hot SCR. Except for the LMS100, the simple cycle units will not include a CO catalyst, but will have a spool piece for future installation.
- GE 7FA combined cycle plants will include SCR and space for a potential CO catalyst to reduce emissions.
- Standard sound enclosures will be included for the combustion turbines.
- Natural gas pressure is assumed to be adequate for the 7FA simple and combined cycle alternatives. Gas compressors will be included for the LM6000 and LMS100 aeroderivative combustion turbines. A regulating and metering station is assumed to be part of the owner's cost for each alternative.
- Demineralized water will be supplied by a demineralized water treatment system for the combined cycle option.
- The LMS100 and the combined cycle alternatives will utilize cooling towers. Groundwater or treated sewage effluent will be used as cooling water.
- The LMS100 has an intercooled compressor and will not utilize inlet cooling. The LM6000 will include the SPRINT option and will also include inlet chillers. The GE 7FA combined cycle will utilize evaporative coolers.
- Field erected service/fire water storage tanks are included.

13.1.1.2 Fuel Assumptions.

- Fuel gas is 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet (scf), with a heat content of 21,515 Btu/lb, lower heating value (LHV).

13.1.1.3 Direct Cost Assumptions.

- Total direct capital costs are expressed in 2008 dollars unless otherwise noted.
- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
- Construction costs are based on an EPC contracting philosophy.
- Spare parts for startup are included. Initial inventory of spare parts for use during operation is included in the owner's costs.
- Permitting and licensing are included in the owner's costs.

13.1.1.4 Indirect Cost Assumptions. The following items are assumed in the capital cost estimate:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.
- Interest during construction and financing fees will be accounted for separately in the economic evaluation and, therefore, are not included in the capital cost or owner's cost estimates.

13.1.1.5 Meteorological Conditions. An average annual temperature and relative humidity of 70° F and 72 percent, respectively, were used for developing performance estimates for use in production cost modeling. Additionally, a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent) were used to develop seasonal performance estimates.

13.1.1.6 Performance Degradation. Power plant output and heat rate performance will degrade with hours of operation because of factors such as blade wear, erosion, corrosion, and increased tube leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance when compared to the unit's new and clean performance. The degradation that cannot be recovered is referred to herein as nonrecoverable degradation, and estimates have been developed to capture its impacts. Nonrecoverable degradation will vary from unit to unit, so specific nonrecoverable output and heat rate factors have been developed and are presented in Table 13-2. The degradation percentages are applied one time to the new and clean performance data, and reflect lifetime aggregate nonrecoverable degradation.

Table 13-2
Nonrecoverable Degradation Factors

Unit Description	Degradation Factor	
	Output (%)	Heat Rate (%)
GE LM6000 Simple Cycle	3.2	1.75
GE LMS100 Simple Cycle	3.2	1.75
GE 7FA Simple Cycle	3.2	1.75
GE 1x1 7FA Combined Cycle	2.7	1.50

13.1.2 Future Sites

The generating unit alternatives considered throughout this Application (excluding the conversion of the Greenland Energy Center to combined cycle operation) were developed on a greenfield site basis.

13.1.3 Simple Cycle Combustion Turbine Alternatives

Combustion turbine generators are sophisticated power generating machines that operate according to the Brayton thermodynamic power cycle. A simple cycle combustion turbine generates power by compressing ambient air and then heating the pressurized air to approximately 2,000° F or more, by burning oil or natural gas, with the hot gases then expanding through a turbine. The turbine drives both the compressor and an electric generator. A typical combustion turbine would convert 30 to 35 percent of the fuel to electric power. A substantial portion of the fuel energy is wasted in the form of hot gases (typically 900° F to 1,100° F) exiting the turbine exhaust. When the combustion turbine is used to generate power and no energy is captured and utilized from the hot exhaust gases, the power cycle is referred to as a "simple cycle" power plant.

Combustion turbines are mass flow devices, and their performance changes with changes in the ambient conditions at which the unit operates. Generally speaking, as temperatures increase, combustion turbine output and efficiency decrease because of the lower density of the air. To lessen the impact of this negative characteristic, most of the newer combustion turbine-based power plants often include inlet air cooling systems to boost plant performance at higher ambient temperatures.

Combustion turbine pollutant emission rates are typically higher on a part per million (ppm) basis at part load operation than at full load. This limitation has an effect on how much plant output can be decreased without exceeding pollutant emissions limits. In general, combustion turbines can operate at a minimum load of about 50 percent of the unit's full load capacity while maintaining emission levels within required limits.

Advantages of simple cycle combustion turbine projects include low capital costs, short design and construction schedules, and the availability of units across a wide range of capacities. Combustion turbine technology also provides rapid startup and modularity for ease of maintenance.

The primary drawback of combustion turbines is that, due to the cost of natural gas and fuel oil, the variable cost per MWh of operation is high compared to other conventional technologies. As a result, simple cycle combustion turbines are often the technology of choice for meeting peak loads in the power industry, but are not usually economical for baseload or intermediate service.

Two different commercially proven combustion turbine sizes were evaluated, as well as the LMS100 (which, as described later in this section, is a relatively new design with limited hours of demonstrated operation). The GE LM6000 has a nominal output in the range of 50 MW at International Organization for Standardization (ISO) conditions with the SPRINT™ design feature included. The GE 7FA has a nominal output of about 170 MW at ISO conditions.

13.1.3.1 GE SPRINT LM6000 Combustion Turbine. The GE SPRINT LM6000 was selected as a potential simple cycle alternative because of its modular design, efficiency, and size. It is a two-shaft gas turbine engine derived from the core of the CF6-80C2, GE's high thrust, high efficiency aircraft engine.

The LM6000 consists of a five-stage low-pressure compressor (LPC); a 14-stage, variable geometry, high-pressure compressor (HPC); an annular combustor; a two-stage, air-cooled, high-pressure turbine (HPT); a five-stage, low-pressure turbine (LPT); and an accessory drive gearbox. The LM6000 has two concentric rotor shafts, with the LPC and LPT assembled on one shaft, forming the LP rotor. The HPC and HPT are assembled on the other shaft, forming the HP rotor.

The LM6000 uses the LPT to power the output shaft. The LM6000 design permits direct coupling to 3,600 rpm generators for 60 hertz power generation. The gas turbine drives its generator through a flexible, dry type coupling connected to the front, or "cold" end, of the LPC shaft. The LM6000 gas turbine generator set has the following attributes:

- Full power in approximately 10 minutes.
- Cycling or peaking operation.
- Synchronous condenser capability.
- Compact, modular design.
- More than 5 million operating hours.
- More than 450 turbines sold.
- LM6000 SPRINT™ spray intercooling for power boost.
- Dual fuel capability.

The capital cost estimate was derived utilizing GE's Next-Gen package for the LM6000. This package includes more factory assembly, resulting in less construction time. Table 13-3 presents the operating characteristics of the LM6000 SPRINT combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent) and a summer temperature of 98° F (relative humidity of 54.9 percent), and annual average temperature conditions (70° F with a relative humidity of 72 percent). High temperature SCR would be used to control NO_x to 2 ppmvd while operating on natural gas. Table 13-4 presents estimated emissions for the LM6000.

13.1.3.2 GE 7FA Combustion Turbine. The GE 7FA combustion turbine, originally introduced in 1986, is the result of a multi-year development program using technology advanced by GE Aircraft Engines and GE's Corporate Research and Development Center. The development program facilitated the application of technologies such as advanced bucket cooling techniques, compressor aerodynamic design, and new alloys for F class gas turbines, enabling these machines to attain higher firing temperatures (2,400° F) than previous generating units.

Table 13-3
GE LM6000 PC SPRINT Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load)	47.4	9,637
Summer (Full Load)	46.2	10,171
Average (Full Load)	47.3	9,933
Average (75% Load)	26.5	11,304
Average (50% Load)	17.5	13,444

[1]Net capacity and net plant heat rate include degradation factors, inlet chilling is considered on full load cases above 60° F, and performance is preliminary.

Table 13-4
GE LM6000 PC SPRINT Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	29
CO, lb/MBtu	0.0648

[1]Emissions are at full load at 70° F, reflect operation on natural gas, and include the effects of SCR.

The GE 7FA combustion turbines have an 18-stage compressor and a 3-stage turbine and feature cold-end drive and axial exhaust, which is beneficial for combined cycle arrangements. With reduced cycle time for installation and startup, the GE 7FA can be installed relatively quickly. The packaging concept of the GE 7FA features consolidated skid-mounted components, controls, and accessories, which reduce piping, wiring, and other onsite interconnection work.

The GE 7FA combustion turbine has also exhibited outstanding environmental characteristics. Because of the higher specific output of these machines, smaller amounts of NO_x and CO are emitted per unit of power produced for the same exhaust concentrations as other generating technologies. GE 7FA turbines have accumulated more than 900,000 operating hours using dry low NO_x burners, which will be part of the NO_x control strategy when operating on natural gas.

Table 13-5 presents the operating characteristics of the GE 7FA combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). The 7FA will utilize dry low NO_x combustors and SCR to control NO_x to 2 ppmvd on natural gas. Table 13-6 presents estimated emissions for the 7FA.

Table 13-5
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load)	187.9	11,009
Summer (Full Load)	142.1	11,241
Average (Full Load)	157.6	10,888
Average (75% Load)	125.9	11,610
Average (50% Load)	78.3	14,327

[1]Net capacity and net plant heat rate include degradation factors and performance is preliminary.

Table 13-6
GE 7FA Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 70° F and include the effects of SCR and dry low NO_x combustors.

13.1.3.3 GE LMS100 Combustion Turbine. The GE LMS100 is a new combustion turbine; the first LMS100 began commercial operation in July 2006. At the time this Application was prepared, only about half a dozen LMS100 units had been ordered from GE. After the reliability of the LMS100 has been successfully demonstrated, it will likely replace the use of two-unit blocks of LM6000s in the future.

The LMS100 is currently the most efficient simple cycle gas turbine in the world. In simple cycle mode, the LMS100 has an efficiency of 46 percent, which is 10 percent greater than the LM6000. It has a high part-load efficiency, cycling capability (without increased maintenance cost), better performance at high ambient temperatures, modular design (minimizing maintenance costs), the ability to achieve full power from a cold start in 10 minutes, and is expected to have high availability, though this availability must be commercially demonstrated before the LMS100 can be considered a conventional alternative.

The LMS100 is an aeroderivative turbine and has many of the same characteristics of the LM6000. The former uses off-engine intercooling within the turbine's compressor section to increase its efficiency. The process of cooling the air optimizes the performance of the turbine and increases output efficiency. At 50 percent turndown, the part-load efficiency of the LMS100 is 40 percent, which is a greater efficiency than most simple cycle combustion turbines at full load.

There are two main differences between the LM6000 and the LMS100. The LM6000 uses the SPRINT intercooling system to cool the compressor with a micro-mist of water, while the LMS100 cools the compressor air with an external heat exchanger after the first stage of compression. Unlike the LM6000, which has a HP turbine and a power turbine, the LMS100 has an additional IP turbine to increase output efficiency.

As a packaged unit, the LMS100 consists of a 6FA turbine compressor, which outputs compressed air to the intercooling system. The intercooling system cools the air, which is then compressed in a second compressor to a high pressure, heated with combusted fuel, and then used to drive the two-stage IP/HP turbine described above. The exhaust stream is then used to drive a five-stage power turbine. Exhaust gases are at a temperature of less than 800° F, which allows the use of a standard SCR system for NO_x control.

Table 13-7 presents the operating characteristics of the LMS100 combustion turbine at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Standard SCR will be used to control NO_x to 2 ppmvd while operating on natural gas. Table 13-8 presents estimated emissions for the LMS100.

Table 13-7
GE LMS100 Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load)	95.6	8,961
Summer (Full Load)	86.4	9,360
Average (Full Load)	96.5	9,095
Average (75% Load)	72.1	9,543
Average (50% Load)	47.8	10,609

[1]Net capacity and full load net plant heat rate include degradation factors, evaporative cooling is not considered, and performance is preliminary.

Table 13-8 GE LMS100 Estimated Emissions[1]	
NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/TBtu	N/A
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	11.4
CO, lb/MBtu	0.025

[1]Emissions are at full load at 70° F and include the effects of SCR and CO catalyst.

13.1.3.4 GE 7FA 1x1 Combined Cycle. Combined cycle power plants use one or more CTGs and one or more STGs to produce energy. Combined cycle power plants operate according to a combination of both the Brayton and Rankine thermodynamic power cycles. HP steam is produced when the hot exhaust gas from the CTG is passed through an HRSG. The HP steam is then expanded through a steam turbine, which spins an electric generator. It is assumed that duct firing will be used in the combined cycle option.

Combined cycle configurations have several advantages over simple cycle combustion turbines. Advantages include increased efficiency and potentially greater operating flexibility if duct burners are used. Disadvantages of combined cycles relative to simple cycles include a small reduction in plant reliability and an increase in the overall staffing and maintenance requirements because of added plant complexity.

The 1x1 combined cycle generating unit includes one GE 7FA CTG, one HRSG, and one STG and will include evaporative cooling. The HRSG will convert waste heat from the combustion turbine exhaust to steam for use in driving the STG. The HRSG is expected to be a natural circulation, three-pressure, reheat unit with supplemental duct firing to maintain full steam turbine generator load at all ambient conditions. SCR and dry low NO_x burners will be included to control NO_x to 2 ppmvd, and space for a CO catalyst will be included.

The steam turbine is expected to be a tandem-compound, single reheat condensing turbine operating at 3,600 rpm. The steam turbine will have one HP section, one IP section, and a two-flow LP section. Turbine suppliers' standard auxiliary equipment; lubricating oil system; hydraulic oil system; and supervisory, monitoring, and control systems are included. A single synchronous generator is included, which will be direct coupled to the steam turbine. The STG will be located outdoors, with a building provided for the major auxiliary electrical power equipment.

Table 13-9 presents the operating characteristics of the GE 1x1 7FA combined cycle at a winter temperature of 24° F (relative humidity of 91.9 percent), a summer temperature of 98° F (relative humidity of 54.9 percent), and an annual average temperature of 70° F (relative humidity of 72 percent). Table 13-10 presents estimated emissions for the 1x1 7FA combined cycle.

13.1.4 Capital Costs, O&M Costs, Schedule, and Maintenance Summary

The capital costs, O&M costs, schedule, forced outage, and maintenance estimates for the generating alternatives are summarized in Table 13-11. All costs are provided in 2008 dollars unless otherwise noted. The EPC cost includes engineering, procurement, construction, and indirect costs for construction of each alternative utilizing a fixed price, turnkey type contracting structure. The assumed owner's cost allowance is representative of typical owner's costs as outlined in Table 13-1, exclusive of escalation, financing fees, and interest during construction, which will be accounted for separately in the economic analyses.

Fixed and nonfuel variable O&M costs are also provided in 2008 dollars. Fixed costs include labor, maintenance, and other fixed expenses excluding backup power, property taxes, and insurance. Nonfuel variable costs include outage maintenance, consumables, and replacements dependent on unit operation. Construction schedules are indicative of typical construction durations for the alternative technology and plant size. Actual costs and schedules will vary from the preliminary estimates provided in Table 13-11.

The scheduled and forced outage assumptions for the generating alternatives are also presented in Table 13-11.

Table 13-9
GE 1x1 7FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1]
Winter (Full Load with Duct Firing)	329.8	7,435
Summer (Full Load with Duct Firing)	299.6	7,445
Average (Full Load with Duct Firing)	307.2	7,420
Average (Full Load without Duct Firing)	247.0	6,969
Average (75% Load)	192.1	7,289
Average (50% Load)	141.0	7,923

[1]Net capacity and net plant heat rate include degradation factors, evaporative cooling is considered at full load cases above 60° F, and performance is preliminary.

Table 13-10
GE 1x1 7FA Combined Cycle Estimated Emissions[1]

NO_x, ppmvd at 15% O_2	2
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	0.0
CO_2, lb/MBtu	114.8
CO, ppmvd at 15% O_2	7.5
CO, lb/MBtu	0.0165

[1]Emissions are at full load at 70° F and include the effects of SCR and dry low NO_x combustors.

Table 13-11
Capital Costs, O&M Costs, and Schedules for the Generating Alternatives
(All Costs in 2008 Dollars)

Supply Alternative	Capital Costs			Total Cost ($/kW) at 70° F	Fixed O&M ($/kW-yr)	Nonfuel Variable O&M ($/MWh)	Construction Schedule (months)	Scheduled Maintenance (days)	Forced Outage (percent)
	EPC Cost ($millions)[1]	Owner's Cost ($millions)[1]	Total Cost ($millions)[1]						
GE LM6000 SC	57.6	14.4	72.0	1,522.9	26.47	3.64	10	10	2.0
GE LMS100 SC	90.1	22.5	112.6	1,166.7	13.45	3.29	12	10	2.0
GE 7FA SC	110.3	27.6	137.9	861.9	8.41	15.57	12	10	2.0
1x1 GE 7FA CC	287.0	62.3	349.3	1,136.9	4.56	3.30	22	14	2.0

(1) Estimated capital costs are presented in overnight 2008 dollars and do not include interest during construction.

14.0 Renewable Energy and Clean Power

JEA recognizes the importance of integrating renewable energy into its power supply portfolio. JEA has pursued several clean power initiatives and is in the process of evaluating potential new renewable energy resources. The remainder of this section discusses JEA's clean power portfolio (including JEA's existing renewable energy resources), and potential new renewable energy resources being evaluated by JEA.

14.1 JEA Clean Power Portfolio

Since 1999, JEA has been working closely with the Sierra Club of Northeast Florida (Sierra Club), the American Lung Association (ALA), and local environmental groups to establish a process to maintain an action plan entitled *Clean Power Action Plan.* The Clean Power Action Plan establishes an Advisory Panel that is comprised of participants from the Jacksonville community, including representatives from the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board. These local members provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Although the Clean Power Action Plan does not speak directly to CO_2 emissions, projects undertaken by JEA pursuant to the Plan have reduced JEA's CO_2 emissions.

JEA has implemented several projects as part of the Clean Power Action Plan, including installation of clean power systems, purchase power agreements, legislative and public education activities, and research into and development of clean power technologies. In particular, JEA has conducted a number of generation efficiency improvements, such as turbine upgrades, which increase the output of generating units without increasing the amount of fuel burned or the amount of CO_2 emitted. These particular projects are described later in this section.

14.1.1 Renewable Energy

In 2005, JEA received a Sierra Club Clean Power Award for its voluntary commitment to increasing the use of solar, wind, and other renewable or green power sources. Since that time, JEA has implemented new renewable energy projects and continues to explore additional opportunities to increase its utilization of renewable energy. As further discussed below, JEA's existing renewable energy sources include installation of solar PV, solar thermal, landfill and wastewater treatment biogas capacity, and wind.

14.1.1.1 Solar Energy. JEA has installed 35 solar PV systems, totaling 220 kW, on all of the public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast). To further promote the acceptance and installation of solar energy systems, JEA implemented the Solar Incentive Program in early 2002. This program provided cash incentives for customers to install solar PV and solar thermal systems on their homes or businesses.

JEA provided customer incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued in favor of the solar water heating program discussed below, which provides more cost effective CO_2 reduction. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. JEA also offers incentives for the installation of solar hot water heaters. To date, the program has resulted in over 500 incentives, or approximately 1.6 MW of capacity savings.

14.1.1.2 Landfill Gas and Biogas. Since 1997, JEA has owned and operated internal combustion engine generators fueled by landfill gas produced by the City of Jacksonville's Girvin Road landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, landfill gas generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The facility uses biogas produced by the wastewater treatment plant to fuel the 800 kW generator. JEA has received approximately 1,500 kW of landfill gas from the North Landfill, where it is used to generate power at Northside Unit 3.

In 2006, JEA signed a purchase power agreement with Landfill Energy Systems to obtain energy from a 9.6 MW landfill gas-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once completed, the facility will be one of the largest landfill gas-to-energy facilities in the Southeast, providing enough renewable energy to supply electricity to approximately 2,275 homes. The projected date of completion for the facility is late 2008.

14.1.1.3 Wind. As part of its ongoing effort to utilize more sources of renewable energy, in 2005 JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA has agreed to purchase 10 MW of capacity from NPPD's wind generation facility for a 20 year period. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes (renewable energy credits, or RECs) and will sell the RECs unless JEA needs them to meet state or federal environmental requirements.

14.1.1.4 Biomass. JEA has issued several RFPs for renewable energy resources. The only bids that JEA has received that were cost effective were for the Trail Ridge Landfill project (discussed previously) and a yard waste power project proposed by Evergreen. JEA attempted to negotiate a purchase power agreement with Evergreen, but the parties were unable to reach agreement on issues surrounding the yard waste fuel source, prompting JEA, in agreement with the City of Jacksonville, to suspend negotiations. JEA will continue to work with the City of Jacksonville and potential third party developers to establish a yard waste biomass project that will be beneficial to both JEA customers and the residents of Jacksonville.

In a continuing effort to obtain cost effective biomass generation, JEA is conducting a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in Northside 1 and 2. The JEA self-build projects would not be eligible for the tax advantages afforded to developers, but would take advantage of JEA's low cost tax exempt financing. Northside 1 and 2 are two of JEA's least cost units, and therefore any decreases in reliability due to the co-firing alternative for Northside 1 and 2 would result in significant increases in costs to JEA's customers due to the higher costs of replacement power.

JEA also periodically receives unsolicited offers for biomass and other renewable generation. JEA evaluates the feasible unsolicited offers, but has been unable to successfully execute a contract for cost-effective biomass or other renewable generation. One notable example is the 70 MW biomass project burning E-grass that JEA executed in 2002 with Biomass Investment Group, Inc. (BIG). Even though JEA executed the purchase power agreement, BIG has not implemented the project.

14.1.1.5 Ongoing Research Efforts. Many of Florida's renewable resources, such as offshore wind, tidal, and energy crops, have potential and need additional research and development before they can become large-scale technologies. JEA's renewable energy research efforts have focused on the development of technologies through a partnership with the UNF. The following projects are currently in progress:

- JEA is working with the UNF to quantify the winter peak reductions of solar hot water systems.
- UNF, along with the University of Florida, is evaluating the effect of biodiesel fuel in a pilot-scale combustion turbine. Biodiesel has been extensively tested on diesel engines, but combustion turbine testing has been very limited.
- UNF is evaluating the tidal hydro-electric potential for North Florida, particularly in the Intracoastal Waterway.
- UNF is in the preliminary stage of evaluating fuel cell technology utilizing methane produced at JEA's Buckman Wastewater Treatment Facility.

- JEA, UNF, and other Florida municipal utilities have partnered on a grant proposal to the Florida Department of Environmental Protection to evaluate the potential for wind development in Florida.
- JEA is providing solar PV equipment to UNF for installation of a solar system at the UNF Engineering Building to be used for student education.
- JEA developed a 15 acre biomass energy farm where the energy yields of various hardwoods and grasses were evaluated over a 3 year period.
- JEA participated in the research of a high temperature solar collector that has the potential for application to electric generation or air conditioning.
- JEA is evaluating the use of biofuels such as fats, oils and greases for potential use in solid fuel units.

14.1.2 Generation Efficiency and New Natural Gas Generation

Since the late 1990s, JEA has been modernizing their natural gas/oil fleet of generating units by replacing less efficient steam units and less efficient combustion turbines with a more efficient combined cycle unit and more efficient combustion turbines. Natural gas emits approximately 70 percent of the CO_2 of No. 6 oil on a fuel basis. This program, coupled with the much greater efficiency of a combined cycle unit compared to No. 6 oil steam units and less efficient combustion turbines, results in significant reduction of CO_2 on a per MWh basis.

14.1.2.1 Prior and Ongoing Projects. As a result of its system efficiency improvement efforts, JEA has retired the following units:

- Kennedy Steam Unit 8--43 MW Summer Heavy Oil/Natural Gas.
- Kennedy Steam Unit 9--43 MW Summer Natural Gas/Heavy Oil.
- Kennedy Steam Unit 10--97 MW Summer Natural Gas/Heavy Oil.
- Kennedy Combustion Turbine Unit 4--51 MW Summer No. 2 Oil.
- Kennedy Combustion Turbine Unit 5--51 MW Summer No. 2 Oil.
- Southside Steam Unit 4--67 MW Summer Natural Gas/Heavy Oil.
- Southside Steam Unit 5--142 MW Summer Natural Gas/Heavy Oil.

The retirement of these units and their replacement with an efficient combined cycle and efficient simple cycle combustion turbines significantly reduces CO_2 emissions. JEA's replacement units include Brandy Branch Unit 1, a 7FA simple cycle combustion turbine, Brandy Branch Combined Cycle, a 2x1 7FA combined cycle, and Kennedy 7, a 7FA simple cycle combustion turbine. These units all burn natural gas as their primary fuel with ultra low sulfur diesel as a backup fuel.

JEA also is installing Kennedy Combustion Turbine Unit 8, which is an efficient 7FA simple cycle combustion turbine designed to burn natural gas as its primary fuel and ultra low sulfur diesel as a backup. Kennedy Combustion Turbine Unit 3, an inefficient diesel fired unit, will be retired with the installation of Kennedy Combustion Turbine Unit 8 further increasing the efficiency of JEA's generating fleet. Commercial operation of Kennedy Combustion Turbine Unit 8 is scheduled for March 2009.

14.1.2.2 Greenland Energy Center. JEA is in the process of permitting the installation of Greenland Units 1 and 2, which will be efficient 7FA simple cycle combustion turbines designed to burn natural gas as their primary fuel with ultra low sulfur oil as backup. The installation of Greenland Units 1 and 2 further increases the efficiency of JEA's natural gas fueled generating fleet.

The conversion of Greenland Units 1 and 2 to combined cycle is a key part of JEA's generating unit efficiency improvement program. The combined cycle conversion allows the output of the GEC to increase over 60 percent without any increase in CO_2 emissions when compared to the simple cycle combustion turbines. The conversion of the Greenland combustion turbines to combined cycle, along with the Brandy Branch combined cycle, allows JEA to generate a large amount of energy with natural gas with its attendant lower CO_2 emissions per unit of electrical output.

The Greenland combined cycle project replaces capacity and energy that JEA planned to receive as its share in the suspended Taylor Energy Center Supercritical Pulverized Coal Unit. Replacing JEA's share of Taylor Energy Center capacity with capacity and energy from the Greenland combined cycle reduces JEA's CO_2 emissions by more than 1 million tons per year from what would have been emitted by JEA's share of Taylor Energy Center.

14.2 History of JEA RFPs for Renewable Energy

As discussed previously in this section, JEA has issued several RFPs for renewable energy sources. The following discussion summarizes the renewable energy RFP processes undertaken by JEA.

14.2.1 2004 RFP for Renewable Energy Generation

In February 2004, JEA issued a RFP for Renewable Energy Generation for 1 MW to 300 MW. The RFP covered projects for all renewable energy resources that resulted in energy being delivered to JEA's service territory. JEA received 13 acceptable responses with capacities between 1 MW and 50 MW. Several of the projects competed for the same fuel - four proposed the City of Jacksonville yard waste as fuel and three proposed the Trail Ridge landfill gas for fuel. The remaining projects were two existing biomass facilities, a proposed biomass facility in Southeast Georgia, a proposed addition to a biomass facility in west Florida, a solar PV and a wind project. Proposals were scored based on JEA's technical and pricing criteria. The technical criteria consisted of company experience, financial capabilities, team member qualifications, impact of the project on the environment, age and location of the facility, community support and size of the project.

The pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2004 dollars. This evaluation involves calculating an annual busbar cost ($/MWh) for the project using the proposed energy, capacity, and transmission wheeling costs, if applicable. Annual avoided fuel, capacity, and O&M costs were calculated. Avoided fuel expenses were calculated by modeling the proposed project as a must-run unit in JEA's production cost model. The model generates a fuel cost or savings using the proposed project in the production cost model versus JEA's base case (i.e., JEA's planned dispatch of generation units without the renewable energy project). The avoided costs for capacity, fixed, and variable O&M were based on the then-current JEA planning estimates for a natural gas fired combustion turbine. The renewable projects were given avoided capacity credit for each year even though they may not avoid capacity from being constructed given the small size of some of the proposed projects. The renewable project also receives a sulfur dioxide (SO_2) reduction credit for the SO_2 avoided by the project. The net cost (or benefit) to JEA over 10 years was calculated by adding the busbar costs, the avoided costs, and the SO_2 credit. Incremental costs for the 13 projects ranged from $6/MWh below to $285/MWh above the base case and a $5 million net savings to $103 million net additional cost to JEA over 10 years.

A final score was calculated for all proposals and Landfill Energy Systems and Evergreen Paper and Energy received the top scores. JEA entered into negotiations with Landfill Energy Systems (9.6 MW) on the Trail Ridge landfill gas and signed a PPA in May 2006. The project is expected to be operational by late 2008. JEA started negotiations with Evergreen Paper and Energy (13 MW using the City's yard waste) but these negotiations were cancelled by JEA in July 2007 after consultation with the City of Jacksonville on the City of Jacksonville-Evergreen yard waste fuel contract. The City of Jacksonville concluded that Evergreen, after several years of negotiation, had failed to deliver an executed contract and the bonding requirement. In addition, Evergreen had not prepared the site to take the yard waste within the timeframe proposed by the City of Jacksonville.

14.2.2 2007 RFP for Renewable Energy Generation

In 2007, JEA decided to again issue a request for renewable energy proposals. In order to allow more creativity and flexibility in the solicitation process, JEA started the process by soliciting letters of interest from companies interested in developing renewable energy projects for JEA. The solicitation was widely distributed, encouraged creativity in power purchase structures, included all renewable energy resources, and allowed project sizes up to 300 MW. Of the 19 responses received, 13 were for biomass projects, and the remaining were tidal, landfill gas, and digester gas projects as discussed below:

One of the projects was proposed by Trail Ridge LLC to generate energy from an additional 9.6 MW of landfill gas at the Trail Ridge landfill. JEA and Trail Ridge LLC continue to evaluate this proposal.

Two of the projects proposed a landfill gas technology but did not identify the landfill gas site that would be used. Since JEA was in negotiations with Trail Ridge LLC on the Trail Ridge landfill, JEA did not believe there was additional landfill opportunities in the JEA service area and did not pursue these technology-only proposals.

One letter of interest was from another Florida municipal utility indicating their interest in working with JEA on development of joint renewable energy projects. Specific projects were not mentioned. Because of the large size and risk of some renewable energy projects, JEA may consider working with other Florida utilities to develop joint projects similar to how several fossil fuel plants have been developed.

One letter of interest was an anaerobic digester using agricultural waste (1 MW). JEA was interested in pursuing this project but further discussion with the developer indicated that a fuel source had not been identified. JEA invited the proposer to contact JEA to begin project negotiations when a fuel source and location had been identified. The proposer has not contacted JEA since the initial discussion.

The final project was a 100 kW tidal demonstration project in the Intracoastal Waterway. JEA started negotiations with Integral Aqua Systems (IAS) on a PPA. However, the capital investor withdrew from this project in May 2007 and IAS has not been able to restructure the project although they did test a prototype hydro turbine in the Intracoastal Waterway in August 2007.

Because of the numerous biomass proposals that were received from the Letter of Interest, JEA issued a RFP for the biomass respondents on August 13, 2007. Proposals were due on September 21, 2007 (extended to September 28, 2007). JEA received four acceptable proposals and rejected five proposals because they did not meet the screening criteria. As part of the screening criteria, JEA required the respondents to complete all the RFP sections, propose a renewable energy resource, use proven technology, and have an availability factor of at least 85 percent. The availability factor is the percent of time a unit is capable of service if adequate resources are available. This factor is used in the purchase contracts as a default mechanism to ensure that the facility is capable of operation during the terms of the contract. Of the five rejected projects, three did not meet the mandatory requirements of the RFP and two of the projects were not received by the due date.

The remaining four acceptable proposals, ranging from 9 MW to 120 MW, were scored based on JEA's technical and pricing scoring criteria. These proposals were evaluated on the following technical aspects: technical viability, fuel availability and security, team experience, financial stability, project financing, site control, and performance guarantees. Each of the four projects proposed viable technology and demonstrated team experience with utility-scale generation projects. However, none of the projects (with the exception of one project which was an existing operating biomass facility) could demonstrate a commitment on the fuel source or site nor did they demonstrate project financing by providing commitment letters from third-party institutions.

The pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2007 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan. The avoided unit was a new natural gas-fired combustion turbine and the process is similar to the pricing evaluation used in the 2004 RFP process and described previously in this section. In addition, biomass projects were given credit for reductions in sulfur dioxide and carbon credits. Incremental costs for the four projects ranged from $10/MWh to $59/MWh above base case and $51 million to $306 million in net additional cost to JEA over 20 years.

JEA chose not to negotiate with any of the proposers because of the high costs and the inability of the proposers to demonstrate fuel or site availability or project financing.

14.3 Renewable Energy (Solar and Wind) RFP

Most recently, JEA issued a RFP for renewable energy, in particular solar and wind resources (Solar and Wind RFP), on March 17, 2008. Responses to the RFP were due on May 16, 2008. The RFP requested projects greater than 1 MW that generate electricity from solar (including PV or thermal electric) or wind. Solar projects greater than 250 kW at a JEA commercial customer's site were also included if the aggregate installation is greater than 1 MW. The RFP also requested proposals for solar PV equipment (panels and inverters) for installation by JEA. These proposals were scored on technical and economic factors very similar to the 2004 and 2007 RFP processes.

14.3.1 Summary of RFP Responses

JEA received ten solar PV proposals and two proposals for solar PV panels (equipment purchase only). JEA did not receive any proposals for solar thermal electric or wind projects. Of the ten solar PV proposals received, eight were for ground-mounted systems from 8 MW to 12 MW in size and two were for distributed roof-top mounted systems from 2 MW to 4 MW in total size. All proposals submitted were for projects to be developed in the JEA service area.

14.3.2 Solar and Wind RFP Response Evaluation Process

The proposals were all scored based on JEA's technical and pricing factors. The technical areas, which were scored on a point scale of 1-10, evaluated the company qualifications, the technical project, and the readiness of the project. Specifically, these factors included: qualifications of the company, financial strength, technical feasibility, ease of interconnection, barriers to project site, other ancillary benefits of the project, level of development of financing plan, level of project development completed, status of major equipment, interconnection design maturity, level of resource assessment performed, level of site control, level of site infrastructure, status of obtaining permits, and project schedule. Questions were submitted to all Bidders and responses were due on June 13, 2008. Projects were ranked based on the technical score. MMA Renewable Ventures, Sun Power, and Rocky Mountain Energy Group submitted the top three technical scoring projects.

The pricing proposals were first evaluated based on their levelized price with levelized costs ranging from approximately $186/MWh to approximately $343/MWh. All of the solar proposals reflect the assumed extension of the benefits of the existing Solar Incentive Tax Credits. Finally, the pricing proposals were evaluated by calculating an incremental cost for each proposal on the basis of all-in cost in nominal 2008 dollars. The incremental cost is the difference between the project's cost of power relative to JEA's existing system and base case plan, with the GEC combined cycle conversion representing the avoided unit. The incremental costs of the proposals ranged from approximately $10/MWh to approximately $150/MWh over a 20 year period. JEA is pursuing negotiations with the company that provided the lowest cost solar PV proposal. That proposal has been carried forward to the detailed economic evaluations as described in Section 17.0 of this Application.

15.0 Conservation and Demand Side Management Portfolio

Throughout its history, JEA has demonstrated a strong commitment to serve its customers' conservation needs. To that end, JEA has undertaken numerous conservation and DSM programs in order to decrease overall energy demands on its system while continuing to provide competitive levels of cost and service to customers.

15.1 Description of Historical Conservation and DSM Programs

JEA's 2005 DSM plan was approved by the FPSC on September 1, 2004. Upon reviewing the plan, the FPSC determined that there were no cost-effective conservation measures available for use by JEA, so the FPSC established and approved zero DSM and conservation goals for JEA's residential and commercial/industrial sectors through 2014 (Docket No. 040030-EG). Nevertheless, JEA has voluntarily continued its historical programs, because it had determined that these programs were in the overall best interest of its customers.

This subsection discusses the historical DSM programs that continue to be offered by JEA. As discussed in future portions of this section, JEA has collaborated with Summit Blue Consulting, LLC (Summit Blue), an independent firm that specializes in DSM program evaluation and development, to identify new DSM programs that are in the process of being implemented

The DSM and conservation programs historically offered by JEA include the following:

- Energy audits (residential and commercial).
- Green Built Homes of Florida.
- Chilled water services.
- Interruptible load.
- Educational events
- School activities.
- Monthly newsletter.

15.1.1 Energy Audits

JEA offers energy audits for both residential and commercial customers free of charge. A home energy audit can be completed online, in person, or by video. A business energy audit can also be done online or in person. The online audit considers the facility location, type of business or home, and floor space, among other factors. An audit completed in person involves a JEA representative performing an inspection and then offering cost-effective ideas to lower energy costs. A video audit is also available upon request and offers tips on energy and water conservation.

In addition to the energy audits, JEA offers an appliance calculator. The calculator performs energy calculations concerning lighting, refrigeration, washer, dryer, cooling systems, room air conditioners, water heaters, and thermostat adjustments, and provides customers with a way to measure their appliance energy use.

15.1.2 Green Built Homes of Florida

Green Built Homes of Florida is an incentive-based program offered by JEA and the Northeast Florida Builders Association (NEFBA), which was launched on June 1, 2006, to promote the use of energy and water efficient building practices in new single-family homes. The incentive is a $255 rebate to builders for each home that passes certification requirements. To be eligible for the incentive, a home must be a newly constructed, single-family home in JEA's electric service area and be Energy Star® inspected and certified by a Class 1 Home Energy Rating Systems (HERS) rater.

Energy Star® is a program developed by the Environmental Protection Agency and the Department of Energy to promote energy efficiency. Common features of an Energy Star® qualified home include tight construction, improved insulation, high performance windows, tightly sealed ducts, and high efficiency, appropriately sized heating and cooling equipment.

15.1.3 Chilled Water Services

JEA's central chilled water system circulates cold water in a continuous flow throughout buildings, then cools the warmed water in a centralized chiller plant. This system is intended to replace central air conditioning in individual buildings. JEA is providing the services to several buildings. These buildings include the new arena, library, baseball park, and Shands Hospital.

15.1.4 Interruptible Load

Interruptible load represents energy usage that can be shed during times of peak demand. This reduces the need for capacity additions to meet future peak periods. Typically, interruptible load is sold as capacity that is available during off-peak times, but not guaranteed during times of peak demand. JEA's current interruptible load program is forecast to be approximately 4.3 percent of the forecast winter 2008 peak demand and 2.9 percent of the forecast winter 2027 peak demand, and approximately 4.0 percent of the forecast summer 2008 peak demand and 2.8 percent of the forecast summer 2027 peak demand.

Interruptible load is available to any customer eligible for the General Service Large Demand (GSLD) rate schedule. To be eligible for GSLD, a customer must have a measured monthly billing demand of at least 1,000 kW or more for 4 or more months out of 12 consecutive monthly billing periods. Additionally, the customer must have an average load factor of 35 percent or more and have agreed to the Interruptible Service Agreement with JEA. Under this agreement, JEA reserves the right to limit the total load served and may interrupt service during any time period in consideration of the limits described in the next paragraph. In exchange for interruptible services, the customer's billing rate is reduced.

JEA is only allowed to interrupt electric power and energy delivery to the customer when it is required to (a) maintain service to JEA's firm power customers and firm power sales commitments, or (b) supply emergency interchange service to another utility for its firm load obligations only, or (c) when the price of power available to JEA from other sources exceeds 30 cents per kWh.

15.1.5 Educational Events

JEA has found that attendance at formal seminars dropped to the point it was not possible to sustain the seminars. Therefore, JEA replaced the seminars with other educational events as summarized in Table 15-1. Although some of the events listed in Table 15-1 had primary topics other than energy conservation, all of these events had conservation literature displayed for the customers attending.

Table 15-1
Educational Events

Event	Target	Total No. Events/Yr	Estimated Contacts
Annual Business Seminar	Commercial	1	250
Annual Business Summit	Commercial	1	225
Rate Education Program	Commercial	As needed	100
Bill Inserts, Messages, TV, Radio & Print Ads	Commercial / Residential	Continuous	65 million
Solar PV Array & Display at the Zoo	Residential	Continuous	350,000
Home & Patio Show	Residential	1	3,000

15.1.6 School Activities

JEA distributed 64,000 energy conservation and 35,000 water conservation brochures to area schools JEA reached an additional 89,500 students through its educational partnership with Tree Hill Nature Center and approximately 200,000 students with the JEA Science Theater and Aqua Expo located in the Museum of Science and History.. JEA also distributed 12,000 energy conservation and 6,000 water conservation brochures through its speaker's bureau and various community events such as Science Nights.

15.1.7 Monthly Newsletter

Since March 2006, JEA has published *JEACommercial Connections*, the monthly electronic newsletter and web portal distributed to thousands of commercial and industrial customers of JEA. The monthly publication allows access to useful industry specific information on benchmarking, best practices, green business, online audits and the like. A searchable library contains thousands of current articles, ask-an-expert, as well as RSS capability.

15.2 Portfolio of New DSM Programs

In June 2006, JEA contracted with Summit Blue to identify potential DSM programs for JEA. As part of this effort, Summit Blue conducted a DSM bench marking and best practices analysis to ensure that the DSM potential estimates and DSM program plans that Summit Blue develops for JEA are reasonable and appropriate, and to identify best practices regarding DSM programs. Summit Blue then characterized reasonable and appropriate DSM measures, which included estimating per unit energy and demand savings, incremental costs compared to standard efficiency measures, and measure lifetimes. Benefit-to-cost analyses were then conducted for the DSM measures, and DSM potential for the 2008 through 2017 period for residential and commercial and industrial customers were estimated.

The remainder of this section summarizes Summit Blue's characterization of DSM measures, the cost effectiveness analysis, the DSM potential study performed by Summit Blue, and the resulting portfolio of new DSM programs developed by Summit Blue for consideration by JEA.

15.2.1 Characterization of Residential DSM and Energy Efficiency Measures

The following subsections describe the residential DSM measures considered by Summit Blue.

15.2.1.1 Domestic Hot Water Measures. The following domestic hot water measures were considered by Summit Blue.

Efficient Water Heaters

Traditional electric water heaters have an overall efficiency of about 90 percent, including standby and distribution losses. High efficiency units achieve 95 percent efficiency with improved insulation and heat traps that minimize convection into under insulated distribution pipes. The savings estimate for the high-efficiency units were calculated based on total hot water energy use and unit efficiencies.

Heat Pump Water Heaters

Heat pump water heaters use compressed refrigerants to extract heat from ambient air (or water) and move that heat to stored hot water. During warm weather these machines can move four units of heat for every one comparable unit of input energy, thus achieving a coefficient of performance (COP) up to 4.0. COP decreases as ambient air temperature decreases. At about 10° F to 20° F, heat pumps become ineffective. At cold ambient temperatures traditional electric resistance heating elements backup the heat pump compressor. Savings were determined using engineering estimates with a linear relationship between COP and outdoor air temperature until 20° F, at which point it was assumed that electric resistance heat would take over.

Tankless Water Heaters

Tankless water heaters are more efficient than standard water heaters since they avoid the energy lost from the hot water that is stored in conventional tanks. Tankless water heaters have "energy factors" of about 98 percent. The savings estimate for the high-efficiency unit is calculated based on total hot water energy use and unit efficiencies.

Solar-Assisted Water Heaters

Solar-assisted water heaters use thermal solar collectors to heat a solution to temperatures high enough to heat water to useful hot water temperatures. While very efficient, these solar collectors are not effective if the sun is not shining. During prolonged cloudy stretches or if sufficient hot water demand occurs at night, the solar collector must be supplemented with traditional electric resistance or gas-fired heating to provide adequate service. Furthermore, a small amount of energy must be consumed by circulating pumps and controls. The cost estimate includes federal incentives that buy-down the cost of solar collectors.

Low Flow Showerheads

Low flow showerheads use an orifice plate inside the fixture to restrict the water flow to a maximum 2.5 gallons per minute versus a 3.5 gallon per minute permitted with standard new showerheads. Water flow from older showerheads typically exceeds 5.0 gallons per minute. Engineering methods were used to estimate savings between the 2.5 and 3.5 gpm showerheads assuming one 7 minute shower per occupant per day.

Faucet Aerators

Faucet aerators introduce air into the water as it leaves the faucet. The result is perceived full flow at a much reduced actual flow rate. It has been estimated that a faucet aerator reduces flow from 2 gallons per minute to 1 gallon per minute during 5 minutes of water use per occupant per day.

Hot Water Pipe Insulation

Pre-formed segments of foam insulation are placed around hot water distribution pipes to minimize heat loss. While useful for the entire length of hot water piping, it is most cost-effective in the first 5-10 feet of pipe extending from the water heater. Engineering estimates of steady state heat loss from the pipes to conditioned indoor air were used to estimate savings.

Hot Water Set-back Thermostat

Similar to a heating, ventilating, and air conditioning (HVAC) set-back thermostat, a water heater setback thermostat reduces the temperature set point of the water tank during periods when full service is not required. Savings accrue from reduced stand-by and distribution system losses. Engineering estimates of steady state heat loss were used to estimate savings.

Drain Water Heat Recovery

These systems recover some of the heat from drain pipe hot water. Savings were based on US Department of Energy information and manufacturer case studies[1]. These devices are typically more expensive to install as retrofits.

[1] http://www.eere.energy.gov/consumer/your_home/water_heating/index.cfm/mytopic=13040 and http://gfxtechnology.com/ELWH.pdf

Energy Star Clothes Washers

Effective January 1, 2007, the minimum efficiency requirement for Energy Star status increased to 48.45 L/kWh/cycle, or 1.72 cu.ft./kWh/cycle. Savings are not climate dependent and were based on the Database for Energy Efficient Resources (DEER). Energy Star horizontal-axis washers are generally more efficient than vertical-axis counterparts due to reduced water use in a horizontal drum.

Energy Star Dishwashers

Energy Star dishwashers must exceed minimum energy efficiency standards by at least 25 percent. Savings are not climate dependent and were based on the DEER database.

15.2.1.2 Residential Space Heating and Cooling Measures. The following residential space heating and cooling measures were considered by Summit Blue.

Energy Star Residential Room Air Conditioners

Energy Star room air conditioners must be at least 10 percent more efficient than standard U.S. models, which are defined as units with a minimum energy efficiency ratio (EER) rating of 9.4-10.8 depending upon the size and type of the unit.[2] Minimum efficiency standards for room air conditioners range from 8.5 EER to 9.8 EER depending on the unit size and type. The savings calculation assumes 2,500 hours of full-load operation and improving from 8.9 to 10.7 EER.

Energy Star Residential Air-Source Heat Pumps

Energy Star air-source heat pumps are units with minimum ratings of 14 seasonal energy efficiency ratio (SEER), EER ratings of 11.0-11.5, and heating system performance factors of 7.0-7.1 or higher[3]. 2006 minimum efficiency standards for heat pumps are 13 SEER and 6.7 heating seasonal performance factor (HSPF).

Energy Star Residential Water-Source Heat Pumps

Water-source heat pumps use the ground as the heat source and sink in the heating and cooling cycles, respectively, rather than ambient air. Since the efficiency of the heat-pump process improves when the heat source is warmer and the cooling energy sink is cooler (near constant 55° F ground temperature versus design ambient air temperatures of 32° F and 94° F), this equipment can achieve very high efficiencies upwards of 15.0 SEER and 5.0 heating COP.

[2] See US DoE Energy Star web site: http://www.energystar.gov/index.cfm?c=roomac.pr_room_ac .
[3] Ibid.

HVAC Diagnostic Repair, Testing, and Maintenance

Many residential and commercial HVAC systems are not operating as efficiently as possible due to inadequate maintenance. This package of services includes ensuring proper refrigerant charge, lubrication, cleanliness and fan operation. The savings estimate assumes that the tune-up improves efficiency by 0.5 EER.

HVAC Duct Sealing, Operations and Maintenance

Many HVAC ducts are not sealed well and leak conditioned air into unconditioned spaces such as basements and attics. Duct sealing reduces such heat loss and reduces fan power. Savings estimates assume 3 percent savings over typical HVAC systems.

HVAC Duct Insulation

Uninsulated HVAC ducts that run through uninsulated spaces like basements or attics transfer some of the heated or cooled air into those spaces rather than the conditioned zones. The amount of this heat loss is reduced with duct insulation. Savings were determined by modeling R-2 insulated ducts versus R-6 insulation.

Ceiling Insulation

Ceiling insulation includes both insulating uninsulated roof areas and adding insulation to under-insulated roof areas. Savings were determined by comparing R-0 versus R-20 roof constructions.

Wall Insulation

Wall insulation is most cost-effective when insulating un-insulated wall areas. Savings were determined by comparing insulated versus un-insulated walls.

Floor Insulation

Savings were determined by comparing insulated versus un-insulated floors.

Efficient Windows

Efficient windows are generally considered to be either triple paned windows, windows with a radiant barrier to reflect heat back into the conditioned space, or windows with low "shading coefficients". Reducing the shading coefficients of glass will reduce the amount of solar heat gain into the building. This reduced solar gain will decrease the cooling load for the building, but may increase the heating load. On the other hand these windows usually have a higher R-value than the windows they replace, thus heating energy can decrease.

Comprehensive Shell Air Sealing

This measure includes caulking, weather stripping, and sealing other visible cracks and penetrations in the building shell. Practically speaking a house should be able to breathe to purge contaminants so a lower limit of 0.35 air changes per hour (ACH) is advised without the addition of mechanical ventilation. Savings were determined by comparing 0.5 ACH versus 0.35 ACH.

15.2.1.3 Residential Lighting Measures. The following residential lighting measures were considered by Summit Blue.

Compact Fluorescent Lamps and Fixtures

Compact fluorescent lamps (CFLs) are the most common alternatives to standard incandescent lamps. CFLs are generally about four times as efficient as incandescent lamps, and last about 10 times as long. The newer "spiral" CFLs are also generally about the same size as incandescent lamps of similar light output. Numerous CFL measures were considered, with savings estimates corresponding to specific measures.

Light Emitting Diode (LED) Holiday Lights

LED holiday lights use LED lamps instead of incandescent lamps. Savings estimates assumed 5 operating hours per night for 30 days per year.

LED Night Lights

LED night lights substitute LED lights for incandescent lamps. Savings estimates assumed 10 operating hours per night.

15.2.1.4 Residential Refrigeration and Appliance Measures

The following residential refrigeration and appliance measures were considered by Summit Blue.

Energy Star Refrigerators and Freezers

Energy Star refrigerators must exceed current federal energy efficiency standards by at least 15 percent for full-size units, and 20 percent for compact size units[4]. Energy Star freezers must exceed minimum energy efficiency standards by at least 10 percent for full-sized units and 20 percent for compact units.

Remove Secondary Refrigerators and Freezers

Second refrigerators and freezers that customers own are often older and less efficient appliances. For example, the most common refrigerator sold in 1990 used between 60-70 kWh per cubic foot, compared to 2003, when the most common refrigerator sold used less than 30 kWh per cubic foot.[5]

Convection Ovens

Convection ovens are similar to traditional ovens except they have circulating fans to increase heat transfer to the food. Food cooks faster and at a slightly lower temperature in a convection oven.

Clothes Dryer with Moisture Sensor

Clothes dryers with moisture sensors tend to run fewer hours than those without because they sense when the clothes are dry rather than operating for a fixed period of time.

Power Strips with Occupancy Sensors

Power strips with occupancy sensors have several inputs that are controlled by an associated occupancy sensor and some that are not controlled. In an office environment, a computer could be plugged into an uncontrolled input and a monitor and task lamp could be plugged into the sensor controlled inputs.

15.2.2 Demand Response and Load Management Measures

The following demand response and load management measures were considered by Summit Blue. Direct load control measures apply to both residential and commercial/industrial customers.

[4] See Energy Star web site: http://www.energystar.gov/index.cfm?c=refrig.pr_refrigerators.

[5] Natural Resources Canada, "Energy Consumption of Major Household Appliances Shipped in Canada, Trends for 1990-2003 ", (NRCAN, Gatineau, QC, December 2005) p.8. U.S. and Canadian efficiency standards and availability are very similar; therefore, we conclude that the old equipment stock that would be removed is similar as well.

Direct Load Control (DLC) - AC/HP Cycling and Water Heater Cycling

DLC programs involve cycling or shutting off customers' air conditioners, heat pumps, water heaters, pool pumps, electric heating systems, or other electrical equipment during utilities' peak demand periods. This measure includes only air-conditioning/heat pumps and water heating.

Critical Peak Pricing (CPP)

CPP programs require the ability to inform customers in advance of a critical peak situation. Customers are given pricing information for the critical peak and they can elect to reduce loads to save cost or continue to purchase electricity at a significantly higher cost during the critical peak period.

Programmable Thermostats

Programmable thermostat measures enable customers to vary the comfort set points for heating and cooling equipment automatically, even when the customer is not present. This permits higher cooling set points during the mid-afternoon when a customer is at work, but preferred comfort settings just prior to when the customer comes home.

15.2.3 Characterization of Commercial/Industrial DSM and Energy Efficiency Measures

The following subsections describe the commercial/industrial DSM measures considered by Summit Blue.

15.2.3.1 Commercial/Industrial Lighting Measures. The following commercial/industrial lighting measures were considered by Summit Blue.

Compact Fluorescent Lamps

CFLs are the most common alternatives to standard incandescent lamps. CFLs are generally about four times as efficient as incandescent lamps, and last about 10 times as long. CFLs can either be screw-in replacements for incandescent lamps or plug-in lamps in fixtures specifically designed around CFL technology. Plug-in lamps in CFL fixtures are assumed to last the life of the fixture, because failed lamps must be replaced with comparable CFLs.

Premium/Regular T8 Lamps and Electronic Ballasts

T8 lamps and electronic ballasts are the most common alternative for standard T12 lamp and magnetic ballast tubular fluorescent lighting systems. T8 fluorescent lamps are one inch in diameter, and are thinner than T12 lamps, which are 1.5 inches in diameter. T8 systems are approximately 30 percent more efficient than standard T12 systems, and Premium T8s are approximately 38 percent more efficient than standard T12 systems.

T5 Lamps and Electronic Ballasts

T5 lamps and electronic ballasts are a newer alternative tubular fluorescent lighting system. T5 fluorescent lamps are 5/8 of an inch in diameter, thinner than both T8 lamps and T12 lamps. T5 lighting systems are primarily used in new construction but are sometimes installed in retrofit situations, although the fixture would have to be changed in that case.

Occupancy Sensors

Occupancy sensors automatically turn off the lights in a room or an area when the area is unoccupied. Occupancy sensors are an alternative to standard wall mounted on/off lighting switches. Savings assume that 10 percent of lighting is controlled by occupancy sensors with an average reduction of 4 hours of use per day. HVAC interactions are included in the estimates.

Daylighting Sensors

Lighting systems are designed assuming no contribution from ambient daylight. In areas where daylight is available, artificial light is unnecessary and possibly detrimental to occupant comfort. Daylight sensors measure the contribution of ambient daylight and either turn-off or dim the lamps of the artificial lighting system. Savings assumed that perimeter zone (less than 12 feet from an exterior fenestrated wall) lighting is controlled by daylight sensors to maintain required lighting levels with 3 steps of lighting control.[6] HVAC interactions are included in the estimates.

LED Exit Signs

LED exit signs are one of the most efficient types of exit signs on the market. They generally only draw about two to three watts of power, compared to 10 watts or more for CFLs, or 20 watts or more for incandescent exit signs.

[6] 3-level switching is an option that can be used with three-lamp fixtures where the first stage of light is energizing the in-board lamp, the second level is energizing the two outboard lamps, and the third level is using all three lamps. This control can be accomplished with special 3-lamp ballasts or by tandem-wiring a 4-lamp and a 2-lamp ballast between two fixtures in close proximity.

15.2.3.2 Commercial/Industrial HVAC and Envelope Measures. The following commercial/industrial HVAC and envelope measures were considered by Summit Blue.

Efficient Commercial Air Conditioning Systems – Chillers, Packaged AC, Heat Pumps, and PTACs/PTHPs

These different types of HVAC equipment can be replaced with higher efficiency units. Efficiencies are specified in terms of kW/ton for chillers, EER for packaged AC, EER and COP for heat pumps, and EER for packaged terminal AC or heat pump.

Energy Management Systems (EMS)

Sophisticated EMS can result in considerable savings if programmed correctly. Most new buildings are built with some kind of EMS in place, but these are not always programmed the most effectively. Therefore, the measure for new buildings is to reprogram the EMS. Existing buildings may not have an EMS, so the measure in that case is to install an EMS. The savings from the retrofitted EMS are higher than those for reprogramming an EMS. Savings estimates were taken from industry literature on savings achieved from actual EMS installations and reprogramming operations, as it was not possible to simulate this measure.

Envelope Measures – Cool Roofs, Roof Insulation, Window Films, and High Efficiency Windows

All of the envelope measures can contribute to savings in both or either heating and cooling loads. Cool roofs reduce direct heating of the building via the roof in the summer, and window films reduce the amount of light and heat entering the building via windows in the summer. High efficiency windows reduce both heating and cooling needs by reducing the amount of thermal conduction through the windows.

15.2.3.3 Commercial/Industrial Process Measures. The following commercial/industrial process measures were considered by Summit Blue.

Energy-Efficient Motors

The National Electrical Manufacturers Association (NEMA) has defined "premium" efficiency motors, and the savings for this measure were estimated based on the different efficiencies of the baseline and premium efficiency motors and the hours of operation.

Variable Frequency Drives

Variable frequency drives (VFDs) or adjustable speed drives (ASDs) vary the speed of motors so that their speeds are proportionate to the loads the motors are serving. This saves energy because motor energy use varies with the cube of the speed at which it runs for applications such as HVAC fans and pumps. Variable frequency drives produce small demand savings but high annual energy savings. Savings are determined by comparing the energy use of a motor with and without a VSD.

Compressed Air Measures – High Efficiency Compressors, Leak Maintenance, and Efficient Nozzles

Compressed air measures can be effective for industrial customers. Energy requirements for compressed air generation typically make up 20 percent of energy used for all industrial processes. The measures of leak maintenance and efficient nozzles are suitable for retrofitting existing compressed air equipment, and the higher efficiency compressors are suitable for either retrofit or new installations

15.2.3.4 Commercial/Industrial Refrigeration Measures. The following commercial/industrial refrigeration measures were considered by Summit Blue.

Strip Curtains and Night Covers

Strip curtains and night covers save energy by increasing the insulation between the cooled area within open case cooling units and the warmer air in the indoor environment. These are standard on new cooling units but may not be installed on older units. Savings are calculated on a linear foot basis, and are calculated by comparing energy use for refrigeration with and without the strip curtains or night covers. There are no demand savings for night covers.

High Efficiency Evaporator Fan Motors, Ice Makers and Refrigeration Compressors

High efficiency refrigeration equipment such as ice makers, evaporator fan motors, and refrigeration compressors save both energy and demand by operating at higher efficiencies. The evaporator fan motor measure definition is to replace a permanent split capacitor unit with an electrically commutated motor. The refrigeration compressor EER was raised from a baseline level of 8.5 to a more efficient level of 9. Savings for the ice maker were taken from industry literature and manufacturers' data.

Vending Machine Controls

Vending machines consume energy at all times of the day with cooling and lighting, but when an area is unoccupied and no one is purchasing products, these energy uses are wasteful. Vending machine controls can reduce lighting and decrease the number of compressor cycles based on occupancy sensor. Savings are based on mid-range savings estimates published by a controls manufacturer.[7]

15.2.4 DSM Cost Effectiveness Analysis

Following characterization of the DSM and energy efficiency measures summarized previously in this section, Summit Blue performed a cost effectiveness analysis. The cost effectiveness analysis evaluated measures using two different tests – the Total Resource Cost (TRC) test and the Rate Impact (RIM) test.

Key general inputs (i.e., inputs that are common across all measures) in the cost effectiveness analysis include avoided capacity costs, avoided transmission and distribution (T&D) costs, and assumptions related to future rate increases. These key inputs are summarized as follows:

- Annualized avoided capacity costs - $80/kW.
- Annualized avoided T&D costs - $25/kW.
- Rate Increases – 30 percent increase from 2006 rates by 2011.

The key inputs into the cost-effectiveness analysis by measure are the energy and demand savings, lifetime, and cost of the measure. The final input into the cost-effectiveness analysis is the program cost. Summit Blue assumed, based on the program benchmarking results, that for existing residential programs, the cost of the program will be $389 per peak kW saved for lighting, and $881 for central AC and heat pumps. It was also assumed that of that amount, 55 percent would be spent on rebate costs, and 45 percent will be spent on administration costs. Commercial and industrial program costs were assumed to vary from $255/kW for demand response measures up to $598/kW for new construction measures. With all of the above information, combined with the load profiles supplied by various sources, there was sufficient information to generate the cost-effectiveness numbers for each measure.

15.2.4.1 DSM Measure Cost Effectiveness Results. This section summarizes the results of the cost effectiveness analysis for both the TRC test and RIM test on the measure level. The TRC test considers the benefits (avoided costs) of generation, transmission and distribution investments and avoided fuel costs due to the conserved energy caused by the DSM measures. The costs for the TRC test are the DSM measure

[7] USA Technologies produces the VendingMiser
http://www.usatech.com/energy_management/energy_vm.php

costs plus the DSM measure administration costs. The RIM test considers the benefits (avoided costs) of generation, transmission and distribution investments, and avoided fuel costs due to the conserved energy caused by the DSM measure. The costs for the RIM test are the DSM measure costs plus the "lost revenues" due to the DSM programs.

The TRC and RIM tests are based on a net benefit to net cost analysis, and therefore test scores above 1.0 indicate that a measure may be cost effective (i.e., the net benefits of a measure are greater than the net costs). Tables 15-2 and 15-3 present the cost effectiveness results for existing single family homes and new single family homes, respectively while Table 15-4 presents the cost effectiveness results for the commercial/industrial sector

15.2.5 DSM Potential Analysis

This section describes the DSM potential analysis approach and methods. The DSM potential analysis used the results of the customer baseline profiles and the DSM measure characterization, along with the DSM benchmarking results, as inputs to the DSM potential spreadsheets.

The general approach for estimating DSM resource potentials consisted of three steps: (1) estimate technical and economic DSM potential; (2) estimate preliminary market penetrations and the resulting achievable potential for each measure; and (3) calibrate the achievable DSM potential estimates using the benchmarking information described in a previous section. This third step is the most important step in Summit Blue's DSM potential estimation process. For this benchmarking analysis, the average annual DSM potential values for each end use and sector were compared to actual program results for corresponding top performing programs and portfolios.

Technical DSM potential represents the amount of DSM savings that could be achieved, not considering economic and market barriers to customers installing DSM measures. Technical potential is calculated as the product of the DSM measures' savings per unit, the quantity of applicable equipment in each facility, the number of facilities in JEA's service area, and the difference between 100 percent and the measure's current market saturation. Technical potential estimates include DSM measures that are not cost effective, and technical potential does not consider market barriers such as customers' lack of awareness of DSM measures. Therefore, technical DSM potential estimates do not provide a realistic basis for setting DSM program goals.

Economic DSM potential represents the amount of technical DSM potential that is "cost effective," as defined by the results of the TRC test. Measures had to pass the TRC test in order to be considered to be cost effective and considered in the DSM potential estimates.

Table 15-2
DSM Cost Effectiveness Results for Existing Single Family Homes

Measure*	TRC	RIM
ENERGY STAR or better Room AC, < 20 kBtu, EER 10.7	4.59	0.67
Diagnostic repair, testing, maintenance	2.04	0.69
Duct Insulation and Sealing	2.02	0.93
Ceiling insulation (R-0 improved to R-20)	2.10	0.94
Ceiling insulation (R-20 improved to R-40)	0.34	0.95
High Efficiency Windows, Low-e; U=0.35	2.22	0.87
Floor insulation (R-0 to R-20)	0.03	0.45
Wall insulation (R-0 to R-20)	1.08	0.72
Comprehensive air shell sealing	0.57	0.38
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	1.06	0.71
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	2.10	0.88
Geothermal Heat Pump (4 Ton, w/ water heating)	0.44	0.88
Central AC SEER 14.0	2.73	0.98
High Efficiency Dryer With Moisture Sensor	0.68	0.49
ENERGY STAR or better Freezer	0.29	0.48
ENERGY STAR or better Refrigerator	0.57	0.48
Remove secondary refrigerator/freezer	1.68	0.47
Convection oven	0.24	0.48
Power strips with occupancy sensors	0.22	0.40
CFL, 6.0 hr/day	4.89	0.39
CFL, 0.5 hr/day	1.27	0.69
CFL, 2.5 hr/day	3.26	0.44
LED nightlights	2.01	0.77
LED holiday lights	0.29	0.12
CFL Fixtures, 0.5 hr/day	0.25	0.74
CFL Fixtures, 2.5 hr/day	0.66	0.45
CFL Fixtures, 6.0 hr/day	1.09	0.39
Low flow showerheads	4.71	0.48
HE Water Heater (EF=0.95)	1.42	0.51
Energy Star Dish Washer (EF=0.58)	0.53	0.70
Heat Pump Water Heater (EF=2.9)	0.78	0.65

Table 15-2 (Continued)
DSM Cost Effectiveness Results for Existing Single Family Homes

Measure*	TRC	RIM
Tankless Water Heater (EF=0.98)	0.11	0.42
Solar Assisted Water Heating	0.24	0.43
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	0.57	0.62
Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25)	0.13	0.64
Faucet Aerators	5.15	1.19
Hot water pipe insulation	9.35	0.76
Drain water heat recovery	0.79	0.62
DHW insulation blanket	4.59	0.47
A/C Cycling Switch	14.07	6.60
WH Cycling Switch	2.34	1.35
RTP	2.61	1.26
Programmable thermostat	2.34	0.80

*Measures are listed multiple times depending whether the savings are for air conditioning, electric resistance heating, or heat pump systems.

Table 15-3
DSM Cost Effectiveness Results for New Single Family Homes

Measure*	TRC	RIM
ENERGY STAR or better Room AC, < 20 kBtu, EER 10.7	4.98	0.88
Diagnostic repair, testing, maintenance	3.12	0.85
Duct Sealing and insulation	1.39	0.76
Ceiling insulation (R-20 improved to R-40)	0.25	0.60
High Efficiency Windows, Low-e; U=0.35	1.44	0.65
Floor insulation (R-10 to R-20)	0.02	0.92
Wall insulation (R-10 to R-20)	0.97	0.68
Comprehensive air shell sealing	0.74	0.57
ENERGY STAR or better Air Source Heat Pump, SEER=14; HSPF=8.5	0.58	0.65
ENERGY STAR or better Air Source Heat Pump, SEER=18; HSPF=9.4	1.58	0.62
Geothermal Heat Pump (4 Ton, w/ water heating)	0.41	0.62
Central AC SEER 14.0	2.02	0.72
High Efficiency Dryer With Moisture Sensor	1.01	0.72
ENERGY STAR or better Freezer	0.38	0.72
ENERGY STAR or better Refrigerator	0.73	0.69
Remove secondary refrigerator/freezer	2.20	0.68
Convection oven	0.36	0.69
Power strips with occupancy sensors	0.34	0.64
CFL, 6.0 hr/day	8.86	0.74
CFL, 0.5 hr/day	1.21	0.69
CFL, 2.5 hr/day	5.03	0.73
LED nightlights	1.75	0.71
LED holiday lights	1.35	0.67
CFL Fixtures, 0.5 hr/day	0.24	0.72
CFL Fixtures, 2.5 hr/day	1.05	0.73
CFL Fixtures, 6.0 hr/day	2.07	0.74
HE Water Heater (EF=0.95)	1.79	0.68
Energy Star Dish Washer (EF=0.58)	0.54	0.73
Heat Pump Water Heater (EF=2.9)	0.82	0.63
Tankless Water Heater (EF=0.98)	0.18	0.69
Solar Assisted Water Heating	0.37	0.68

Table 15-3 (Continued)
DSM Cost Effectiveness Results for New Single Family Homes

Measure*	**TRC**	**RIM**
Horizontal-Axis Clothes Washer: Energy Star CW (EF=2.5)	0.62	0.65
Energy Star Vertical-Axis Clothes Washer: SEHA CW Tier 2 (EF=3.25)	0.15	0.66
Faucet Aerators	2.86	0.75
Hot water pipe insulation	7.56	0.73
Drain water heat recovery	1.50	0.73
A/C Cycling Switch	2.36	1.31
WH Cycling Switch	2.48	1.38
RTP	2.75	1.26
Programmable thermostat	3.12	0.80

*Measures are listed multiple times depending whether the savings are for air conditioning, electric resistance heating, or heat pump systems.

Table 15-4
DSM Cost Effectiveness Results for Commercial/Industrial

Measure	TRC	RIM
CFLs	3.32	0.62
Regular T8 w/ EB	2.59	0.68
Premium T8 w/ EB	3.21	0.72
T5 w/ EB from T12	1.29	0.58
T5 w/ EB from PSMH	1.08	0.71
LED Exit Signs	1.9	0.58
Occupancy Sensors - FLTG	1.91	0.56
Occupancy Sensors - HID	2.97	0.65
Daylighting	2.34	0.74
Hi-E Air-Cooled Chillers	5.65	0.77
Hi-E Water-Cooled Chillers	4.14	0.75
Hi-E Packaged DX	1.66	0.81
Hi-E Heat Pump	2.74	0.76
Hi-E PTAC/PTHP	2.62	0.85
Roof Insulation	0.22	0.78
Cool Roofs	0.1	0.74
Window Films	0.45	0.78
Premium Efficiency Motors	0.8	0.74
Motor VFDs	11.04	0.74
Hi-E Evaporator Fan Motors	0.57	0.27
Hi-E Refrigeration Compressors	0.72	0.61
Hi-E Ice Makers	1.32	0.56
Strip Curtains	1.2	0.42
Night Covers	0.76	0.37
Hi-E Air Compressors	13.05	0.77
Leak Maintenance	0.17	0.08
Efficient Nozzles	0.34	0.19
Energy Mgmt System Install	15.13	0.75
Solar PV	3.64	0.84
Premium T8 w/ EB	2.18	0.55
T5 w/ EB from T8	0.66	0.29

Table 15-4 (Continued)
DSM Cost Effectiveness Results for Commercial/Industrial

Measure	TRC	RIM
T5 w/ EB from PSMH	2.05	0.74
Occupancy Sensors - FLTG	1.72	0.53
Occupancy Sensors - HID	2.82	0.64
Daylighting	2.07	0.73
Hi-E Air-Cooled Chillers	5.78	0.81
Hi-E Water-Cooled Chillers	3.96	0.74
Hi-E Packaged DX	1.64	0.8
Hi-E Heat Pump	2.66	0.75
Hi-E PTAC/PTHP	2.3	0.82
Hi-E Windows	1.9	0.81
Cool Roofs	0.04	0.54
Premium Efficiency Motors	4.9	0.73
Motor VFDs	11.02	0.74
Hi-E Refrigeration Compressors	0.71	0.59
Hi-E Air Compressors	12.93	0.77
Energy Mgmt System Reprogram	10.91	0.76
Solar PV	3.64	0.84

Achievable potential is an estimate of the amount of DSM potential that could be captured by realistic DSM programs over the ten-year forecast period (2008-2017) covered by this DSM potential analysis. The key parameter that must be estimated to forecast achievable DSM potential is the market penetration for each DSM measure at the end of the forecast period in 2017. Summit Blue estimated this parameter for each DSM measure based primarily on the DSM benchmarking analysis, as well as previous DSM potential projects conducted by Summit Blue.

For most nonlighting measures, maximum market penetrations of 20 percent over the forecast period were assumed, while lighting DSM measure saturations were generally assumed to reach 70 percent to 90 percent saturation by 2017, as that range of CFL measure saturations are widely expected to be achieved over the long term, and some utilities with aggressive DSM program histories have already achieved the lower end of that range in the commercial/industrial sector. However, it is important to emphasize that Summit Blue's assumptions regarding end of period DSM measure saturation estimates were made so as to produce DSM potential estimates for each sector and end use that are consistent with the utility and agency DSM program benchmarking results discussed previously.

15.2.5.1 Residential DSM Potential Results. This section provides the overall DSM potential results for the residential sector. The total and annual residential achievable DSM potential results for the 10 year forecast period are presented in Table 15-5. The energy values shown in Table 15-5 are for the DSM measures' first-year energy savings at the generator, the demand savings are the peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebate or other customer incentive costs, as well as administrative, implementation, and evaluation costs.

15.2.5.2 Residential Demand Response Results. Summit Blue estimated the potential for two residential demand response options:

1. Direct load control of central air conditioners and heat pumps.
2. Direct load control of electric water heaters.

Some utilities include other types of end use equipment in direct load control programs. However, water heaters are the most common additional type of equipment covered by DLC programs after central air conditioners and heat pumps.

Table 15-5
Total 10 Year Residential Achievable Potential Estimates[1]

Residential Total	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Lighting											
Achievable Potential Summer Demand Savings (MW)	38.8	1.9	3.1	3.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Achievable Potential Winter Demand Savings (MW)	38.8	1.9	3.1	3.9	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Achievable Potential Energy Savings (GWh)	296.4	14.8	23.7	29.6	32.6	32.6	32.6	32.6	32.6	32.6	32.6
Program Costs (Million $)	$15.1	$0.8	$1.2	$1.5	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7	$1.7
Heating /HVAC											
Achievable Potential Summer Demand Savings (MW)	32.2	1.6	2.6	3.2	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Achievable Potential Winter Demand Savings (MW)	35.0	1.8	2.8	3.5	3.9	3.9	3.9	3.9	3.9	3.9	3.9
Achievable Potential Energy Savings (GWh)	112.8	5.6	9.0	11.3	12.4	12.4	12.4	12.4	12.4	12.4	12.4
Program costs (Million $)	$30.8	$1.5	$2.5	$3.1	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4	$3.4
Water Heating											
Achievable Potential Summer Demand Savings (MW)	8.4	0.4	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Achievable Potential Winter Demand Savings (MW)	7.8	0.4	0.6	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Achievable Potential Energy Savings (GWh)	47.2	2.4	3.8	4.7	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Program Costs (Million $)	$3.3	$0.2	$0.3	$0.3	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4	$0.4
Load Management/DLC											
Achievable Potential Summer Demand Savings (MW)	81.3	4.1	6.5	8.1	9.0	9.0	9.0	9.0	9.0	9.0	9.0
Achievable Potential Winter Demand Savings (MW)	130.5	6.5	10.4	13.1	14.4	14.4	14.4	14.4	14.4	14.4	14.4
Achievable Potential Energy Savings (GWh)	-0.34	-0.02	-0.03	-0.03	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04	-0.04
Program Costs (Million $)	$18.9	$0.9	$1.5	$1.9	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
Refrigeration & Miscellaneous											
Achievable Potential Summer Demand Savings (MW)	0.5	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Achievable Potential Winter Demand Savings (MW)	0.5	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Achievable Potential Energy Savings (GWh)	4.2	0.2	0.3	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Program Costs (Million $)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Residential Total											
Achievable Potential Summer Demand Savings (MW)	161.1	8.1	12.9	16.1	17.7	17.7	17.7	17.7	17.7	17.7	17.7
Achievable Potential Winter Demand Savings (MW)	212.5	10.6	17.0	21.3	23.4	23.4	23.4	23.4	23.4	23.4	23.4
Achievable Potential Energy Savings (GWh)	460.2	23.0	36.8	46.0	50.6	50.6	50.6	50.6	50.6	50.6	50.6
Program Costs (Million $)	$68.3	$3.4	$5.5	$6.8	$7.5	$7.5	$7.5	$7.5	$7.5	$7.5	$7.5

[1] Totals may not exactly equal the sum of the individual year demand and energy savings and program costs due to rounding.

For purposes of comparison, Summit Blue reviewed the results its demand response potential assessment for the International Energy Agency's demand response resources project. [8] As part of that project, Summit Blue surveyed 40 North American utilities on their demand response programs in late 2004. The survey indicated that the top-performing residential direct load control programs had achieved impacts that amounted to 10 percent or more of the utilities' residential peak demands. Large majorities of the impacts from these utilities' demand response programs were from direct load control of central air conditioners during summer peak demand periods.

15.2.5.3 Residential Energy Efficiency Results by End Use. Residential lighting measures, primarily CFLs in high-use, medium-use, and low-use fixtures, account for about 64 percent of the total estimated residential energy conservation potential, a total of about 39 MW of coincident peak demand reduction and 296 GWh of energy savings over the ten-year forecast period. The average energy savings are similar to the top-performing residential lighting programs.

HVAC and building envelope DSM measures are estimated to have second largest total energy savings impacts of about 112 GWh and 35 MW of peak demand reduction potential over the ten year period. Water heating measures are estimated to have the third largest total energy savings impacts, of about 47 GWh of energy savings potential and 7.8 MW of peak demand reduction potential. Refrigeration and other measures have relatively small DSM potentials of 4 GWh of energy savings impacts and 0.5 MW of peak demand reductions. The small refrigeration DSM potential is primarily due to the fact that government minimum energy efficiency standards have already caused most of the energy conservation potential for more efficient refrigeration measures to be realized. Each of these three DSM measure categories have about 5-10 or more applicable DSM measures each that were included in the DSM potential analysis.

The largest HVAC or building envelope measure in terms of energy conservation potential is insulating uninsulated walls. The largest impact water heating conservation measure is drain water heat recovery.

15.2.5.4 Commercial/Industrial DSM Potential Results. The total and annual commercial/industrial achievable demand response potential results for the 10 year forecast period are shown in Table 15-6. The demand savings shown are for both the winter and summer peak coincident demand savings, and the program costs are the total estimated DSM program budgets for a given year, including rebates or other customer incentive costs, as well as administrative, implementation, and evaluation costs.

[8] Limited results from this study are publicly available at www.demandresponseresources.com.

Table 15-6
Total 10 Year Commercial/Industrial Demand Response Achievable Potential Estimates[1]

Demand Response	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Direct Load Control											
Achievable Potential Summer Demand Savings (MW)	23.74	1.19	2.37	3.56	3.56	3.56	1.90	1.90	1.90	1.90	1.90
Achievable Potential Winter Demand Savings (MW)	16.58	0.83	1.66	2.49	2.49	2.49	1.331	1.33	1.33	1.33	1.33
Achievable Potential Energy Savings (GWh)	0.36	0.02	0.04	0.05	0.05	0.05	0.03	0.03	0.03	0.03	0.03
Program Costs (Million $)	$4.2	0.21	0.42	0.63	0.63	0.63	0.34	0.34	0.34	0.34	0.34
Interruptible/Callable Rates											
Achievable Potential Summer Demand Savings (MW)	118.70	5.94	11.87	17.81	17.81	17.81	9.50	9.50	9.50	9.50	9.50
Achievable Potential Winter Demand Savings (MW)	82.90	4.15	8.29	12.44	12.44	12.44	6.63	6.63	6.63	6.63	6.63
Achievable Potential Energy Savings (GWh)	6.0	0.30	0.60	0.90	0.90	0.90	0.48	0.48	0.48	0.48	0.48
Program Costs (Million $)	$4.6	0.23	0.46	0.68	0.68	0.68	0.36	0.36	0.36	0.36	0.36
RTP											
Achievable Potential Summer Demand Savings (MW)	23.74	1.19	2.37	3.56	3.56	3.56	1.90	1.90	1.90	1.90	1.90
Achievable Potential Winter Demand Savings (MW)	16.58	0.83	1.66	2.49	2.49	2.49	1.33	1.33	1.33	1.33	1.33
Achievable Potential Energy Savings (GWh)	0	0	0	0	0	0	0	0	0	0	0
Program Costs (Million $)	$0.2	0.01	0.02	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.02
Total											
Achievable Potential Summer Demand Savings (MW)	166.18	8.31	16.62	24.93	24.93	24.93	13.29	13.29	13.29	13.29	13.29
Achievable Potential Winter Demand Savings (MW)	116.06	5.80	11.61	17.41	17.41	17.41	9.28	9.28	9.28	9.28	9.28
Achievable Potential Energy Savings (GWh)	6.37	0.32	0.64	0.96	0.96	0.96	0.96	0.96	0.96	0.96	0.96
Program Costs (Million $)	$9.0	0.45	0.90	1.35	1.35	1.35	0.72	0.72	0.72	0.72	0.72

[1] Totals may not exactly equal the sum of the individual year demand and energy savings and program costs due to rounding.

Summit Blue estimated the DSM potentials for three demand response program options:

1. Direct load control of commercial and industrial customers' air conditioners and heat pumps.
2. Interruptible rates, somewhat similar to JEA's existing program.
3. Real-time pricing.

To estimate the commercial/industrial demand response potential, Summit Blue reviewed the results from its International Energy Agency demand response resources project. The 2004 utility survey that Summit Blue conducted for that project revealed that utilities with top-performing interruptible rate programs can reduce their commercial/industrial peak demands by about 10 percent through these programs. However, with a very small number of exceptions, the demand response program impacts realized by most utilities from commercial/industrial direct load control and RTP programs are generally quite modest, at about 2 percent of utility commercial/industrial peak demands each.

In total, Summit Blue estimates that total commercial/industrial demand response programs would have a demand reduction potential of about 166 MW over the ten year forecast period. Estimated annual program impacts would follow the regular s-shaped diffusion curve initially and then taper off in the latter part of the forecast period as the programs achieve increasing market saturation.

15.2.5.5 Overall Commercial/Industrial Energy Efficiency Results. The total and annual commercial/industrial achievable energy efficiency potential results for the 10 year forecast period are presented in Table 15-7.

The total estimated commercial and industrial energy efficiency potential over the 10 year forecast period is about 610 GWh, 48 MW of winter peak demand reduction, and 106 MW of summer peak demand reduction. About 30 percent of this energy efficiency potential is projected to come from energy efficient lighting products, about 40 percent is projected to come from energy efficient motors and air compressors, and about 26 percent of the total potential is expected to come from efficient HVAC measures and energy management systems.

Table 15-7
Total 10 Year Commercial/Industrial Energy Efficiency Potential Estimates[1]

Total Commercial and Industrial	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Lighting											
Achievable Potential Summer Demand Savings (MW)	37.81	1.13	2.27	3.40	3.78	4.54	4.54	4.54	4.54	4.54	4.54
Achievable Potential Winter Demand Savings (MW)	10.29	0.31	0.62	0.93	1.03	1.24	1.24	1.24	1.24	1.24	1.24
Achievable Potential Energy Savings (GWh)	182.05	5.46	10.92	16.38	18.21	21.85	21.85	21.85	21.85	21.85	21.85
Program Costs (Million $)	$57.05	1.71	3.42	5.13	5.71	6.85	6.85	6.85	6.85	6.85	6.85
HVAC											
Achievable Potential Summer Demand Savings (MW)	36.76	1.10	2.21	3.31	3.68	4.41	4.41	4.41	4.41	4.41	4.41
Achievable Potential Winter Demand Savings (MW)	13.31	0.40	0.80	1.20	1.33	1.60	1.60	1.60	1.60	1.60	1.60
Achievable Potential Energy Savings (GWh)	78.86	2.31	4.61	6.92	7.69	9.22	9.22	9.22	9.22	9.22	9.22
Program Costs (Million $)	$21.20	0.64	1.27	1.91	2.12	2.54	2.54	2.54	2.54	2.54	2.54
Building Envelope											
Achievable Potential Summer Demand Savings (MW)	0.12	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Achievable Potential Winter Demand Savings (MW)	0.22	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Achievable Potential Energy Savings (GWh)	0.40	0.01	0.02	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Program Costs (Million $)	$0.18	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Motors											
Achievable Potential Summer Demand Savings (MW)	2.57	0.08	0.15	0.23	0.26	0.31	0.31	0.31	0.31	0.31	0.31
Achievable Potential Winter Demand Savings (MW)	3.26	0.10	0.20	0.29	0.33	0.39	0.39	0.39	0.39	0.39	0.39
Achievable Potential Energy Savings (GWh)	123.22	3.70	7.39	11.09	12.32	14.79	14.79	14.79	14.79	14.79	14.79
Program Costs (Million $)	$7.22	0.22	0.43	0.65	0.72	0.87	0.87	0.87	0.87	0.87	0.87
Refrigeration											
Achievable Potential Summer Demand Savings (MW)	0.90	0.03	0.05	0.08	0.09	0.11	0.11	0.11	0.11	0.11	0.11
Achievable Potential Winter Demand Savings (MW)	0.90	0.03	0.05	0.08	0.09	0.11	0.11	0.11	0.11	0.11	0.11
Achievable Potential Energy Savings (GWh)	9.86	0.30	0.59	0.89	0.99	1.18	1.18	1.18	1.18	1.18	1.18
Program Costs (Million $)	$1.44	0.04	0.09	0.13	0.14	0.17	0.17	0.17	0.17	0.17	0.17

Table 15-7 (Continued)
Total 10 Year Commercial/Industrial Energy Efficiency Potential Estimates[1]

Total Commercial and Industrial	10 Year Total	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Compressed Air											
Achievable Potential Summer Demand Savings (MW)	16.56	0.50	0.99	1.49	1.66	1.99	1.99	1.99	1.99	1.99	1.99
Achievable Potential Winter Demand Savings (MW)	16.56	0.50	0.99	1.49	1.66	1.99	1.99	1.99	1.99	1.99	1.99
Achievable Potential Energy Savings (GWh)	122.03	3.66	7.32	10.98	12.20	14.64	14.64	14.64	14.64	14.64	14.64
Program Costs (Million $)	$6.28	0.19	0.38	0.56	0.63	0.75	0.75	0.75	0.75	0.75	0.75
EMS											
Achievable Potential Summer Demand Savings (MW)	6.35	0.19	0.38	0.57	0.64	0.76	0.76	0.76	0.76	0.76	0.76
Achievable Potential Winter Demand Savings (MW)	3.70	0.11	0.22	0.33	0.37	0.44	0.44	0.44	0.44	0.44	0.44
Achievable Potential Energy Savings (GWh)	83.94	2.52	5.04	7.55	8.39	10.07	10.07	10.07	10.07	10.07	10.07
Program Costs (Million $)	$1.98	0.06	0.12	0.18	0.20	0.24	0.24	0.24	0.24	0.24	0.24
Renewables											
Achievable Potential Summer Demand Savings (MW)	4.79	0.14	0.29	0.43	0.48	0.57	0.57	0.57	0.57	0.57	0.57
Achievable Potential Winter Demand Savings (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Achievable Potential Energy Savings (GWh)	12.11	0.36	0.73	1.09	1.21	1.45	1.45	1.45	1.45	1.45	1.45
Program Costs (Million $)	$46.12	1.38	2.77	4.15	4.61	5.53	5.53	5.53	5.53	5.53	5.53
Total											
Achievable Potential Summer Demand Savings (MW)	105.86	3.18	6.35	9.53	10.59	12.70	12.70	12.70	12.70	12.70	12.70
Achievable Potential Winter Demand Savings (MW)	48.25	1.45	2.90	4.34	4.83	5.79	5.79	5.79	5.79	5.79	5.79
Achievable Potential Energy Savings (GWh)	610.48	18.31	36.63	54.94	61.05	73.26	73.26	73.26	73.26	73.26	73.26
Program Costs (Million $)	$141.47	4.24	8.49	12.73	14.15	16.98	$16.98	$16.98	$16.98	$16.98	$16.98

[1] Totals may not exactly equal the sum of the individual year demand and energy savings and program costs due to rounding.

The total commercial/industrial energy efficiency potential amounts to approximately 8.5 percent of JEA's 2007 commercial/industrial energy consumption of about 7,160 GWh. This is equal to annual average energy savings of about 61 GWh. Based on the histories of the benchmark utilities and energy agencies, Summit Blue estimates that a three to four year ramp-up period will generally be required before most of JEA's DSM results would hit the annual average impacts for the forecast period. It is estimated that the annual achievements of the total DSM potential will follow an s-shaped curve for most end use categories, with impacts of 3 percent of the total energy efficiency potential in the first year, 6 percent in the second year, 9 percent in the third year, 10 percent in the fourth year, and 12 percent in the fifth year and beyond to the end of the 10-year forecast period.

15.2.5.6 Commercial/Industrial Energy Efficiency Results by End Use. Commercial/industrial lighting measures account for the largest share of commercial/ industrial energy efficiency potential of any individual end use, comprising about 30 percent of the total estimated commercial/industrial energy conservation potential, a total of about 182 GWh of energy conservation potential, 10 MW of winter coincident peak demand reduction, and 38 MW of summer peak demand reduction potential over the ten-year forecast period. This amounts to an average of about 1 MW of winter peak and 18 GWh per year.

T8 lamps and electronic ballasts in regular and high-bay applications are expected to account for the largest share of commercial/industrial lighting energy efficiency potential, about one-third of the total. CFL lamps and fixtures, T5 lamps and electronic ballasts, and LED exit signs are expected to account for most of the other commercial/industrial lighting potential.

Efficient air compressors and variable speed drives applied to motor systems are expected to account for about 40 percent of total commercial/industrial energy savings at about 245 GWh of first year energy savings in total. The energy efficiency process potential is almost exactly equally divided between these two process DSM measures.

Efficient HVAC and control systems are estimated to account for the third largest share of commercial/industrial energy efficiency potential, 161 GWh of first year energy savings and 17 MW of winter peak demand reduction over the 10 year forecast period. Energy management systems account for slightly more than half of the energy savings from HVAC and control measures.

Other end use categories such as refrigeration are expected to account for small shares of energy efficiency potential over the forecast period. This expectation is primarily drawn from the results of the DSM benchmarking analysis discussed previously.

15.2.6 Resulting DSM Portfolio for JEA

Based on the Summit Blue analyses, JEA's senior management approved a new DSM portfolio through 2012 in accordance with guidance established by JEA's Board. The portfolio will be funded by a JEA Board approved conservation charge of $0.50 per MWh for all customers and an additional $1.00 per MWh for residential customers with consumption above 2.75 MWh per month. The new DSM portfolio was designed to address all customer classes (i.e. residential and commercial/industrial). It also ensures no future upward pressure on customer rates by maintaining portfolio RIM of no less than 1. The approved DSM portfolio consists of the following five programs:

- **JEA's Residential Lighting Program** promotes the use of energy efficient compact fluorescent light bulbs in homes and small businesses by offering a financial incentive and recycling options to its customers. JEA has aligned itself with the Department of Energy's "Change a Light, Change the World" campaign in an effort to educate its customers in the use of energy efficient lighting products. JEA includes appropriate messaging concerning the proper disposal of compact fluorescent light bulbs.
- **JEA's Neighborhood Efficiency Program** offers education concerning the efficient use of energy and water as well as the direct installation of an array of energy and water efficient measures at no cost to income qualified customers. The Neighborhood Efficiency Program is a partnership with the City of Jacksonville.
- **JEA's Residential Efficiency Upgrades Program** will promote the use of energy and water efficient building practices in existing homes. The program targets measures such as energy audits, HVAC equipment and envelope upgrades. The program will align itself with the Department of Energy's "Home Performance with Energy Star" campaign in an effort to educate its customers in the use of energy efficient home products.
- **JEA's Residential Direct Load Control (DLC) Program** will offer financial incentives to residential and small commercial customers to control central air conditioners, central electric heating systems, water heaters, and pool pumps during critical periods to reduce JEA's winter and summer peak demands.
- **JEA's Commercial Direct Load Control Program** will offer financial incentives to mid-to-large-sized commercial/industrial customers to curtail loads when requested by JEA in response to winter and summer peaks or system emergencies. The program focuses on utilizing customer sited energy management systems and standby generation.

Following JEA's approval of the DSM portfolio, Summit Blue provided the projected energy efficiency and peak demand response savings corresponding to the policies and conservation funding limits. In addition to seasonal peak demand and energy savings, Summit Blue provided projected annual costs of the approved DSM portfolio. Tables 15-8 through 15-11 present the annual summer and winter coincident peak demand and net energy for load reductions, as well as the annual program costs, corresponding to the DSM portfolio being implemented by JEA.

Table 15-8
Target JEA DSM Portfolio Summer Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012
Residential Lighting	2.8	8.5	14.2	19.8	25.5
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0
Residential Efficiency Upgrades	0.0	2.3	6.8	11.3	15.8
Residential Direct Load Control	0.0	7.1	21.2	36.5	51.8
Commercial Direct Load Control	0.0	5.9	17.8	35.6	53.4
Total Cumulative Demand Reductions(1)	3.0	24.2	60.5	104.0	147.5

(1) Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Table 15-9
Target JEA DSM Portfolio Winter Peak Demand Reductions
(Cumulative MW Reductions)

DSM Program	2008	2009	2010	2011	2012
Residential Lighting	1.9	5.7	11.3	16.3	21.2
Neighborhood Efficiency	0.2	0.4	0.6	0.8	1.0
Residential Efficiency Upgrades	0.0	1.5	4.5	9.0	13.0
Residential Direct Load Control	0.0	8.2	26.9	51.4	75.9
Commercial Direct Load Control	0.0	5.8	17.4	31.3	45.3
Total Cumulative Demand Reductions(1)	2.0	21.5	60.7	108.7	156.3

(1) Totals may not exactly equal the sum of the individual program demand reductions due to rounding.

Table 15-10
Target JEA DSM Portfolio Total Annual Energy Reductions
(GWh Reductions)

DSM Program	Calendar Year 2008(1)	Calendar Year 009	Calendar Year 2010	Calendar Year 2011	Calendar Year 2012
Residential Lighting	2.2	14.1	37.2	67.1	87.2
Neighborhood Efficiency	0.2	1.0	1.8	2.6	3.2
Residential Efficiency Upgrades	0.3	3.8	17.4	41.9	66.3
Residential Direct Load Control	0.0	0.0	0.0	0.0	0.0
Commercial Direct Load Control	0.0	0.0	0.0	0.0	0.0
Total Cumulative Energy Reductions(2)	2.7	18.8	56.4	111.6	156.8

(1) Energy reductions were not provided by Summit Blue for 2008. The 2008 GWh reductions have been estimated based on actual performance to date.
(2) Totals may not exactly equal the sum of the individual program energy reductions due to rounding.

Table 15-11
Target JEA DSM Portfolio Annual Program Costs
(Millions $)

DSM Program	Fiscal Year 2008	Fiscal Year 2009	Fiscal Year 2010	Fiscal Year 2011	Fiscal Year 2012
Residential Lighting	$0.6	$1.5	$2.2	$1.9	$1.9
Neighborhood Efficiency	$0.25	$0.35	$0.35	$0.35	$0.35
Residential Efficiency Upgrades	$0.1	$1.0	$2.1	$3.1	$2.7
Residential Direct Load Control	$0.6	$1.2	$2.7	$3.6	$3.6
Commercial Direct Load Control	$0.2	$0.4	$0.9	$1.1	$1.1
Total Program Costs(1)	$1.85	$4.45	$8.35	$10.05	$9.65

(1) Totals may not exactly equal the sum of the individual program costs due to rounding.

16.0 Evaluation Methodology

Detailed economic analyses were performed to evaluate the economics of the GEC combined cycle conversion as part of JEA's least-cost expansion plan to satisfy forecast capacity requirements throughout the 20 year evaluation period considered in this Application. This section discusses the evaluation methodology used in the economic analyses. The results of the analyses are presented in Section 17.0.

16.1 Expansion Planning Simulation

Optimal generation expansion planning and production cost modeling was performed using STRATEGIST, a computer software system licensed through Ventyx (which recently acquired NewEnergy Associates, LLC, the original developer of STRATEGIST). STRATEGIST is a proven and effective modeling program for optimal generation expansion planning and production cost modeling. According to Ventyx, over 50 utilities now use STRATEGIST for integrated corporate strategic planning, including least-cost expansion planning.

STRATEGIST includes an automatic expansion planning module that can determine the optimal balanced demand and supply plan for a utility system under a prescribed set of constraints and assumptions. STRATEGIST evaluates all combinations of generating unit alternatives and purchase power options in conjunction with existing capacity resources to satisfy forecast capacity requirements while maintaining user-defined reliability criteria. STRATEGIST simulates the hourly operation of a utility system to determine the cost and reliability effects of adding resources to the system or modifying the load through DSM programs. The simulation of the utility system operation is accomplished using dynamic programming, a mathematical technique useful for making a sequence of interrelated decisions for determining the combination of decisions that optimizes the desired outcome. In this Application, all expansion plans were analyzed over a 20 year period from 2008 through 2027.

16.2 Fuel and CO_2 Emissions Allowance Price Forecasts

Section 7.0 presents the fuel and CO_2 emissions allowance price forecasts used throughout this Application, including price forecasts for various sensitivity cases. The fuel and CO_2 emissions allowance price forecasts presented in Section 7.0 were developed in constant 2006 dollars. For purposes of the economic analyses presented throughout this Application, the constant 2006 dollars price projections were converted to nominal dollars using the 2.5 percent general inflation rate discussed in Section 4.0.

For sensitivity analyses that consider the potential regulation of emissions of CO_2, the emissions rates for every existing generating resource, as well as new capacity additions being considered, were included in the dispatching decisions made by STRATEGIST. Because each generating unit, whether existing or being considered as a supply-side alternative, has a unique emissions profile, the annual emissions allowance costs vary for each unit. Including emissions allowance costs in this manner allows the analysis to take into consideration the "all-in" production costs for each unit, including fuel costs, nonfuel variable costs, and costs associated with emissions of CO_2.

16.3 Firm Natural Gas Transportation Costs

As discussed in Section 8.0, the GEC site will receive natural gas from both Southern Natural Gas and Florida Gas Transmission Company through the SeaCoast Pipeline to the GEC Lateral for delivery to GEC. JEA is expected to have sufficient firm natural gas transportation capacity to reliably serve its natural gas fired generating units, including the GEC combined cycle, based on current contractual capacity as well as planned future increases to firm natural gas transportation capacity. For the 1x1 7FA combined cycle alternative, the economic analysis assumed 37,990 MBtu/day of incremental firm natural gas transportation capacity at $1.28/MBtu. Firm natural gas transportation for simple cycle combustion turbine alternatives is not included; however, Interruptible Transportation Service at the tariff rate of $0.598/MBtu is included for simple cycle combustion turbine alternatives.

16.4 New Nuclear Generating Units

In March 2008, the JEA Board of Directors approved the pursuit of nuclear energy partnerships with the goal of providing 10 percent of JEA's energy requirements from nuclear sources. Adding power from nuclear sources to JEA's portfolio is part of a resource strategy resulting in less dependence upon fossil fuels and a reduction in CO_2 emissions.

In June 2008, JEA entered into a PPA with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to Vogtle Units 3 and 4, which are proposed new nuclear units to be constructed at the existing Plant Vogtle. Under this PPA, JEA will be entitled to a total of 206 MW of firm capacity from the proposed units. After accounting for transmission losses, JEA is anticipated to receive a total of 200 MW of net firm capacity from the proposed units. For purposes of the analyses presented throughout this Application, it has been assumed that 100 MW (net) of capacity is available to JEA beginning January 1, 2016 from Vogtle Unit 3, and an additional 100 MW (net) is available to JEA beginning January 1, 2017 from Vogtle Unit 4. The costs associated with this PPA are confidential, and although the costs have been included in the analyses they are not presented separately in order to maintain confidentiality.

16.5 DSM Portfolio

As discussed in Section 15.0, JEA has developed a DSM portfolio consisting of new programs which address all customer classes. The projected annual seasonal demand reductions, net energy for load reductions, and costs for each program included in JEA's new DSM portfolio are summarized in Subsection 15.2.6. Several of the economic evaluations summarized in Section 17.0 include analysis of various scenarios that reflect the demand and energy savings, as well as corresponding annual costs, for the new DSM portfolio.

In order to accurately reflect the on-peak seasonal demand reductions projected to result from the energy efficiency programs included in JEA's new DSM portfolio in the economic evaluations discussed in Section 17.0, adjustments were made to the demand reductions presented in Tables 15-8 and 15-9 to account for meteorological data specific to the Jacksonville area.

16.6 Cumulative Present Worth Cost Analysis

Economic comparisons between competing expansion plans were developed on a CPWC basis. The CPWC calculation accounts for annual system costs (fuel, energy, and nonfuel variable O&M for existing resources and new unit additions, as well as fixed O&M and levelized capital costs for new unit additions) for each year of the expansion planning period and discounts each back to 2008 using the 5.0 percent present worth discount rate discussed in Section 4.0. These annual present-worth costs were then totaled over the 2008 through 2027 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various expansion plans, and the plan with the lowest CPWC is considered the least-cost expansion plan for any given case considered.

17.0 Economic Evaluation

Detailed economic analyses were performed to evaluate the cost-effectiveness of the GEC combined cycle conversion to help satisfy forecast capacity and energy requirements. Numerous evaluations were conducted in order to consider reference case fuel price and load forecasts as well as sensitivity cases related to fuel prices, load forecasts, capital costs, and regulation of CO_2 emissions. Additionally, the cost-effectiveness of the GEC combined cycle conversion was evaluated under several scenarios involving new renewable energy resources that may be available to JEA and reductions in coincident peak demand resulting from the implementation of the new DSM portfolio, both of which have been described in previous sections of this Application. The remainder of this section describes each of the scenarios evaluated and presents the corresponding CPWC for expansion plans with and without the GEC combined cycle conversion in June 2012.

The economic analyses described herein compare the economics of the least-cost expansion plan including the GEC combined cycle conversion in June 2012 versus the economics of the least-cost expansion plan that does not include the conversion in June 2012. For comparison purposes, the GEC combined cycle conversion in June 2012 was treated as a committed resource, and the optimal expansion model, STRATEGIST, was allowed to select among the supply-side alternatives presented in Section 13.0 to develop the least-cost expansion plan to meet capacity requirements beyond 2012. For cases in which the GEC combined cycle conversion was not treated as a committed resource in 2012, STRATEGIST was allowed to select among the same supply-side alternatives presented in Section 13.0 to meet capacity requirements.

17.1 Overview of Evaluation Scenarios

The economics of the GEC combined cycle conversion were considered for several cases among four distinct scenarios as outlined below. The results of the economic analyses for each case considered for each scenario are presented in subsequent subsections.

17.1.1 Scenario 1 – Conventional Expansion Scenario

The *Conventional Expansion Scenario* considers the addition of only conventional (fossil fueled) generating resources, with the exception of the new nuclear generating resources discussed in Section 16.4. As described previously in this section, the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 were evaluated against the economics of an expansion plan that does not include the GEC combined cycle conversion. The Scenario 1 evaluations were performed for several sensitivity cases described as follows.

17.1.1.1 Reference Case. The *Reference Case* considers the reference case fuel price projections included in Section 7.3 and base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in the reference case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.2 High Fuel Price Case. The *High Fuel Price Case* considers the high fuel price projections presented in Section 7.5. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.3 Low Fuel Price Case. The *Low Fuel Price Case* considers the low fuel price projections presented in Section 7.5. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.4 High Load Case. The *High Load Case* considers the high load forecast presented in Section 5.0. Fuel price projections used in this case correspond to the reference case projections included in Section 7.3. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.5 Low Load Case. The *Low Load Case* considers the low load forecast presented in Section 5.0. Fuel price projections used in this case correspond to the reference case projections included in Section 7.3. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.6 High Capital Case. The *High Capital Case* reflects an increase of 20 percent in the capital cost of the GEC combined cycle conversion presented in Section 9.3 as well as the capital costs of all other generating unit alternatives presented in Section 13.0. Fuel price projections used in this case correspond to the reference case projections included in Section 7.3. The base case load forecast presented in Section 5.0 was used in the high capital cost case.

17.1.1.7 Regulated CO_2 Case. The *Regulated CO_2 Case* considers the fuel and CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.2191 as presented in Section 7.8. The CO_2 emissions allowance prices used in this case correspond to the *S.2191 Core* analysis. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.8 High Fuel with Regulated CO_2 Case. The *High Fuel with Regulated CO_2 Case* considers the high fuel price projections in Section 7.5 and also considers the CO_2 emissions allowance price projections corresponding to the EIA's analysis of S.2191. The CO_2 emissions allowance prices used in this case correspond to the *S.2191 Core* analysis. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

17.1.1.9 High Regulated CO_2 Case. The *High Regulated CO_2 Case* considers CO_2 emissions allowance price projections based on the EIA's analysis of S.2191. The CO_2 emissions allowance price projections used in the *High Regulated CO_2 Case* correspond to the EIA's *S.2191 Limited Offsets/No International Case.* This analysis was selected because the resulting CO_2 emissions allowance prices are the highest of the S.2191 scenarios evaluated by the EIA.

The EIA analysis of S.2191 presented CO_2 emissions allowance price projections in 2006 dollars per metric ton beginning in 2012 and extending through 2030. For analysis purposes, the 2006 dollars per metric ton price projections were converted to 2006 dollars per short ton. These prices were then converted to nominal dollars using the 2.5 percent general inflation rate presented in Section 4.1. The resulting CO_2 emissions allowance price projections for 2012 through 2027 that were used in the *High Regulated CO_2 Case* are presented in Table 17-1. For comparison purposes, Table 17-1 also presents the CO_2 emissions allowance price projections used in the *Regulated CO_2 Case*, which were based on the EIA S.2191 Core case projections presented in Section 7.8. The fuel prices for this case correspond to the fuel prices presented in the EIA's *S.2191 Limited Offsets/No International Case.*

This scenario provides an indication of the potential effect of a higher-cost CO_2 regulatory regime than that assumed in the *Regulated CO_2 Case* described above. Capacity requirements used in this case correspond to the base case load forecast presented in Section 5.0. The capital cost for the GEC combined cycle conversion used in this case is presented in Section 9.3, while the capital costs for all other generating unit alternatives are presented in Section 13.0.

Table 17-1
Projected CO_2 Emission Allowance Prices
EIA S.2191 Limited Offsets/ No International Scenario and
EIA S.2191 Core
(Nominal $/Ton)

Year	Limited Offsets/ No International	Core
2012	53.26	17.75
2013	50.95	19.54
2014	55.09	21.52
2015	60.65	23.69
2016	66.77	26.08
2017	73.50	28.71
2018	80.91	31.60
2019	89.07	34.79
2020	98.06	38.29
2021	107.94	42.16
2022	118.83	46.41
2023	130.81	51.10
2024	144.01	56.24
2025	158.53	61.92
2026	174.52	68.17
2027	192.12	75.03

17.1.2 Scenario 2 – Renewable Expansion Scenario

The *Renewable Expansion Scenario* considers the addition of the new renewable energy resources being considered by JEA (including biomass and solar PV) as discussed in Section 14.0 in addition to conventional generating resources and the new nuclear generating resources. As with Scenario 1, the *Renewables Expansion Scenario* evaluates the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 against the economics of an expansion plan that does not include the GEC combined cycle conversion. Scenario 2 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Subsection 17.1.1.

The *Renewables Expansion Scenario* assumes the installation of a 35 MW biomass unit with a commercial operation date of January 1, 2012 and the installation of 5 MW and 10 MW of solar photovoltaics with commercial operation dates of January 1, 2010 and July 1, 2010, respectively. The characteristics of these renewable resources are more fully described in Section 14.0.

17.1.3 Scenario 3 – DSM Expansion Scenario

The *DSM Expansion Scenario* considers the addition of the new DSM portfolio being evaluated by JEA as discussed in Section 15.2 in addition to conventional generating resources and the new nuclear generating resources. Existing conservation and DSM programs as discussed in Section 15.1 are embedded in JEA's base case load forecast. As with Scenario 1, the *DSM Expansion Scenario* evaluates the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 against the economics of an expansion plan that does not include the GEC combined cycle conversion. Scenario 3 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Section 17.1.1.

As presented in Section 12.0, JEA's 2012 summer capacity requirements are 167 MW. With the *DSM Expansion Scenario*, JEA's 2012 summer capacity requirements are reduced to 41 MW.

17.1.4 Scenario 4 – Renewables and DSM Expansion Scenario

The *Renewables and DSM Expansion Scenario* considers the addition of both the new renewable energy resources and the new DSM portfolio being evaluated (as considered in Scenarios 3 and 4, respectively) in addition to conventional generating resources and the new nuclear generating resources. As with the other scenarios, the *Renewables and DSM Expansion Scenario* evaluates the economics of an expansion plan including the GEC combined cycle conversion as a committed resource in June 2012 against the economics of an expansion plan that does not include the GEC combined cycle conversion. Scenario 4 evaluations were performed for both the *Reference Case* and the *Regulated CO_2 Case*, each of which are described in Subsection 17.1.1.

17.2 Results of the Economic Evaluations

CPWC evaluations were performed for the various scenarios and cases within each of the scenarios as discussed previously. The CPWC associated with each of the expansion plans for each of the cases and scenarios are presented in this section.

17.2.1 CPWC Results of Scenario 1 Evaluations

The results of the CPWC evaluations for Scenario 1 are presented in Table 17-2. Analysis of the CPWC associated with each of the cases presented in Table 17-2 indicates that expansion plans including the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for all cases considered.

17.2.2 CPWC Results of Scenario 2 Evaluations

The results of the CPWC evaluations for Scenario 2 are presented in Table 17-3. Analysis of the CPWC associated with both of the cases presented in Table 17-3 indicates that expansion plans including the new renewable resources being considered by JEA as well as the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for the two cases considered.

17.2.3 CPWC Results of Scenario 3 Evaluations

The results of the CPWC evaluations for Scenario 3 are presented in Table 17-4. Analysis of the CPWC associated with both of the cases presented in Table 17-4 indicates that expansion plans including the new DSM portfolio being considered by JEA as well as the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for the two cases considered.

17.2.4 CPWC Results of Scenario 4 Evaluations

The results of the CPWC evaluations for Scenario 4 are presented in Table 17-5. Analysis of the CPWC associated with both of the cases presented in Table 17-5 indicates that expansion plans including the new renewable resources and DSM portfolio being considered by JEA as well as the GEC combined cycle conversion in June 2012 are the most cost-effective expansion plans for the two cases considered.

17.3 Conclusions

The CPWC results summarized throughout this section demonstrate that the addition GEC combined cycle conversion in June 2012 is included in the least cost expansion plan for each of the different scenarios and cases evaluated. When combined with both the new renewable resources and the new DSM portfolio being considered by JEA, the GEC combined cycle conversion provides the most cost-effective resource addition to the JEA system to serve its forecast capacity requirements.

Table 17-2
CPWC Summaries for Scenario 1
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	11,054,686	11,177,317	122,631
High Fuel	11,528,352	11,637,336	108,984
Low Fuel	10,501,774	10,598,528	96,754
High Load	12,495,350	12,638,740	143,390
Low Load	10,001,095	10,058,137	57,042
High Capital Cost	11,183,032	11,295,586	112,554
Regulated CO_2	15,861,139	16,028,653	167,514
High Fuel with Regulated CO_2	16,681,496	16,840,280	158,784
High Regulated CO_2	23,814,086	24,215,124	401,038

Table 17-3
CPWC Summaries for Scenario 2
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	11,228,052	11,345,073	117,021
Regulated CO_2	15,999,936	16,154,956	155,020

Table 17-4
CPWC Summaries for Scenario 3
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,803,625	10,938,494	134,869
Regulated CO_2	15,581,425	15,767,659	186,234

Table 17-5
CPWC Summaries for Scenario 4
($000)

Case	CPWC of Expansion Plan Including GEC Conversion in 2012	CPWC of Expansion Plan Without GEC Conversion in 2012	CPWC Savings for Expansion Plan with GEC Conversion in 2012
Reference Case	10,987,500	11,058,147	70,648
Regulated CO_2	15,724,591	15,851,309	126,719

18.0 Consequences of Delay

As demonstrated by the economic evaluations presented in this Application, the GEC combined cycle conversion in 2012 represents the most cost-effective alternative to satisfy JEA's forecast capacity requirements and continue to reliably serve its customers. The consequences of delaying the commercial operation of the GEC combined cycle conversion are significant from an economic and reliability standpoint for JEA. This section describes the negative consequences of delaying the GEC combined cycle conversion.

18.1 Economic Consequences

If the commercial operation of the GEC combined cycle conversion is delayed, JEA would be required to replace the capacity and energy that would otherwise be provided by a new, efficient combined cycle generating unit. The economic consequence of a one year delay in the commercial operation of the GEC combined cycle conversion (from June 2012 until June 2013) is approximately $36.7 million in CPWC, based on *Reference Case* assumptions.

18.2 Reliability Consequences

As shown in Section 12.0, JEA will require a significant amount of capacity in the summer of 2012 to maintain its reserve margin requirements. If the conversion of GEC to combined cycle is delayed and no additional generating capacity is installed to meet JEA's forecast capacity requirements by 2012, JEA's summer reserve margin will fall to approximately 9.6 percent (or 167 MW less than JEA's 15 percent reserve margin criterion) in 2012. The capacity deficit in the summer of 2012 represents a significant portion of the capacity that will be provided by the conversion of GEC to combined cycle. With a reserve margin below 15 percent in 2012, JEA's system will be exposed to decreased reliability and increased costs.

19.0 Financial Analysis

JEA has the necessary funding sources available to finance the GEC combined cycle conversion. JEA anticipates the need to finance an estimated $419 million for the conversion, including direct and indirect engineering, procurement, and construction costs, owner's costs, and interest during construction.

JEA typically finances large generation capital projects using fixed and floating rate subordinate long-term debt. Up to a maximum of 30 percent of the debt may be floating rate. During the preliminary design, engineering, and permitting, JEA may use internal funds from operations or from prior issuances to fund early project costs. As the initial development concludes and construction commences, JEA may initiate various tranches of revenue bond issuances for long-term financing with terms of up to 30 years. For large projects, JEA may issue bonds every one to two years to cover expected construction related capital costs over these periods. By having multiple issuances, JEA will limit the amount of interest incurred during construction of the plant. In addition, JEA may pool the financing for GEC with other smaller capital addition costs that may be required concurrent with GEC.

JEA's senior electric system debt has a long-term credit rating of AA- from S&P, Aa2 from Moody's Investor Services, and an AA- from Fitch. To protect against fluctuations in the interest rate, JEA may use interest rate swap contracts to take advantage of favorable market conditions and caps, to limit risk associated with variable rate debt exposure. With its excellent credit rating, JEA should expect that it will have no difficulties in obtaining bond financing for the GEC construction. The actual financing for GEC is expected to result in debt service requirements less than the assumed debt service presented in the economic parameters in Section 4.0.