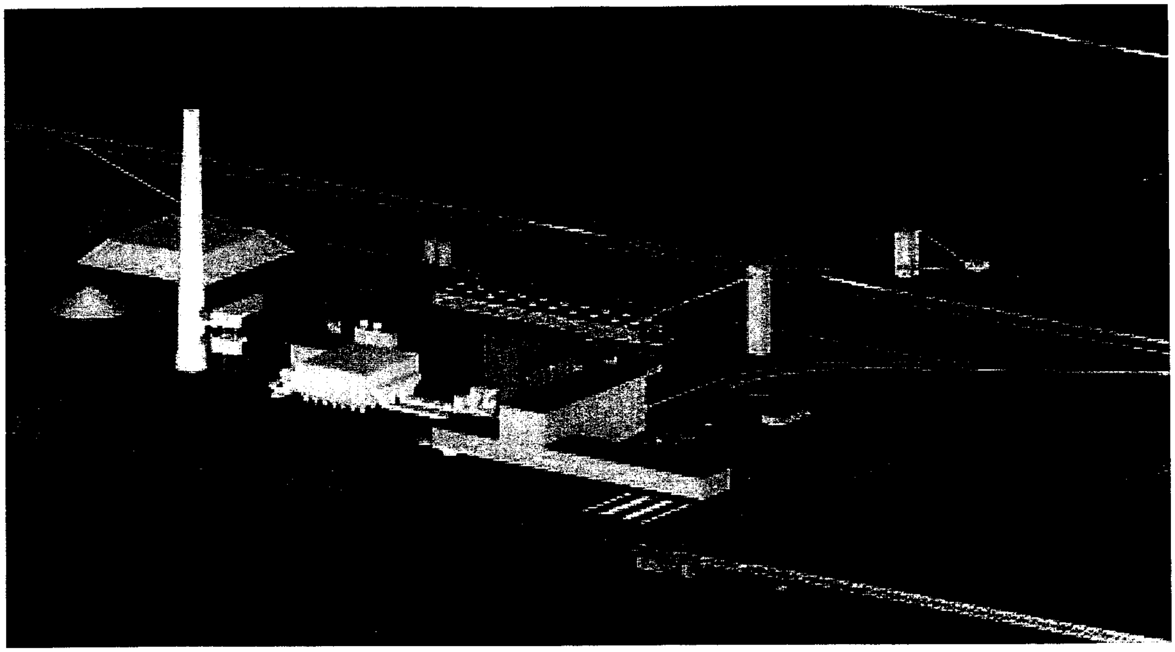
Florida Electrical Power Plant Siting Act
Need for Power Application

Taylor Energy Center

060635-EU



Submitted by:

Florida Municipal Power Agency
JEA
Reedy Creek Improvement District
City of Tallahassee

September 2006

Volume C

Florida Municipal Power Agency

REEDY CREEK IMPROVEMENT DISTRICT

City of Tallahassee
Your Own Utilities

Prepared by:
Black & Veatch Corporation

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building a world of difference

ENERGY WATER INFORMATION GOVERNMENT

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Abbreviations

AFUDC	Allowance for Funds Used During Construction
ALA	American Lung Association
ASD	Adjustable Speed Drive
BACT	Best Available Control Technology
BIG	Biomass Investment Group
BIT	Bituminous Coal
Brandy Branch	Brandy Branch Generating Station
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CDD	Cooling Degree-Days
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
City	City of Jacksonville
CO_2	Carbon Dioxide
COP	Coefficient of Performance
CPWC	Cumulative Present Worth Cost
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DX	Direct Exchange
EER	Energy Efficiency Ratio
EF	Energy Factor
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
FGT	Florida Gas Transmission Company
FIRE	Florida Integrated Resource Evaluator
FMPA	Florida Municipal Power Agency
FO2	No. 2 Fuel Oil
FO6	No. 6 Fuel Oil
FOR	Forced Outage Rate
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
FPU	Florida Public Utilities
FRCC	Florida Reliability Coordinating Council
FTS	Firm Transportation Service

GE	General Electric
GS	General Service
GSD	General Service Demand
GSLD	General Service Large Demand
GT	Gas Turbine
HDD	Heating Degree Days
HERS	Home Energy Ratings System
Hg	Mercury
HRSG	Heat Recovery Steam Generator
IC	Internal Combustion
IRP	Integrated Resource Plan
ITS	Integrated Transmission System
Kennedy	J. Dillon Kennedy Generating Station
LFG	Landfill Gas
LOLP	Loss of Load Probability
MEF	Modified Energy Factor
MOU	Memorandum of Understanding
NEFBA	Northeast Florida Builders Association
NEL	Net Energy for Load
NERC	North American Electric Reliability Coordinating Council
NG	Natural Gas
NO_x	Nitrogen Oxide
Northside	Northside Generating Station
NPPD	Nebraska Public Power District
OUC	Orlando Utilities Commission
PEF	Progress Energy Florida
petcoke	Petroleum Coke
PL	Pipeline
Plan	JEA's 2005 Demand-Side Management Plan
Power Park	St. Johns River Power Park Bulk Power System
PPA	Power Purchase Agreement
PRB	Powder River Basin
PV	Photovoltaic
QF	Qualifying Facility
RCID	Reedy Creek Improvement District
RFP	Request for Proposal
RR	Railroad

Scherer Unit 4	Robert W. Scherer Electric Generating Plant
SEER	Seasonal Energy Efficiency Ratio
Sierra Club	Sierra Club of Northeast Florida
SJRPP	St. Johns River Power Park
SO_2	Sulfur Dioxide
Southern	Southern Power Company
ST	Steam Turbine
STG	Steam Turbine Generator
SUB	Subbituminous Coal
TCEC	Treasure Coast Energy Center
TEA	The Energy Authority
TEC	Taylor Energy Center
TK	Tank
TYSP	Ten-Year Site Plan
UPS	Unit Power Sales
WA	Water
WESP	Wet Electrostatic Precipitator

C.1.0 JEA Introduction

C.1.1 JEA Overview

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers all of Duval County and portions of Clay and St. Johns Counties. JEA's service area covers approximately 900 square miles and serves over 380,000 customers. JEA consists of three financially separate entities: the Electric System, the bulk power system St. Johns River Power Park Units 1 and 2 (the Power Park or SJRPP), and the bulk power system Robert W. Scherer Electric Generating Plant (Scherer Unit 4). The total summer net capability of the Electric System, Power Park, and Scherer Unit 4 generation is 3,473 MW, and the total winter net capability is 3,661 MW. Because of the long-term reserve shutdown of Kennedy Combustion Turbine (CT) 4 and CT 5, the total available summer net capability is 3,371 MW, and the total available winter net capability is 3,535 MW in the near term.

JEA is a winter peaking system, and expects significant growth during the forecast period. The firm winter peak demand is projected to increase from 2,831 MW in 2006 to 4,630 MW in 2024, and the firm summer peak is projected to increase from 2,651 MW in 2006 to 3,729 MW in 2024.

JEA currently has 17 generating units installed within the Electric System fleet, the Power Park bulk power system, and Scherer Unit 4 bulk power system. These units, or JEA's ownership, range in size from 51 MW to 567 MW and include multiple technologies and operating load profiles. In addition, JEA has a 207 MW purchase contract for Unit Power Sales (UPS) from Southern Company (refer to Subsection C.2.3) of firm coal fired capacity and energy supplied from five units, which expires in 2010.

The Taylor Energy Center (TEC) is being proposed as a joint development project by four municipal entities, including the Florida Municipal Power Agency (FMPA), JEA, Reedy Creek Improvement District (RCID), and the City of Tallahassee (collectively, the Participants). The Participants are developing TEC to realize the benefits associated with the economies of scale inherent in constructing and operating a large power plant. TEC will be developed on a site consisting of approximately 3,000 acres to be located approximately 5 miles southeast of Perry, in Taylor County, Florida. The land is bordered by Highway 27 on the north and the Fenholloway River on the west. The plant is proposed to be a 765 MW (net) supercritical pulverized coal unit with a net heat rate of 9,238 Btu/kWh when firing a blend of Latin American bituminous coal and petroleum coke (petcoke). Additional details regarding TEC are included in Section A.3.0 of this Application. JEA's ownership interest in TEC will be 31.5 percent, or about 245 MW (net at average ambient operating conditions).

In addition to providing a reliable, cost-effective resource to meet JEA's growing electric capacity and energy needs, TEC will provide additional benefits to the State of Florida. The project will use proven supercritical boiler technology and advanced pollution control equipment to limit emissions while burning a variety of solid fuels, including Powder River Basin (PRB) coal (which has the largest coal reserves of any region within the United States), as well as Central Appalachian coals, Latin American coals, and petcoke. TEC will provide JEA and the other Participants with fuel diversity. The State of Florida will benefit from having the ability to source fuel from locations outside the hurricane-susceptible natural gas producing regions within the Gulf Coast. In addition, JEA's customers will have access to an energy supply source with less price volatility than natural gas, which should help electric energy rates become more stable and predictable over time.

C.1.2 JEA Summary

Information specific to JEA is included in this Volume C. The remainder of Volume C of this Application comprises nine additional sections:

- Section C.2.0 - Description of JEA's Existing System.
- Section C.3.0 - Forecast of JEA's Electrical Demand and Consumption.
- Section C.4.0 – JEA's Need for Capacity.
- Section C.5.0 – JEA's Economic Analysis.
- Section C.6.0 – JEA's Sensitivity Analyses.
- Section C.7.0 – JEA's Demand-Side Management.
- Section C.8.0 – JEA's Strategic Considerations.
- Section C.9.0 – JEA's Consequences of Delay.
- Section C.10.0 – JEA's Financial Analysis.

The information and analyses presented throughout this Volume C and the complete Application demonstrate that the proposed TEC satisfies the requirements set forth in Section 403.519, Florida Statutes. In particular, TEC is the most cost-effective alternative available to JEA to satisfy forecast capacity requirements in a reliable, environmentally responsible manner. TEC will provide JEA, and the State of Florida as a whole, with increased fuel diversity and supply reliability. In selecting TEC as its next generating resource, JEA considered all reasonable conservation and demand-side management (DSM) measures available beyond its existing portfolio of energy conservation offerings, and none were found that could cost-effectively defer JEA's participation in TEC.

C.2.0 Description of JEA's Existing System

C.2.1 General Overview

JEA is the eighth largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers all of Duval County and portions of Clay and St. Johns counties. JEA's service area covers approximately 900 square miles and serves more than 380,000 customers. JEA consists of three financially separate entities: the Electric System, the bulk power system St. Johns River Power Park Units 1 and 2 (the Power Park or SJRPP), and the bulk power system Robert W. Scherer Electric Generating Plant (Scherer Unit 4). The total summer net capability of the Electric System, Power Park, and Scherer Unit 4 generation is 3,473 MW, and the total winter net capability is 3,661 MW. Because of the long-term reserve shutdown of Kennedy CT 4 and CT 5, the total summer net capability is 3,371 MW, and the total winter net capability is 3,535 MW in the near term. Details of the existing facilities are presented in Table C.2-1.

C.2.1.1 JEA Electric System

The Electric System includes generation, transmission, interconnection, and distribution facilities. The generating facilities are located on three plant sites within the City of Jacksonville (City): the J. Dillon Kennedy Generating Station (Kennedy), the Northside Generating Station (Northside), and the Brandy Branch Generating Station (Brandy Branch). Collectively, these plants consist of two petcoke and coal fired circulating fluidized bed (CFB) steam turbine generator (STG) units (Northside steam Units 1 and 2); one dual fired (oil/gas) STG unit (Northside steam Unit 3); four dual fired (gas/diesel) combustion turbine generator (CTG) units (Kennedy CT 7, Brandy Branch CT 1, 2, and 3); seven diesel fired CTG units (Kennedy CT 3, 4, and 5 and Northside CT 3, 4, 5, and 6); and one combined cycle STG unit (Brandy Branch steam Unit 4). The total summer net capability of the Electric System is 2,261 MW, and the total winter net capability is 2,441 MW. Because of the long-term reserve shutdown of Kennedy CT 4 and CT 5, the total available summer net capability of the Electric System is 2,169 MW, and the total available winter net capability is 2,315 MW in the near term.

C.2.1.1.1 Kennedy Generating Station. Kennedy Generating Station is located in JEA's urban core 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 capable CTG unit (Kennedy CT 7) that was placed in commercial operation in June 2000, and three diesel fueled CTGs (Kennedy CTs 3, 4, and 5) that were placed in

Table C.2-1
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 Capability Summer	Net MW Capability Winter	Ownership
Kennedy								372,400	210	254	
	3	GT	FO2		WA	TK	7/1973	68,600	51	63	Utility
	4(1)	GT	FO2		WA	TK	7/1973	68,600	51	63	Utility
	5(1)	GT	FO2		WA	TK	7/1973	68,600	51	63	Utility
	7	GT	NG	FO2	PL	WA	6/2000	203,800	159	191	Utility
Northside								1,407,100	1,267	1,301	
	1	ST	PC	BIT	WA	RR	11/1966	297,500	275	275	Utility
	2	ST	PC	BIT	WA	RR	3/1972	297,500	275	275	Utility
	3	ST	NG	FO6	PL	WA	7/1977	563,700	505	505	Utility
	3-6	GT	FO2		WA	TK	1/1975	248,400	212	246	Utility
Brandy Branch								879,800	691	759	
	1	GT	NG	FO2	PL	TK	5/2001	203,800	159	191	Utility
	2	CT	NG	FO2	PL	TK	5/2001	203,800	159	191	Utility
	3	CT	NG	FO2	PL	TK	10/2001	203,800	159	191	Utility
	4	ST	NG	FO2	PL	TK	1/2005	268,400	215	185	Utility
Girvin Landfill	1-4	IC	LFG		PL		6/1997	1.2	1.2	1.2	Utility
St. Johns River Power Park								1,359,200	1,002(2)	1,020(2)	
	1	ST	BIT/PC		RR	WA	3/1987	679,600	501	510	Joint
	2	ST	BIT/PC		RR	WA	5/1988	679,600	501	510	Joint
Scherer	4	ST	SUB	BIT	RR	RR	2/1989	846,000(3)	200(3)	200(3)	Joint
JEA System Total(4, 5)									**3,371**	**3,535**	

(1)Units placed in reserve shutdown in April 2005.
(2)Net capability reflects JEA's 80 percent ownership of Power Park. Nameplate is original nameplate of the unit.
(3)Nameplate and net capability reflect JEA's 23.64 percent ownership in Scherer 4.
(4)Numbers may not add up due to rounding.
(5)Units in reserve shutdown are not included in totals.

commercial operation in the summer of 1973. The total summer net capability of Kennedy is 312 MW, and the total winter net capability is 380 MW. As of April 2005, Units CT 4 and CT 5 were placed in long-term reserve shutdown. Because of the long-term reserve shutdown of Kennedy CT 4 and CT 5, the total available summer net capability is 210 MW, and the total available winter net capability is 254 MW in the near term.

C.2.1.1.2 Northside Generating Station. 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. Northside Generating Station consists of two petcoke and coal fired CFB STG units (Northside steam Units 1 and 2), one dual fuel fired (oil/gas) STG unit (Northside steam Unit 3), and four diesel fired CTG units (Northside CTs 3, 4, 5, and 6). Northside steam Unit 2 was originally placed in service in March 1972, as an oil fired STG. Northside steam Unit 2 was repowered as a CFB and returned to service in February 2002. Northside steam Unit 1 was originally placed in service in November 1966, as an oil fired steam turbine generator. Northside steam Unit 1 was repowered as a CFB and returned to service in May 2002. Limestone is blended with petcoke and coal for sulfur dioxide (SO_2) removal. Northside steam Unit 3 is a steam unit burning residual oil (1.8 percent sulfur) and natural gas. Steam Unit 2 and Steam Unit 3 are interconnected to the 230 kV system. Steam Unit 1 and CTs 3 through 6 are interconnected to the 138 kV system. The total summer net capability of Northside Generating Station is 1,267 MW, and the total winter net capability is 1,301 MW.

C.2.1.1.3 Brandy Branch Generating Station. Brandy Branch Generating Station is located in JEA's northwest district load center. Brandy Branch consists of three simple cycle GE 7FA CTG units (Brandy Branch CT 1, 2, and 3); 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.

Brandy Branch CT Units 2 and 3 were subsequently converted to provide heat input for Brandy Branch steam Unit 4 with the installation of two heat recovery steam generators (HRSGs). This 2x1 combined cycle unit was placed in commercial operation in January 2005. 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 capability of 175 MW and a winter net capability of 185 MW. Supplemental duct firing using natural gas is available on the combined cycle unit, for an additional summer net capability of 40 MW. At this time, JEA does not believe it can realize any additional capability with duct firing in the winter because of the thermal saturation of the HRSG system. The duct firing capability is added into the overall combined cycle (CT 2, CT 3, and STG 4) capability for a net summer capability of 532 MW and a net winter capability of 567 MW. The total summer net capability of Brandy Branch Generating Station is 691 MW, and the total winter net capability is 759 MW.

C.2.2 JEA Electric Bulk Power Systems

C.2.2.1 St. Johns River Power Park Bulk Power System (Power Park)

Power Park generating station is located in JEA's north district load center, adjacent to and northeast of Northside Generating Station. Power Park consists of two pulverized bituminous coal and petcoke fired steam electric generating units (EGUs) (SJRPP 1 and 2). Power Park is jointly owned by JEA and Florida Power & Light (FPL); JEA has an 80 percent ownership interest in the Power Park. The Electric System is entitled to 50 percent (equal to 638 MW net) of the capacity and is required to pay for such capacity on a "take-or-pay" basis. Pursuant to the FPL-Power Park sale, JEA has sold to FPL 37.5 percent of the capacity of JEA's interest in the Power Park, until the Power Park Joint Ownership Agreement expires in 2022, subject to the limitation that FPL may not receive energy in excess of 25 percent of the product of (a) the nameplate capacity of JEA's ownership interest in the Power Park and (b) the number of years from the date FPL first took energy pursuant to such sale until the latest maturity date of the Power Park bonds. Based on the historical rates at which FPL has taken energy from Power Park, JEA expects that the terms of the energy sales will be satisfied with FPL as early as 2014; however, for the purposes of performing a conservative analysis of JEA's capacity and energy needs, this Application assumes that the energy sales will continue until 2017. After the terms of the energy sales are satisfied, JEA will receive 80 percent of the Power Park's capacity and related energy output, representing a summer net capability of 1,002 MW and a winter net capability of 1,020 MW. SJRPP 1 began commercial operation in March 1987, and SJRPP 2 followed in May 1988.

C.2.2.2 Robert W. Scherer Electric Generating Plant Bulk Power System (Scherer Unit 4)

Scherer Unit 4 is located near Forsyth, Georgia. Scherer Unit 4 is a pulverized coal fired, steam electric generator. Similar to Power Park, JEA and FPL jointly own interests in Scherer Unit 4; 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 (such ownership interests are referred to as the Scherer 4 Project). 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 the Electric System 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 capability of 846 MW.

C.2.3 JEA Generating Fleet Reliability

JEA currently has 17 independent generating units installed within the Electric System fleet, the Power Park bulk power system, and Scherer Unit 4 bulk power system. These units, or JEA's ownership, range in size from 51 MW to 567 MW and use various designs and various complexities of technology and operating requirements. In addition, JEA's unit power sales (UPS) purchases from Southern Company (refer to Subsection C.2.5.1) consist of five separate units representing various allocated capacities totaling 207 MW. Collectively, these 22 units provide diversity for unplanned outages, which results in a high level of system reliability. Each unit has its own historical and projected availability due to either planned outages or unplanned outages, which are represented by an annual forced outage rate (FOR).

The largest unit in JEA's fleet is the Brandy Branch combined cycle unit, with a winter net capacity of 567 MW. This unit has several combinations of unavailability: (1) all capacity is lost when the STG is out of service or both CT 2 and CT 3 are out of service, (2) half the summer capacity is lost when one of the CTs or one HRSG is out of service, and (3) half the winter capacity is lost when one of the CTs is out of service. The first scenario above is partially mitigated by the capability to run the CTs and bypass steam to the condenser when the steam turbine is off line. This type of operation is inefficient and would be limited in duration.

The next largest unit in JEA's system is Northside steam Unit 3, with a 505 MW summer and winter net capability. This unit also has several combinations of unavailability, primarily related to the availability of key components of the unit; however, if the boiler, turbine, or generator is out of service, the entire capability is lost. When JEA's Power Park sales to FPL expire, SJRPP steam Units 1 and 2 will then each be the next largest units in JEA's system, with a winter net capability of 510 MW.

All remaining JEA units are 300 MW or less in size. These smaller units account for the majority of the units in JEA's system.

C.2.4 JEA Generating Efficiency

JEA's generating fleet is committed and dispatched according to each unit's overall efficiency and ability to produce electricity at the lowest variable cost. The two primary components considered when determining dispatch order are the cost of a unit's fuel relative to its heat content and the unit's efficiency. JEA's generating fleet efficiency varies from 7,169 Btu/kWh at maximum output of the combined cycle unit to

14,045 Btu/kWh at maximum output of JEA's oldest CT in operation. Table C.2-2 lists JEA's generating unit efficiencies by heat rate ordered from baseload solid fuel units to intermediate load gas/oil fired units to peaking load gas/oil fired CTs. The economics of generator unit efficiencies are considered in the economic analysis within this Application, will produce a future expansion plan that is not only robust and reliable, but also economical.

C.2.5 JEA Purchased Power

C.2.5.1 Southern Company Unit Power Sales (UPS)

JEA contracted with Southern Company for the purchase of 207 MW of coal fired capacity and energy from June 1995 through May 2010 (Southern 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). Upon 3 years' notice to Southern Company, JEA may elect to reduce its capacity obligations by as much as 150 MW. To date, JEA has not given such notice to Southern Company. The capacity and energy are priced based on 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 retains the transmission rights for this capacity even after the expiration of the UPS Purchase.

C.2.5.2 The Energy Authority

The Energy Authority (TEA) actively trades energy with a large number of counterparties throughout the United States and is generally able to acquire capacity and energy from other market participants when any of TEA's 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.

Typically, TEA acquires the necessary short-term purchase the season before the need (based on market conditions), identifies a number of potential suppliers within Florida and Georgia, selects the best offer, and enters into back-to-back power purchase agreements (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, gives JEA assurance that a plan which includes short-term market purchases is viable.

Table C.2-2
Existing Generating Fleet Efficiency

Unit	Minimum Output (MW)	Heat Rate at Min (Btu/kWh)	Winter Net Output (MW)	Heat Rate at Max Output (Btu/kWh)	Average[(1)] Heat Rate (Btu/kWh)
Northside Unit 1	119	10,246	275	9,227	9,803
Northside Unit 2	119	10,246	275	9,227	9,795
SJRPP Unit 1	120	10,589	510	9,273	9,746
SJRPP Unit 2	120	10,628	510	9,205	9,865
Scherer Unit 4	53	11,765	200	10,300	10,095
Brandy Branch Combined Cycle[(2)]	251	8,066	567	7,169	8,317
Northside Steam Unit 3	46	16,145	505	9,711	10,670
Brandy Branch CT 1	79	13,587	191	10,378	12,223
Kennedy CT 7	79	13,587	191	10,378	12,771
Northside CT 3	20	17,875	62	12,793	16,439
Northside CT 4	20	17,875	62	12,793	16,480
Northside CT 5	20	17,875	62	12,793	15,671
Northside CT 6	20	17,875	62	12,793	16,794
Kennedy CT 3	20	23,437	63	14,045	18,756
Kennedy CT 4	20	23,437	63	14,045	18,482
Kennedy CT 5	20	23,437	63	14,045	18,617

[(1)]Annual average heat rates were based on Fiscal Year 04/05 performance (except Kennedy CT 3 through 5, which were based on earlier years, and Brandy Branch combined cycle, which became operational in 2005).
[(2)]Brandy Branch Combined Cycle (CT2, CT3, and ST4 units) became operational in 2005, after the addition of Unit ST4.

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 six seasonal periods. Of these six seasons, approximately 65 percent of the purchases were out-of-state resources and approximately 35 percent were Florida resources.

C.2.5.3 Clean Power

As good stewards of the environment and as part of JEA's commitment to improve the quality of life in the communities it serves, JEA is working closely with the Sierra Club of Northeast Florida (Sierra Club) and the American Lung Association (ALA), local environmental groups, to establish a process to create and update an action plan entitled "Clean Power Action Plan." The "Clean Power Action Plan" establishes an Advisory Panel, comprised of participants from the Jacksonville community, who provide guidance and recommendations to JEA in the development and implementation of the Clean Power Program. Current members of the Advisory Panel include the Sierra Club, ALA, and the newest member, the City of Jacksonville Environmental Protection Board.

JEA has made considerable progress toward clean power initiatives. This progress includes installation of clean power systems, commitment to purchase power agreements, legislative and public education activities, and research and development into clean power technologies.

JEA currently has approximately 91 MW of renewable capacity committed toward its goal, including approximately 321 kW of solar photovoltaic (PV) capacity, 9 MW of solar thermal capacity, 6 MW in landfill biogas capacity, 800 kW in digester biogas capacity, 10 MW of wind capacity, 22 MW of proposed landfill and biomass projects, and 43 MW of generating unit efficiency improvements. Over the past several years, JEA has received several awards for its clean power program.

C.2.5.3.1 Solar and the Solar Incentive Program. JEA has installed 36 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 one of the largest solar PV systems in the Southeast at the Jacksonville International Airport. 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 paid incentives for more than 25 solar PV systems (for a total of 98 kW) until January 2005, when the PV incentive was discontinued. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems.

C.2.5.3.2 Biomass. In 2001, JEA signed a 15 year PPA with Biomass Investment Group (BIG) to purchase 70 MW of renewable energy. This developer proposed to grow a biomass crop (e-grass or arundo donax) as a fuel for a gasification plant in Florida. The project has been delayed many times and, since the commercial operation date of this unit is not firm, this project is not included as a resource for JEA's system. Although JEA committed to this project, the developer has not been able to bring it to commercial status as was originally planned.

C.2.5.3.3 Landfill Gas. JEA owns and operates three internal combustion engine generators located at the 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, 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. JEA also receives approximately 1,500 kW of landfill gas from the North Landfill, which is pumped to the Northside Generating Station and is used to generate power at Northside Unit 3.

The JEA Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The new facility manages the sludge using two anaerobic digesters and a sludge dryer to produce a fertilizer pellet product. The methane gas from the digesters is used by the sludge dryer and the 800 kW generator.

C.2.5.3.4 Wind. As part of its ongoing effort to utilize more sources of renewable energy, JEA has 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 (over a 20 year period) 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD will buy back the energy at specified on/off peak charges. JEA expects that it will retain the rights to the green tags and will sell the green tags unless JEA needs them to meet state or federal environmental requirements.

C.2.5.3.5 Renewable Project Request for Proposal Solicitation. On February 6, 2004, JEA issued a Request for Proposal (RFP) for Renewable Energy Generation for 1 MW to 300 MW. The RFP covered all renewable energy resources that result in energy being delivered to JEA's service territory. More than 80 companies requested a copy of the RFP. JEA received 16 responses to the RFP, consisting of renewable energy projects ranging from 1 MW to 300 MW. Of the 300 MW proposed, 114 MW were from existing biomass facilities. The remaining proposals represented only five unique projects for 121 MW, since several projects competed for the same fuel or land use. JEA is currently in negotiations with two of these projects – Landfill Energy Systems and Evergreen Paper and Energy.

C.2.5.3.6 Trail Ridge Landfill and Yard Waste Power Purchase Agreements. JEA has signed a PPA with Landfill Energy Systems to purchase energy from a 9.6 MW landfill gas (LFG)-to-energy facility at the Trail Ridge Landfill in Jacksonville. Once the facility is completed, it will be one of the largest LFG-to-energy facilities in the Southeast. The projected date of completion for the facility is September 2008.

JEA is also negotiating with Evergreen Paper and Energy to convert a former paper mill into a biomass-fueled electric generation plant. The plant's boiler is expected to burn yard and tree trimming debris that is received from Jacksonville's yard waste collection program. The plant is expected to generate 20 MW of renewable energy. The projected date of completion for the project is 2008.

C.2.5.3.7 Green Tags. JEA does not currently have a green pricing program. However, JEA meters the energy produced from each renewable facility so that green tags can be sold to produce additional revenue.

C.2.5.3.8 Research Efforts. JEA's renewable efforts also include several research and development programs. JEA recently completed research at 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. The utility also sponsors a research laboratory at the University of North Florida and installed a solar technology demonstration center at the Florida Community College of Jacksonville.

C.2.5.4 Cogeneration

JEA has encouraged and continues to monitor 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, which 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.

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

Table C.2-3
JEA Service Territory Qualifying Facilities

Cogenerator Name	Unit Type	In-Service Date	Net Capability[(1)] – MW	
			Summer	Winter
Anheiser 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 capability, not net generation sold to JEA.
[(2)]Cogenerator.
[(3)]Small Power Producer.

C.2.6 JEA Power Sales

JEA furnishes wholesale power to Florida Public Utilities Company (FPU) for resale in the city of Fernandina Beach in Nassau County, north of Jacksonville. JEA is contractually committed to supply FPU until December 31, 2007. Currently, FPU does not have a contract with JEA to renew this sale. Therefore, starting in January 2008, sales to FPU are not included in JEA's load and energy forecast. In 2004, sales to FPU totaled 468 GWh (3.5 percent of JEA's total system energy requirements). The FPU projected summer and winter demands and net energy for load are presented in Table C.2-4.

C.2.7 JEA Transmission and Interconnections

C.2.7.1 General Overview

The JEA transmission system consists of 727 circuit-miles of bulk power transmission facilities operating at four voltage levels: 69 kV, 138 kV, 230 kV, and 500 kV.

Table C.2-4
FPU Projected Summer and Winter Peak Demands and Net Energy for Load

Year	Summer Demand (MW)	Winter Demand (MW)	Net Energy for Load (MWh)
2008	110	102	555,500
2009	114	105	576,577
2010	119	109	598,462
2011	123	114	621,189
2012	128	118	644,790
Percent Change for Period 2008 Through 2012	3.86%	3.71%	3.80%

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 Georgia Integrated Transmission System (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 the 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 FPL's Sampson substation 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 Jacksonville Beach Utility'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 FPU for resale within the City of Fernandina Beach, Nassau County, Florida.

C.2.7.2 JEA Transmission System Considerations

JEA continues to monitor and upgrade the bulk power transmission system as necessary to provide reliable electric service to its customers. JEA continually reviews needs and options for increasing the capability of the transmission system. JEA has set forth the following planning criteria for the transmission system:

- Plan to limit the loading of transmission lines and autotransformers to provide safe and reliable transmission service under normal and single contingency conditions.
- Plan the transmission system to withstand single contingencies without loss of customer load (a single contingency is the unexpected failure of any one line, transformer, or generator).
- Plan the transmission system to operate within 5 percent of nominal voltage during normal and single contingency conditions.
- Plan the transmission system so that circuit breakers can interrupt the maximum available breaker fault current.
- Plan substation relays to sense breaker failures and clear faults in sufficient time to avoid generator instability problems.
- Plan to provide lead time for transmission projects of approximately 3 to 5 years.
- Plan to meet the Florida Reliability Coordinating Council's (FRCC's) guidelines on how the Florida electric utilities plan to operate. These guidelines are similar to JEA's transmission planning criteria discussed previously.
- Plan to meet or exceed the FRCC's reliability guidelines for transmission system interface available transfer capabilities. This includes the use of single contingency criteria, as well as considering the needs for operating reserve requirements, capacity benefit margins, and the reliability margins outlined in industry-standard publications.
- Plan to meet or exceed specific subparts of the transmission system reliability planning criteria published by the North American Electric Reliability Coordinating Council (NERC), including Planning Criteria Categories A, B, C.2, and C.5, and to meet or exceed these criteria generally as they are interpreted by the FRCC, when updated occasionally.

C.2.8 JEA Unit Retirements

Kennedy Generating Station consists, in part, of three 1973 vintage diesel fueled CT units. Based on the age, reliability, and costs for scheduled major overhauls, as of April 2005, CT 4 and CT 5 were placed in long-term reserve shutdown. In 2008, CT 3 is scheduled for either a major overhaul or long-term reserve shutdown. The retirement of these units is currently being evaluated by JEA.

Northside Unit 3 is a large oil and gas fueled conventional steam power plant that has been in service since 1977, or for approximately 29 years. Units of this type will typically have a useful life of 40 to 45 years. This Application currently covers a 30 year period ending in 2035, which may be beyond the useful life of Northside Unit 3. In addition, other factors may affect the economical useful life of Northside Unit 3, such as future major repairs, potential pollution control retrofits, and the overall cost of generation. JEA plans to continue to monitor the performance of Northside Unit 3 over the planning horizon period. While there are no plans to retire Northside Unit 3 in the base case, JEA recognizes that it may be necessary to re-evaluate this retirement during the second half of the planning period.

C.2.9 JEA Generating Unit Emission Rates

The Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) will introduce cap-and-trade emissions allowance programs that will affect the cost of generation from JEA's fleet. As a result, the expected emissions and potential allowance costs will be estimated on the basis of forecast operation.

Table C.2-5 presents approximate nitrogen oxide (NO_x) and SO_2 emission rates for JEA's existing generating units. If available, emission rates were determined using continuous emissions monitoring system (CEMS) data. If CEMS data was not available, estimates of emission rates were developed using the EPA's AP-42 emission factors. These emission rates will be used to determine emission allowance costs on the basis of forecast operation.

Mercury (Hg) and carbon dioxide (CO_2) emission rates for existing units are not currently recorded by the CEMS or subject to specific permit limits. As a result, estimated emission rates for these constituents were developed. The emission rates for Hg and CO_2 used in the analyses in this Application are summarized in Table C.2-6.

Table C.2-5
NO_x and SO_2 Emission Rates for JEA's Existing Generating Units

Generating Unit	SO_2 Emission Rate (lb/MBtu)	NO_x Emission Rate (lb/MBtu)
Kennedy CTs 3-5	0.0060	0.3200
Kennedy CT 7	0.0060	0.5940
Northside ST 1	0.1427	0.0679
Northside ST 2	0.1500	0.0675
Northside ST 3	1.1293	0.3000
Northside CTs 3-6	0.0060	0.3200
Brandy Branch CT 1	0.0060	0.0481
Brandy Branch CC	0.0353	0.0128
SJRPP ST 1 and 2	0.1800	0.1000
Scherer ST 4	0.6174	0.1342

Table C.2-6
Estimated Hg and CO_2 Emission Rates

Generating Unit	Hg Emission Rate (lb/MBtu)	CO_2 Emission Rate (lb/MBtu)
SJRPP 1 and 2	0.00000210	205.7
Scherer	0.00000400	212.7
Northside 1	0.00000155	205.8
Northside 2	0.00000155	234.1
Northside 3	0.00000000	144.6

Note: SJRPP 1 and 2, and Scherer Hg emission rates are post new pollution control system upgrades scheduled for 2010.

C.3.0 Forecast of JEA's Electrical Demand and Consumption

C.3.1 Load Forecast

This section presents and describes the peak demand and net energy for load forecasts for JEA for the years 2006 through 2024. JEA's need for capacity was determined through a comparison of available firm capacity resources with JEA's forecast peak demand plus reserve requirements. The forecasts presented in this section were based on JEA's fiscal year, which runs from October 1 to September 30. The forecasts were converted to a calendar basis for the economic analysis presented in Section C.5.0.

C.3.1.1 JEA Historical Peak Demand

The forecast of peak demand requires projecting both the summer and winter peaks. On a weather-normalized basis, JEA has historically experienced annual peaks in both the summer and winter periods. Table C.3-1 indicates that between 1986 and 2005, the system peak occurred most often during the summer period. However, the system peak occurred during the winter period in 4 of the most recent 6 years on a weather-normalized basis. Thus, JEA is experiencing an important change in the characteristics of its system.

Table C.3-1 indicates that from 1986 to 2005, the weather-normalized summer peak demand increased from 1,586 MW to 2,891 MW, which is an average annual growth rate of 3.21 percent. The 1986 weather-normalized winter peak demand level was 1,488 MW, and the 2005 weather-normalized winter peak was 2,794 MW. The average annual growth rate for the weather-normalized winter peak demand was 3.37 percent.

The average annual growth rate for the years 1996 through 2005 was 2.64 percent and 3.12 percent for the winter and summer weather-normalized seasons, respectively.

C.3.1.2 JEA Peak Demand Forecast

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

Table C.3-1
Historical JEA Peak Demand
(Weather Normalized)

Fiscal Year	Winter (MW)	Summer (MW)
1986	1,488	1,586
1987	1,560	1,645
1988	1,659	1,708
1989	1,740	1,750
1990	1,778	1,774
1991	1,698	1,855
1992	1,883	1,927
1993	1,883	1,998
1994	2,007	2,018
1995	2,064	2,130
1996	2,210	2,192
1997	2,115	2,318
1998	2,258	2,341
1999	2,343	2,420
2000	2,483	2,333
2001	2,666	2,610
2002	2,734	2,583
2003	2,858	2,706
2004	2,626	2,644
2005	2,794	2,891
Average Percent Change 1986-2005	3.37%	3.21%
Average Percent Change 1996-2005	2.64%	3.12%

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 p.m. load is lower than the 3 p.m. load. Since JEA demand peaks in the late afternoon during the summer, the highest value between 2 p.m. and 8 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 a.m. load to be higher than the load between 1 a.m. and 11 a.m.

After the summer and winter data were adjusted as described above, a nonlinear regression analysis was conducted to forecast the summer and winter peaks. The forecast temperature used in the regression was the 20 year median of the seasonal extreme temperatures (summer 99° F and winter 24° F) wherein 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 C.3-2 for total demand, firm demand, and interruptible demand levels. During the 20 year forecast period, total summer peak demand is forecast to increase at an average annual growth rate of 1.89 percent overall. The annual growth rate in summer interruptible load is 1.48 percent, and the average annual increase in summer firm peak demand is 1.91 percent. During the winter period, the total growth rate in winter peak demand is projected to increase at an average annual growth rate of 2.70 percent. The average annual increase in winter interruptible load is 1.50 percent, and the average annual increase in winter firm peak demand is 2.77 percent.

Since the winter peak demand is projected to continue to increase at a higher average annual growth rate, the trend in which the winter peak is above the summer peak on a weather-normalized basis is expected to continue. Table C.3-2 indicates that the total JEA peak demand in 2006 is projected to be 3,004 MW in the winter, compared to a summer total peak demand of 2,826 MW. In the final year of the forecast, the 2024 total winter peak demand is projected to be 4,856 MW, compared to 3,957 MW during the summer period. A similar pattern holds for the firm peak demand projections. The firm

Table C.3-2
JEA Peak Demand Forecast
(without FPU after 2007)

Fiscal Year	Total Peak Demand		Non-Firm Demand		Firm Peak Demand	
	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)
2006	3,004	2,826	173	175	2,831	2,651
2007	3,099	2,893	175	177	2,924	2,716
2008	3,099	2,878	178	180	2,921	2,698
2009	3,195	2,944	180	183	3,015	2,761
2010	3,294	3,009	183	185	3,111	2,824
2011	3,393	3,076	186	188	3,207	2,888
2012	3,496	3,141	189	191	3,307	2,950
2013	3,599	3,208	192	194	3,407	3,014
2014	3,704	3,275	194	197	3,510	3,078
2015	3,811	3,358	197	200	3,614	3,158
2016	3,920	3,424	200	203	3,720	3,221
2017	4,031	3,491	203	206	3,828	3,285
2018	4,143	3,557	206	209	3,937	3,348
2019	4,258	3,623	209	212	4,049	3,411
2020	4,375	3,690	213	215	4,162	3,475
2021	4,492	3,756	216	218	4,276	3,538
2022	4,612	3,824	219	222	4,393	3,602
2023	4,733	3,890	222	225	4,511	3,665
2024	4,856	3,957	226	228	4,630	3,729
Average Percent Change	2.70%	1.89%	1.50%	1.48%	2.77%	1.91%

winter peak demand is projected to increase from 2,831 MW in 2006 to 4,630 MW in 2024, and the firm summer peak demand is projected to increase from 2,651 MW in 2006 to 3,729 MW in 2024. All numbers assume that the FPU load (approximately 100 MW) will not be served starting January 1, 2008. Figure C.3-1 shows the historical and forecast summer and winter peaks for JEA.

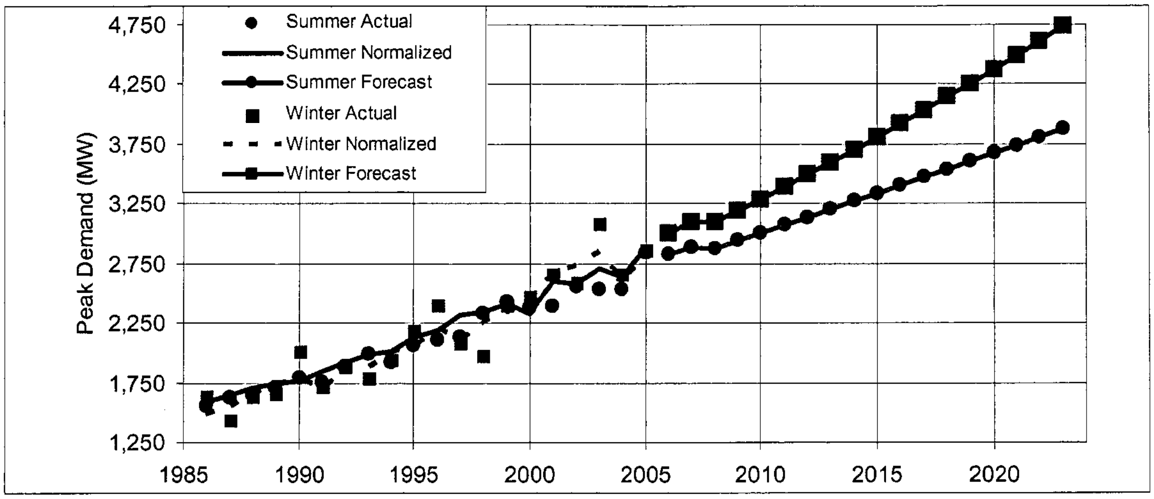

Figure C.3-1
JEA Historical and Forecast Summer and Winter Peaks

In addition to a base case forecast, JEA performed a forecast that incorporates the effects that moderate or extreme temperatures could have on peak demand. 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 93° F and 103° F for the moderate and extreme forecasts, respectively. The moderate and extreme peak forecasts for the summer and winter seasons are presented in Table C.3-3.

C.3.1.3 JEA Historical Net Energy for Load

JEA's historical net energy for load (NEL) requirements are shown in Table C.3-4. NEL is defined as the energy generated and purchased minus off-system sales. From 1986 through 2005, the annual average growth rate in NEL on the JEA system was 3.11 percent. This growth rate was lower than the growth rate in JEA's winter and summer peak demand. Total NEL requirements during the period increased from 7,319 GWh in fiscal year 1986 to 13,092 GWh in fiscal year 2005.

Table C.3-3
JEA Moderate and Extreme Peak Demand Forecast
(without FPU)

Fiscal 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)
2006	2,558	2,385	2,670	2,506	3,553	3,349	2,896	2,716
2007	2,636	2,461	2,739	2,572	3,669	3,462	2,961	2,778
2008	2,631	2,456	2,724	2,557	3,688	3,481	2,943	2,760
2009	2,712	2,532	2,794	2,623	3,808	3,596	3,008	2,821
2010	2,795	2,610	2,865	2,690	3,931	3,713	3,074	2,883
2011	2,879	2,689	2,936	2,757	4,057	3,833	3,139	2,943
2012	2,965	2,770	3,008	2,825	4,184	3,954	3,205	3,005
2013	3,053	2,853	3,081	2,894	4,314	4,078	3,270	3,065
2014	3,141	2,936	3,154	2,962	4,446	4,204	3,336	3,127
2015	3,231	3,021	3,228	3,032	4,580	4,332	3,401	3,187
2016	3,323	3,107	3,303	3,102	4,717	4,462	3,467	3,248
2017	3,416	3,195	3,378	3,173	4,856	4,595	3,532	3,308
2018	3,511	3,284	3,454	3,244	4,997	4,729	3,598	3,369
2019	3,607	3,374	3,531	3,317	5,141	4,866	3,664	3,430
2020	3,704	3,465	3,608	3,389	5,287	5,006	3,729	3,490
2021	3,803	3,558	3,686	3,462	5,435	5,147	3,795	3,551
2022	3,904	3,653	3,764	3,535	5,585	5,289	3,861	3,612
2023	4,006	3,749	3,843	3,609	5,738	5,435	3,927	3,673
2024	4,109	3,846	3,923	3,684	5,893	5,583	3,992	3,732
Average Annual Percent Change	2.67%	2.69%	2.16%	2.16%	2.85%	2.88%	1.80%	1.78%

(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.

Table C.3-4
Historical JEA Net Energy for Load Requirements

Fiscal Year	Actual NEL (GWh)	Heating and Cooling Degree-Days	
		HDD	CDD
1986	7,319	1,154	2,924
1987	7,712	1,467	2,574
1988	7,943	1,559	2,513
1989	8,225	1,278	2,936
1990	8,645	774	3,068
1991	8,748	1,085	3,166
1992	8,979	1,301	2,750
1993	9,452	1,391	2,670
1994	9,619	1,036	2,540
1995	10,090	1,443	2,783
1996	10,600	1,541	2,585
1997	10,489	1,174	2,519
1998	11,401	1,011	3,050
1999	11,682	1,206	2,611
2000	11,915	1,478	2,456
2001	12,517	1,213	2,537
2002	12,626	1,333	2,872
2003	13,181	1,432	2,616
2004	13,282	1,384	2,761
2005	13,092	1,302	2,736
Average Annual Percent Increase 1986 to 2005	3.11%	NA	NA
Average Annual Percent Increase 1996 to 2005	2.37%	NA	NA

C.3.1.4 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 (HDD) and cooling degree-days (CDD). The HDD and CDD parameter estimate projections were based on the 1985 through 2004 historical averages.

The NEL forecast for JEA is shown in Table C.3-5. The NEL is forecast to increase at an average annual growth rate of 2.2 percent during the 2006 through 2024 forecast period. NEL is forecast to increase from 14,077 GWh in fiscal year 2006 to 20,851 GWh in fiscal year 2024. These figures assume that FPU requirements are not part of JEA's total NEL beginning January 1, 2008.

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 C.3-6. Under the Extreme Condition forecast, the total NEL would increase from 15,658 GWh in 2006 to 23,597 GWh in 2024, yielding an average annual growth rate of 2.3 percent. Under the Moderate Condition forecast, the total NEL would increase from 13,441 GWh in 2006 to 20,581 GWh in 2024, yielding an average annual growth rate of 2.4 percent.

C.3.1.5 JEA Load Forecast Summary

Since 1986, JEA has experienced its peak load 14 times in the summer and 6 times in the winter. However, recent historical peaks have occurred during the winter in 4 of the past 6 years. As the forecast indicates, JEA's time of system peak is transitioning from a summer peaking utility to a winter peaking utility, resulting in a divergence of these peaks. JEA intends to continue to evaluate the impact of this changing trend for its future planning.

Table C.3-5
JEA Forecasted Net Energy for Load
(without FPU)

Fiscal Year	NEL (GWh)	Heating and Cooling Degree-Days	
		HDD	CDD
2006	14,077	1,279	2,678
2007	14,456	1,279	2,678
2008	14,444	1,279	2,678
2009	14,787	1,279	2,678
2010	15,168	1,279	2,678
2011	15,552	1,279	2,678
2012	15,976	1,279	2,678
2013	16,327	1,279	2,678
2014	16,719	1,279	2,678
2015	17,113	1,279	2,678
2016	17,555	1,279	2,678
2017	17,913	1,279	2,678
2018	18,316	1,279	2,678
2019	18,723	1,279	2,678
2020	19,178	1,279	2,678
2021	19,546	1,279	2,678
2022	19,960	1,279	2,678
2023	20,379	1,279	2,678
2024	20,851	1,279	2,678
Average Annual Percent Increase	2.2%	NA	NA

Table C.3-6
JEA Net Energy for Load--Moderate and Extreme Cases

Fiscal Year	Moderate Forecast[1] (GWh)	Extreme Forecast[2] (GWh)
2006	13,441	15,658
2007	13,808	16,069
2008	14,214	16,520
2009	14,552	16,902
2010	14,928	17,323
2011	15,308	17,747
2012	15,730	18,214
2013	16,077	18,605
2014	16,466	19,038
2015	16,858	19,474
2016	17,297	19,958
2017	17,652	20,358
2018	18,054	20,803
2019	18,458	21,252
2020	18,914	21,752
2021	19,278	22,161
2022	19,692	22,619
2023	20,109	23,081
2024	20,581	23,597
Average Annual Percent Change	2.4%	2.3%

(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.

C.4.0 JEA's Need for Capacity

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 or lower than anticipated available capacity. This section presents the development and analysis of the reliability criteria used by JEA.

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 not considered in the 15 percent reserve margin.

C.4.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. One method is the reserve margin and another is the Loss of Load Probability (LOLP), which apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. JEA uses a reserve margin for planning purposes that accounts for partial requirements and other purchases that include reserves. These two methods are discussed below.

C.4.1.1 Reserve Margin

The most commonly used deterministic method is the reserve margin method, which is calculated as follows:

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

C.4.1.2 Loss of Load Probability

The second commonly used method of calculating the reliability of a utility system is the LOLP method. This method is advantageous in that it can result in a measure of how much capacity (and reserves) is needed to meet a target level of reliability (typically, an LOLP criterion of no more than 1 day in 10 years is used). FRCC utilizes a reserve margin criterion (Resource Adequacy Standard) for capacity planning purposes that results in resource levels that meet an LOLP criterion of no more than 1 day in 10 years. The Resource Adequacy Standard calls for a reserve margin of 15 percent versus firm load. Therefore, JEA uses the reserve margin method as the planning criterion that produces the most conservative reliability level.

C.4.2 JEA Reliability Need

To determine JEA's need for power, a forecast of net system capacity and system peak demand was developed for the summer and winter peaks. The forecast system peak demand through 2024 is presented in Section C.3.0. Forecasts of system peak demand for the summer and winter of 2025 were extrapolated using the growth rate from the previous 2 years. The net system capacity includes existing generation resources, existing system purchases, system sales, reserves associated with partial requirements purchases, firm capacity additions, and firm retirements.

Kennedy Units 4 and 5 have been placed in reserve shutdown and are not included as generating units. Kennedy Unit 3 is scheduled for a major overhaul in 2008, and may also be placed in long-term reserve shutdown. For the purposes of this study, Unit 3 is assumed to be shut down on October 1, 2008. Additionally, JEA does not have any partial requirements purchases.

Planned unit additions included in JEA's 2006 Ten-Year Site Plan (TYSP) prior to the installation of TEC are included as committed resources for JEA. The planned unit additions include three 177 MW CTs in 2009, 2010, and 2011.

The existing purchases include 207 MW from Southern Company through May 31, 2010, and a total of 22 MW of renewable energy starting in the summer of 2007. Renewable purchases are included in the analyses presented in this Application.

Existing sales include 383 MW (winter) and 376 MW (summer) to FPL. This contract has a fixed expiration date of 2022 and allows for only a certain quantity of energy. Based on FPL's past and current usage rates, JEA projects that the latter will last no longer than the summer of 2016. For this analysis, it was assumed that the capacity would be available to JEA beginning in the winter of 2016/17 (refer to Subsection C.2.2.1).

The projected reliability levels for the winter base case and the summer base case (based on JEA's currently available capacity resources, which are described in Section C.2.0) are presented in Tables C.4-1 and C.4-2, respectively, shown at the end of this section. The tables show that JEA's capacity will fall below its required 15 percent reserve margin in the winter of 2011/12. At that time, JEA's reserve margin is projected to fall to 13.0 percent, 67 MW short of the 15 percent required reserves. The deficit would continue to increase during the winter of 2012/13, when the margin is projected to be 9.7 percent, 182 MW short of the 15 percent required reserve margin.

In the winter of 2019/20, JEA's projected peak would exceed its net system capacity. The reserve margin falls to -1.1 percent, or 672 MW short of the required 15 percent reserve margin.

Table C.4-1
Projected Reliability Levels – Winter/Base Case

Year	2006 Net Generating Capacity (MW)[3]	Non-Partial Requirements Purchases (MW)[4,5]	Non-Partial Requirements Sales (MW)[6]	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements (MW)[7,8]	Net Firm Capacity Additions/ (Reductions) (MW)[9,10]	Net System Capacity (MW)	System Peak Demand[1]		Reserve Margin[2]		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)
2005/06	3,535	229	383	0	0	18	3,399	3,004	2,831	13.2	20.1	(55)	144
2006/07	3,557	229	383	0	0	36	3,439	3,099	2,924	11.0	17.6	(125)	76
2007/08	3,557	229	383	0	0	36	3,439	3,099	2,921	11.0	17.7	(125)	80
2008/09	3,748	229	383	0	63	36	3,567	3,195	3,015	11.6	18.3	(108)	99
2009/10	3,939	229	383	0	63	31	3,752	3,294	3,111	13.9	20.6	(36)	175
2010/11	4,130	22	383	0	63	31	3,736	3,393	3,207	10.1	16.5	(166)	48
2011/12	4,130	22	383	0	63	31	3,736	3,496	3,307	6.9	13.0	(284)	(67)
2012/13	4,130	22	383	0	63	31	3,736	3,599	3,407	3.8	9.7	(402)	(182)
2013/14	4,130	22	383	0	63	27	3,732	3,704	3,510	0.8	6.3	(527)	(304)
2014/15	4,130	22	383	0	63	27	3,732	3,811	3,614	-2.1	3.3	(650)	(424)
2015/16	4,130	22	383	0	63	27	3,732	3,921	3,720	-4.8	0.3	(777)	(546)
2016/17	4,130	22	0	0	63	27	4,115	4,032	3,828	2.1	7.5	(521)	(287)
2017/18	4,130	22	0	0	64	27	4,114	4,144	3,937	-0.7	4.5	(651)	(413)
2018/19	4,130	22	0	0	64	27	4,114	4,259	4,049	-3.4	1.6	(783)	(542)
2019/20	4,130	22	0	0	64	27	4,114	4,374	4,162	-5.9	-1.1	(916)	(672)
2020/21	4,130	22	0	0	64	27	4,114	4,492	4,276	-8.4	-3.8	(1,051)	(803)
2021/22	4,130	22	0	0	64	27	4,114	4,612	4,393	-10.8	-6.3	(1,189)	(938)
2022/23	4,130	22	0	0	64	27	4,114	4,733	4,511	-13.1	-8.8	(1,329)	(1,073)
2023/24	4,130	22	0	0	64	27	4,114	4,856	4,630	-15.3	-11.1	(1,470)	(1,210)
2024/25	4,130	22	0	0	64	27	4,114	4,982	4,752	-17.4	-13.4	(1,615)	(1,351)

(1) Load reflects the end of FPU's load on December 31, 2007.
(2) Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
(3) Includes peak firing capacity on Kennedy CT 7, Brandy Branch CTs 1 through 3, and Brandy Branch ST 4 upgrade in the summer of 2006. Also includes three 191 MW (winter rating) CTs in 2009, 2010, and 2011.
(4) Assumes 207 MW purchase from Southern will expire on May 31, 2010.
(5) Assumes no purchases from TEA.
(6) Assumes FPL contract to purchase 30 percent of SJRPP will reach contracted energy limitation on October 1, 2016; based on a conservative estimate made by JEA for planning purposes.
(7) Assumes the placement of Kennedy CT Unit 3 in reserve shutdown on October 1, 2008. Total capacity loss is 63 MW.
(8) Assumes that Girvin Landfill will be retired on October 1, 2017.
(9) Assumes turbine upgrades at Northside ST Units 1, 2, and 3 on June 1, 2006; December 1, 2006; and December 15, 2005, respectively. Total capacity increase is 36 MW.
(10) Assumes capacity reduction due to auxiliary power required for emissions control in January 2010. Assumes that auxiliary load increase would reduce unit capacity. 80 percent of SJRPP 1 and 2, and 23.64 percent of Scherer 4 auxiliary load increases are assigned to JEA. Total assumed loss is 7.2 MW.

Table C.4-2
Projected Reliability Levels – Summer/Base Case

Year	2006 Net Generating Capacity (MW)(3)	Non-Partial Requirements Purchases (MW)(4,5)	Non-Partial Requirements Sales (MW)(6)	Partial Requirements Purchases (MW)	Net Firm Planned Capacity Retirements (MW)(7,8)	Net Firm Capacity Additions/ (Reductions) (MW)(9,10)	Net System Capacity (MW)	System Peak Demand(1)		Reserve Margin(2)		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)
2006	3,390	207	376	0	0	27	3,248	2,826	2,651	14.9	22.5	(2)	199
2007	3,390	229	376	0	0	36	3,279	2,893	2,716	13.3	20.7	(48)	156
2008	3,390	229	376	0	0	36	3,279	2,878	2,698	13.9	21.5	(31)	176
2009	3,538	229	376	0	51	36	3,376	2,944	2,761	14.7	22.3	(10)	201
2010	3,686	22	376	0	51	31	3,312	3,009	2,824	10.1	17.3	(149)	64
2011	3,834	22	376	0	51	31	3,460	3,076	2,888	12.5	19.8	(78)	139
2012	3,834	22	376	0	51	31	3,460	3,141	2,950	10.1	17.3	(152)	67
2013	3,834	22	376	0	51	31	3,460	3,208	3,014	7.8	14.8	(229)	(6)
2014	3,834	22	376	0	51	27	3,456	3,275	3,078	5.5	12.3	(311)	(84)
2015	3,834	22	376	0	51	27	3,456	3,341	3,158	3.4	9.4	(386)	(176)
2016	3,834	22	376	0	51	27	3,456	3,407	3,221	1.4	7.3	(462)	(248)
2017	3,834	22	0	0	51	27	3,832	3,473	3,285	10.3	16.6	(162)	54
2018	3,834	0	0	0	52	27	3,809	3,539	3,348	7.6	13.8	(261)	(42)
2019	3,834	0	0	0	52	27	3,809	3,606	3,411	5.6	11.7	(338)	(114)
2020	3,834	0	0	0	52	27	3,809	3,673	3,475	3.7	9.6	(415)	(188)
2021	3,834	0	0	0	52	27	3,809	3,740	3,538	1.8	7.7	(492)	(260)
2022	3,834	0	0	0	52	27	3,809	3,807	3,602	0.0	5.7	(569)	(334)
2023	3,834	0	0	0	52	27	3,809	3,874	3,665	-1.7	3.9	(646)	(406)
2024	3,834	0	0	0	52	27	3,809	3,941	3,729	-3.4	2.1	(723)	(480)
2025	3,834	0	0	0	52	27	3,809	4,009	3,794	-5.0	0.4	(802)	(555)

(1)Load reflects the end of FPU's load on December 31, 2007.
(2)Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand).
(3)Includes peak firing capacity on Kennedy CT 7, Brandy Branch CTs 1 through 3, and Brandy Branch ST 4 upgrade in the summer of 2006. Also includes three 148 MW (summer rating) CTs in 2009, 2010, and 2011.
(4)Assumes 207 MW purchase from Southern will expire on May 31, 2010.
(5)Assumes no purchases from TEA.
(6)Assumes FPL contract to purchase 30 percent of SJRPP will reach contracted energy limitation on October 1, 2016; based on a conservative estimate made by JEA for planning purposes.
(7)Assumes the placement of Kennedy CT Unit 3 in reserve shutdown on October 1, 2008. Total capacity loss is 51 MW.
(8)Assumes that Girvin Landfill will be retired on October 1, 2017.
(9)Assumes turbine upgrades at Northside ST Units 1, 2, and 3 on June 1, 2006; December 1, 2006; and December 15, 2005, respectively. Total capacity increase is 36 MW.
(10)Assumes capacity reduction due to auxiliary power required for emissions control in January 2010. Assumes that auxiliary load increase would reduce unit capacity. 80 percent of SJRPP 1 and 2, and 23.64 percent of Scherer 4 auxiliary load increases are assigned to JEA. Total assumed loss is 7.2 MW.

C.5.0 JEA's Economic Analysis

A detailed economic analysis was performed to evaluate the cost-effectiveness of JEA's participation in TEC and to determine the least-cost capacity expansion plan to meet JEA's forecast capacity requirements during the planning horizon, as presented in Section C.5.0. This section presents the assumptions and methodology used in the economic analysis, as well as the results of the base case analysis.

The economic analysis described herein compares the economics of the least-cost capacity expansion plan, utilizing conventional and emerging supply-side alternatives, including JEA's share of capacity and energy from TEC, versus the economics of the least-cost expansion plan for JEA's system utilizing conventional and emerging supply-side alternatives that does not include participation in TEC. The capacity associated with JEA's share of TEC, as well as construction of any of the supply-side alternatives presented in Section A.6.0, is only sufficient to satisfy JEA's forecast capacity requirements for a portion of the expansion planning horizon. To meet the forecast capacity requirements, multiple unit additions were selected from JEA's supply-side alternatives considered for individual participation that passed the supply-side screening described in Section A.6.6. Analyses of JEA's joint participation in supply-side alternatives other than TEC are presented as sensitivity cases in Section C.6.0.

C.5.1 Expansion Planning and Production Costing Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model that Black & Veatch developed as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. Both POWROPT and its detailed chronological production costing module, POWRPRO, have been used in numerous Need for Power Applications approved by the Florida Public Service Commission (FPSC), including FMPA's Treasure Coast Energy Center (TCEC) Unit 1 Need for Power Application approved in July 2005 and the Orlando Utilities Commission (OUC) Stanton B Need for Power Application approved in May 2006.

POWROPT operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans to satisfy forecast capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options, in conjunction with existing capacity resources, while maintaining user-defined reliability criteria. All capacity expansion plans were analyzed over a 30 year period from 2006 through 2035.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's POWRPRO was used to obtain the annual production cost for the expansion plan. POWRPRO is a computer-based chronological production costing model developed for use in power supply systems planning. POWRPRO simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs are carried forward from those used in POWROPT and include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

POWRPRO summarizes each unit's operating characteristics for every year of the planning horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours the unit was on line, the capacity factor, variable operations and maintenance (O&M) costs, and the number of starts and associated costs. Fixed O&M costs were included only for new unit additions, since the fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another. Similarly, the annual capacity charges for the Southern Company UPS and the Renewable Energy Purchases were not included, since they also represent sunk costs. In addition, fixed costs for firm natural gas transportation capacity from Florida Gas Transmission Company (FGT) for existing units are considered sunk costs and were not included. The operating costs of each unit were aggregated to determine the annual operating costs for each year of the expansion plan. Capital costs, fixed O&M costs, and incremental costs for natural gas transportation (for combined cycle capacity addition alternatives) were then added for each capacity addition selected, at which point the cumulative present worth cost (CPWC) of each expansion plan was calculated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M for capacity additions, nonfuel variable O&M, startup, and levelized capital) for each year of the expansion planning period and discounts each back to 2006 at the present worth discount rate of 5.0 percent. These annual present worth costs were then summed over the 2006 through 2035 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans, and the plan with the lowest CPWC is considered the least-cost capacity expansion plan.

C.5.2 Least-Cost Capacity Expansion Analysis

The economic analysis consisted of comparing the economics of the optimal capacity expansion plan, including JEA's participation in TEC, with the optimal capacity expansion plan not including participation in TEC. As described previously in this section, Black & Veatch first used its optimum generation expansion program, POWROPT, to select unit additions from JEA's supply-side alternatives considered for individual participation, which was presented in Section A.6.0. Once the least-cost expansion plan for each case was determined, POWRPRO was used to determine the annual total system costs and to develop a comparison of CPWCs associated with each expansion plan.

C.5.2.1 Peak Demand and Energy Growth

As presented in Sections C.3.0 and C.4.0, a forecast of peak demand and NEL was provided for JEA's system through 2025. For evaluation purposes (as discussed in Section A.8.0), loads have been held constant beyond 2025.

C.5.2.2 Supply-Side Candidate Unit Additions

As described in Section C.4.0, JEA's forecast capacity requirements are dictated by projected capacity shortfalls in the winter season of each year of the planning period. On a weather-normalized basis, JEA's winter peak typically occurs in January of a given calendar year; however, JEA's actual winter peak could occur as early as December of the previous calendar year. To ensure that new capacity additions are available to meet forecast winter reserve margin requirements, all unit additions considered for JEA's individual ownership (as presented in Section A.6.0) are assumed to be installed by December 1.

Section A.6.0 presented capital and O&M costs for both greenfield and brownfield units considered for JEA's individual ownership. Since JEA's existing Northside and Kennedy sites do not currently have sufficient infrastructure or site space to accommodate the number of unit additions required to meet JEA's forecast capacity requirements, the number of brownfield generating unit additions to JEA's system was limited. It was assumed that JEA's existing Northside and Kennedy sites could accommodate a total of up to two LMS100 CTs, two 7FA CTs, one 1x1 7FA combined cycle unit, one 1x1 integrated gasification combined cycle (IGCC) unit, and two CFB units. Although the Northside and Kennedy sites cannot accommodate all of these generating units, the lower cost brownfield units were used to ensure a conservative economic analysis.

In the base case economic analysis, POWROPT was allowed to select up to the assumed maximum number of units for each brownfield alternative when developing capacity expansion plans for the cases with and without JEA's participation in TEC. If the maximum number of brownfield units for one type of generating alternative was selected as capacity additions, then subsequent units of that type were limited to greenfield units only. The different capital and O&M costs for greenfield and brownfield units selected in the optimum capacity expansion plans were carried forward to the POWRPRO analysis.

C.5.2.3 Fuel Prices and Natural Gas Transportation

As described in Section A.4.0 of this Application, projections of delivered fuel prices were developed by TEC Fuels. The base case fuel price projections presented in Section A.4.0 have been used for the evaluations presented in this section.

For all capacity expansion plan evaluations, it was necessary to account for the natural gas transportation capacity associated with the new combined cycle unit alternatives. JEA currently has contracts in place with FGT and El Paso Municipal for firm natural gas transportation to fuel its existing natural gas fired units. For the 1x1 7FA combined cycle option included in Section A.6.0, it was assumed that JEA would purchase firm transportation in accordance with FGT's tariff so that 6.0 percent of the daily natural gas transportation allocation would be adequate to operate the unit at full load for an hour, based on the performance at average ambient conditions. This would require 37,323 MBtu of firm natural gas per day. Using the Firm Transportation Service (FTS) reservation charge of $0.769 per MBtu (pursuant to FGT's April 2006, effective rates for incremental Firm Market Area Transportation), firm transportation costs of $2.92 per kW-month were added to the fixed O&M costs of the 1x1 7FA combined cycle alternative. It has been assumed that JEA will not purchase firm natural gas transportation capacity from FGT for simple cycle CTs but, instead, will utilize an interruptible service rate assumed to be $0.37 per MBtu, which was added to the annual commodity price forecasts for natural gas presented in Section A.4.0. Any natural gas required for JEA's system in excess of the firm natural gas transportation for the existing and new units is priced at the interruptible service rate.

C.5.2.4 Emissions Cost Considerations

To reflect the economic effects of CAIR and CAMR (as described in Section A.5.0), the forecast prices of emissions allowances were incorporated into the fuel costs for each unit, including existing units that will be regulated under CAIR and CAMR, beginning with the first phases of CAIR and CAMR. The allowance price forecasts presented in Section A.5.0 provide emissions costs on a dollar per ton (dollar per pound for Hg) basis. These costs were used to calculate a fuel cost adder for both the existing units and candidate units, based on the emissions rates of each individual unit. As a result, each generating unit was modeled using different prices for fuel because of differences in emissions rates. The forecast market value of the allowances allocated to

JEA's existing units was not included in the economic analysis. since it represents the same credit for each capacity expansion plan.

Emissions rates for some of JEA's existing units may be modified through fuel switching or retrofits for emissions control to help meet the NO_x, SO_2, and Hg reductions mandated by CAIR and CAMR. Although JEA's system-wide emissions control strategy is still not definite, several units were modeled with reduced emissions rates to reflect likely emissions control additions or retrofits. Emissions control strategies for Scherer 4 and St. Johns River Power Park (SJRPP) 1 and 2 were assumed to be consistent with the emissions control strategies presented in JEA's 2006 Integrated Resource Plan (IRP). Capital and fixed O&M costs for emissions controls were not considered in the analysis, since they represent the sunk costs that are the same in all plans; however, variable O&M adders of $1.11 per MWh and $0.17 per MWh were added to Scherer 4 and the SJRPP units, respectively. The variable O&M adders are consistent with the adders presented in JEA's 2006 IRP, and reflect additional costs for additives, chemicals, and catalyst replacement. Both the unit output and performance for the SJRPP units and Scherer 4 were adjusted to include the auxiliary power requirements of the emissions control additions. Table C.5-1 summarizes the emissions control strategies considered in this analysis.

Table C.5-2 presents the emissions cost adders for JEA's existing units, which include the reductions presented in Table C.5-1. Table C.5-3 presents the emissions cost adders for JEA's candidate units presented in Section A.6.0.

C.5.2.5 Dispatch Assumptions

Nonfuel variable O&M and forecast emissions allowance costs were included in the unit dispatch modeling in POWROPT and POWRPRO, along with the fuel costs. These costs were included in the dispatch modeling to ensure the most cost-effective dispatch of both existing and new generating units.

C.5.2.6 Analysis of JEA's Participation in TEC

The evaluation of JEA's participation in TEC was performed by modeling the capacity expansion plan presented in JEA's 2006 TYSP (until commercial operation of TEC) as a committed expansion plan. The TYSP includes the addition of a 191 MW CT in 2009, a second 191 MW CT in 2010, a third 191 MW CT in 2011, a winter seasonal purchase of 70 MW in 2012, and participation in TEC beginning May 1, 2012. The winter seasonal purchase was modeled with an energy cost of $164.09 per MWh and a capacity cost of $7.50 per kW-month in 2012 dollars.

Table C.5-1
Emissions Control Strategies

Unit	SJRPP 1	SJRPP 2	Scherer 4
Addition/Modification[1]	SCR Retrofit Wet FGDs	SCR Retrofit Wet FGDs	SCR Wet Scrubber
Expected Year of Implementation	2009	2009	2014
Post Retrofit NO_x Emission Rate (lb/MBtu)	0.06	0.06	0.06
Post Retrofit SO_2 Emission Rate (lb/MBtu)	0.10	0.10	0.04
Post Retrofit Hg Emission Rate (lb/TBtu)[2]	2.10	2.10	4.00
Variable O&M Increase ($/MWh)	0.17	0.17	1.11
Reduction in Full-Load Output (MW)	2.64	2.64	4.02
Increase in Full-Load Heat Rate (Btu/kWh)	41.6	41.6	45.4

(1)Only reflects additions and modifications that will improve SO_2 and NO_x emission rates. Other additions or modifications may be made to specifically reduce Hg or particulate matter (PM) emissions, but have not been included in the evaluations.

(2)Hg emission rates presented reflect expected co-benefits of emission control strategies to reduce NO_x and SO_2 emission rates for CAIR compliance.

Table C.5-2
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Existing Units
(Nominal $/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.07	$0.11	$0.11	$0.60	$0.37	$0.06	$0.02	$0.09	$0.09	$0.08
2010	$0.10	$0.16	$0.16	$0.70	$0.51	$0.08	$0.03	$0.15	$0.15	$0.17
2011	$0.10	$0.17	$0.17	$0.72	$0.54	$0.08	$0.03	$0.16	$0.16	$0.18
2012	$0.10	$0.17	$0.17	$0.78	$0.56	$0.09	$0.03	$0.16	$0.16	$0.17
2013	$0.11	$0.18	$0.18	$0.80	$0.57	$0.09	$0.03	$0.17	$0.17	$0.19
2014	$0.12	$0.19	$0.19	$0.92	$0.62	$0.09	$0.04	$0.17	$0.17	$0.17
2015	$0.19	$0.30	$0.31	$1.41	$0.99	$0.15	$0.05	$0.27	$0.27	$0.29
2016	$0.20	$0.32	$0.32	$1.56	$1.07	$0.16	$0.06	$0.28	$0.28	$0.28
2017	$0.17	$0.29	$0.30	$1.49	$0.92	$0.14	$0.06	$0.26	$0.26	$0.25
2018	$0.18	$0.33	$0.33	$1.55	$0.95	$0.15	$0.06	$0.29	$0.29	$0.31
2019	$0.23	$0.39	$0.39	$1.84	$1.25	$0.19	$0.07	$0.35	$0.35	$0.36
2020	$0.28	$0.45	$0.46	$2.14	$1.50	$0.23	$0.08	$0.40	$0.40	$0.41
2021	$0.27	$0.45	$0.45	$2.14	$1.43	$0.22	$0.08	$0.40	$0.40	$0.41
2022	$0.26	$0.45	$0.45	$2.14	$1.37	$0.21	$0.08	$0.40	$0.40	$0.41
2023	$0.33	$0.58	$0.58	$2.58	$1.76	$0.27	$0.10	$0.53	$0.53	$0.58
2024	$0.49	$0.78	$0.79	$3.54	$2.64	$0.40	$0.14	$0.71	$0.71	$0.76
2025	$0.54	$0.89	$0.89	$3.78	$2.86	$0.44	$0.15	$0.82	$0.82	$0.94
2026	$0.58	$0.95	$0.96	$4.02	$3.09	$0.47	$0.16	$0.89	$0.89	$1.02
2027	$0.62	$1.03	$1.03	$4.31	$3.34	$0.51	$0.17	$0.96	$0.96	$1.10
2028	$0.67	$1.10	$1.11	$4.61	$3.59	$0.55	$0.18	$1.03	$1.03	$1.19
2029	$0.72	$1.18	$1.19	$4.93	$3.85	$0.59	$0.20	$1.11	$1.11	$1.29
2030	$0.77	$1.27	$1.27	$5.25	$4.13	$0.63	$0.21	$1.19	$1.19	$1.38
2031	$0.83	$1.36	$1.36	$5.60	$4.42	$0.67	$0.22	$1.28	$1.28	$1.49
2032	$0.89	$1.45	$1.46	$5.98	$4.73	$0.72	$0.24	$1.37	$1.37	$1.60
2033	$0.95	$1.56	$1.56	$6.38	$5.07	$0.77	$0.25	$1.47	$1.47	$1.72
2034	$1.02	$1.67	$1.67	$6.81	$5.43	$0.82	$0.27	$1.57	$1.57	$1.85
2035	$1.09	$1.79	$1.79	$7.26	$5.82	$0.88	$0.29	$1.69	$1.69	$1.99

Table C.5-3
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Candidate Units
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.01	$0.01	$0.01	$0.10	$0.11	$0.13	$0.07
2010	$0.01	$0.01	$0.01	$0.15	$0.16	$0.19	$0.10
2011	$0.01	$0.01	$0.01	$0.16	$0.17	$0.20	$0.11
2012	$0.01	$0.01	$0.01	$0.16	$0.17	$0.20	$0.11
2013	$0.01	$0.01	$0.01	$0.17	$0.18	$0.21	$0.11
2014	$0.01	$0.01	$0.01	$0.18	$0.19	$0.22	$0.12
2015	$0.02	$0.02	$0.02	$0.28	$0.30	$0.36	$0.20
2016	$0.02	$0.02	$0.02	$0.30	$0.32	$0.38	$0.21
2017	$0.02	$0.02	$0.02	$0.27	$0.29	$0.34	$0.18
2018	$0.02	$0.02	$0.02	$0.30	$0.32	$0.37	$0.19
2019	$0.03	$0.03	$0.03	$0.36	$0.39	$0.46	$0.25
2020	$0.03	$0.03	$0.03	$0.42	$0.45	$0.53	$0.30
2021	$0.03	$0.03	$0.03	$0.42	$0.45	$0.52	$0.28
2022	$0.03	$0.03	$0.03	$0.41	$0.44	$0.51	$0.27
2023	$0.04	$0.04	$0.04	$0.54	$0.57	$0.67	$0.35
2024	$0.06	$0.06	$0.06	$0.74	$0.78	$0.93	$0.52
2025	$0.07	$0.07	$0.07	$0.84	$0.89	$1.05	$0.57
2026	$0.07	$0.07	$0.07	$0.91	$0.95	$1.13	$0.61
2027	$0.08	$0.08	$0.08	$0.98	$1.03	$1.22	$0.66
2028	$0.08	$0.08	$0.08	$1.05	$1.11	$1.31	$0.71
2029	$0.09	$0.09	$0.09	$1.13	$1.19	$1.41	$0.76
2030	$0.09	$0.09	$0.09	$1.21	$1.27	$1.51	$0.82
2031	$0.10	$0.10	$0.10	$1.29	$1.36	$1.62	$0.88
2032	$0.11	$0.11	$0.11	$1.39	$1.46	$1.73	$0.94
2033	$0.12	$0.12	$0.12	$1.49	$1.56	$1.86	$1.01
2034	$0.12	$0.12	$0.12	$1.59	$1.67	$1.99	$1.08
2035	$0.13	$0.13	$0.13	$1.71	$1.79	$2.13	$1.15

POWROPT was used to determine the set of optimum capacity additions after the construction of TEC from the conventional technologies considered for individual ownership by JEA as presented in Section A.6.0. Additional capacity for JEA's system is projected to be required during the winter of 2013/14. All of the conventional generating alternatives, except the IGCC unit (which was characterized as an emerging technology in Section A.6.0), were assumed to be available to meet capacity requirements in 2013. Given its current developmental status, it has been assumed that the IGCC option would not be available before 2018. This would allow for 3 years of successful commercial operation of the next generation of IGCC units (such as OUC's Stanton B IGCC, which is scheduled to begin operation on June 1, 2010), followed by an assumed 2 year engineering, permitting, and licensing process and 3 year construction schedule.

C.5.2.6.1 TEC Capital Cost. As described in Sections A.3.0 and A.8.0, the installed capital cost for TEC would be $1,752.4 million in 2012 dollars, inclusive of escalation and interest during construction. It was assumed that JEA would be responsible for a percentage of the capital costs equal to JEA's ownership share of 31.5 percent. JEA's total share of TEC's installed cost is approximately $552.0 million in 2012 dollars, which includes the costs for engineering, procurement, and construction (EPC); allowance for funds used during construction (AFUDC); land; community contribution; initial coal inventory; and owner's costs for TEC. Table C.5-4 presents a summary of JEA's share of the capital costs for TEC.

Table C.5-4
TEC Capital Cost – JEA's Share
(All Costs in 2012 Dollars)

Description	Entire Unit ($1,000s)	JEA's Share[1] ($1,000s)
EPC Cost	$1,420,892	$447,581
AFUDC	$135,413	$42,655
Owner's Cost	$116,994	$36,853
Initial Coal Inventory	$39,010	$12,288
Community Contribution	$20,000	$6,300
Land Cost	$20,100	$6,332
Total	**$1,752,409**	**$552,009**

[1]Reflects JEA's 31.5 percent ownership share of TEC.

C.5.2.6.2 Transmission Considerations. As described in Section A.3.0, JEA will be utilizing the transmission systems of Florida Power & Light (FPL) and Progress Energy Florida (PEF) for delivery from the Perry Substation to JEA's transmission system. JEA will be required to pay transmission tariffs to both FPL and PEF. The transmission tariffs assumed for JEA's use of the FPL and PEF transmission systems are $1,390.80 per MW-month and $1,193.00 per MW-month, respectively. It was assumed that JEA would purchase firm transmission for 241.1 MW, which will ensure that enough firm transmission is available for JEA to receive its full entitlement of capacity and energy from TEC in both the winter and summer seasons. The annual transmission tariffs that JEA will pay to FPL and PEF are $3,939,754 and $3,451,931, respectively. JEA's total annual cost for firm transmission is $7,391,685, which is included as an additional cost to JEA starting on May 1, 2012.

The line losses for the FPL and PEF transmission systems are 2.19 percent and 2.10 percent, respectively. These losses were considered when modeling JEA's participation in TEC, and the resulting net output and net plant heat rates for JEA are summarized in Table C.5-5.

Table C.5-5
JEA's Share of TEC (Average Ambient Conditions)
Output and Performance Considering Transmission Losses

Without Transmission Losses		Including Transmission Losses[1]	
Output (MW)	Net Plant Heat Rate (Btu/kWh)	Output (MW)	Net Plant Heat Rate (Btu/kWh)
241.1	9,238	230.9	9,647
235.5	9,238	225.5	9,647
186.7	9,428	178.7	9,846
123.7	9,933	118.5	10,373
85.8	10,535	82.2	11,002

[1]Assumes losses of 4.24 percent.

C.5.2.6.3 Operations and Maintenance Costs. Section A.3.0 presented the fixed and nonfuel variable O&M costs for TEC. It was assumed that JEA would be responsible for a share of the O&M costs for TEC equal to JEA's ownership share of 31.5 percent. Total fixed O&M costs for TEC include an adder for ongoing capital expenditures of $2.97 per kW-year in 2012 dollars, which escalates 2.0 percent higher than the general inflation rate. Excluding the adder for ongoing capital expenditures, the total annual cost for TEC's fixed O&M is $17.7 million in 2005 dollars. JEA's share of the fixed O&M cost for TEC is $5.58 million or about $24.16 per kW-year (net after considering transmission losses) in 2005 dollars. Section A.3.0 presented the nonfuel variable O&M cost for TEC before transmission losses as $1.36 per MWh. With transmission losses considered, JEA's net nonfuel variable O&M cost is $1.42 per MWh in 2005 dollars.

C.5.2.6.4 TEC Scheduled Maintenance and Forced Outages. As presented in Section A.3.0, TEC is expected to have an average of 16 scheduled maintenance days per year. Scheduled maintenance is assumed to begin on October 1 of every year after 2012. The scheduled maintenance period is consistent for all of the economic evaluations presented in this Application. TEC is assumed to have an equivalent forced outage rate of 5.23 percent.

C.5.2.6.5 Community Contribution. For purposes of this analysis, the TEC Participants are assumed to pay a community contribution of $2.5 million per year, in addition to an initial contribution of $20.0 million (included in the capital cost) described previously in this section. Similar to the other fixed costs for TEC, it was assumed that JEA would be responsible for a percentage of the annual community contribution proportionate to its ownership share of TEC. JEA's share of the annual community contribution is approximately $787,500 in 2012 dollars. The community contribution is included as an additional annual cost to JEA, escalated at the general inflation rate of 2.5 percent per year after May 1, 2012.

C.5.2.7 Analysis of Alternative Expansion Plans to Participation in TEC

In the analysis of the capacity expansion plan without participation in TEC, the capacity expansion plan presented in JEA's 2006 TYSP was considered a committed expansion plan until the winter of 2011/12. The 2006 TYSP indicates a winter seasonal purchase, followed by participation in TEC. For this analysis, it was assumed that JEA would neither purchase seasonal capacity nor participate in TEC. Instead, POWROPT was utilized to determine the least-cost capacity expansion plan for JEA's system with a need for capacity in the winter of 2011/12. To determine this plan, POWROPT selected generating unit alternatives from among JEA's individual ownership supply-side alternatives identified in Section A.6.0 to meet the forecast capacity requirements identified in Section C.4.0. All conventional supply-side alternatives were assumed to be available to meet JEA's need for capacity in 2011, except for the IGCC alternative which, as described in Subsection C.5.2.6, was assumed to be available in 2018.

C.5.3 Cumulative Present Worth Cost Analysis

The previous sections described the assumptions and methodology that were used in POWROPT to select least-cost capacity expansion plans for a scenario that included JEA's participation in TEC and another scenario in which it was assumed that TEC would not be constructed. Once these least-cost capacity expansion plans were identified, POWRPRO was used to determine the total annual system costs and to develop a comparison of CPWCs associated with each expansion plan.

C.5.3.1 Analysis of the Capacity Expansion Plan with TEC

The least-cost capacity expansion plan, assuming that JEA participates in TEC in May 2012, includes construction of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield IGCC unit in 2023.

C.5.3.2 Analysis of Alternative Capacity Expansion Plan

The least-cost capacity expansion plan without JEA's participation in TEC includes construction of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 combined cycle in 2020, a brownfield IGCC unit in 2022, a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024.

C.5.3.3 Comparison of Cumulative Present Worth Costs

As shown in Table C.5-6, the CPWC of the least-cost capacity expansion plan that includes JEA's participation in TEC is $14,139.0 million. Table C.5-7 indicates that the CPWC of the least-cost capacity expansion plan without TEC is $14,178.1 million. A comparison of the CPWCs of the two plans demonstrates that the expansion plan that includes participation in TEC is the least-cost plan by $39.1 million over the planning period.

Table C.5-6 Expansion Plan Economic Summary - With Taylor Energy Center in 2012

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
IGCC BF	721,900	38	12/01/23	1,167,256	84,673

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Adder ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,721,165
2012	$534,104	$57,858	$4,451	$596,413	$26,805	$786	$4,928	$2,100	$477	$35,097	$631,511	$3,192,408
2013	$542,117	$58,439	$7,609	$608,165	$44,294	$807	$7,392	$0	$748	$53,242	$661,407	$3,662,457
2014	$518,304	$62,774	$16,762	$597,841	$90,103	$827	$7,392	$0	$782	$99,104	$696,945	$4,134,177
2015	$574,301	$67,247	$18,034	$659,583	$94,570	$848	$7,392	$0	$817	$103,627	$763,209	$4,626,149
2016	$540,883	$67,840	$27,902	$636,626	$142,698	$869	$7,392	$0	$854	$151,813	$788,438	$5,110,162
2017	$522,631	$63,602	$28,600	$614,832	$142,698	$891	$7,392	$0	$892	$151,873	$766,705	$5,558,456
2018	$568,600	$69,235	$29,315	$667,150	$142,698	$913	$7,392	$0	$933	$151,935	$819,085	$6,014,555
2019	$609,429	$71,818	$30,048	$711,294	$142,698	$936	$7,392	$0	$974	$152,000	$863,294	$6,472,378
2020	$668,808	$78,510	$30,901	$778,219	$143,427	$959	$7,392	$0	$1,018	$152,796	$931,016	$6,942,605
2021	$708,681	$81,336	$33,042	$823,060	$152,619	$983	$7,392	$0	$1,064	$162,258	$985,318	$7,416,559
2022	$724,340	$82,044	$36,693	$843,077	$170,153	$1,008	$7,392	$0	$1,112	$179,665	$1,022,742	$7,885,089
2023	$790,871	$86,456	$40,693	$918,020	$186,031	$1,033	$7,392	$0	$1,162	$195,618	$1,113,638	$8,370,966
2024	$826,829	$97,534	$58,445	$982,808	$263,512	$1,059	$7,392	$0	$1,214	$273,178	$1,255,985	$8,892,854
2025	$896,942	$102,055	$59,906	$1,058,903	$263,512	$1,086	$7,392	$0	$1,269	$273,259	$1,332,162	$9,420,035
2026	$918,226	$103,768	$61,404	$1,083,398	$263,512	$1,113	$7,392	$0	$1,326	$273,343	$1,356,741	$9,931,377
2027	$948,901	$107,189	$62,939	$1,119,028	$263,512	$1,141	$7,392	$0	$1,386	$273,430	$1,392,459	$10,431,189
2028	$983,960	$109,389	$64,512	$1,157,841	$263,512	$1,169	$7,392	$0	$1,448	$273,521	$1,431,363	$10,920,500
2029	$1,037,064	$112,016	$66,125	$1,215,205	$263,512	$1,198	$7,392	$0	$1,513	$273,616	$1,488,821	$11,405,218
2030	$1,089,306	$115,507	$67,778	$1,272,591	$263,512	$1,228	$7,392	$0	$1,581	$273,714	$1,546,305	$11,884,677
2031	$1,109,608	$115,305	$69,473	$1,294,386	$263,512	$1,259	$7,392	$0	$1,653	$273,816	$1,568,201	$12,347,771
2032	$1,161,791	$119,167	$71,209	$1,352,167	$263,512	$1,290	$7,392	$0	$1,727	$273,921	$1,626,089	$12,805,094
2033	$1,219,040	$122,231	$72,990	$1,414,260	$263,512	$1,323	$7,392	$0	$1,805	$274,031	$1,688,292	$13,257,300
2034	$1,260,296	$124,494	$74,814	$1,459,604	$263,512	$1,356	$7,392	$0	$1,888	$274,146	$1,733,750	$13,699,568
2035	$1,328,869	$128,944	$76,685	$1,534,498	$263,512	$1,390	$7,392	$0	$1,971	$274,264	$1,808,762	$14,139,061

Table C.5-7 Expansion Plan Economic Summary - Without Taylor Energy Center

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
GE LMS100 CT BF	65,100	17	12/01/19	93,372	8,377
1x1 7FA CC BF	204,000	30	12/01/20	303,850	24,050
IGCC UNIT BF	712,900	38	12/01/22	1,124,589	61,578
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Other Capital Cost ($1,000)	Other Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,846
2011	$533,799	$61,578	$82	$595,458	$584	$0	$0	$0	$0	$584	$596,042	$2,720,863
2012	$575,868	$65,675	$1,777	$643,321	$11,024	$0	$0	$0	$0	$11,024	$654,345	$3,209,145
2013	$514,377	$61,464	$10,566	$586,407	$55,715	$0	$0	$0	$0	$55,715	$642,122	$3,665,469
2014	$563,433	$71,101	$11,663	$646,197	$60,073	$0	$0	$0	$0	$60,073	$706,270	$4,143,520
2015	$551,272	$72,012	$21,142	$644,425	$107,027	$0	$0	$0	$0	$107,027	$751,452	$4,627,913
2016	$584,044	$74,841	$21,670	$680,556	$107,027	$0	$0	$0	$0	$107,027	$787,583	$5,111,420
2017	$548,068	$67,594	$22,212	$637,874	$107,027	$0	$0	$0	$0	$107,027	$744,901	$5,546,949
2018	$604,155	$73,800	$22,767	$700,722	$107,027	$0	$0	$0	$0	$107,027	$807,749	$5,996,733
2019	$647,276	$77,538	$23,436	$748,249	$107,738	$0	$0	$0	$0	$107,738	$855,988	$6,450,682
2020	$704,320	$82,148	$26,230	$812,698	$117,447	$0	$0	$0	$0	$117,447	$930,145	$6,920,468
2021	$722,639	$80,849	$38,875	$842,363	$139,454	$0	$0	$0	$0	$139,454	$981,817	$7,392,739
2022	$769,561	$88,070	$41,064	$898,695	$146,382	$0	$0	$0	$0	$146,382	$1,045,077	$7,871,501
2023	$751,723	$96,994	$58,300	$907,016	$221,858	$0	$0	$0	$0	$221,858	$1,128,874	$8,364,025
2024	$862,583	$102,531	$61,251	$1,026,365	$231,609	$0	$0	$0	$0	$231,609	$1,257,973	$8,886,739
2025	$922,486	$106,348	$64,167	$1,093,002	$240,735	$0	$0	$0	$0	$240,735	$1,333,736	$9,414,544
2026	$946,249	$108,351	$65,509	$1,120,109	$240,735	$0	$0	$0	$0	$240,735	$1,360,844	$9,927,431
2027	$978,619	$111,479	$66,885	$1,156,983	$240,735	$0	$0	$0	$0	$240,735	$1,397,718	$10,429,132
2028	$1,022,396	$114,332	$68,295	$1,205,023	$240,735	$0	$0	$0	$0	$240,735	$1,445,758	$10,923,364
2029	$1,063,303	$116,419	$69,741	$1,249,463	$240,735	$0	$0	$0	$0	$240,735	$1,490,198	$11,408,530
2030	$1,135,299	$120,928	$71,223	$1,327,450	$240,735	$0	$0	$0	$0	$240,735	$1,568,185	$11,894,774
2031	$1,162,448	$122,072	$72,741	$1,357,261	$240,151	$0	$0	$0	$0	$240,151	$1,597,412	$12,366,494
2032	$1,209,512	$125,185	$74,298	$1,408,995	$233,859	$0	$0	$0	$0	$233,859	$1,642,854	$12,828,531
2033	$1,261,713	$128,182	$75,894	$1,465,788	$233,859	$0	$0	$0	$0	$233,859	$1,699,647	$13,283,779
2034	$1,317,080	$131,240	$77,529	$1,525,850	$233,859	$0	$0	$0	$0	$233,859	$1,759,709	$13,732,669
2035	$1,384,780	$135,738	$79,205	$1,599,724	$233,859	$0	$0	$0	$0	$233,859	$1,833,583	$14,178,132

C.6.0 JEA's Sensitivity Analyses

Several sensitivity analyses were performed to supplement JEA's base case economic analysis and demonstrate the robustness of the capacity expansion plans, including JEA's participation in TEC. These analyses measured the impact of varying the key assumptions used in the base case economic analysis, as well as the effects of considerations not included in the base case.

As described in Section C.5.0, the base case economic analysis compared the CPWC of the optimal capacity expansion plan, including JEA's participation in TEC, to the optimal capacity expansion plan without participation in TEC. For the base case analysis that included participation in TEC, the proposed TEC was treated as a committed unit starting May 1, 2012, while in the base case analysis without TEC, no candidate units were committed. POWROPT, Black & Veatch's optimal generation and capacity expansion model, was used to select the least-cost expansion plan to meet JEA's capacity needs. Once the optimal capacity expansion plan was developed for each case, POWRPRO (Black & Veatch's production costing model) was used to determine each plan's production costs, which were used to develop an overall CPWC for each plan.

The general methodology used in the sensitivity analyses is similar to the methodology used in the base case analysis. POWROPT was used to determine the optimal capacity expansion plan for all cases considered under the various assumptions described in this section. POWRPRO was then utilized to calculate production costs of each plan, to compare each plan's CPWC and to determine the least-cost expansion plan. The remainder of this section presents the methodology and results of the sensitivity analyses.

C.6.1 Input Parameter Sensitivities

The sensitivities described in this section reflect changes to the base case input assumptions, including fuel prices, load forecast, capital costs, emissions allowance prices, and potential environmental regulations related to CO_2 emissions.

C.6.1.1 High Fuel Price Forecast

The high fuel price sensitivity analysis is based on Hill & Associates' high fuel price forecasts and the corresponding emissions allowance price forecasts. The high fuel price forecasts are presented in Section A.4.0, while the emissions allowance price forecasts corresponding to the high fuel price forecast are presented in Section A.5.0.

As in the base case analysis described in Section C.5.0, the costs of emissions allowances were added to the fuel prices for both the existing and candidate units in the high fuel price sensitivity. Table C.6-1 presents the emissions cost adders for JEA's existing units, and Table C.6-2 presents the emissions adders for the candidate units under the high fuel price sensitivity.

Under the high fuel price forecast scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield CFB in 2022, and a brownfield IGCC unit in 2023. The optimal capacity expansion plan for the case without participation in TEC consists of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a brownfield IGCC unit in 2019, a second brownfield LMS100 CT in 2021, a greenfield CFB in 2022, a greenfield LMS100 CT in 2023, and a second LMS100 CT in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $15,521.2 million and $15,580.9 million, respectively. A comparison of these CPWCs shows that the expansion plan with TEC is the least-cost plan by $59.7 million over the evaluation period.

C.6.1.2 Low Fuel Price Forecast

The low fuel price sensitivity analysis is based on Hill & Associates' low fuel price forecasts and the corresponding emissions allowance price forecasts. The low fuel price forecasts are presented in Section A.4.0, while the emissions allowance price forecasts corresponding to the low fuel price forecast are presented in Section A.5.0.

As in the base case analysis described in Section C.5.0, the costs of emissions allowances were added to the fuel prices for both the existing and candidate units in the low fuel price sensitivity. Table C.6-3 presents the emissions cost adders for JEA's existing system, and Table C.6-4 presents the emissions cost adders for the candidate units under the low fuel price sensitivity.

Under the low fuel price forecast scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a brownfield LMS100 CT in 2015, a second brownfield CFB in 2019, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, two additional greenfield LMS100 CTs in 2023, a fifth LMS100 CT in 2024. The optimal capacity expansion plan for the case without participation in TEC consists of a brownfield LMS100 CT in 2011, a

Table C.6-1
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Existing Units – High Fuel Forecast
(Nominal $/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.07	$0.08	$0.08	$0.36	$0.38	$0.06	$0.02	$0.07	$0.07	$0.07
2010	$0.10	$0.17	$0.17	$0.72	$0.53	$0.08	$0.03	$0.16	$0.16	$0.18
2011	$0.10	$0.17	$0.17	$0.76	$0.55	$0.08	$0.03	$0.16	$0.16	$0.17
2012	$0.11	$0.18	$0.18	$0.83	$0.59	$0.09	$0.03	$0.17	$0.17	$0.18
2013	$0.12	$0.19	$0.19	$0.88	$0.63	$0.10	$0.03	$0.17	$0.17	$0.19
2014	$0.13	$0.21	$0.22	$1.03	$0.69	$0.11	$0.04	$0.19	$0.19	$0.19
2015	$0.23	$0.35	$0.35	$1.64	$1.20	$0.18	$0.06	$0.31	$0.31	$0.33
2016	$0.21	$0.33	$0.34	$1.59	$1.09	$0.17	$0.06	$0.30	$0.30	$0.31
2017	$0.22	$0.34	$0.35	$1.71	$1.14	$0.17	$0.07	$0.30	$0.30	$0.29
2018	$0.27	$0.43	$0.43	$2.00	$1.42	$0.22	$0.08	$0.38	$0.38	$0.40
2019	$0.28	$0.45	$0.45	$2.12	$1.49	$0.23	$0.08	$0.40	$0.40	$0.42
2020	$0.35	$0.55	$0.55	$2.62	$1.88	$0.29	$0.10	$0.48	$0.48	$0.49
2021	$0.41	$0.63	$0.63	$3.01	$2.18	$0.33	$0.12	$0.56	$0.56	$0.56
2022	$0.46	$0.70	$0.70	$3.30	$2.45	$0.37	$0.13	$0.62	$0.62	$0.62
2023	$0.42	$0.69	$0.70	$3.07	$2.25	$0.34	$0.12	$0.63	$0.63	$0.69
2024	$0.54	$0.84	$0.85	$3.79	$2.89	$0.44	$0.15	$0.77	$0.77	$0.83
2025	$0.60	$0.96	$0.97	$4.13	$3.18	$0.48	$0.16	$0.89	$0.89	$1.01
2026	$0.65	$1.05	$1.06	$4.48	$3.48	$0.53	$0.18	$0.98	$0.98	$1.11
2027	$0.71	$1.14	$1.15	$4.84	$3.80	$0.58	$0.19	$1.06	$1.06	$1.21
2028	$0.77	$1.24	$1.24	$5.22	$4.14	$0.63	$0.21	$1.15	$1.15	$1.32
2029	$0.84	$1.34	$1.34	$5.62	$4.48	$0.68	$0.22	$1.25	$1.25	$1.43
2030	$0.91	$1.45	$1.45	$6.03	$4.84	$0.73	$0.24	$1.35	$1.35	$1.56
2031	$0.98	$1.56	$1.57	$6.48	$5.23	$0.79	$0.26	$1.46	$1.46	$1.69
2032	$1.06	$1.69	$1.69	$6.96	$5.66	$0.86	$0.28	$1.58	$1.58	$1.84
2033	$1.14	$1.82	$1.83	$7.47	$6.11	$0.93	$0.30	$1.71	$1.71	$2.00
2034	$1.23	$1.97	$1.97	$8.03	$6.60	$1.00	$0.32	$1.85	$1.85	$2.17
2035	$1.33	$2.13	$2.13	$8.62	$7.14	$1.08	$0.35	$2.01	$2.01	$2.35

Table C.6-2
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Candidate Units – High Fuel Forecast
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.01	$0.01	$0.01	$0.08	$0.08	$0.11	$0.07
2010	$0.01	$0.01	$0.01	$0.16	$0.17	$0.20	$0.10
2011	$0.01	$0.01	$0.01	$0.16	$0.17	$0.20	$0.11
2012	$0.01	$0.01	$0.01	$0.17	$0.18	$0.22	$0.12
2013	$0.01	$0.01	$0.01	$0.18	$0.19	$0.23	$0.12
2014	$0.02	$0.02	$0.02	$0.20	$0.21	$0.25	$0.14
2015	$0.03	$0.03	$0.03	$0.33	$0.35	$0.42	$0.24
2016	$0.02	$0.02	$0.03	$0.31	$0.33	$0.39	$0.22
2017	$0.03	$0.03	$0.03	$0.32	$0.34	$0.40	$0.23
2018	$0.03	$0.03	$0.03	$0.40	$0.43	$0.51	$0.28
2019	$0.03	$0.03	$0.03	$0.42	$0.45	$0.53	$0.29
2020	$0.04	$0.04	$0.04	$0.52	$0.55	$0.65	$0.37
2021	$0.05	$0.05	$0.05	$0.59	$0.63	$0.75	$0.43
2022	$0.06	$0.06	$0.06	$0.66	$0.70	$0.84	$0.48
2023	$0.05	$0.05	$0.05	$0.65	$0.69	$0.82	$0.45
2024	$0.07	$0.07	$0.07	$0.80	$0.85	$1.01	$0.57
2025	$0.07	$0.07	$0.07	$0.92	$0.97	$1.15	$0.63
2026	$0.08	$0.08	$0.08	$1.00	$1.05	$1.26	$0.69
2027	$0.09	$0.09	$0.09	$1.09	$1.15	$1.37	$0.75
2028	$0.09	$0.09	$0.09	$1.18	$1.24	$1.49	$0.82
2029	$0.10	$0.10	$0.10	$1.28	$1.35	$1.61	$0.89
2030	$0.11	$0.11	$0.11	$1.39	$1.45	$1.74	$0.96
2031	$0.12	$0.12	$0.12	$1.50	$1.57	$1.88	$1.03
2032	$0.13	$0.13	$0.13	$1.62	$1.70	$2.03	$1.12
2033	$0.14	$0.14	$0.14	$1.75	$1.83	$2.19	$1.21
2034	$0.15	$0.15	$0.15	$1.89	$1.98	$2.37	$1.30
2035	$0.16	$0.16	$0.16	$2.05	$2.14	$2.56	$1.41

Table C.6-3
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Existing Units – Low Fuel Forecast
(Nominal $/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.07	$0.08	$0.07	$0.33	$0.36	$0.05	$0.01	$0.07	$0.07	$0.07
2010	$0.09	$0.15	$0.15	$0.65	$0.48	$0.07	$0.03	$0.14	$0.14	$0.16
2011	$0.09	$0.16	$0.16	$0.67	$0.50	$0.08	$0.03	$0.15	$0.15	$0.17
2012	$0.10	$0.17	$0.17	$0.74	$0.54	$0.08	$0.03	$0.16	$0.16	$0.17
2013	$0.10	$0.18	$0.18	$0.76	$0.56	$0.09	$0.03	$0.16	$0.16	$0.19
2014	$0.11	$0.18	$0.18	$0.85	$0.59	$0.09	$0.03	$0.16	$0.16	$0.17
2015	$0.17	$0.28	$0.28	$1.28	$0.90	$0.14	$0.05	$0.25	$0.25	$0.27
2016	$0.11	$0.21	$0.22	$1.06	$0.60	$0.09	$0.04	$0.19	$0.19	$0.19
2017	$0.13	$0.24	$0.24	$1.21	$0.68	$0.11	$0.05	$0.21	$0.21	$0.20
2018	$0.17	$0.30	$0.30	$1.37	$0.89	$0.14	$0.05	$0.27	$0.27	$0.29
2019	$0.19	$0.32	$0.33	$1.52	$0.99	$0.15	$0.06	$0.29	$0.29	$0.31
2020	$0.19	$0.33	$0.33	$1.54	$1.03	$0.16	$0.06	$0.29	$0.29	$0.31
2021	$0.21	$0.36	$0.36	$1.66	$1.10	$0.17	$0.06	$0.32	$0.32	$0.34
2022	$0.22	$0.37	$0.37	$1.70	$1.16	$0.18	$0.07	$0.33	$0.33	$0.36
2023	$0.24	$0.43	$0.43	$1.88	$1.29	$0.20	$0.07	$0.40	$0.40	$0.45
2024	$0.26	$0.47	$0.47	$1.99	$1.36	$0.21	$0.08	$0.44	$0.44	$0.51
2025	$0.28	$0.55	$0.55	$2.20	$1.51	$0.23	$0.08	$0.53	$0.53	$0.64
2026	$0.29	$0.57	$0.57	$2.24	$1.54	$0.24	$0.09	$0.55	$0.55	$0.68
2027	$0.31	$0.60	$0.61	$2.37	$1.64	$0.25	$0.09	$0.59	$0.59	$0.73
2028	$0.33	$0.64	$0.65	$2.51	$1.75	$0.27	$0.10	$0.62	$0.62	$0.78
2029	$0.35	$0.68	$0.69	$2.65	$1.85	$0.28	$0.10	$0.66	$0.66	$0.83
2030	$0.37	$0.72	$0.73	$2.80	$1.96	$0.30	$0.11	$0.71	$0.71	$0.89
2031	$0.39	$0.77	$0.77	$2.95	$2.08	$0.32	$0.11	$0.75	$0.75	$0.95
2032	$0.41	$0.82	$0.82	$3.12	$2.20	$0.34	$0.12	$0.80	$0.80	$1.01
2033	$0.44	$0.87	$0.87	$3.29	$2.34	$0.36	$0.13	$0.85	$0.85	$1.08
2034	$0.46	$0.92	$0.93	$3.47	$2.48	$0.38	$0.13	$0.91	$0.91	$1.16
2035	$0.49	$0.98	$0.98	$3.67	$2.62	$0.40	$0.14	$0.97	$0.97	$1.23

Table C.6-4
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Candidate Units – Low Fuel Forecast
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.01	$0.01	$0.01	$0.08	$0.08	$0.10	$0.07
2010	$0.01	$0.01	$0.01	$0.14	$0.15	$0.18	$0.10
2011	$0.01	$0.01	$0.01	$0.15	$0.16	$0.19	$0.10
2012	$0.01	$0.01	$0.01	$0.16	$0.17	$0.20	$0.11
2013	$0.01	$0.01	$0.01	$0.17	$0.18	$0.21	$0.11
2014	$0.01	$0.01	$0.01	$0.17	$0.18	$0.21	$0.12
2015	$0.02	$0.02	$0.02	$0.26	$0.28	$0.33	$0.18
2016	$0.01	$0.01	$0.01	$0.19	$0.21	$0.24	$0.12
2017	$0.02	$0.02	$0.02	$0.21	$0.23	$0.27	$0.14
2018	$0.02	$0.02	$0.02	$0.27	$0.29	$0.34	$0.18
2019	$0.02	$0.02	$0.02	$0.30	$0.32	$0.38	$0.20
2020	$0.02	$0.02	$0.02	$0.30	$0.32	$0.38	$0.21
2021	$0.03	$0.03	$0.03	$0.33	$0.35	$0.41	$0.22
2022	$0.03	$0.03	$0.03	$0.34	$0.37	$0.43	$0.23
2023	$0.03	$0.03	$0.03	$0.40	$0.43	$0.50	$0.26
2024	$0.03	$0.03	$0.03	$0.43	$0.46	$0.54	$0.28
2025	$0.03	$0.03	$0.03	$0.51	$0.54	$0.63	$0.31
2026	$0.04	$0.04	$0.04	$0.53	$0.56	$0.65	$0.32
2027	$0.04	$0.04	$0.04	$0.56	$0.60	$0.69	$0.34
2028	$0.04	$0.04	$0.04	$0.60	$0.64	$0.74	$0.36
2029	$0.04	$0.04	$0.04	$0.63	$0.68	$0.78	$0.38
2030	$0.04	$0.04	$0.04	$0.67	$0.72	$0.83	$0.40
2031	$0.05	$0.05	$0.05	$0.72	$0.77	$0.88	$0.43
2032	$0.05	$0.05	$0.05	$0.76	$0.81	$0.94	$0.45
2033	$0.05	$0.05	$0.05	$0.81	$0.87	$1.00	$0.48
2034	$0.06	$0.06	$0.06	$0.86	$0.92	$1.06	$0.51
2035	$0.06	$0.06	$0.06	$0.91	$0.98	$1.13	$0.54

brownfield CFB in 2012, a second brownfield CFB in 2014, a brownfield 1x1 7FA combined cycle unit in 2019, a second brownfield LMS100 CT in 2021, a brownfield IGCC unit in 2022, a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $12,650.7 million and $12,651.3 million, respectively. A comparison of these CPWCs shows that the expansion plan with participation in TEC is the least-cost plan by $0.6 million over the evaluation period.

C.6.1.3 High Load and Energy Growth

Load and energy growth sensitivities are important analyses that help to demonstrate the robustness of future capacity additions, since load growth is a fundamental variable in determining an optimal capacity expansion plan. The high load and energy growth sensitivity demonstrates the effects of planning to meet capacity and energy requirements in a case where both load and energy grow at a rate that is higher than the expected rate used in the base case economic evaluation presented in Section C.5.0. This scenario requires the addition of more generation to meet reserve margin requirements and, therefore, results in increased CPWCs compared to the base case capacity expansion plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section C.3.0. Tables C.6-5 and C.6-6 present JEA's projected reliability levels under the high load and energy growth scenario for the winter and summer seasons, respectively.

Although the need for capacity additions is shown as early as 2006 in Tables C.6-5 and C.6-6, this need was not considered in the development of optimal capacity expansion plans, since construction and development schedules would preclude the addition of any of the supply-side alternatives presented in Section A.6.0 to meet this need. Rather than planning to meet capacity needs in 2006, the need for capacity in both cases (with and without TEC) was not considered until 2007.

In the base case economic evaluation, the capacity expansion plan with JEA's participation in TEC included a seasonal purchase during the winter of 2011/2012. This purchase was included and modeled to be consistent with JEA's 2006 TYSP in the base case. Since JEA would need to add additional capacity in the high load and energy growth scenario prior to 2011, the seasonal purchase was not included in the evaluation. All other planned near-term capacity additions and retirements were made consistent with JEA's 2006 TYSP.

Under the high load and energy growth sensitivity analysis, the optimal capacity expansion plan with TEC in 2012 consists of two brownfield 7FA CTs and two greenfield 7FA CTs in 2007, two brownfield LMS100 CTs in 2011, a brownfield CFB in 2014, a second brownfield CFB in 2015, a brownfield 1x1 7FA combined cycle unit in 2019, a brownfield IGCC unit in 2021, two greenfield LMS100 CTs in 2023, and two additional greenfield LMS100 CTs in 2024. The optimal capacity expansion plan without participation in TEC consists of two brownfield 7FA CTs and two greenfield 7FA CTs in 2007, a brownfield 1x1 7FA combined cycle unit in 2011, a brownfield CFB in 2013, a second brownfield CFB in 2014, a brownfield IGCC unit in 2018, a brownfield LMS100 CT in 2020, a greenfield CFB in 2021, a second brownfield LMS100 CT in 2022, two greenfield LMS100 CTs in 2023, and two additional greenfield LMS100 CTs in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $17,591.0 and $17,721.5 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $130.5 million over the evaluation period.

C.6.1.4 Low Load and Energy Growth

The low load and energy growth sensitivity demonstrates the effects of planning to meet capacity and energy requirements in a case where both load and energy grow at a rate that is lower than the expected rate used in the base case economic evaluation. This scenario requires the addition of less generation to meet reserve margin requirements and, therefore, results in decreased CPWCs over the planning period compared to the base case capacity expansion plan. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section C.3.0. Tables C.6-7 and C.6-8 present JEA's projected reliability levels under the low load and energy growth scenario for the winter and summer seasons, respectively.

The seasonal purchase described in Section C.5.0 was not considered in this sensitivity, since no capacity is needed during the winter of 2011/2012. All other capacity additions were included in a manner consistent with JEA's 2006 TYSP.

Under the low load and energy growth sensitivity analysis, the optimal capacity expansion plan with TEC in 2012 consists of a brownfield CFB in 2021 and a second brownfield CFB in 2024. The optimal capacity expansion plan without participation in TEC consists of a brownfield CFB in 2014, a second brownfield CFB in 2021, and a brownfield IGCC unit in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $13,371.9 and $13,427.3 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $55.4 million over the evaluation period.

Table C.6-5
Projected Reliability Levels High Load and Energy Growth - Winter

Year	Net Generating Capacity (MW)[3]	Non-Partial Requirements Purchases (MW)[4,5]	Non-Partial Requirements Sales (MW)[6]	Net Firm Planned Capacity Retirements (MW)[7,8]	Net Firm Capacity Additions/ (Reductions) (MW)[9,10]	Net System Capacity (MW)	System Peak Demand[1]		Reserve Margin[2]		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)
2005/06	3,535	229	383	0	18	3,399	3,553	3,349	-4.3	1.5	(687)	(452)
2006/07	3,557	229	383	0	36	3,439	3,669	3,462	-6.3	-0.7	(781)	(543)
2007/08	3,557	229	383	0	36	3,439	3,688	3,481	-6.8	-1.2	(803)	(564)
2008/09	3,748	229	383	63	36	3,567	3,808	3,596	-6.3	-0.8	(813)	(569)
2009/10	3,939	229	383	63	31	3,752	3,931	3,713	-4.5	1.1	(768)	(518)
2010/11	4,130	22	383	63	31	3,736	4,057	3,833	-7.9	-2.5	(929)	(672)
2011/12	4,130	22	383	63	31	3,736	4,184	3,954	-10.7	-5.5	(1,075)	(811)
2012/13	4,130	22	383	63	31	3,736	4,134	4,078	-9.6	-8.4	(1,018)	(953)
2013/14	4,130	22	383	63	27	3,732	4,446	4,204	-16.1	-11.2	(1,381)	(1,102)
2014/15	4,130	22	383	63	27	3,732	4,580	4,332	-18.5	-13.8	(1,535)	(1,249)
2015/16	4,130	22	383	63	27	3,732	4,717	4,462	-20.9	-16.4	(1,692)	(1,399)
2016/17	4,130	22	0	63	27	4,115	4,856	4,595	-15.3	-10.4	(1,469)	(1,169)
2017/18	4,130	22	0	64	27	4,114	4,997	4,729	-17.7	-13.0	(1,632)	(1,324)
2018/19	4,130	22	0	64	27	4,114	5,141	4,866	-20.0	-15.4	(1,798)	(1,482)
2019/20	4,130	22	0	64	27	4,114	5,287	5,006	-22.2	-17.8	(1,966)	(1,643)
2020/21	4,130	22	0	64	27	4,114	5,435	5,147	-24.3	-20.1	(2,136)	(1,805)
2021/22	4,130	22	0	64	27	4,114	5,585	5,289	-26.3	-22.2	(2,308)	(1,968)
2022/23	4,130	22	0	64	27	4,114	5,738	5,435	-28.3	-24.3	(2,484)	(2,136)
2023/24	4,130	22	0	64	27	4,114	5,893	5,583	-30.2	-26.3	(2,663)	(2,306)
2024/25	4,130	22	0	64	27	4,114	6,052	5,735	-32.0	-28.3	(2,846)	(2,481)

(1)Load reflects the end of FPU's load on December 31, 2007.
(2)Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand - Partial Requirements Purchases).
(3)Includes peak firing capacity on Kennedy CT 7, Brandy Branch CTs 1 through 3, and Brandy Branch ST 4 upgrade in the summer of 2006. Also includes three 191 MW (winter rating) CTs in 2009, 2010, and 2011.
(4)Assumes 207 MW purchase from Southern will expire on May 31, 2010.
(5)Assumes no purchases from TEA.
(6)Assumes FPL contract to purchase 30 percent of SJRPP will reach contracted energy limitation on October 1, 2016; based on a conservative estimate made by JEA for planning purposes.
(7)Assumes the placement of Kennedy CT Unit 3 in reserve shutdown on October 1, 2008. Total capacity loss is 63 MW.
(8)Assumes that Girvin Landfill will be retired on October 1, 2017.
(9)Assumes turbine upgrades at Northside ST Units 1, 2, and 3 on June 1, 2006; December 1, 2006; and December 15, 2005, respectively. Total capacity increase is 36 MW.
(10)Assumes capacity reduction due to auxiliary power required for emissions control in January 2010. Assumes that auxiliary load increase reduces unit capacity. 80 percent of SJRPP 1 and 2, and 23.64 percent of Scherer 4 auxiliary load increases are assigned to JEA. Total assumed loss is 7.2 MW.

Table C.6-6
Projected Reliability Levels High Load and Energy Growth - Summer

							System Peak Demand[1]		Reserve Margin[2]		Excess/(Deficit) to Maintain 15% Reserve Margin	
Year	Net Generating Capacity (MW)[3]	Non-Partial Requirements Purchases (MW)[4,5]	Non-Partial Requirements Sales (MW)[6]	Net Firm Planned Capacity Retirements (MW)[7,8]	Net Firm Capacity Additions/ (Reductions) (MW)[9,10]	Net System Capacity (MW)	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)
2006	3,390	207	376	0	27	3,248	2,896	2,716	12.2	19.6	(82)	125
2007	3,390	229	376	0	36	3,279	2,961	2,778	10.7	18.0	(126)	84
2008	3,390	229	376	0	36	3,279	2,943	2,760	11.4	18.8	(105)	105
2009	3,538	229	376	51	36	3,376	3,008	2,821	12.2	19.7	(83)	132
2010	3,686	22	376	51	31	3,312	3,074	2,883	7.7	14.9	(223)	(4)
2011	3,834	22	376	51	31	3,460	3,139	2,943	10.2	17.6	(150)	75
2012	3,834	22	376	51	31	3,460	3,205	3,005	7.9	15.1	(226)	4
2013	3,834	22	376	51	31	3,460	3,270	3,065	5.8	12.9	(301)	(65)
2014	3,834	22	376	51	27	3,456	3,336	3,127	3.6	10.5	(381)	(140)
2015	3,834	22	376	51	27	3,456	3,401	3,187	1.6	8.4	(455)	(209)
2016	3,834	22	376	51	27	3,456	3,467	3,248	-0.3	6.4	(531)	(280)
2017	3,834	22	0	51	27	3,832	3,532	3,308	8.5	15.8	(230)	28
2018	3,834	0	0	52	27	3,809	3,598	3,369	5.9	13.1	(329)	(66)
2019	3,834	0	0	52	27	3,809	3,664	3,430	3.9	11.0	(405)	(136)
2020	3,834	0	0	52	27	3,809	3,729	3,490	2.1	9.1	(480)	(205)
2021	3,834	0	0	52	27	3,809	3,795	3,551	0.4	7.3	(556)	(275)
2022	3,834	0	0	52	27	3,809	3,861	3,612	-1.4	5.4	(631)	(345)
2023	3,834	0	0	52	27	3,809	3,927	3,673	-3.0	3.7	(707)	(415)
2024	3,834	0	0	52	27	3,809	3,992	3,732	-4.6	2.1	(782)	(483)
2025	3,834	0	0	52	27	3,809	4,058	3,792	-6.1	0.4	(858)	(552)

(1)Load reflects the end of FPU's load on December 31, 2007.
(2)Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand - Partial Requirements Purchases).
(3)Includes peak firing capacity on Kennedy CT 7, Brandy Branch CTs 1 through 3, and Brandy Branch ST 4 upgrade in the summer of 2006. Also includes three 148 MW (summer rating) CTs in 2009, 2010, and 2011.
(4)Assumes 207 MW purchase from Southern will expire on May 31, 2010.
(5)Assumes no purchases from TEA.
(6)Assumes FPL contract to purchase 30 percent of SJRPP will reach contracted energy limitation on October 1, 2016; based on a conservative estimate made by JEA for planning purposes.
(7)Assumes the placement of Kennedy CT Unit 3 in reserve shutdown on October 1, 2008. Total capacity loss is 51 MW.
(8)Assumes that Girvin Landfill will be retired on October 1, 2017.
(9)Assumes turbine upgrades at Northside ST Units 1, 2, and 3 on June 1, 2006; December 1, 2006; and December 15, 2005, respectively. Total capacity increase is 36 MW.
(10)Assumes capacity reduction due to auxiliary power required for emissions control in January 2010. Assumes that auxiliary load increase reduces unit capacity. 80 percent of SJRPP 1 and 2, and 23.64 percent of Scherer 4 auxiliary load increases are assigned to JEA. Total assumed loss is 7.2 MW.

Table C.6-7
Projected Reliability Levels Low Load and Energy Growth - Winter

Year	Net Generating Capacity (MW)[3]	Non-Partial Requirements Purchases (MW)[4,5]	Non-Partial Requirements Sales (MW)[6]	Net Firm Planned Capacity Retirements (MW)[7,8]	Net Firm Capacity Additions/ (Reductions) (MW)[9,10]	Net System Capacity (MW)	System Peak Demand[1]		Reserve Margin[2]		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)
2005/06	3,535	229	383	0	18	3,399	2,558	2,385	32.9	42.5	458	656
2006/07	3,557	229	383	0	36	3,439	2,636	2,461	30.5	39.7	407	609
2007/08	3,557	229	383	0	36	3,439	2,631	2,456	30.7	40.0	413	614
2008/09	3,748	229	383	63	36	3,567	2,712	2,532	31.5	40.9	448	655
2009/10	3,939	229	383	63	31	3,752	2,795	2,610	34.3	43.8	538	751
2010/11	4,130	22	383	63	31	3,736	2,897	2,689	29.0	39.0	405	644
2011/12	4,130	22	383	63	31	3,736	2,965	2,770	26.0	34.9	327	551
2012/13	4,130	22	383	63	31	3,736	3,053	2,853	22.4	31.0	225	455
2013/14	4,130	22	383	63	27	3,732	3,141	2,936	18.8	27.1	120	356
2014/15	4,130	22	383	63	27	3,732	3,231	3,021	15.5	23.5	17	258
2015/16	4,130	22	383	63	27	3,732	3,323	3,107	12.3	20.1	(89)	159
2016/17	4,130	22	0	63	27	4,115	3,416	3,195	20.5	28.8	187	441
2017/18	4,130	22	0	64	27	4,114	3,511	3,284	17.2	25.3	77	338
2018/19	4,130	22	0	64	27	4,114	3,607	3,374	14.1	21.9	(34)	234
2019/20	4,130	22	0	64	27	4,114	3,704	3,465	11.1	18.7	(145)	130
2020/21	4,130	22	0	64	27	4,114	3,803	3,558	8.2	15.6	(259)	23
2021/22	4,130	22	0	64	27	4,114	3,904	3,653	5.4	12.6	(375)	(87)
2022/23	4,130	22	0	64	27	4,114	4,006	3,749	2.7	9.7	(493)	(197)
2023/24	4,130	22	0	64	27	4,114	4,109	3,846	0.1	7.0	(611)	(309)
2024/25	4,130	22	0	64	27	4,114	4,215	3,946	-2.4	4.3	(732)	(423)

(1)Load reflects the end of FPU's load on December 31, 2007.
(2)Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand - Partial Requirements Purchases).
(3)Includes peak firing capacity on Kennedy CT 7, Brandy Branch CTs 1 through 3, and Brandy Branch ST 4 upgrade in the summer of 2006. Also includes three 191 MW (winter rating) CTs in 2009, 2010, and 2011.
(4)Assumes 207 MW purchase from Southern will expire on May 31, 2010.
(5)Assumes no purchases from TEA.
(6)Assumes FPL contract to purchase 30 percent of SJRPP will reach contracted energy limitation on October 1, 2016; based on a conservative estimate made by JEA for planning purposes.
(7)Assumes the placement of Kennedy CT Unit 3 in reserve shutdown on October 1, 2008. Total capacity loss is 63 MW.
(8)Assumes that Girvin Landfill will be retired on October 1, 2017.
(9)Assumes turbine upgrades at Northside ST Units 1, 2, and 3 on June 1, 2006; December 1, 2006; and December 15, 2005, respectively. Total capacity increase is 36 MW.
(10)Assumes capacity reduction due to auxiliary power required for emissions control in January 2010. Assumes that auxiliary load increase reduces unit capacity. 80 percent of SJRPP 1 and 2, and 23.64 percent of Scherer 4 auxiliary load increases are assigned to JEA. Total assumed loss is 7.2 MW.

Table C.6-8
Projected Reliability Levels Low Load and Energy Growth - Summer

Year	Net Generating Capacity (MW)(3)	Non-Partial Requirements Purchases (MW)(4,5)	Non-Partial Requirements Sales (MW)(6)	Net Firm Planned Capacity Retirements (MW)(7,8)	Net Firm Capacity Additions/ (Reductions) (MW)(9,10)	Net System Capacity (MW)	System Peak Demand(1)		Reserve Margin(2)		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)
2006	3,390	207	376	0	27	3,248	2,670	2,506	21.6	29.6	178	366
2007	3,390	229	376	0	36	3,279	2,739	2,572	19.7	27.5	129	321
2008	3,390	229	376	0	36	3,279	2,724	2,557	20.4	28.2	146	338
2009	3,538	229	376	51	36	3,376	2,794	2,623	20.8	28.7	163	360
2010	3,686	22	376	51	31	3,312	2,865	2,690	15.6	23.1	17	218
2011	3,834	22	376	51	31	3,460	2,936	2,757	17.8	25.5	83	289
2012	3,834	22	376	51	31	3,460	3,008	2,825	15.0	22.5	1	211
2013	3,834	22	376	51	31	3,460	3,081	2,894	12.3	19.5	(83)	132
2014	3,834	22	376	51	27	3,456	3,154	2,962	9.6	16.7	(171)	49
2015	3,834	22	376	51	27	3,456	3,228	3,032	7.1	14.0	(257)	(31)
2016	3,834	22	376	51	27	3,456	3,303	3,102	4.6	11.4	(343)	(112)
2017	3,834	22	0	51	27	3,832	3,378	3,173	13.4	20.8	(53)	183
2018	3,834	0	0	52	27	3,809	3,454	3,244	10.3	17.4	(163)	78
2019	3,834	0	0	52	27	3,809	3,531	3,317	7.9	14.8	(252)	(6)
2020	3,834	0	0	52	27	3,809	3,608	3,389	5.6	12.4	(341)	(89)
2021	3,834	0	0	52	27	3,809	3,686	3,462	3.3	10.0	(430)	(173)
2022	3,834	0	0	52	27	3,809	3,764	3,535	1.2	7.7	(520)	(257)
2023	3,834	0	0	52	27	3,809	3,843	3,609	-0.9	5.5	(611)	(342)
2024	3,834	0	0	52	27	3,809	3,923	3,684	-2.9	3.4	(703)	(428)
2025	3,834	0	0	52	27	3,809	4,005	3,761	-4.9	1.3	(797)	(516)

(1)Load reflects the end of FPU's load on December 31, 2007.
(2)Reserve margin calculated as (Net System Capacity - System Peak Demand) / (System Peak Demand - Partial Requirements Purchases).
(3)Includes peak firing capacity on Kennedy CT 7, Brandy Branch CTs 1 through 3, and Brandy Branch ST 4 upgrade in the summer of 2006. Also includes three 148 MW (summer rating) CTs in 2009, 2010, and 2011.
(4)Assumes 207 MW purchase from Southern will expire on May 31, 2010.
(5)Assumes no purchases from TEA.
(6)Assumes FPL contract to purchase 30 percent of SJRPP will reach contracted energy limitation on October 1, 2016; based on a conservative estimate made by JEA for planning purposes.
(7)Assumes the placement of Kennedy CT Unit 3 in reserve shutdown on October 1, 2008. Total capacity loss is 51 MW.
(8)Assumes that Girvin Landfill will be retired on October 1, 2017.
(9)Assumes turbine upgrades at Northside ST Units 1, 2, and 3 on June 1, 2006; December 1, 2006; and December 15, 2005, respectively. Total capacity increase is 36 MW.
(10)Assumes capacity reduction due to auxiliary power required for emissions control in January 2010. Assumes that auxiliary load increase reduces unit capacity. 80 percent of SJRPP 1 and 2, and 23.64 percent of Scherer 4 auxiliary load increases are assigned to JEA. Total assumed loss is 7.2 MW.

C.6.1.5 High Capital Costs

In the high capital cost sensitivity, the capital costs for the candidate units and the proposed TEC are increased by 20 percent. Considering an increase in capital costs helps capture uncertainty related to the future costs of material, labor, and equipment. Increasing capital costs can change the emphasis on the timing of capital intensive units and may result in the selection of units with relatively lower capital costs but higher operating and production costs earlier than units with relatively higher capital costs but lower operating and production costs.

Under the high capital cost scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield 1x1 7FA combined cycle unit in 2023. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 7FA combined cycle unit in 2020, a brownfield IGCC unit in 2022, a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are \$14,465.4 and \$14,500.7 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by \$35.3 million over the evaluation period.

C.6.1.6 Low Capital Costs

In the low capital cost sensitivity, the capital costs for the candidate units and the proposed TEC are decreased by 20 percent. Considering a decrease in capital costs helps capture uncertainty related to the future costs of material, labor, and equipment. Decreasing capital costs can change the emphasis on the timing of capital intensive units and may result in the selection of units with relatively higher capital costs but lower operating and production costs earlier than units with relatively lower capital costs but higher operating and production costs.

Under the low capital cost scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield IGCC unit in 2023. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in

2014, a brownfield IGCC unit in 2019, a second brownfield LMS100 CT in 2021, two greenfield LMS100 CTs in 2022, and a brownfield 1x1 7FA combined cycle unit in 2023.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $13,788.2 and $13,877.7 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $89.5 million over the evaluation period.

C.6.1.7 High Emissions Allowance Prices

The base economic analysis presented in Section C.5.0 utilizes the base fuel and corresponding emissions allowance price forecasts provided by Hill & Associates. Historically, prices for emissions allowances have been volatile, and this sensitivity demonstrates the effects of higher allowance prices than the forecasts provided by Hill & Associates.

In the high emissions allowance price sensitivity case, the base case allowance price forecasts provided by Hill & Associates were increased by 25 percent on an annual basis, while the fuel price forecasts were left unchanged from those provided by Hill & Associates in the base case. Increasing the allowance prices results in a higher fuel cost adder for the fuels being burned in existing and candidate generating units. The increase in allowance prices results in a greater economic incentive to operate units with lower emissions rates for electric generation, and also results in higher CPWCs relative to the base case economic analysis. Table C.6-9 presents the emissions allowance prices used in the high emissions allowance price sensitivity analysis. Tables C.6-10 and C.6-11 present the emissions cost adders included for JEA's existing and candidate units, respectively, for the high emissions allowance price sensitivity.

In the high emissions allowance price scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield 1x1 7FA combined cycle unit in 2023. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 7FA combined cycle unit in 2020, a brownfield IGCC unit in 2022, a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $14,427.7 and $14,459.1 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $31.4 million over the evaluation period.

Table C.6-9
High and Low Allowance Prices
All Prices in Nominal Dollars

Calendar Year	High Sensitivity			Low Sensitivity		
	SO_2 (\$/ton)	NO_x (\$/ton)	Hg (\$/lb)	SO_2 (\$/ton)	NO_x (\$/ton)	Hg (\$/lb)
2009	--	\$2,864	--	--	\$1,718	--
2010	\$480	\$3,994	\$21,103	\$288	\$2,397	\$12,662
2011	\$490	\$4,189	\$21,491	\$294	\$2,513	\$12,894
2012	\$566	\$4,358	\$17,393	\$340	\$2,615	\$10,436
2013	\$581	\$4,463	\$22,743	\$348	\$2,678	\$13,646
2014	\$754	\$4,834	\$13,549	\$452	\$2,900	\$8,129
2015	\$1,075	\$7,721	\$26,165	\$645	\$4,632	\$15,699
2016	\$1,247	\$8,346	\$17,456	\$748	\$5,008	\$10,473
2017	\$1,398	\$7,163	\$16,616	\$839	\$4,298	\$9,970
2018	\$1,465	\$7,413	\$33,133	\$879	\$4,448	\$19,880
2019	\$1,493	\$9,725	\$32,251	\$896	\$5,835	\$19,351
2020	\$1,629	\$11,726	\$33,057	\$978	\$7,036	\$19,834
2021	\$1,778	\$11,146	\$36,152	\$1,067	\$6,688	\$21,691
2022	\$1,913	\$10,650	\$38,114	\$1,148	\$6,390	\$22,869
2023	\$2,076	\$13,676	\$69,280	\$1,246	\$8,206	\$41,568
2024	\$2,379	\$20,578	\$71,286	\$1,427	\$12,347	\$42,771
2025	\$2,437	\$22,318	\$113,955	\$1,462	\$13,391	\$68,373
2026	\$2,479	\$24,131	\$125,244	\$1,487	\$14,479	\$75,146
2027	\$2,621	\$26,022	\$137,025	\$1,573	\$15,613	\$82,215
2028	\$2,769	\$27,991	\$149,318	\$1,661	\$16,795	\$89,591
2029	\$2,923	\$30,043	\$162,139	\$1,754	\$18,026	\$97,284
2030	\$3,082	\$32,180	\$175,509	\$1,849	\$19,308	\$105,305
2031	\$3,250	\$34,469	\$189,980	\$1,950	\$20,681	\$113,988
2032	\$3,428	\$36,921	\$205,645	\$2,057	\$22,153	\$123,387
2033	\$3,615	\$39,547	\$222,602	\$2,169	\$23,728	\$133,561
2034	\$3,812	\$42,360	\$240,956	\$2,287	\$25,416	\$144,574
2035	\$4,021	\$45,373	\$260,824	\$2,412	\$27,224	\$156,495

Table C.6-10
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Existing Units – High Allowance Prices
(Nominal $/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.09	$0.10	$0.10	$0.43	$0.46	$0.07	$0.02	$0.09	$0.09	$0.09
2010	$0.12	$0.20	$0.20	$0.87	$0.64	$0.10	$0.03	$0.19	$0.19	$0.21
2011	$0.13	$0.21	$0.21	$0.90	$0.67	$0.10	$0.04	$0.20	$0.20	$0.22
2012	$0.13	$0.22	$0.22	$0.97	$0.70	$0.11	$0.04	$0.20	$0.20	$0.21
2013	$0.13	$0.23	$0.23	$1.00	$0.72	$0.11	$0.04	$0.21	$0.21	$0.24
2014	$0.15	$0.24	$0.24	$1.15	$0.78	$0.12	$0.04	$0.21	$0.21	$0.21
2015	$0.23	$0.38	$0.38	$1.77	$1.24	$0.19	$0.07	$0.34	$0.34	$0.36
2016	$0.25	$0.40	$0.40	$1.96	$1.34	$0.20	$0.08	$0.35	$0.35	$0.35
2017	$0.22	$0.37	$0.37	$1.86	$1.15	$0.18	$0.07	$0.32	$0.32	$0.31
2018	$0.22	$0.41	$0.41	$1.94	$1.19	$0.18	$0.07	$0.37	$0.37	$0.38
2019	$0.29	$0.49	$0.49	$2.30	$1.56	$0.24	$0.09	$0.43	$0.43	$0.45
2020	$0.35	$0.57	$0.57	$2.68	$1.88	$0.29	$0.10	$0.50	$0.50	$0.52
2021	$0.34	$0.56	$0.57	$2.68	$1.79	$0.27	$0.10	$0.50	$0.50	$0.51
2022	$0.32	$0.56	$0.56	$2.68	$1.71	$0.26	$0.10	$0.50	$0.50	$0.51
2023	$0.41	$0.72	$0.72	$3.22	$2.19	$0.34	$0.12	$0.66	$0.66	$0.73
2024	$0.62	$0.98	$0.98	$4.43	$3.30	$0.50	$0.17	$0.89	$0.89	$0.95
2025	$0.67	$1.11	$1.11	$4.72	$3.58	$0.54	$0.19	$1.03	$1.03	$1.17
2026	$0.72	$1.19	$1.19	$5.02	$3.87	$0.59	$0.20	$1.11	$1.11	$1.27
2027	$0.78	$1.28	$1.29	$5.38	$4.17	$0.63	$0.21	$1.20	$1.20	$1.38
2028	$0.84	$1.38	$1.38	$5.76	$4.49	$0.68	$0.23	$1.29	$1.29	$1.49
2029	$0.90	$1.48	$1.48	$6.16	$4.82	$0.73	$0.24	$1.39	$1.39	$1.61
2030	$0.96	$1.58	$1.59	$6.57	$5.16	$0.78	$0.26	$1.49	$1.49	$1.73
2031	$1.03	$1.70	$1.70	$7.01	$5.52	$0.84	$0.28	$1.60	$1.60	$1.86
2032	$1.11	$1.82	$1.82	$7.47	$5.92	$0.90	$0.30	$1.71	$1.71	$2.00
2033	$1.19	$1.95	$1.95	$7.97	$6.34	$0.96	$0.32	$1.83	$1.83	$2.15
2034	$1.27	$2.08	$2.09	$8.51	$6.79	$1.03	$0.34	$1.97	$1.97	$2.31
2035	$1.36	$2.23	$2.24	$9.08	$7.27	$1.10	$0.36	$2.11	$2.11	$2.48

Table C.6-11
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Candidate Units – High Allowance Prices
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.01	$0.01	$0.01	$0.10	$0.10	$0.13	$0.09
2010	$0.01	$0.01	$0.01	$0.19	$0.20	$0.24	$0.13
2011	$0.02	$0.02	$0.02	$0.20	$0.21	$0.25	$0.13
2012	$0.02	$0.02	$0.02	$0.20	$0.21	$0.25	$0.14
2013	$0.02	$0.02	$0.02	$0.21	$0.23	$0.27	$0.14
2014	$0.02	$0.02	$0.02	$0.22	$0.24	$0.28	$0.15
2015	$0.03	$0.03	$0.03	$0.36	$0.38	$0.45	$0.24
2016	$0.03	$0.03	$0.03	$0.37	$0.40	$0.47	$0.26
2017	$0.03	$0.03	$0.03	$0.34	$0.36	$0.42	$0.23
2018	$0.03	$0.03	$0.03	$0.37	$0.40	$0.47	$0.24
2019	$0.04	$0.04	$0.04	$0.45	$0.48	$0.57	$0.31
2020	$0.04	$0.04	$0.04	$0.53	$0.56	$0.67	$0.37
2021	$0.04	$0.04	$0.04	$0.52	$0.56	$0.66	$0.35
2022	$0.04	$0.04	$0.04	$0.51	$0.55	$0.64	$0.34
2023	$0.05	$0.05	$0.05	$0.67	$0.71	$0.84	$0.44
2024	$0.07	$0.07	$0.08	$0.93	$0.98	$1.17	$0.65
2025	$0.08	$0.08	$0.08	$1.05	$1.11	$1.31	$0.71
2026	$0.09	$0.09	$0.09	$1.13	$1.19	$1.42	$0.77
2027	$0.09	$0.09	$0.10	$1.22	$1.29	$1.53	$0.83
2028	$0.10	$0.10	$0.10	$1.31	$1.38	$1.64	$0.89
2029	$0.11	$0.11	$0.11	$1.41	$1.48	$1.76	$0.96
2030	$0.12	$0.12	$0.12	$1.51	$1.59	$1.89	$1.02
2031	$0.12	$0.12	$0.13	$1.62	$1.70	$2.02	$1.10
2032	$0.13	$0.13	$0.14	$1.73	$1.82	$2.17	$1.17
2033	$0.14	$0.14	$0.15	$1.86	$1.95	$2.32	$1.26
2034	$0.15	$0.15	$0.16	$1.99	$2.09	$2.49	$1.35
2035	$0.16	$0.16	$0.17	$2.13	$2.24	$2.67	$1.44

C.6.1.8 Low Emissions Allowance Prices

In the low emission allowance price sensitivity case, the base case allowance price forecasts provided by Hill & Associates were decreased by 25 percent on an annual basis, while the fuel price forecasts were left unchanged from those provided by Hill & Associates in the base case. Decreasing the allowance prices results in a lower fuel cost adder for the fuels being burned in existing and candidate generating units. The decrease in allowance prices reduces the economic incentive to operate units with lower emissions rates for electric generation, and also results in lower CPWCs relative to the base case economic analysis. Table C.6-9 presents the emissions allowance prices used in the low emissions allowance price sensitivity analysis. Tables C.6-12 and C.6-13 present the emissions cost adders included for JEA's existing and candidate units, respectively, for the low emissions allowance price sensitivity.

In the low emissions allowance price scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield IGCC unit in 2023. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 7FA combined cycle unit in 2020, a brownfield IGCC unit in 2022, a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $13,850.4 and $13,896.7 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $46.3 million over the evaluation period.

C.6.1.9 Carbon Dioxide Regulations Sensitivity

This sensitivity, which is presented for information purposes only, considers the potential economic impact associated with a regulatory environment in which emissions of CO_2 would be subject to a cap-and-trade program, similar to that contemplated under CAIR and CAMR. To date, the United States has not mandated any reductions in CO_2 emissions through nationwide environmental regulations. However, in the last few years, legislation has been proposed suggesting various approaches to regulating CO_2 emissions in the United States. Section A.4.0 presented a description of Hill & Associates' assumptions utilized in developing the fuel price forecast and corresponding emissions

Table C.6-12
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Existing Units – Low Allowance Prices
(Nominal $/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.05	$0.06	$0.06	$0.26	$0.27	$0.04	$0.01	$0.05	$0.05	$0.05
2010	$0.07	$0.10	$0.10	$0.36	$0.38	$0.06	$0.02	$0.10	$0.10	$0.12
2011	$0.08	$0.13	$0.13	$0.54	$0.40	$0.06	$0.02	$0.12	$0.12	$0.13
2012	$0.08	$0.13	$0.13	$0.58	$0.42	$0.06	$0.02	$0.12	$0.12	$0.13
2013	$0.08	$0.14	$0.14	$0.60	$0.43	$0.07	$0.02	$0.13	$0.13	$0.14
2014	$0.09	$0.14	$0.14	$0.69	$0.47	$0.07	$0.03	$0.13	$0.13	$0.13
2015	$0.14	$0.23	$0.23	$1.06	$0.74	$0.11	$0.04	$0.20	$0.20	$0.21
2016	$0.15	$0.24	$0.24	$1.17	$0.80	$0.12	$0.05	$0.21	$0.21	$0.21
2017	$0.13	$0.22	$0.22	$1.12	$0.69	$0.11	$0.04	$0.19	$0.19	$0.19
2018	$0.13	$0.24	$0.25	$1.16	$0.71	$0.11	$0.04	$0.22	$0.22	$0.23
2019	$0.18	$0.29	$0.29	$1.38	$0.94	$0.14	$0.05	$0.26	$0.26	$0.27
2020	$0.21	$0.34	$0.34	$1.61	$1.13	$0.17	$0.06	$0.30	$0.30	$0.31
2021	$0.20	$0.34	$0.34	$1.61	$1.07	$0.16	$0.06	$0.30	$0.30	$0.31
2022	$0.19	$0.33	$0.34	$1.61	$1.03	$0.16	$0.06	$0.30	$0.30	$0.31
2023	$0.25	$0.43	$0.43	$1.93	$1.32	$0.20	$0.07	$0.40	$0.40	$0.44
2024	$0.37	$0.59	$0.59	$2.66	$1.98	$0.30	$0.10	$0.53	$0.53	$0.57
2025	$0.40	$0.66	$0.67	$2.83	$2.15	$0.33	$0.11	$0.62	$0.62	$0.70
2026	$0.43	$0.71	$0.72	$3.01	$2.32	$0.35	$0.12	$0.67	$0.67	$0.76
2027	$0.47	$0.77	$0.77	$3.23	$2.50	$0.38	$0.13	$0.72	$0.72	$0.83
2028	$0.50	$0.83	$0.83	$3.46	$2.69	$0.41	$0.14	$0.78	$0.78	$0.90
2029	$0.54	$0.89	$0.89	$3.69	$2.89	$0.44	$0.15	$0.83	$0.83	$0.96
2030	$0.58	$0.95	$0.95	$3.94	$3.09	$0.47	$0.16	$0.89	$0.89	$1.04
2031	$0.62	$1.02	$1.02	$4.20	$3.31	$0.50	$0.17	$0.96	$0.96	$1.12
2032	$0.66	$1.09	$1.09	$4.48	$3.55	$0.54	$0.18	$1.03	$1.03	$1.20
2033	$0.71	$1.17	$1.17	$4.78	$3.80	$0.58	$0.19	$1.10	$1.10	$1.29
2034	$0.76	$1.25	$1.25	$5.10	$4.07	$0.62	$0.20	$1.18	$1.18	$1.39
2035	$0.82	$1.34	$1.34	$5.45	$4.36	$0.66	$0.22	$1.27	$1.27	$1.49

Table C.6-13
Combined SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Candidate Units – Low Allowance Prices
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.01	$0.01	$0.01	$0.06	$0.06	$0.08	$0.05
2010	$0.01	$0.01	$0.01	$0.10	$0.10	$0.13	$0.07
2011	$0.01	$0.01	$0.01	$0.12	$0.13	$0.15	$0.08
2012	$0.01	$0.01	$0.01	$0.12	$0.13	$0.15	$0.08
2013	$0.01	$0.01	$0.01	$0.13	$0.14	$0.16	$0.09
2014	$0.01	$0.01	$0.01	$0.13	$0.14	$0.17	$0.09
2015	$0.02	$0.02	$0.02	$0.21	$0.23	$0.27	$0.15
2016	$0.02	$0.02	$0.02	$0.22	$0.24	$0.28	$0.16
2017	$0.02	$0.02	$0.02	$0.20	$0.22	$0.25	$0.14
2018	$0.02	$0.02	$0.02	$0.22	$0.24	$0.28	$0.14
2019	$0.02	$0.02	$0.02	$0.27	$0.29	$0.34	$0.19
2020	$0.03	$0.03	$0.03	$0.32	$0.34	$0.40	$0.22
2021	$0.02	$0.02	$0.02	$0.31	$0.33	$0.39	$0.21
2022	$0.02	$0.02	$0.02	$0.31	$0.33	$0.39	$0.20
2023	$0.03	$0.03	$0.03	$0.40	$0.43	$0.50	$0.26
2024	$0.04	$0.04	$0.05	$0.56	$0.59	$0.70	$0.39
2025	$0.05	$0.05	$0.05	$0.63	$0.67	$0.79	$0.43
2026	$0.05	$0.05	$0.05	$0.68	$0.72	$0.85	$0.46
2027	$0.06	$0.06	$0.06	$0.73	$0.77	$0.92	$0.50
2028	$0.06	$0.06	$0.06	$0.79	$0.83	$0.99	$0.53
2029	$0.07	$0.07	$0.07	$0.85	$0.89	$1.06	$0.57
2030	$0.07	$0.07	$0.07	$0.91	$0.95	$1.13	$0.61
2031	$0.07	$0.07	$0.08	$0.97	$1.02	$1.21	$0.66
2032	$0.08	$0.08	$0.08	$1.04	$1.09	$1.30	$0.70
2033	$0.09	$0.09	$0.09	$1.12	$1.17	$1.39	$0.75
2034	$0.09	$0.09	$0.09	$1.19	$1.26	$1.49	$0.81
2035	$0.10	$0.10	$0.10	$1.28	$1.34	$1.60	$0.87

allowance price forecasts for a scenario in which CO_2 emissions are regulated and a cap-and-trade market evolves for CO_2 allowances. As described in Section A.4.0 and discussed further in Section A.5.0, the assumptions supporting Hill & Associates' regulated-CO_2 sensitivity case fuel and emissions allowance price forecasts are based on the utility industry complying with the proposed McCain-Lieberman *Climate Stewardship Act of 2005* (S. 342, introduced to the 109th Congress).

Similar to the methodology described throughout this Application for consideration of the SO_2, NO_x, and Hg emissions allowance price forecasts, adders for the regulated-CO_2 emissions allowance price forecasts were developed for each existing and candidate unit being considered. Tables C.6-14 and C.6-15 present the CO_2 cost adders for JEA's existing and candidate units, respectively, for the CO_2 regulation sensitivity. Tables C.6-16 and C.6-17 present the combined adders for CO_2, SO_2, NO_x, and Hg for JEA's existing and candidate units, respectively, for the CO_2 regulation sensitivity. Tables C.6-14 through C.6-17 were developed utilizing the emissions allowance prices developed by Hill & Associates for the CO_2 regulation sensitivity, which are included in Section A.5.0.

Under this scenario, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield 1x1 7FA combined cycle unit in 2023. The optimal capacity expansion plan without participation in TEC consists of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 7FA combined cycle unit in 2020, a greenfield CFB in 2022, a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $15,659.2 and $15,712.6 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $53.4 million over the evaluation period.

C.6.1.10 Summary of the Sensitivity Cases for Input Parameters

Table C.6-18 summarizes the results of the sensitivity analyses described in this section. Appendix C.1 presents the CPWC summary sheets for all of the cases presented in Table C.6-18. The optimal capacity expansion plan with participation in TEC in 2012 was the least-cost plan in each of the scenarios. Overall, these results demonstrate the robustness and flexibility of the expansion plan with TEC to overcome variations and deviations from the base case assumptions.

Table C.6-14
CO_2 Emissions Adders for JEA's Existing Units – Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2010	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012	$0.29	$0.52	$0.59	$0.36	$0.29	$0.29	$0.29	$0.52	$0.52	$0.53
2013	$0.59	$1.06	$1.20	$0.74	$0.59	$0.59	$0.59	$1.06	$1.06	$1.09
2014	$0.78	$1.39	$1.59	$0.98	$0.78	$0.78	$0.78	$1.39	$1.39	$1.44
2015	$0.74	$1.32	$1.50	$0.93	$0.74	$0.74	$0.74	$1.32	$1.32	$1.36
2016	$0.77	$1.39	$1.58	$0.98	$0.77	$0.77	$0.77	$1.39	$1.39	$1.43
2017	$0.69	$1.23	$1.40	$0.86	$0.69	$0.69	$0.69	$1.23	$1.23	$1.27
2018	$0.19	$0.34	$0.39	$0.24	$0.19	$0.19	$0.19	$0.34	$0.34	$0.36
2019	$0.28	$0.50	$0.57	$0.35	$0.28	$0.28	$0.28	$0.50	$0.50	$0.52
2020	$0.21	$0.38	$0.43	$0.27	$0.21	$0.21	$0.21	$0.38	$0.38	$0.39
2021	$0.25	$0.45	$0.52	$0.32	$0.25	$0.25	$0.25	$0.45	$0.45	$0.47
2022	$0.55	$0.98	$1.11	$0.69	$0.55	$0.55	$0.55	$0.98	$0.98	$1.01
2023	$0.71	$1.27	$1.45	$0.89	$0.71	$0.71	$0.71	$1.27	$1.27	$1.31
2024	$0.56	$1.01	$1.15	$0.71	$0.56	$0.56	$0.56	$1.01	$1.01	$1.04
2025	$0.65	$1.17	$1.33	$0.82	$0.65	$0.65	$0.65	$1.17	$1.17	$1.21
2026	$0.70	$1.25	$1.42	$0.88	$0.70	$0.70	$0.70	$1.25	$1.25	$1.29
2027	$0.77	$1.38	$1.57	$0.97	$0.77	$0.77	$0.77	$1.38	$1.38	$1.43
2028	$0.85	$1.52	$1.73	$1.07	$0.85	$0.85	$0.85	$1.52	$1.52	$1.57
2029	$0.93	$1.67	$1.90	$1.17	$0.93	$0.93	$0.93	$1.67	$1.67	$1.72
2030	$1.01	$1.82	$2.07	$1.28	$1.01	$1.01	$1.01	$1.82	$1.82	$1.88
2031	$1.10	$1.98	$2.25	$1.39	$1.10	$1.10	$1.10	$1.98	$1.98	$2.05
2032	$1.20	$2.16	$2.46	$1.52	$1.20	$1.20	$1.20	$2.16	$2.16	$2.23
2033	$1.31	$2.35	$2.68	$1.65	$1.31	$1.31	$1.31	$2.35	$2.35	$2.43
2034	$1.43	$2.57	$2.92	$1.80	$1.43	$1.43	$1.43	$2.57	$2.57	$2.65
2035	$1.56	$2.80	$3.18	$1.97	$1.56	$1.56	$1.56	$2.80	$2.80	$2.89

Table C.6-15
CO_2 Emissions Adders for JEA's Candidate Units – Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2010	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2011	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2012	$0.29	$0.29	$0.29	$0.53	$0.52	$0.52	$0.55
2013	$0.59	$0.59	$0.59	$1.09	$1.07	$1.07	$1.13
2014	$0.78	$0.78	$0.78	$1.43	$1.41	$1.41	$1.49
2015	$0.74	$0.74	$0.74	$1.35	$1.33	$1.33	$1.41
2016	$0.77	$0.77	$0.77	$1.42	$1.40	$1.40	$1.48
2017	$0.69	$0.69	$0.69	$1.26	$1.24	$1.24	$1.31
2018	$0.19	$0.19	$0.19	$0.35	$0.35	$0.35	$0.37
2019	$0.28	$0.28	$0.28	$0.52	$0.51	$0.51	$0.54
2020	$0.21	$0.21	$0.21	$0.39	$0.39	$0.39	$0.41
2021	$0.25	$0.25	$0.25	$0.47	$0.46	$0.46	$0.49
2022	$0.55	$0.55	$0.55	$1.00	$0.99	$0.99	$1.05
2023	$0.71	$0.71	$0.71	$1.30	$1.28	$1.28	$1.36
2024	$0.56	$0.56	$0.56	$1.04	$1.02	$1.02	$1.08
2025	$0.65	$0.65	$0.65	$1.20	$1.18	$1.18	$1.25
2026	$0.70	$0.70	$0.70	$1.28	$1.26	$1.26	$1.34
2027	$0.77	$0.77	$0.77	$1.42	$1.40	$1.40	$1.48
2028	$0.85	$0.85	$0.85	$1.56	$1.54	$1.54	$1.63
2029	$0.93	$0.93	$0.93	$1.71	$1.68	$1.68	$1.78
2030	$1.01	$1.01	$1.01	$1.86	$1.83	$1.83	$1.94
2031	$1.10	$1.10	$1.10	$2.03	$2.00	$2.00	$2.12
2032	$1.20	$1.20	$1.20	$2.21	$2.18	$2.18	$2.31
2033	$1.31	$1.31	$1.31	$2.41	$2.38	$2.38	$2.52
2034	$1.43	$1.43	$1.43	$2.63	$2.59	$2.59	$2.74
2035	$1.56	$1.56	$1.56	$2.87	$2.82	$2.82	$2.99

Table C.6-16
Combined CO_2, SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Existing Units – Regulated-CO_2 Sensitivity Case
(Nominal \$/MBtu)

Calendar Year	Kennedy CT 7	Northside ST 1	Northside ST 2	Northside ST 3	Northside CTs	Brandy Branch CT 1	Brandy Branch CC	SJRPP ST 1	SJRPP ST 2	Scherer ST 4
2009	$0.05	$0.06	$0.06	$0.28	$0.29	$0.04	$0.01	$0.06	$0.06	$0.06
2010	$0.07	$0.12	$0.13	$0.52	$0.38	$0.06	$0.02	$0.12	$0.12	$0.14
2011	$0.07	$0.13	$0.13	$0.55	$0.39	$0.06	$0.02	$0.12	$0.12	$0.14
2012	$0.35	$0.63	$0.70	$0.83	$0.63	$0.34	$0.31	$0.62	$0.62	$0.65
2013	$0.66	$1.19	$1.33	$1.28	$0.94	$0.64	$0.61	$1.18	$1.18	$1.23
2014	$0.84	$1.50	$1.69	$1.47	$1.09	$0.83	$0.80	$1.49	$1.49	$1.55
2015	$0.86	$1.52	$1.70	$1.82	$1.43	$0.84	$0.77	$1.51	$1.51	$1.57
2016	$0.91	$1.60	$1.79	$1.95	$1.50	$0.88	$0.81	$1.57	$1.57	$1.63
2017	$0.83	$1.46	$1.63	$1.93	$1.48	$0.81	$0.73	$1.43	$1.43	$1.48
2018	$0.32	$0.57	$0.62	$1.22	$0.88	$0.30	$0.23	$0.55	$0.55	$0.59
2019	$0.41	$0.73	$0.80	$1.35	$0.98	$0.39	$0.32	$0.72	$0.72	$0.76
2020	$0.36	$0.64	$0.69	$1.40	$1.01	$0.33	$0.26	$0.62	$0.62	$0.65
2021	$0.39	$0.70	$0.76	$1.41	$0.98	$0.36	$0.29	$0.68	$0.68	$0.72
2022	$0.68	$1.23	$1.37	$1.83	$1.27	$0.66	$0.59	$1.21	$1.21	$1.27
2023	$0.86	$1.56	$1.74	$2.17	$1.53	$0.83	$0.76	$1.54	$1.54	$1.62
2024	$0.86	$1.46	$1.60	$2.75	$2.13	$0.80	$0.64	$1.42	$1.42	$1.48
2025	$0.96	$1.69	$1.85	$2.96	$2.31	$0.91	$0.74	$1.66	$1.66	$1.78
2026	$1.03	$1.81	$1.98	$3.16	$2.50	$0.97	$0.79	$1.78	$1.78	$1.91
2027	$1.13	$1.98	$2.18	$3.41	$2.71	$1.07	$0.87	$1.95	$1.95	$2.10
2028	$1.24	$2.17	$2.38	$3.68	$2.93	$1.17	$0.95	$2.13	$2.13	$2.30
2029	$1.35	$2.36	$2.59	$3.97	$3.17	$1.27	$1.04	$2.32	$2.32	$2.50
2030	$1.46	$2.56	$2.81	$4.26	$3.41	$1.38	$1.13	$2.52	$2.52	$2.72
2031	$1.58	$2.78	$3.05	$4.57	$3.67	$1.49	$1.23	$2.74	$2.74	$2.95
2032	$1.72	$3.01	$3.31	$4.91	$3.95	$1.62	$1.34	$2.97	$2.97	$3.20
2033	$1.86	$3.27	$3.59	$5.28	$4.26	$1.76	$1.46	$3.22	$3.22	$3.48
2034	$2.02	$3.54	$3.90	$5.67	$4.59	$1.91	$1.59	$3.50	$3.50	$3.78
2035	$2.19	$3.85	$4.23	$6.09	$4.94	$2.07	$1.73	$3.80	$3.80	$4.10

Table C.6-17
Combined CO_2, SO_2, NO_x, and Hg Emissions Cost Adders for JEA's Candidate Units – Regulated-CO_2 Sensitivity Case
(Nominal $/MBtu)

Calendar Year	LMS100 CT	7FA CT	1x1 7FA CC	TEC	CFB (80 percent petcoke 20 percent coal)	CFB (100 percent coal)	IGCC (100 percent petcoke)
2009	$0.01	$0.01	$0.01	$0.06	$0.06	$0.08	$0.06
2010	$0.01	$0.01	$0.01	$0.12	$0.12	$0.15	$0.08
2011	$0.01	$0.01	$0.01	$0.12	$0.13	$0.15	$0.08
2012	$0.30	$0.30	$0.30	$0.63	$0.63	$0.65	$0.62
2013	$0.60	$0.60	$0.60	$1.20	$1.19	$1.21	$1.20
2014	$0.79	$0.79	$0.79	$1.53	$1.51	$1.53	$1.55
2015	$0.75	$0.75	$0.75	$1.55	$1.54	$1.58	$1.55
2016	$0.79	$0.79	$0.79	$1.62	$1.61	$1.65	$1.63
2017	$0.70	$0.70	$0.70	$1.48	$1.47	$1.51	$1.47
2018	$0.21	$0.21	$0.21	$0.56	$0.57	$0.61	$0.51
2019	$0.30	$0.30	$0.30	$0.73	$0.74	$0.78	$0.68
2020	$0.23	$0.23	$0.23	$0.63	$0.64	$0.68	$0.57
2021	$0.27	$0.27	$0.27	$0.69	$0.70	$0.74	$0.63
2022	$0.56	$0.56	$0.56	$1.24	$1.24	$1.28	$1.19
2023	$0.73	$0.73	$0.73	$1.57	$1.57	$1.62	$1.53
2024	$0.60	$0.60	$0.60	$1.47	$1.47	$1.56	$1.39
2025	$0.69	$0.69	$0.69	$1.69	$1.70	$1.80	$1.58
2026	$0.74	$0.74	$0.74	$1.81	$1.82	$1.93	$1.70
2027	$0.82	$0.82	$0.82	$1.99	$2.00	$2.11	$1.86
2028	$0.90	$0.90	$0.90	$2.18	$2.18	$2.31	$2.04
2029	$0.98	$0.98	$0.98	$2.37	$2.38	$2.51	$2.23
2030	$1.07	$1.07	$1.07	$2.57	$2.58	$2.72	$2.42
2031	$1.16	$1.16	$1.16	$2.79	$2.80	$2.95	$2.63
2032	$1.27	$1.27	$1.27	$3.03	$3.04	$3.20	$2.86
2033	$1.38	$1.38	$1.38	$3.29	$3.29	$3.47	$3.10
2034	$1.50	$1.50	$1.50	$3.57	$3.57	$3.76	$3.37
2035	$1.64	$1.64	$1.64	$3.87	$3.88	$4.08	$3.66

Table C.6-18
Summary of Sensitivity Analyses
(Varying Base Case Input Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	With TEC	Without TEC	Differential CPWC Savings with TEC
Base Case	$14,139.0	$14,178.1	$39.1
High Fuel Prices	$15,521.2	$15,580.9	$59.7
Low Fuel Prices	$12,650.7	$12,651.3	$0.6
High Load and Energy Growth	$17,591.0	$17,721.5	$130.5
Low Load and Energy Growth	$13,371.9	$13,427.3	$55.4
High Capital Cost	$14,465.4	$14,500.7	$35.3
Low Capital Cost	$13,788.2	$13,877.7	$89.5
High Emissions Allowance Costs	$14,427.7	$14,459.1	$31.4
Low Emissions Allowance Costs	$13,850.4	$13,896.7	$46.3
Regulated CO_2	$15,659.2	$15,712.6	$53.4

C.6.2 External Parameter Sensitivities

The sensitivities described in this section reflect changes to the base case external parameter assumptions, including the opportunity to participate in joint development capacity additions other than TEC, consideration of different types of generating technologies to meet capacity needs, and consideration of an alternative coal source for TEC. For each of the sensitivities described in this section, the base case input parameters (fuel prices, emissions allowance prices, load forecast, and capital cost estimates) have not been altered.

C.6.2.1 3x1 CC Joint Development Project

To demonstrate that participation in TEC in May 2012 is part of the least-cost capacity expansion plan for JEA, sensitivities were developed assuming that JEA had the option to participate in other jointly owned projects with different generating technologies. Since participation in another jointly owned generation project would provide JEA with similar economies of scale to participation in TEC, this sensitivity allows a more comparable evaluation of the economics of different generating technologies than the base case analysis.

In this sensitivity, it was assumed that JEA would participate in a jointly owned 3x1 7FA combined cycle unit with a commercial operation date of May 1, 2012, in lieu of participation in TEC. In this analysis, JEA would retain the same expected ownership share percentage in the 3x1 7FA combined cycle unit as in the proposed TEC, which provides JEA with a similarly sized amount of capacity compared to JEA's share of the proposed TEC. Section A.6.0 presented cost, performance, and availability estimates for the jointly owned 3x1 7FA combined cycle option.

The jointly owned 3x1 combined cycle unit is assumed to be located at the TEC site to make the alternative as similar as possible to TEC. All relevant costs associated with the development of a generating alternative at the TEC site were considered and included for the 3x1 combined cycle alternative, including the community contribution assumed for TEC, and the transmission tariffs and losses described in Section C.5.0.

Table C.6-19 presents the output and performance of JEA's share of the jointly owned 3x1 combined cycle alternative, including transmission losses. Using the methodology described in Section C.5.0, the total annual firm transmission cost to JEA for its share of the 3x1 combined cycle alternative is $8,761,331 per year.

Table C.6-19
JEA's Share of a Jointly Owned 3x1 7FA Combined Cycle Unit
Output and Performance Considering Transmission Losses
(Average Ambient Conditions)

Without Transmission Losses		Including Transmission Losses[1]	
Output (MW)	Net Plant Heat Rate (Btu/kWh)	Output (MW)	Net Plant Heat Rate (Btu/kWh)
285.8	7,412	273.7	7,740
232.4	7,006	222.5	7,317
182.8	7,282	175.0	7,605
134.9	7,877	129.2	8,226
50.4	10,826	48.3	11,306

[1]Assumes losses of 4.24 percent.

JEA's share of the fixed O&M cost for the 3x1 combined cycle alternative is $1.4 million or about $5.25 per kW-year (net after considering transmission losses) in 2006 dollars. As described in Section C.5.0, an adder for firm natural gas transportation of $2.89 per kW-month was included to provide JEA's system with an additional 35,305 MBtu/day of firm natural gas transportation. Section A.6.0 presented the nonfuel variable O&M cost for the 3x1 combined cycle before transmission losses as $4.29 per MWh. With transmission losses considered, JEA's net nonfuel variable O&M cost is $4.49 per MWh in 2006 dollars.

The optimal capacity expansion plan involving participation in the 3x1 combined cycle option consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield IGCC unit in 2020, a brownfield LMS100 CT in 2022, a brownfield and a greenfield LMS100 CT in 2023, and a second greenfield LMS100 CT in 2024, with a CPWC of $14,362.4 million. A comparison of the CPWCs for this case and the base case capacity expansion plan that includes participation in TEC (presented in Section C.5.0) shows that this plan is $223.4 million higher in CPWC than the expansion plan that includes participation in TEC.

C.6.2.2 Three-Train 1x1 IGCC Joint Development Project

In this sensitivity, it was assumed that JEA would participate in a jointly owned three-train 1x1 IGCC unit with a commercial operation date of May 1, 2012, in lieu of participation in TEC. Although it is unlikely that the Participants would construct an IGCC unit prior to 2018 for the reasons described in Sections A.6.0 and C.5.0, it is important to compare the emerging IGCC technology with the supercritical pulverized coal technology proposed for TEC in an economic analysis, to demonstrate that participation in TEC is part of the least-cost expansion plan for JEA.

In this analysis, JEA would retain the same expected ownership share percentage in the three-train 1x1 IGCC unit as in the proposed TEC, which would provide JEA with a similarly sized amount of capacity compared to JEA's share of the proposed TEC. Section A.6.0 presented cost, performance, and availability estimates for the jointly owned three-train 1x1 IGCC.

The jointly owned three-train 1x1 IGCC unit is assumed to be located at the TEC site to make the alternative as similar as possible to TEC. All relevant costs associated with the development of a generating alternative at the TEC site were considered and included for the three-train 1x1 IGCC alternative, including the community contribution assumed for TEC, and the transmission tariffs and losses described in Section C.5.0.

Table C.6-20 presents the output and performance of JEA's share of the jointly owned three-train 1x1 IGCC alternative, including transmission losses. Using the methodology described in Section C.5.0, the total annual firm transmission cost to JEA for its share of the three-train 1x1 IGCC alternative is approximately $8,401,035 per year. This cost is included as of May 1, 2012, and is not escalated with inflation.

Table C.6-20
JEA's Share of a Jointly Owned Three-Train 1x1 IGCC Unit
Output and Performance Considering Transmission Losses
(Average Ambient Conditions - 100 Percent Petcoke)

Without Transmission Losses		Including Transmission Losses[1]	
Output (MW)	Net Plant Heat Rate (Btu/kWh)	Output (MW)	Net Plant Heat Rate (Btu/kWh)
272.2	10,018	260.6	10,462
211.4	10,576	202.4	11,045
148.1	11,601	141.8	12,115

[1]Assumes losses of 4.24 percent.

JEA's share of the fixed O&M cost for the three-train 1x1 IGCC alternative is $10.5 million or about $40.11 per kW-year (net after considering transmission losses) in 2006 dollars. Section A.6.0 presented the nonfuel variable O&M cost for the three train 1x1 IGCC before transmission losses as $5.86 per MWh. With transmission losses considered, JEA's net nonfuel variable O&M cost is $6.12 per MWh in 2006 dollars.

The optimal capacity expansion plan involving participation in the three-train 1x1 IGCC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield 1x1 7FA combined cycle unit in 2020, a brownfield LMS100 CT in 2022, a second brownfield LMS100 CT in 2023, and two greenfield LMS100 CTs in 2024, with a CPWC of $14,176.1 million. A comparison of the CPWCs for this case and the base case capacity expansion plan that includes participation in TEC (presented in Section C.5.0) shows that this plan is $37.1 million higher in CPWC than the capacity expansion plan that includes participation in TEC.

C.6.2.3 Second Jointly Owned Pulverized Coal Unit

Currently, there are no coal fired generation projects identified that JEA could participate in before TEC. Furthermore, JEA has no firm plans for participation in a large, jointly developed pulverized coal unit in the near term. As such, no additional pulverized coal units were considered as supply-side alternatives after construction of TEC in the base case analysis. This sensitivity considers the possibility of joint participation in a second pulverized coal unit located at either the TEC site or another unidentified site in Florida.

The costs and performance of a second supercritical pulverized coal unit are assumed to be identical to those presented for TEC in Section A.3.0, to reflect indicative estimates for a large coal unit. Section C.5.0 presents JEA's share of the capital and O&M costs for TEC, which are assumed to be the same as those for the second pulverized coal option. Since the TEC Participants would not likely engage in the construction of another pulverized coal unit with a construction schedule that overlaps the construction of TEC, the second pulverized coal unit was not assumed to be available until 2016, to allow for a 4 year construction schedule for the second potential unit.

In this sensitivity case, the optimal capacity expansion plan for the case with TEC in 2012 consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, participation in a supercritical pulverized coal unit in 2020, two brownfield LMS100 CTs in 2022, a greenfield LMS100 CT in 2023, and two additional greenfield LMS100 CTs in 2024.

The CPWC for the expansion plan with TEC and a second jointly owned pulverized coal unit is $14,109.2 million, which represents a decrease in CPWC of $29.8 million over the evaluation period, compared to the base case TEC CPWC.

C.6.2.4 All Natural Gas Capacity Expansion Plan

To develop a more complete understanding of the economics associated with the expansion plan (including JEA's participation in TEC), a sensitivity case was developed to reflect costs associated with a capacity expansion plan that only includes natural gas fired capacity expansion alternatives.

In this scenario, POWROPT and POWRPRO were used to determine the least-cost capacity expansion plan for the case without TEC, if the CFB and IGCC supply-side alternatives are not considered as alternatives to meet JEA's capacity needs. This sensitivity analysis results in higher CPWCs relative to the base case expansion plans because of the higher costs of natural gas generation compared to solid fuel alternatives.

In this sensitivity case, the optimal capacity expansion plan (including only natural gas fired capacity additions) consists of a brownfield 1x1 7FA combined cycle unit in 2011, a brownfield LMS100 CT in 2013, a second brownfield LMS100 CT in 2014, a greenfield 1x1 7FA combined cycle unit in 2015, a greenfield LMS100 CT in 2020, two greenfield LMS100 CTs in 2021, a second greenfield 1x1 7FA combined cycle unit in 2022, and a fourth greenfield LMS100 CT in 2024.

The CPWC for the all natural gas capacity expansion plan is $15,055.2 million. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $916.2 million over the evaluation period.

C.6.2.5 Direct-Fired Biomass Supply-Side Alternative

This sensitivity includes the 30 MW direct-fired biomass (stoker-fired) alternative presented in Section A.6.0 as a committed unit in 2011, in the cases with and without TEC, since this is the first year that JEA would need capacity under the base case assumptions. In the case including participation in TEC, JEA's seasonal purchase was reduced by 30 MW, corresponding to the additional capacity provided from the direct-fired biomass alternative.

Cost and performance estimates for the direct-fired biomass alternative are presented in Section A.6.0. The unit was modeled as a "must run" unit, without consideration of emissions allowance costs, to allow for a conservative economic analysis and because biomass emissions are highly dependent on the type of biomass utilized in power generation.

In this sensitivity case, the optimal capacity expansion plan for the case with TEC in 2012 consists of a 30 MW biomass unit in 2011, a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a second brownfield LMS100 CT in 2021, two greenfield LMS100 CTs in 2022, and a brownfield 1x1 7FA combined cycle unit in 2023. The optimal capacity expansion plan without participation in TEC consists of a 30 MW biomass unit and a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 7FA combined cycle unit in 2020, a brownfield IGCC unit in 2022, and two greenfield LMS100 CTs in 2024.

The CPWCs for the expansion plan with TEC and the plan without participation in TEC are $14,218.3 and $14,230.1 million, respectively. A comparison of the CPWCs shows that the case with TEC is the least-cost plan by $11.8 million over the evaluation period. However, compared to the base case TEC CPWC, including the 30 MW biomass resource in 2011 increases the CPWC by $79.3 million.

C.6.2.6 Powder River Basin Coal for TEC

The base case economic analysis and all other sensitivity analyses performed assume that TEC will burn a blend of Latin American coal and petcoke. However, as described in Section A.3.0, TEC will be designed to be capable of burning blends of PRB coal and petcoke, as well as blends of Central Appalachian coal and petcoke. This sensitivity assumes that TEC will burn a blend of PRB coal and petcoke and is based on the corresponding operating cost and performance estimates provided by Sargent & Lundy, which were presented in Section A.3.0.

Hill & Associates' forecast of Latin American coal prices is lower than the forecasts of PRB coal prices, and the corresponding operating costs of TEC are expected to be lower when burning a blend of Latin American coal and petcoke than when burning a blend of PRB coal and petcoke. However, this sensitivity is intended to demonstrate that the additional flexibility of TEC resulting from its capability to burn multiple types of coal allows TEC to be a cost-effective alternative, if the preferred (Latin American) coal source is unavailable for any reason.

The optimal capacity expansion plan involving operation of TEC on a blend of PRB coal and petcoke consists of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a brownfield IGCC unit in 2023, and a second greenfield LMS100 CT in 2024. This plan has a CPWC of $14,159.5 million. A comparison of the CPWCs for this case and the base case capacity expansion plan that includes participation in TEC (presented in Section C.5.0) shows that the plan with TEC's operation on a blend of PRB coal and petcoke is $20.5 million higher in CPWC than the plan with TEC's operation on a blend of Latin American coal and petcoke, but is still lower in CPWC than the base case capacity expansion plan without participation in TEC by $18.6 million over the evaluation period.

C.6.2.7 Summary of the Sensitivity Cases for External Parameters

Appendix C.1 presents the CPWC summary sheets for all of the cases presented in Table C.6-21. The optimal capacity expansion plan with TEC in 2012 was the least-cost plan in each of the scenarios, except for the second jointly owned pulverized coal unit sensitivity. Overall, these results demonstrate the robustness and flexibility of the expansion plan with TEC to overcome external variations and deviations from the base case assumptions.

C.6.3 Analysis of RFP Responses

As described in Section A.7.0, Southern Power Company (Southern) responded to the Participants' RFP and provided bids for a pulverized coal unit and a 2x1 combined cycle unit. Southern's proposed costs and estimated performance for the units are confidential. Although both of Southern's bids were determined by R.W. Beck to not be least-cost to TEC on a levelized cost basis, each bid has been evaluated for JEA's system as a sensitivity to further assess the cost-effectiveness of JEA's participation in TEC. This section briefly describes the bids and the resulting optimal capacity expansion plans under each scenario.

Table C.6-21
Summary of Sensitivity Analyses
(Varying External Parameters)

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
3x1 Combined Cycle Joint Development	$14,362.4	$14,139.0	$223.4
Three-Train 1x1 IGCC Joint Development	$14,176.1	$14,139.0	$37.1
Second Jointly Owned Pulverized Coal Unit	$14,109.2	$14,139.0	($29.8)
All Natural Gas Capacity Expansion Plan	$15,055.2	$14,139.0	$916.2
Biomass Supply-Side Addition with TEC	$14,218.3	$14,139.0	$79.3
Biomass Supply-Side Addition without TEC	$14,230.1	$14,139.0	$91.1
PRB Coal for TEC	$14,159.5	$14,139.0	$20.5

C.6.3.1 Southern's Pulverized Coal Unit Bid

Southern's pulverized coal unit bid was considered a committed unit for JEA, and all costs and performance for the unit were made to be consistent with Southern's bid. The optimal expansion plan for JEA's system with Southern's pulverized coal bid, which was considered a committed unit in 2012, consisted of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a brownfield IGCC unit in 2022, and a second greenfield LMS100 CT in 2024, with a CPWC of $14,626.1 million. A comparison of CPWCs shows that the base case expansion plan with JEA's participation in TEC is $487.1 million lower in CPWC than the expansion plan with Southern's pulverized coal bid over the evaluation period.

C.6.3.2 Southern's 2x1 Combined Cycle Bid

Southern's 2x1 combined cycle unit bid was considered a committed unit for JEA, and all costs and performance for the unit were made to be consistent with Southern's bid. The optimal expansion plan for JEA's system with Southern's 2x1 combined cycle bid, which was considered a committed unit in 2012, consisted of a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a brownfield IGCC unit in 2022, and a second greenfield LMS100 CT in 2024, with a CPWC of $14,446.7 million. A comparison of

CPWCs shows that the base case expansion plan with JEA's participation in TEC is $307.7 million lower in CPWC than the expansion plan with Southern's combined cycle bid over the evaluation period.

C.6.3.3 Summary of the Sensitivity Cases for JEA's Share of the RFP Responses

As shown in Table C.6-22, JEA's optimal capacity expansion plan with TEC in 2012 was the least-cost plan compared to JEA's share of both of Southern's bids.

Table C.6-22
Summary of JEA's Share of Southern's Bids

Sensitivity Case	Expansion Plan CPWC Cost ($ million)		
	Sensitivity Scenario	Base Case TEC in 2012	Differential CPWC Savings of Base Case
Southern's Pulverized Coal Unit	$14,626.1	$14,139.0	$487.1
Southern's 2x1 Combined Cycle Unit	$14,446.7	$14,139.0	$307.7

C.7.0 JEA's Demand-Side Management

According to Section 403.519 of the Florida Statutes, in its determination of need, the FPSC must take into consideration conservation measures that might mitigate the need for the proposed plant. To address this requirement, JEA has tested potential DSM measures for cost-effectiveness. Measures were evaluated using the Florida Integrated Resource Evaluator (FIRE) model previously relied upon by the FPSC. The FIRE model evaluates the economic impact of existing and proposed conservation measures by determining the relative cost-effectiveness of the measures compared to an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation (now Progress Energy Florida [PEF]) and is used by several utilities in Florida. The FIRE model has been used in numerous Need for Power filings (including the FMPA TCEC Unit 1 Need for Power Application, Docket No. 050256-EM, approved by the FPSC in July 2005, and the OUC Stanton Energy Center Unit B Combined Cycle Need for Power Application, Docket No. 060155-EM, approved by the FPSC in May 2006) and was also utilized by JEA in its 2000 and 2004 Numeric Conservation Goals filings with the FPSC.

The remainder of this section summarizes JEA's existing DSM programs and presents a discussion of the FIRE model and the methodology used to determine the potential cost-effectiveness of new DSM measures. A description is provided for each of the DSM measures included in the FIRE model evaluation, and the results of the FIRE model cost-effectiveness evaluations are also presented.

C.7.1 Existing DSM and Conservation Programs

Throughout its history, JEA has demonstrated a strong commitment to serve its customers' conservation needs. JEA has undertaken numerous conservation programs to meet customer needs and expectations. JEA's 2005 Demand-Side Management Plan (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 existing programs, because it had determined that these programs were in the overall best interest of its customers.

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

- Energy audits.
- Solar Incentives Program.
- Green Built Homes of Florida.

- Chilled water services.
- Interruptible load.

C.7.1.1 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 location, type, size, and fuel used for its evaluation, while an audit completed in person involves a JEA representative performing an inspection and then offering cost-effective ideas to lower energy costs. JEA further offers free water management evaluations with this service. 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.

C.7.1.2 Solar Incentives Program

In 2001, JEA developed its Green Power Program to encourage widespread application of renewable energy technology in its service territory. JEA established two Clean Power Capacity goals. The first, contained in JEA's internal *Clean Power Program Action Plan*, calls for a minimum of 4.0 percent clean power capacity by 2007. The second goal is to have 7.5 percent clean power capacity by 2015. As part of the Green Power Program, JEA implemented the Solar Incentives Program in early 2002. This program provides cash incentives for customers to install solar PV and solar thermal systems at their homes or businesses.

Under this program, prequalified solar contractors provide customers with a quote for a solar energy system inclusive of the incentives paid by JEA. Once the customer has signed a statement of satisfaction and the solar system passes inspection, JEA pays the incentive directly to the contractor. JEA requires disclosure of other incentives when the Incentive Fund Request form and Solar Certificate are submitted. The incentives vary by project type and vendor location, with values of up to $800 per solar water heater collector for residential customers and 30 percent of the system cost for businesses. The amount of the incentives paid is based on details of the individual installation and is limited to a maximum of $5,000 for each installation. If other incentives (rebates, grants, etc.) are used to fund a solar system, these funds combined with JEA funds cannot exceed the cost of the system. The customer benefits from this program by receiving a reduced cost for installation of a solar energy system to provide a faster return on investment, lower electric bills, and increase energy self-sufficiency. More than 300 domestic solar hot water systems have been installed since 2002 as a result of the Solar Incentives Program.

JEA paid incentives for more than 25 solar PV systems (98 kW total) until January 2005, when the PV incentive was discontinued. In addition to the PV incentive program, JEA established a residential net-metering program to encourage the use of customer-sited solar PV systems. This policy stipulates that the solar PV systems must be installed according to JEA engineering standards to ensure system compatibility and safety for JEA personnel. JEA installs a meter that runs backwards when the customer's system is generating more energy than it is using. Thus, the amount of electricity that the customer is billed for by JEA is reduced by the amount of electricity exported to the JEA system. JEA does not pay the customer for any electricity if the customer's system generates more energy than the customer uses for a given billing period; however, this amount is credited toward the next billing period.

C.7.1.3 Green Built Homes of Florida

Green Built Homes of Florida is an incentive-based program offered by JEA and 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 EPA 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.

C.7.1.4 Chilled Water Services

JEA is embarking on a new venture involving the use of chilled water. The goal is to develop a central chilled water system that will circulate cold water in a continuous flow throughout buildings, then cool the warmed water in a centralized chiller plant. This system is intended to replace central air conditioning in individual buildings. JEA will provide the system to several new buildings in conjunction with the *Better Jacksonville Plan*. These buildings include the new arena, library, baseball park, and shipyard development.

C.7.1.5 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 forecasts that its interruptible load will increase by 2 to 3 MW every year during the planning period. The forecasted interruptible load in 2024 is 228 MW in the summer and 226 MW in the winter. These 2024 interruptible loads account for 5.8 percent and 4.6 percent of the forecasted loads for the summer and winter, respectively.

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.

C.7.2 FIRE Model Assumptions

The cost-effectiveness evaluation performed with the FIRE model was based on the following assumptions about the electric system:

- System demand is growing. Demand reductions caused by DSM will result in the reduced need for system expansion.
- Individual demand reductions can be related to a reduced need for system generation expansion.
- The generation reduction will be evaluated with respect to specified generation.
- Decreases or increases in revenue as a result of demand-side programs will affect rate levels and will be passed on to all customers.
- Additional conservation that occurs after the next deferred generating unit will affect subsequent units.

C.7.2.1 FIRE Model Inputs

There are two types of FIRE model input files. The first input file contains data specific to the utility's next proposed unit, the avoided unit. The second input file contains data specific to the DSM measure being tested for cost-effectiveness. Input data for the avoided unit is on a per kW basis, allowing the potential DSM measures to be tested individually to evaluate cost-effectiveness.

C.7.2.2 FIRE Model Outputs

FIRE model results are presented in the form of three cost-effectiveness tests, all of which are based on a comparison of discounted present worth benefits to costs for each specific DSM measure. Each of the following three tests is designed to measure costs and benefits from a different perspective:

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

C.7.3 Analysis of DSM Alternatives

JEA considers it important to evaluate additional DSM measures that may potentially be cost-effective, and thereby benefit JEA's customers. This section presents the general assumptions that were used in the FIRE model cost-effectiveness analysis, which is described in detail in Section C.7.2.

The evaluated DSM measures can be divided into the following four main categories:

- New Residential Construction.
- New Commercial and Industrial Construction.
- Existing Residential Construction.
- Existing Commercial and Industrial Construction.

These main categories were further classified as one of the following subcategories:

- Appliance Efficiency.
- Building Envelope.
- Direct Load Control.
- Heating, Ventilating, and Air Conditioning (HVAC) Efficiency.
- Lighting.
- Water Heating Efficiency.

C.7.3.1 General Assumptions

General assumptions were developed to compare all DSM measures on an equivalent economic basis. These assumptions were developed from input received from JEA and other appropriate sources. General cost-effective analysis assumptions and their sources are presented in Table C.7-1. The estimated capital cost for TEC and its projected performance are presented in Table C.7-2.

C.7.3.2 Descriptions and Assumptions of DSM Measures

This subsection provides a brief summary of each DSM measure evaluated for cost-effectiveness.

C.7.3.2.1 DSM Measures for Residential Construction. These measures can be implemented in the construction of new houses and other residential structures, as well as in existing houses and residential structures. Individual cost-effectiveness results for each of the measures are provided for each of the three FIRE model outputs (Total Resource Test, Participant Test, and Rate Impact Test).

C.7.3.2.1.1 Appliance efficiency measures for new and existing residential construction.

Energy Efficient Clothes Washer. This measure assumes that an Energy Star qualified clothes washer is installed rather than a standard efficiency model. The standard efficiency model was assumed to have a Modified Energy Factor (MEF) of 1.04, while the high efficiency model was assumed to have an MEF of 1.42.

Energy Efficient Refrigerator (Frost-Free). This measure assumes that an Energy Star-qualified frost-free refrigerator is installed, rather than a standard efficiency unit.

Table C.7-1
General Cost-Effective Analysis Assumptions and Sources

- The study period for the cost-effectiveness evaluation encompasses 10 years (2006-2015).
- The economic parameters and fuel forecasts are consistent with those presented in Section A.4.0, with the addition of emissions allowance adders described in Section A.8.0.
- The system average fuel cost was derived from the production cost model used for economic evaluations in Section C.5.0.
- Retail electric rates were based on JEA's existing rates.
- The nonfuel cost in residential customers' bills was based on JEA's existing residential rate schedule.
- The nonfuel cost in commercial customers' bills was based on JEA's existing GS, GSD, and GSLD rate schedules.
- The customer demand charge was based on JEA's existing rate schedules.

Table C.7-2
Generating Unit Characteristics for the Avoided Unit
(All values represent JEA's share of the TEC)

Item	
Total Capital Cost (2012 \$) (1)	\$552,009,000
O&M Cost - Baseload Duty	
Fixed O&M Cost (2006 \$/kW-yr) (2), (3)	\$31.68
Variable O&M Cost (2006 \$/MWh) (3)	\$1.42
Net Plant Capacity at 72° F (MW) (3)	241.1
Net Heat Rate at 72° F (Btu/kWh-HHV) (3)	9,647

(1) Capital cost does not include interest during construction.
(2) Includes an adder for ongoing capital expenditures, levelized over the assumed economic life of TEC.
(3) Values after accounting for transmission losses applicable to TEC.

Energy Efficient Refrigerator (Manual Defrost). This measure assumes that an Energy Star-qualified manual defrost refrigerator is installed, rather than a standard efficiency unit.

C.7.3.2.1.2 Building envelope measures for new and existing residential construction.

Light-Colored Roof Material. This measure assumes that white galvanized steel roofing is installed instead of standard black asphalt shingles.

C.7.3.2.1.3 Direct load control measures for new and existing residential construction.

On-Call Direct Load Control. This measure assumes that FM/VHF switches are installed to cycle off central air conditioning, central heating, electric water heaters, and pool pumps during peak times. Table C.7-3 shows the assumed incentives that would be offered for the 15 minute and extended peak times. The 15 minute savings option allows the utility to cycle off the appliances for up to 15 minutes of every 30 minute period. The extended savings option allows the utility to cycle off the air conditioner for up to 3 hours, and the other appliances up to 4 hours.

C.7.3.2.1.4 HVAC efficiency measures for new and existing residential construction.

High Efficiency Central Air Conditioning. A high efficiency central air conditioning unit with a Seasonal Energy Efficiency Ratio (SEER) of 18.0 was assumed to be installed, instead of a standard unit with an SEER of 13.0.

High Efficiency Room Air Conditioning. This measure assumes that a high efficiency room air conditioning unit with an energy efficiency ratio (EER) of 12.6 is installed, rather than a standard efficiency unit with an EER of 8.3.

C.7.3.2.1.5 Lighting measures for new and existing residential construction.

Compact Fluorescent Lights. This measure assumes that two each of 9 watt, 15 watt, and 26 watt compact fluorescent light bulbs are installed, instead of the same number of 40 watt, 60 watt, and 100 watt incandescent light bulbs. Table C.7-4 summarizes the bulb replacements.

High-Pressure Sodium Lighting (Outdoor). This measure assumes that one 70 watt high-pressure sodium lighting fixture is installed in place of one 100 watt outdoor incandescent fixture.

C.7.3.2.1.6 Water heating efficiency measures for new and existing residential construction.

Domestic Water Heater Pipe Insulation. This measure assumes that 70 feet of hot water piping insulation is installed.

Table C.7-3
On-Call Direct Load Control Incentives

15 Minute Savings		
Appliance	Season	Savings
Central Air Conditioner	April - October	$21/year
Central Heater	November - March	$10/year
Extended Savings		
Appliance	Season	Savings
Central Air Conditioner	April - October	$63/year
Central Heater	November - March	$20/year
Water Heater	All year	$18/year
Pool Pump	All year	$36/year

Source: www.fpl.com.

Table C.7-4
Incandescent Bulb Replacement

Current Incandescent Bulbs to be Replaced		Proposed Compact Fluorescent Replacements	
Bulb Type	Total Power Drawn, watts	Bulb Type	Total Power Drawn, watts
Two 40 watt bulbs	80	Two 9 watt bulbs	18
Two 60 watt bulbs	120	Two 15 watt bulbs	30
Two 100 watt bulbs	200	Two 26 watt bulbs	52
Total	400	Total	100

High Efficiency Electric Water Heater. This measure assumes that a high efficiency water heater with an energy factor (EF) of 0.95 is installed, rather than a standard efficiency unit with an EF of 0.92.

Add-On Heat Pump Water Heater. This measure assumes that an add-on heat pump water heater is installed.

Heat Recovery Water Heater. This measure assumes that a supplemental heat recovery water heater is installed and connected to the air conditioner exhaust heat.

Supplemental Solar Water Heater. This measure assumes that a supplemental solar water heater is installed.

C.7.3.2.1.7 Appliance efficiency measures for existing residential construction only.

High Efficiency Residential Pool Pump. This measure assumes that a standard efficiency (82.5 percent) pool filter motor and circulation pump is replaced with a premium efficiency motor (85.5 percent).

Low-Flow Showerhead. This measure assumes that a low-flow showerhead is installed in place of an existing showerhead.

Energy Efficient Freezer (Manual). This measure assumes that an Energy Star qualified manual defrost freezer is installed, rather than a standard efficiency unit.

C.7.3.2.1.8 Appliance removal measures for existing residential construction only.

Remove Second Freezer. This measure consists of the removal of a second freezer.

Remove Second Refrigerator. This measure consists of the removal of a second refrigerator.

C.7.3.2.1.9 Building envelope measures for existing residential construction only.

Ceiling Insulation (R-0 to R-19). This measure only applies to existing dwellings with no ceiling insulation and assumes the installation of R-19 rated insulation in the ceiling.

Ceiling Insulation (R-11 to R-30). This measure only applies to existing dwellings with R-11 ceiling insulation and involves the installation of insulation with an R-value of R-19, for a total R-value of R-30.

Low Emissivity Glass. For this measure, double-pane glass with an argon gas fill and a low emissivity coating on the inner surface of the outer pane is installed in place of single- and double-pane clear glass windows. This measure reduces heat transmission through windows.

Window Film/Reflective Windows. This measure assumes that window films are installed on single-pane windows.

Window Shade Screens. This measure assumes that four windows are installed with retractable shade screens.

C.7.3.2.1.10 HVAC efficiency measures for existing residential construction only.

Air Conditioning System Maintenance. This measure assumes that an existing air conditioner is serviced by a professional.

C.7.3.2.1.11 Water heating efficiency measures for existing residential construction only.

Domestic Water Heater Heat Trap. This measure consists of the installation of a heat trap on the inlet and outlet piping of an electric resistance water heater.

Domestic Water Heater Tank Insulation. This measure consists of the installation of a water heater jacket with an R-value of at least 6.7.

C.7.3.2.2 DSM Measures for Commercial and Industrial Construction. These measures can be implemented in the construction of new commercial and industrial buildings and structures, as well as in existing buildings and structures. Individual cost-effectiveness results for each of the measures are provided for each of the three FIRE model outputs (Total Resource Test, Participant Test, and Rate Impact Test).

C.7.3.2.2.1 Appliance efficiency measures for new and existing commercial and industrial construction.

Energy Efficient Electric Fryer. This measure assumes that a high efficiency electric fryer with an electric demand of 2.4 kW is installed, rather than a standard efficiency unit with an electric demand of 2.8 kW.

C.7.3.2.2.2 Direct load control measures for new and existing commercial and industrial construction.

Business On-Call. This measure assumes that FM/VHF switches are installed to cycle off air conditioning units for 15 minutes out of every 30 minute period, during peak times from April through October.

C.7.3.2.2.3 HVAC efficiency measures for new and existing commercial and industrial construction.

High Efficiency Chiller. This measure assumes that a high efficiency screw chiller with a coefficient of performance (COP) of 5.9 is installed, instead of a standard efficiency reciprocating chiller with a COP of 4.2 for the GSD rate class. For the GSLD rate class, a high efficiency centrifugal chiller with a COP of 6.4 is installed, instead of a standard efficiency centrifugal chiller with a COP of 5.6. The chillers for the GSD rate class were assumed to be 100 tons; chillers for the GSLD rate class were assumed to be 200 tons.

High Efficiency Chiller with ASD. This option consists of installing an adjustable speed drive (ASD) controller onto high efficiency centrifugal chillers. The same assumptions apply here as in the high efficiency chiller option. The high efficiency chiller with an ASD is compared to a high efficiency chiller without an ASD to estimate savings.

High Efficiency DX Air Conditioning Units. This measure assumes that a high efficiency direct exchange (DX) air conditioning unit (5 ton for GS, 20 ton for GSD, and 100 ton for GSLD) with an EER rating of 13.0 is installed, rather than the standard of 10.3.

High Efficiency Room Air Conditioning Units. This measure assumes that a high efficiency room air conditioning unit with an EER of 12.6 is installed, rather than a standard efficiency unit with an EER of 8.3. The room air conditioning unit was assumed to have a cooling rating of 17,000 Btu/h.

High Efficiency Motors - Chiller. This measure assumes that a high efficiency motor (96 percent efficiency) is installed, rather than a standard efficiency motor (91 percent efficiency) in a chiller.

High Efficiency Motors - DX Air Conditioning. This measure assumes that a high efficiency motor (94 percent efficiency) is installed, rather than a standard efficiency motor (87 percent efficiency) in a DX air conditioning unit.

Leak Free Ducts. This measure consists of the utilization of aerosol duct sealing on a commercial building's duct system. Cooling and ventilation demand and energy savings are estimated to be 3.0 percent. The buildings were assumed to have floor areas of 5,000 ft^2, 20,000 ft^2, and 100,000 ft^2 for the GS, GSD, and GSLD rate classes, respectively.

Cool Thermal Storage. This measure assumes that a chiller (50 ton for GSD and 150 ton for GSLD) is augmented with a cooled water thermal storage system. The system is sized for 4 hours at full chiller capacity. The chiller was assumed to have a COP of 4.75 for the GSD rate class and a COP of 5.9 for the GSLD rate class. It was also assumed that existing pumps would be capable of circulating the stored chilled water through the air conditioning system during peak hours, so there would be no assumed energy savings or energy use increase from the pumps.

C.7.3.2.2.4 Lighting measures for new and existing commercial and industrial construction.

Incandescent Replacement with Compact Fluorescent. This measure assumes that a new commercial building uses ten 15 watt, 18 watt, and 27 watt compact fluorescent lamps instead of the same number of 60 watt, 75 watt, and 100 watt incandescent lamps. Table C.7-5 summarizes the lamp replacements.

Table C.7-5 Incandescent Lamp Replacement			
Current Incandescent Lamp to be Replaced		Proposed Compact Fluorescent Replacements	
Lamp Type	Total Power Drawn, watts	Lamp Type	Total Power Drawn, watts
Ten 60 watt bulbs	600	Ten 15 watt bulbs	150
Ten 75 watt bulbs	750	Ten 18 watt bulbs	180
Ten 100 watt bulbs	1,000	Ten 27 watt bulbs	270
Total	2,350	Total	600

Incandescent Replacement with 2x18 Watt Compact Fluorescent. This measure consists of the installation of ten 2 x 18 watt compact fluorescent fixtures, instead of the installation of ten 1 x 150 watt incandescent fixtures.

C.7.3.2.2.5 Water heating efficiency measures for new and existing commercial and industrial construction.

Heat Pump Water Heater. This measure assumes that a heat pump water heater is installed in combination with an electric resistance water heater. The electric resistance water heater was assumed to have a COP of 0.92, while the heat pump water heater was assumed to have a COP of 3.0.

Heat Recovery Water Heater. This measure consists of an electric water heater that utilizes a supplemental heat source from the cooling system waste heat recovered from a double-bundle chiller or condenser heat exchanger.

C.7.3.2.2.6 Appliance efficiency measures for existing commercial and industrial construction only.

Low or Variable Flow Showerhead. This retrofit measure consists of installing low or variable flow showerheads in place of existing showers and faucets to reduce the flow of hot water.

Multiplex Refrigeration System with No Subcooling. This measure assumes that an existing grocery store replaces an existing single compressor system with a multiplex refrigeration system. The single compressor system was assumed to have an EER of 9.0, while the multiplex system was assumed to have an annual EER of 11.0.

Multiplex Refrigeration System with Ambient Subcooling. This measure assumes that an existing grocery store replaces an existing single compressor system with a multiplex system with ambient subcooling. The single compressor was assumed to have an EER of 9.0, while the multiplex system with ambient subcooling was assumed to have an EER of 11.22.

Multiplex Refrigeration System with Mechanical Subcooling. This measure assumes that an existing grocery store replaces an existing single compressor system with a multiplex system with mechanical subcooling. The single compressor was assumed to have an EER of 9.0, while the multiplex system with mechanical subcooling was assumed to have an EER of 12.65.

Multiplex Refrigeration System with Ambient and Mechanical Subcooling. This measure consists of various air-cooled refrigeration systems that are compared to a stand-alone compressor system. Systems include a multiplex system with or without ambient or mechanical subcooling and an external liquid suction heat exchanger, in addition to an open-drive refrigeration system. This measure was assumed applicable to restaurant, grocery, warehouse, and hospital market segments.

C.7.3.2.2.7 Building envelope measures for existing commercial and industrial construction only.

Light-Colored Roof - Air Chiller. This measure assumes that commercial buildings with a black, flat roof with an albedo of 0.05 install a light-colored Energy Star rated white membrane with an albedo of 0.75. The roofs were assumed to have areas of 10,000 ft^2 and 50,000 ft^2 for the GSD and GSLD rate classes, respectively. Savings were calculated based on using standard efficiency air-cooled screw chillers with COP values of 3.0 (100 ton for the GSD rate class and a 200 ton chiller for the GSLD rate class).

Light Colored Roof - DX Air Conditioning. This measure assumes that commercial buildings with a black, flat roof with an albedo of 0.05 would install a light-colored Energy Star-rated white membrane with an albedo of 0.75. The roofs were assumed to have areas of 5,000 ft^2, 10,000 ft^2, and 50,000 ft^2 for the GS, GSD, and GSLD rate classes, respectively. Savings were calculated based on using standard efficiency DX air conditioning units with EER ratings of 8.9 (100 ton for GSLD, 20 ton for GSD, and 5 ton for GS).

Light-Colored Roof - Water Chiller. This measure assumes that commercial buildings with a black, flat roof with an albedo of 0.05 would install a light-colored Energy Star-rated white membrane with an albedo of 0.75. The roofs were assumed to have areas of 10,000 ft^2 and 50,000 ft^2 for the GSD and GSLD rate classes, respectively. Savings were calculated based on using standard efficiency water-cooled reciprocating chillers with COP values of 4.0 (100 ton chiller for the GSD rate class and a 200 ton chiller for the GSLD rate class).

Roof Insulation – Chiller. This measure assumes that buildings with an existing R-value of 2.53 upgrade roof insulation to an average R-value of 10.0. The roofs were assumed to have areas of 10,000 ft^2 and 50,000 ft^2 for the GSD and GSLD rate classes, respectively.

Roof Insulation – DX Air Conditioning. This measure assumes that buildings with an existing R-value of 2.53 upgrade roof insulation to an average R-value of 10.0. The roofs were assumed to have areas of 5,000 ft^2, 10,000 ft^2, and 50,000 ft^2 for the GS, GSD, and GSLD rate classes, respectively.

Window Film – Chiller. This option consists of installing window film on existing construction. The shading coefficient was assumed to improve from 0.85 to 0.23 and the U-value from 1.06 to 0.69.

Window Film - DX Air Conditioning. This option consists of installing window film on existing construction. The shading coefficient was assumed to improve from 0.85 to 0.23 and the U-value from 1.06 to 0.69. Energy savings were calculated as the reduction in DX air conditioning power and energy demand.

C.7.3.2.2.8 HVAC efficiency measures for existing commercial and industrial construction only.

Two-Speed Motor for Cooling Tower. This measure assumes that one 5 hp, two-speed motor is installed in an existing cooling tower.

Speed Control for Cooling Tower Motors. This measure assumes that an adjustable speed drive is installed on one 5 hp cooling tower motor.

C.7.3.2.2.9 Lighting measures for existing commercial and industrial construction only.

4 Foot Fluorescent with Electronic Ballast Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 2 (40 watt) fluorescent fixtures with standard ballasts with twenty 4 foot by 2 (34 watt) fluorescent lamps with electronic ballasts.

8 Foot Fluorescent with Electronic Ballast Replacement. This measure assumes that a commercial building replaces twenty 8 foot by 2 (75 watt) fluorescent fixtures with standard ballasts with twenty 8 foot by 2 fluorescent lamps with electronic ballasts, with a total fixture rating of 95 watt.

4 Foot T8 with Electronic Ballast Lamp Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 2 (40 watt) fluorescent fixtures with twenty 4 foot by 2 T8 (32 watt) fluorescent lamps and an electronic ballast, with a total fixture rating of 60 watt.

4 Foot Fluorescent with Reflector Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 4 (40 watt) fluorescent fixtures with twenty 4 foot by 2 (40 watt) fluorescent lamps with a reflector.

4 Foot Fluorescent with T8 and Reflector Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 4 (40 watt) fluorescent fixtures with twenty 4 foot by 2 T8 (32 watt) fluorescent lamps with a reflector.

4 Foot 34 Watt with Reflector Replacement. This measure assumes that a commercial building replaces twenty 4 foot by 4 (40 watt) fixtures with four 4 foot by 2 (40 watt) fixtures with reflectors and sixteen 4 foot by 2 (34 watt) fixtures with reflectors.

8 Foot 75 Watt Delamping with Reflector Kit and Electronic Ballasts. This measure assumes that a commercial building replaces twenty 8 foot by 2 (75 watt) fixtures with twenty 4 foot by T8 lamps (32 watt) and a reflector kit, and electronic ballasts.

High-Pressure Sodium Lighting (70 Watt/100 Watt/150 Watt/250 Watt) Replacement. This measure considers a mix of five each of 70 watt, 100 watt, 150 watt, and 250 watt high-pressure sodium lamps/fixtures replacing the same mix of 100 watt, 175 watt, 250 watt, and 400 watt Hg vapor lamps/fixtures. Table C.7-6 summarizes the proposed changes.

Table C.7-6
Incandescent Bulb Replacement

Hg Vapor Fixtures to be Replaced		High-Pressure Sodium Fixture Replacements	
Fixture Type	Total Power Drawn, watts	Fixture Type	Total Power Drawn, watts
Five 100 watt bulbs	500	Five 70 watt bulbs	350
Five 175 watt bulbs	875	Five 100 watt bulbs	500
Five 250 watt bulbs	1,250	Five 150 watt bulbs	750
Five 400 watt bulbs	2,000	Five 250 watt bulbs	1,250
Total	4,625	Total	2,850

Outdoor High-Pressure Sodium Lighting (70 Watt) Replacement. This measure considers replacing five 150 watt incandescent lamps with five 70 watt high-pressure sodium fixtures.

C.7.3.2.2.10 Water heating efficiency measures for existing commercial and industrial construction only.

Water Heater Insulation. This is a retrofit measure consisting of wrapping an existing water tank with additional insulation.

Water Heater Heat Trap. This retrofit measure reduces hot water energy loss caused by backflow through the pipes from natural convection.

Off-Peak Battery Charging. This measure typically applies to golf courses and requires that they charge golf carts during off-peak hours (at night). The customer must purchase the equipment to automatically start and control the charging process.

C.7.4 Results of the FIRE Model Cost-Effectiveness Evaluations

The following tables (Tables C.7-7 through C.7-10) present the results of the FIRE model DSM cost-effectiveness analyses of the DSM measures described previously in this section. The tables include the three tests used by the FIRE model to determine cost-effectiveness - the Total Resource Test, the Participant Test, and the Rate Impact Test - each of which is described in Section C.7.2. Cost-effectiveness results are categorized as discussed in Section C.7.3. As indicated in Tables C.7-7 through C.7-10, none of the potential new DSM measures evaluated are cost-effective, based on the Rate Impact Test. Therefore, it can be concluded that there are no cost-effective DSM measures that would mitigate the need for TEC. JEA will continue to evaluate the potential for cost-effective DSM measures.

There are numerous DSM measures that were evaluated and that have a negative Rate Impact Test result. This can be explained by considering the impact of removing TEC, as the avoided unit, from JEA's generating resources. With TEC as a resource, JEA's lower cost generating units will dispatch near their assumed availability. When TEC is not included as a generating resource, a significant amount of higher cost generation is utilized to replace the generation provided by TEC. This increases the system incremental cost as well as the average cost per MWh generated. In the FIRE model calculation of net benefits associated with a DSM measure, when the replacement fuel costs exceed the fuel savings associated with a DSM measure, the net benefit is presented as a negative number. If the summation of each year's net benefits is negative, the resulting benefit-to-cost ratio will also be a negative number.

Table C.7-7
FIRE Model Cost-Effectiveness Results for
New and Existing Residential Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Efficient Clothes Washer - Existing - Residential	0.05	0.63	0.03
Efficient Clothes Washer - New - Residential	0.01	0.70	0.01
Energy Efficient Refrigerator (Frost-Free) - Existing - Residential	0.25	0.30	0.08
Energy Efficient Refrigerator (Frost-Free) - New - Residential	0.18	0.88	0.16
Energy Efficient Refrigerator (Manual) - Existing - Residential	0.23	0.36	0.09
Energy Efficient Refrigerator (Manual) - New - Residential	0.16	0.80	0.14
Building Envelope Measures			
Light-Colored Roof Material - Existing - Residential	0.13	0.10	0.01
Light-Colored Roof Material - New - Residential	0.13	0.43	0.06
Direct Load Control Measures			
On-Call Direct Load Control - Existing - Residential	-0.40	1.00	-0.72
On-Call Direct Load Control - New - Residential	-0.40	1.00	-0.72
HVAC Efficiency Measures			
High Efficiency Central Air Conditioning - Existing - Residential	0.09	0.30	0.03
High Efficiency Central Air Conditioning - New - Residential	0.03	1.00	0.05
High Efficiency Room Air Conditioning - Existing - Residential	0.15	0.28	0.04
High Efficiency Room Air Conditioning - New - Residential	0.15	2.77	0.37
Lighting Measures			
Compact Fluorescent Lights - Existing - Residential	0.15	29.24	0.35
Compact Fluorescent Lights - New - Residential	0.22	11.70	1.29
High-Pressure Sodium Lighting (Outdoor) - Existing - Residential	0.29	2.57	0.52
High-Pressure Sodium Lighting (Outdoor) - New - Residential	0.32	2.57	0.59
Water Heating Efficiency Measures			
Domestic Water Heater Pipe Insulation - Existing - Residential	0.08	0.29	0.04
Domestic Water Heater WH Pipe Insulation - New - Residential	0.08	0.08	0.01
High Efficiency Electric Water Heater - Existing - Residential	-0.11	0.57	-0.06
High Efficiency Electric Water Heater - New - Residential	-0.25	1.00	-0.42
Add-On Heat Pump Water Heater - Existing - Residential	0.37	1.09	0.40
Add-On Heat Pump Water Heater - New - Residential	0.36	1.45	0.52
Heat Recovery Water Heater - Existing - Residential	0.32	0.93	0.30
Heat Recovery Water Heater - New - Residential	0.32	0.93	0.30
Supplemental Solar Water Heater - Existing - Residential	0.34	0.17	0.06
Supplemental Solar Water Heater - New - Residential	0.34	0.17	0.06

Table C.7-8
FIRE Model Cost-Effectiveness Results for
Existing Residential Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
High Efficiency Pool Pump - Existing - Residential	0.11	0.13	0.02
Low-Flow Showerhead - Existing - Residential	0.33	19.60	2.07
Energy Efficient Freezer (Manual) - Existing - Residential	0.25	0.45	0.12
Appliance Removal Measures			
Remove Second Freezer - Existing - Residential	0.34	1.00	4.89
Remove Second Refrigerator - Existing - Residential	0.34	1.00	5.48
Building Envelope Measures			
Ceiling Insulation (R0-R19) - Existing - Residential	0.15	1.19	0.18
Ceiling Insulation (R19-R30) - Existing - Residential	0.14	0.49	0.07
Low Emissivity Glass - Existing - Residential	0.15	0.92	0.14
Window Film/Reflective Windows - Existing - Residential	0.15	0.61	0.09
Window Shade Screens - Existing - Residential	0.10	1.11	0.11
HVAC Efficiency Measures			
Air Conditioning System Maintenance - Existing - Residential	0.10	5.25	0.24
Water Heating Efficiency Measures			
Domestic Water Heater Heat Trap - Existing - Residential	0.15	1.00	0.29
Domestic Water Heater Tank Insulation - Existing - Residential	0.27	3.60	0.54

Table C.7-9
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Energy Efficient Electric Fryer - Existing - GSND	0.14	0.15	0.02
Energy Efficient Electric Fryer - Existing - GSD	0.14	0.16	0.02
Energy Efficient Electric Fryer - Existing - GSLD	0.13	0.17	0.02
Energy Efficient Electric Fryer - New - GSND	0.14	0.51	0.08
Energy Efficient Electric Fryer - New - GSD	0.14	0.54	0.08
Energy Efficient Electric Fryer - New - GSLD	0.13	0.58	0.08
Direct Load Control Measures			
Business On-Call Direct Load Control - Existing - GSND	-0.74	1.00	-2.16
Business On-Call Direct Load Control - Existing - GSD	-0.36	1.00	-9.24
Business On-Call Direct Load Control - Existing - GSLD	-0.30	1.00	-9.24
Business On-Call Direct Load Control - New - GSND	-0.74	1.00	-2.16
Business On-Call Direct Load Control - New - GSD	-0.36	1.00	-9.24
Business On-Call Direct Load Control - New - GSLD	-0.30	1.00	-9.24
HVAC Efficiency Measures			
High Efficiency Chiller - Existing - GSD	0.15	1.02	0.15
High Efficiency Chiller - Existing - GSLD	0.14	0.36	0.05
High Efficiency Chiller - New - GSD	0.15	6.23	0.92
High Efficiency Chiller - New - GSLD	0.14	1.84	0.26
High Efficiency Chiller w/ASD - Existing - GSD	0.15	2.01	0.30
High Efficiency Chiller w/ASD - Existing - GSLD	0.14	2.29	0.32
High Efficiency Chiller w/ASD - New - GSD	0.15	2.01	0.30
High Efficiency Chiller w/ASD - New - GSLD	0.14	2.29	0.32
High Efficiency DX Air Conditioning Units - Existing - GSND	0.15	0.51	0.08
High Efficiency DX Air Conditioning Units - Existing - GSD	0.15	0.42	0.06
High Efficiency DX Air Conditioning Units - Existing - GSLD	0.14	0.50	0.07
High Efficiency DX Air Conditioning Units - New - GSND	0.22	0.94	0.20
High Efficiency DX Air Conditioning Units - New - GSD	0.15	0.35	0.05
High Efficiency DX Air Conditioning Units - New - GSLD	0.14	0.73	0.10
High Efficiency Room Air Conditioning Units - Existing - GSND	0.15	1.03	0.15
High Efficiency Room Air Conditioning Units - New - GSND	0.23	1.00	0.82
High Efficiency Motors - Chiller - Existing - GSD	0.15	1.11	0.16
High Efficiency Motors - Chiller - Existing- GSLD	0.14	1.18	0.16
High Efficiency Motors - Chiller - New - GSD	0.15	6.65	0.96

Table C.7-9 (Continued)
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
High Efficiency Motors - Chiller - New - GSLD	0.14	7.11	0.96
High Efficiency Motors - DX Air Conditioning - New - GSND	0.19	1.00	0.64
High Efficiency Motors - DX Air Conditioning - New - GSD	0.14	8.62	1.03
High Efficiency Motors - DX Air Conditioning - New - GSLD	0.14	8.85	1.17
High Efficiency Motors - DX Air Conditioning - Existing - GSND	0.14	0.66	0.10
High Efficiency Motors - DX Air Conditioning - Existing - GSD	0.14	1.43	0.21
High Efficiency Motors - DX Air Conditioning - Existing - GSLD	0.14	1.47	0.20
Leak Free Ducts - Existing - GSND	0.15	0.30	0.05
Leak Free Ducts - Existing - GSD	0.15	0.32	0.05
Leak Free Ducts - Existing - GSLD	0.14	0.34	0.05
Leak Free Ducts - New - GSND	0.13	0.12	0.02
Leak Free Ducts - New - GSD	0.14	0.12	0.02
Leak Free Ducts - New - GSLD	0.14	0.13	0.02
Cool Thermal Storage - Existing - GSD	-0.20	1.82	-0.86
Cool Thermal Storage - Existing - GSLD	-0.19	2.27	-0.86
Cool Thermal Storage - New - GSD	-0.20	1.57	-0.75
Cool Thermal Storage - New - GSLD	-0.19	1.58	-0.60
Lighting Measures			
Incandescent Replacement w/Compact Fluorescent - Existing - GSND	0.37	25.29	4.51
Incandescent Replacement w/Compact Fluorescent - Existing - GSD	0.40	22.77	4.51
Incandescent Replacement w/Compact Fluorescent - Existing - GSLD	0.40	23.12	4.51
Incandescent Replacement w/Compact Fluorescent - New - GSND	0.37	25.29	6.45
Incandescent Replacement w/Compact Fluorescent - New - GSD	0.42	22.77	6.45
Incandescent Replacement w/Compact Fluorescent - New - GSLD	0.41	23.12	6.45
Incandescent Replacement w/2x18 Watt Compact Fluorescent - Existing - GSND	0.23	6.56	1.08
Incandescent Replacement w/2x18 Watt Compact Fluorescent - Existing - GSD	0.26	5.95	1.08
Incandescent Replacement w/2x18 Watt Compact Fluorescent - Existing - GSLD	0.25	6.03	1.08
Incandescent Replacement w/2x18 Watt Compact Fluorescent - New - GSND	0.25	4.46	1.08
Incandescent Replacement w/2x18 Watt Compact Fluorescent - New - GSD	0.28	4.04	1.08
Incandescent Replacement w/2x18 Watt Compact Fluorescent - New - GSLD	0.27	4.10	1.08

Table C.7-9 (Continued)
FIRE Model Cost-Effectiveness Results for
New and Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Water Heating Efficiency Measures			
Heat Pump Water Heater - Existing - GSND	-0.07	1.00	-0.15
Heat Pump Water Heater - Existing - GSD	-0.18	1.00	-0.67
Heat Pump Water Heater - Existing - GSLD	0.09	1.00	0.25
Heat Pump Water Heater - New - GSND	-0.08	1.00	-0.26
Heat Pump Water Heater - New - GSD	-0.19	1.00	-0.94
Heat Pump Water Heater - New - GSLD	0.11	1.00	0.39
Heat Recovery Water Heater - Existing - GSND	0.17	1.00	0.47
Heat Recovery Water Heater - Existing - GSD	0.27	1.84	0.49
Heat Recovery Water Heater - Existing - GSLD	0.27	1.89	0.49
Heat Recovery Water Heater - New - GSND	0.19	1.00	0.65
Heat Recovery Water Heater - New - GSD	0.27	1.84	0.49
Heat Recovery Water Heater - New - GSLD	0.27	1.89	0.49

Table C.7-10
FIRE Model Cost-Effectiveness Results for
Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Appliance Efficiency Measures			
Low or Variable Flow Showerhead - Existing - GSND	0.30	145.84	4.71
Low or Variable Flow Showerhead - Existing - GSD	0.35	122.83	4.71
Low or Variable Flow Showerhead - Existing - GSLD	0.35	121.83	4.71
Multiplex Refrigeration with No Subcooling - Existing - GSD	0.49	0.32	0.16
Multiplex Refrigeration with No Subcooling - Existing - GSLD	0.52	0.30	0.16
Multiplex Refrigeration with Ambient Subcooling - Existing - GSD	0.49	0.34	0.17
Multiplex Refrigeration with Ambient Subcooling - Existing - GSLD	0.52	0.33	0.17
Multiplex Refrigeration with Mechanical Subcooling - Existing - GSD	-0.64	0.08	-0.05
Multiplex Refrigeration with Mechanical Subcooling - Existing - GSLD	-0.47	0.10	-0.05
Multiplex Refrigeration: Ambient and Mechanical Subcooling - Existing - GSD	0.50	0.00	0.57
Multiplex Refrigeration: Ambient and Mechanical Subcooling - Existing - GSLD	0.53	0.00	0.57
Building Envelope Measures			
Light-Colored Roof - Air Chiller - Existing - GSD	0.15	2.16	0.32
Light-Colored Roof - Air Chiller - Existing - GSLD	0.14	0.92	0.13
Light-Colored Roof - DX Air Conditioning - Existing - GSND	0.15	0.26	0.04
Light-Colored Roof - DX Air Conditioning - Existing - GSD	0.15	0.55	0.08
Light-Colored Roof - DX Air Conditioning - Existing - GSLD	0.14	0.59	0.08
Light-Colored Roof - Water Chiller - Existing - GSD	0.15	1.76	0.26
Light-Colored Roof - Water Chiller - Existing - GSLD	0.14	0.62	0.09
Roof Insulation - Chiller - Existing - GSD	0.15	0.27	0.04
Roof Insulation - Chiller - Existing - GSLD	0.14	0.06	0.01
Roof Insulation - DX Air Conditioning - Existing - GSND	0.16	0.42	0.07
Roof Insulation - DX Air Conditioning - Existing - GSD	0.15	0.22	0.03
Roof Insulation - DX Air Conditioning - Existing - GSLD	0.14	0.05	0.01
Window Film - Chiller - Existing - GSD	0.15	2.22	0.32
Window Film - Chiller - Existing - GSLD	0.14	2.37	0.32
Window Film - DX Air Conditioning - Existing - GSND	0.19	1.00	0.32
Window Film - DX Air Conditioning - Existing - GSD	0.15	2.55	0.37
Window Film - DX Air Conditioning - Existing - GSLD	0.14	2.72	0.37

Table C.7-10 (Continued)
FIRE Model Cost-Effectiveness Results for
Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
HVAC Efficiency Measures			
Two-Speed Motor for Cooling Tower - Existing - GSD	0.14	2.30	0.31
Two-Speed Motor for Cooling Tower - Existing - GSLD	0.13	2.46	0.31
Speed Control for Cooling Tower Motors - Existing - GSD	0.14	0.82	0.12
Speed Control for Cooling Tower Motors - Existing - GSLD	0.13	0.88	0.12
Lighting Measures			
4 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSND	0.29	0.42	0.12
4 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSD	0.33	0.36	0.12
4 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSLD	0.33	0.36	0.12
8 ft Fluorescent w/Electronic Ballast Replacement - Existing - GSND	0.20	1.57	0.29
8 ft Fluorescent w/Electronic Ballast Replacement - GSD	0.21	1.44	0.29
8 ft Fluorescent w/Electronic Ballast Replacement - GSLD	0.21	1.46	0.29
4 ft T8 Lamp Replacement - Existing - GSND	0.13	1.18	0.15
4 ft T8 Lamp Replacement - Existing - GSD	0.14	1.10	0.15
4 ft T8 Lamp Replacement - Existing - GSLD	0.14	1.12	0.15
4 ft Fluorescent with Reflector Replacement - Existing - GSND	0.22	3.39	0.60
4 ft Fluorescent with Reflector Replacement - Existing - GSD	0.23	3.09	0.60
4 ft Fluorescent with Reflector Replacement - Existing - GSLD	0.23	3.13	0.60
4 ft T8 Fluorescent with Reflector Replacement - Existing - GSND	0.22	3.98	0.72
4 ft T8 Fluorescent with Reflector Replacement - Existing - GSD	0.24	3.62	0.72
4 ft T8 Fluorescent with Reflector Replacement - Existing - GSLD	0.24	3.67	0.72
4 ft 34 Watt w/Reflector Replacement - Existing - GSND	0.22	3.74	0.67
4 ft 34 Watt w/Reflector Replacement - Existing - GSD	0.24	3.41	0.67
4 ft 34 Watt w/Reflector Replacement - Existing - GSLD	0.24	3.45	0.67
8 ft 75 Watt Delamping w/Reflector Kit - Existing - GSND	0.23	3.50	0.69
8 ft 75 Watt Delamping w/Reflector Kit - Existing - GSD	0.25	3.18	0.69
8 ft 75 Watt Delamping w/Reflector Kit - Existing - GSLD	0.25	3.22	0.69
High-Pressure Sodium (70 Watt/100 Watt/150 Watt/250 Watt) Replacement - Existing - GSND	0.30	0.37	0.11
High-Pressure Sodium (70 Watt/100 Watt/150 Watt/250 Watt) Replacement - Existing - GSD	0.35	0.31	0.11
High-Pressure Sodium (70 Watt/100 Watt/150 Watt/250 Watt) Replacement - Existing - GSLD	0.35	0.31	0.11

Table C.7-10 (Continued)
FIRE Model Cost-Effectiveness Results for
Existing Commercial and Industrial Conservation and DSM Measures

Measure	Rate Impact Test	Participant Test	Total Resource Test
Outdoor High-Pressure Sodium (70 Watt) Replacement - Existing - GSND	0.29	0.34	0.10
Outdoor High-Pressure Sodium (70 Watt) Replacement - Existing - GSD	0.33	0.30	0.10
Outdoor High-Pressure Sodium (70 Watt) Replacement - Existing - GSLD	0.33	0.30	0.10
Water Heating Efficiency Measures			
Domestic Water Heater Insulation - Existing - GSND	0.27	17.17	1.32
Domestic Water Heater Insulation - Existing - GSD	0.31	14.46	1.32
Domestic Water Heater Insulation - Existing - GSLD	0.31	14.34	1.32
Domestic Water Heater Heat Trap - Existing - GSND	0.07	1.00	0.12
Domestic Water Heater Heat Trap - Existing - GSD	0.34	1.00	0.96
Domestic Water Heater Heat Trap - Existing - GSLD	0.29	1.00	0.59
Off-Peak Battery Charging - FPL - Existing - GSD	-0.63	1.80	-1.03
Off-Peak Battery Charging - FPL - Existing - GSLD	-0.47	2.46	-1.03

C.8.0 JEA's Strategic Considerations

In addition to cost-effectively meeting JEA's capacity needs, there were several strategic considerations and advantages associated with the TEC project, which led JEA to consider participation in the TEC project as its next baseload generating unit. These strategic considerations include both economic and non-economic attributes and are discussed in the remainder of this section.

C.8.1 JEA's Fuel Diversity

TEC will provide an increase in fuel diversity for JEA's system and Florida as a whole. The project will have the ability to source solid fuels from both domestic and international coal producing regions, including the PRB, Central Appalachia, and Latin American regions, as well as petcoke from the Gulf Coast region and the Caribbean. Historically, coals from these regions and petcoke have experienced significantly less fluctuation in price and generally have less volatile commodity prices than oil and natural gas on an annual basis. As a result, TEC will not only provide additional solid fuel capacity for JEA and Florida, but it will also provide further fuel diversification through the capability to source coal and petcoke from numerous different regions via different transportation modes and routes. This additional choice in fuel for JEA's generating fleet will provide more flexibility to respond to fuel price fluctuations that exist within all fuel markets due to extenuating events that occur from time to time.

Additionally, the low cost baseload energy from TEC will help JEA and Florida reduce their dependence on volatile, higher cost energy from natural gas and oil. Figures C.8-1 and C.8-2 show JEA's projected capacity resources by fuel type in 2006 and 2013, respectively. Figures C.8-3 and C.8-4 show JEA's projected energy resources by fuel type in 2006 and 2013, respectively.

C.8.2 Reliability of JEA's Fuel Supply

The addition of solid-fueled generation increases the reliability of JEA's fuel supply. The plant design will allow for up to at least 90 days of coal and petcoke inventory, minimizing the short-term supply disruptions that occurred with natural gas as a result of hurricanes affecting the Gulf Coast supply region. Furthermore, onsite fuel storage minimizes the short-term disruptions of fuel transportation systems.

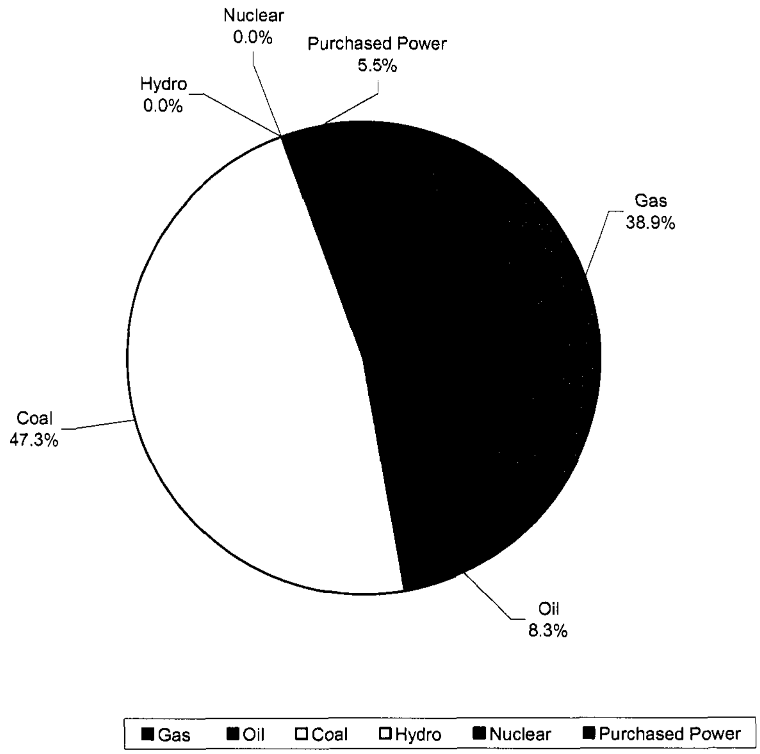

Figure C.8-1
JEA's 2006 Capacity Resources by Fuel Type

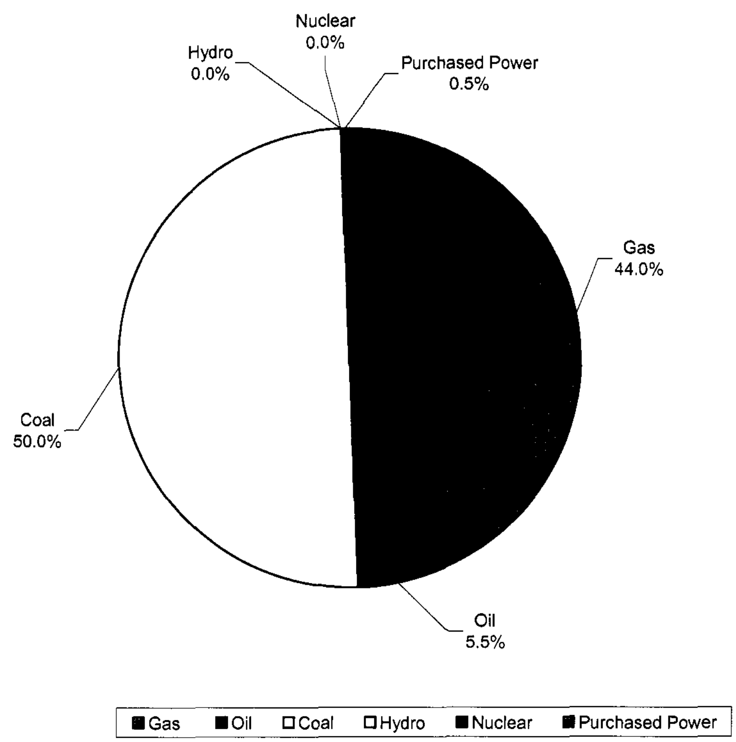

Figure C.8-2
JEA's 2013 Capacity Resources by Fuel Type

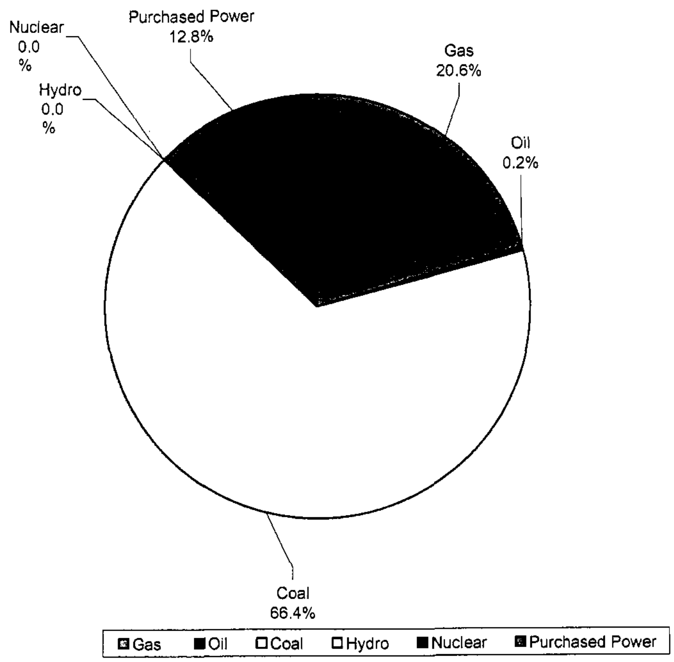

Figure C.8-3
JEA's 2006 Energy Resources by Fuel Type

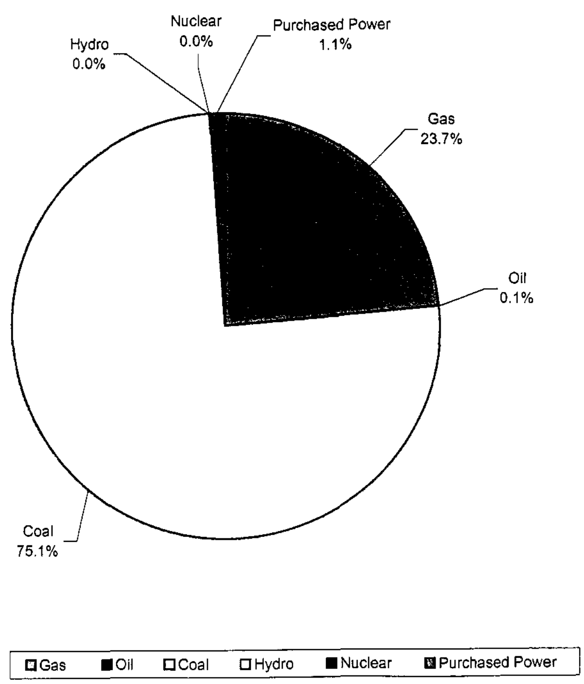

Figure C.8-4
JEA's 2013 Energy Resources by Fuel Type

C.8.3 Stability of JEA's Electric Rates

TEC will help to satisfy the need for low cost, baseload energy within JEA's service territory and the State of Florida as a whole. Additional low cost, baseload energy from TEC will help stabilize electric rates for consumers and businesses. Electric rate stability will be beneficial for long-term planning and should also help facilitate more stable growth within the economy.

C.8.4 Long Service Life

Although economic evaluations have been conducted through 2035 for this Application, TEC will be designed for, and is expected to have, a service life significantly greater than the 23 years of operation captured by the analysis period. The benefits of TEC's expected actual service life of 35 to 50 or more years have not been captured in the economic analysis, but are expected to be realized by JEA and the other Participants. Therefore, the total cost savings and benefits of TEC are understated in the economic analysis.

C.8.5 Supercritical Clean Coal Technology

By using supercritical pulverized coal boiler technology (which operates at a higher steam pressure than subcritical pulverized coal boilers) with BACT pollution control systems, TEC will be among the most efficient and cleanest coal plants within the State of Florida. Supercritical clean coal technology is proven, has been in commercial service for decades, and provides at least a 2 percent lower heat rate in comparison to subcritical pulverized coal technology. This improvement in heat rate means that more energy can be generated with the same fuel input. The lower heat rate also translates into lower emissions from fuel combustion, because less fuel is needed for the same quantity of kilowatt-hours of energy output.

In addition, TEC will include BACT pollution control equipment to further reduce emissions per unit of fuel input. Combustion and post-combustion pollution controls will include low NO_x burners, SCR, wet FGD, wet electrostatic precipitator (WESP), baghouse, and a zero liquid discharge. As a result, TEC will have very low emissions rates.

C.8.6 Demonstrated Technology

Supercritical pulverized coal technology is a demonstrated technology that has been in commercial use for decades and has proven to be a reliable, baseload technology. Selection of a demonstrated technology is important to minimize risk to JEA's customers.

The use of supercritical pulverized coal, as a demonstrated technology, allows the Participants to achieve economies of scale inherent in larger generating units. Moreover, demonstrated technology is generally more favored by financing institutions and bond investors.

C.8.7 Environmental Considerations

As described in Section A.5.0, CAIR and CAMR will require much of the United States, including the State of Florida, to make significant reductions in the emissions of NO_x, SO_2, and Hg. With high natural gas prices, coal fired facilities will likely be the most economical type of generation to meet capacity requirements for utilities throughout the CAIR region. Generally, conventional coal fired generation has higher emissions of NO_x, SO_2, and Hg than natural gas or fuel oil generation. As a result of the planned pollution control measures to be implemented on TEC as listed above and described in more detail in Section A.3.0, the proposed TEC project is designed to have lower emissions of NO_x, SO_2, and Hg than other coal fired power plants currently in operation.

C.8.8 Geographic Diversity

For JEA, the other Participants, and the State of Florida as a whole, TEC will provide geographic diversity, because it will be constructed on a greenfield site. The greenfield site provides JEA with additional baseload generation without increasing the concentration of its generation resources at one location or within its service territory. JEA currently has approximately two thirds of its generating resources located at two adjacent sites (Northside and SJRPP). This diversity should increase reliability and availability of generating resources, particularly if a hurricane or other extreme condition causes forced outages at the adjacent Northside and SJRPP sites.

C.9.0 JEA's Consequences of Delay

The proposed TEC is unique compared to the other supply-side alternatives considered in this analysis because the project is significantly further along in the development process than the other options presented in Section A.6.0 and considered to meet JEA's capacity and energy needs. As a result, the consequences of delaying the commercial operation of TEC are significant from a project risk, economic, and reliability standpoint for JEA. This section describes the negative consequences of delaying the TEC project.

C.9.1 Economic Consequences

If the commercial operation of TEC is delayed by 1 year to May 1, 2013, JEA will not be able to realize the economic benefit of the low cost, base load energy from TEC and will need to secure capacity for an additional year to maintain its target 15 percent reserve margin. As a result, JEA will need to continue to satisfy its demand and energy requirements with higher cost energy from natural gas and additional seasonal purchases. The capacity expansion plan including TEC delayed 1 year until May 1 2013 includes a seasonal purchase of 70 MW in 2012, a second seasonal purchase of 185 MW in 2013, and TEC as a committed resource beginning May 1, 2013. The winter seasonal purchases were modeled with an assumed energy cost of $164.09 per MWh (escalating at 2.5 percent annually) and a capacity cost of $7.50 per kW-month (with no escalation) in 2012 dollars. Following operation of TEC in May 2013, the remainder of the capacity expansion plan includes a brownfield CFB in 2013, a second brownfield CFB in 2015, a brownfield LMS100 CT in 2020, a brownfield and a greenfield LMS100 CT in 2021, a second greenfield LMS100 CT in 2022, and a brownfield IGCC unit in 2023. The CPWC of this plan is $14,180.7 million, which is about $41.7 million higher in CPWC over the planning period than the base case plan with TEC in 2012 (presented in Section C.5.0).

However, the CPWC of the plan with TEC delayed one year is $2.6 million higher in cost than the lowest cost plan without TEC presented in Section C.5.0. The economic benefit of the low cost, base load energy from TEC, available only after May of 2013, is not sufficient to offset the higher cost energy in 2012 and 2013 from the seasonal purchases for the plan with TEC delayed one year when compared to the low cost, base load energy from the addition of a brownfield CFB in 2012 for the lowest cost plan without TEC in Section C.5.0.

C.9.2 Reliability Consequences

If TEC is delayed and no additional generating capacity is installed to meet JEA's forecast capacity requirements by 2012, JEA's reserve margin will fall to approximately 13 percent. This is below JEA's reserve criterion of 15 percent. Operation of JEA's system below its reserve margin criteria will increase the probability that JEA will not be able to serve its retail customers and will expose JEA's retail customers to potentially high purchase power costs.

C.10.0 JEA's Financial Analysis

JEA has the necessary funding sources available to finance the development and construction of JEA's ownership share of the TEC. Given its 31.5 percent ownership stake in the project, JEA will be responsible for financing an estimated $552.0 million of the total cost. These total costs include interest during construction, owner's costs, land acquisition, and a community contribution.

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 TEC with other smaller capital addition costs that may be required concurrent with TEC.

JEA's senior electric system debt has a 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 TEC construction.

The detailed financing for TEC is expected to result in debt service requirements less than the assumed debt service presented in the economic parameters in Section A.4.0.

Appendix C.1 – JEA's CPWC Summary Sheets

Table C.1-1 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Fuel Prices

Case Description	
Fuel Forecast:	High Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,302	40,064
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
IGCC BF	721,900	38	12/01/23	1,167,256	84,673

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Adder ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$548,436	$28,130	$0	$576,565	$0	$0	$0	$0	$0	$0	$576,565	$576,565
2007	$488,461	$28,658	$0	$517,119	$0	$0	$0	$0	$0	$0	$517,119	$1,069,060
2008	$495,086	$30,057	$0	$525,143	$0	$0	$0	$0	$0	$0	$525,143	$1,545,380
2009	$487,016	$35,484	$0	$522,501	$0	$0	$0	$0	$0	$0	$522,501	$1,996,735
2010	$545,891	$48,593	$0	$594,483	$0	$0	$0	$0	$0	$0	$594,483	$2,485,818
2011	$601,802	$61,729	$0	$663,531	$0	$0	$0	$0	$0	$0	$663,531	$3,005,712
2012	$602,463	$57,685	$4,451	$664,599	$26,819	$788	$4,928	$2,100	$477	$35,111	$699,711	$3,527,847
2013	$608,092	$58,302	$7,609	$674,003	$44,316	$807	$7,392	$0	$748	$53,263	$727,266	$4,044,701
2014	$580,535	$62,811	$16,762	$660,109	$90,124	$827	$7,392	$0	$782	$99,125	$759,234	$4,558,580
2015	$647,923	$67,331	$18,034	$733,288	$94,591	$848	$7,392	$0	$817	$103,648	$836,936	$5,098,077
2016	$598,392	$67,969	$27,902	$694,263	$142,719	$869	$7,392	$0	$854	$151,834	$846,097	$5,617,507
2017	$579,989	$63,773	$28,600	$672,362	$142,719	$891	$7,392	$0	$892	$151,894	$824,256	$6,099,432
2018	$639,899	$68,863	$29,315	$738,076	$142,719	$913	$7,392	$0	$933	$151,956	$890,033	$6,595,036
2019	$680,833	$71,882	$30,048	$782,763	$142,719	$936	$7,392	$0	$974	$152,021	$934,784	$7,090,772
2020	$757,633	$78,713	$30,901	$867,247	$143,448	$959	$7,392	$0	$1,018	$152,818	$1,020,064	$7,605,973
2021	$820,591	$81,531	$33,042	$935,165	$152,840	$983	$7,392	$0	$1,064	$162,279	$1,097,444	$8,133,863
2022	$852,623	$82,235	$36,693	$971,551	$170,174	$1,008	$7,392	$0	$1,112	$179,686	$1,151,237	$8,661,258
2023	$899,542	$87,522	$40,693	$1,027,758	$186,052	$1,033	$7,392	$0	$1,162	$195,639	$1,223,397	$9,195,022
2024	$922,335	$99,023	$58,445	$1,079,803	$263,534	$1,059	$7,392	$0	$1,214	$273,199	$1,353,002	$9,757,222
2025	$1,003,196	$103,545	$59,906	$1,166,647	$263,534	$1,086	$7,392	$0	$1,269	$273,280	$1,439,927	$10,327,050
2026	$1,035,071	$105,859	$61,404	$1,202,333	$263,534	$1,113	$7,392	$0	$1,326	$273,364	$1,475,698	$10,883,225
2027	$1,070,621	$108,943	$62,939	$1,242,503	$263,534	$1,141	$7,392	$0	$1,386	$273,452	$1,515,955	$11,427,365
2028	$1,116,283	$111,099	$64,512	$1,291,894	$263,534	$1,169	$7,392	$0	$1,448	$273,543	$1,565,437	$11,962,510
2029	$1,176,650	$114,585	$66,125	$1,357,359	$263,534	$1,198	$7,392	$0	$1,513	$273,637	$1,630,996	$12,493,515
2030	$1,238,653	$117,394	$67,778	$1,423,825	$263,534	$1,228	$7,392	$0	$1,581	$273,735	$1,697,560	$13,019,874
2031	$1,267,981	$118,596	$69,473	$1,456,050	$263,534	$1,259	$7,392	$0	$1,653	$273,837	$1,729,887	$13,530,714
2032	$1,331,277	$122,030	$71,209	$1,524,517	$263,534	$1,290	$7,392	$0	$1,727	$273,943	$1,798,459	$14,036,514
2033	$1,400,126	$125,465	$72,990	$1,598,580	$263,534	$1,323	$7,392	$0	$1,805	$274,053	$1,872,632	$14,538,096
2034	$1,453,944	$127,854	$74,814	$1,656,612	$263,534	$1,356	$7,392	$0	$1,886	$274,167	$1,930,779	$15,030,625
2035	$1,535,971	$132,337	$76,685	$1,744,993	$263,534	$1,390	$7,392	$0	$1,971	$274,286	$2,019,279	$15,521,202

Table C.1-2 Expansion Plan Economic Summary - Without Taylor Energy Center - High Fuel Prices

Case Description	
Fuel Forecast:	High Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
IGCC UNIT BF	712,900	38	12/01/19	1,044,293	75,753
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
CFB UNIT GF	574,000	44	12/01/22	910,948	66,080
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*								Cumulative
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Other Capital Cost ($1,000)	Other Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$548,436	$28,130	$0	$576,565	$0	$0	$0	$0	$0	$0	$576,565	$576,565
2007	$488,461	$28,658	$0	$517,119	$0	$0	$0	$0	$0	$0	$517,119	$1,069,060
2008	$495,086	$30,057	$0	$525,143	$0	$0	$0	$0	$0	$0	$525,143	$1,545,380
2009	$487,016	$35,484	$0	$522,501	$0	$0	$0	$0	$0	$0	$522,501	$1,996,735
2010	$545,891	$48,593	$0	$594,483	$0	$0	$0	$0	$0	$0	$594,483	$2,485,818
2011	$601,055	$61,290	$82	$662,427	$584	$0	$0	$0	$0	$584	$663,011	$3,005,305
2012	$653,535	$65,116	$1,777	$720,427	$11,024	$0	$0	$0	$0	$11,024	$731,451	$3,551,125
2013	$579,700	$61,497	$10,566	$651,764	$55,715	$0	$0	$0	$0	$55,715	$707,479	$4,053,917
2014	$636,603	$70,616	$11,663	$718,881	$60,073	$0	$0	$0	$0	$60,073	$778,954	$4,581,143
2015	$620,890	$72,103	$21,142	$714,135	$107,027	$0	$0	$0	$0	$107,027	$821,161	$5,110,471
2016	$656,858	$75,628	$21,670	$754,156	$107,027	$0	$0	$0	$0	$107,027	$861,183	$5,639,163
2017	$609,802	$67,711	$22,212	$699,725	$107,027	$0	$0	$0	$0	$107,027	$806,752	$6,110,854
2018	$684,823	$73,882	$22,767	$781,473	$107,027	$0	$0	$0	$0	$107,027	$888,499	$6,605,604
2019	$719,312	$78,105	$24,709	$822,126	$113,461	$0	$0	$0	$0	$113,461	$935,586	$7,101,765
2020	$715,014	$86,925	$40,487	$842,426	$182,780	$0	$0	$0	$0	$182,780	$1,025,206	$7,619,564
2021	$773,476	$91,305	$41,604	$906,385	$183,527	$0	$0	$0	$0	$183,527	$1,089,912	$8,143,830
2022	$831,367	$95,490	$45,004	$971,861	$197,194	$0	$0	$0	$0	$197,194	$1,169,054	$8,679,388
2023	$827,527	$98,393	$59,586	$985,506	$258,488	$0	$0	$0	$0	$258,488	$1,243,993	$9,222,138
2024	$932,587	$104,353	$62,831	$1,099,772	$268,238	$0	$0	$0	$0	$268,238	$1,368,010	$9,790,574
2025	$1,004,192	$107,520	$66,049	$1,177,760	$277,365	$0	$0	$0	$0	$277,365	$1,455,125	$10,366,417
2026	$1,024,502	$109,076	$67,700	$1,201,278	$277,365	$0	$0	$0	$0	$277,365	$1,478,642	$10,923,701
2027	$1,070,758	$113,379	$69,392	$1,253,529	$277,365	$0	$0	$0	$0	$277,365	$1,530,894	$11,473,204
2028	$1,103,890	$114,564	$71,127	$1,289,581	$277,365	$0	$0	$0	$0	$277,365	$1,566,945	$12,008,864
2029	$1,171,475	$118,513	$72,905	$1,362,893	$277,365	$0	$0	$0	$0	$277,365	$1,640,258	$12,542,885
2030	$1,229,224	$121,310	$74,728	$1,425,262	$277,365	$0	$0	$0	$0	$277,365	$1,702,627	$13,070,815
2031	$1,271,536	$123,463	$76,596	$1,471,595	$276,781	$0	$0	$0	$0	$276,781	$1,748,376	$13,587,115
2032	$1,326,825	$126,045	$78,511	$1,531,381	$270,489	$0	$0	$0	$0	$270,489	$1,801,870	$14,093,874
2033	$1,393,055	$130,391	$80,474	$1,603,920	$270,489	$0	$0	$0	$0	$270,489	$1,874,409	$14,595,931
2034	$1,446,382	$132,122	$82,486	$1,660,989	$270,489	$0	$0	$0	$0	$270,489	$1,931,478	$15,088,639
2035	$1,534,144	$136,977	$84,548	$1,755,669	$270,489	$0	$0	$0	$0	$270,489	$2,026,158	$15,580,887

Table C.1-3 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Fuel Prices

Case Description	
Fuel Forecast:	Low Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	550,065	39,902
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
GE LMS100 CT BF	65,100	17	12/01/15	84,591	7,589
CFB UNIT BF	544,700	41	12/01/19	800,312	58,055
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy Cost	O&M		*Total Production Cost*	Unit Capital Cost	Community Contribution	Transmission Charge	Seasonal Purchase	Ongoing Capex Adder	*Total Capital Cost*	Total System Cost	Cumulative Present Worth Cost
Year	($1,000)	Variable ($1,000)	Fixed ($1,000)	*($1,000)*	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	*($1,000)*	($1,000)	($1,000)
2006	$429,193	$28,160	$0	$457,352	$0	$0	$0	$0	$0	$0	$457,352	$457,352
2007	$389,956	$28,802	$0	$418,758	$0	$0	$0	$0	$0	$0	$418,758	$856,169
2008	$394,585	$30,195	$0	$424,780	$0	$0	$0	$0	$0	$0	$424,780	$1,241,457
2009	$393,085	$35,615	$0	$428,701	$0	$0	$0	$0	$0	$0	$428,701	$1,611,785
2010	$433,528	$49,266	$0	$482,795	$0	$0	$0	$0	$0	$0	$482,795	$2,008,981
2011	$465,965	$61,936	$0	$527,901	$0	$0	$0	$0	$0	$0	$527,901	$2,422,605
2012	$468,924	$57,975	$4,451	$531,351	$26,710	$788	$4,928	$2,100	$477	$35,003	$566,354	$2,845,227
2013	$482,077	$59,314	$7,609	$549,000	$44,153	$807	$7,392	$0	$748	$53,101	$602,101	$3,273,129
2014	$464,997	$63,276	$16,762	$545,035	$89,962	$827	$7,392	$0	$782	$98,963	$643,998	$3,709,013
2015	$515,430	$67,357	$17,272	$600,058	$90,607	$848	$7,392	$0	$817	$99,664	$699,722	$4,160,060
2016	$528,202	$68,271	$18,699	$615,172	$97,552	$869	$7,392	$0	$854	$106,666	$721,838	$4,603,206
2017	$510,281	$60,886	$19,166	$590,333	$97,552	$891	$7,392	$0	$892	$106,727	$697,059	$5,010,762
2018	$557,894	$66,795	$19,645	$644,335	$97,552	$913	$7,392	$0	$933	$106,789	$751,124	$5,429,016
2019	$599,439	$71,987	$21,078	$692,504	$102,482	$936	$7,392	$0	$974	$111,784	$804,288	$5,855,547
2020	$587,929	$76,898	$31,999	$696,826	$155,606	$959	$7,392	$0	$1,018	$164,976	$861,802	$6,290,815
2021	$633,998	$82,202	$33,042	$749,242	$157,140	$983	$7,392	$0	$1,064	$166,580	$915,822	$6,731,341
2022	$649,523	$82,486	$36,693	$768,702	$174,475	$1,008	$7,392	$0	$1,112	$183,987	$952,689	$7,167,779
2023	$695,437	$87,023	$39,469	$821,930	$184,814	$1,033	$7,392	$0	$1,162	$194,401	$1,016,331	$7,611,201
2024	$760,793	$90,312	$43,817	$894,922	$203,468	$1,059	$7,392	$0	$1,214	$213,133	$1,108,056	$8,071,621
2025	$811,779	$93,761	$46,559	$952,098	$212,595	$1,086	$7,392	$0	$1,269	$222,341	$1,174,439	$8,536,387
2026	$834,576	$96,501	$47,723	$978,800	$212,595	$1,113	$7,392	$0	$1,326	$222,425	$1,201,225	$8,989,115
2027	$852,142	$97,334	$48,916	$998,391	$212,595	$1,141	$7,392	$0	$1,386	$222,513	$1,220,904	$9,427,350
2028	$886,085	$100,160	$50,139	$1,036,384	$212,595	$1,169	$7,392	$0	$1,448	$222,603	$1,258,988	$9,857,734
2029	$918,212	$101,876	$51,393	$1,071,480	$212,595	$1,198	$7,392	$0	$1,513	$222,698	$1,294,178	$10,279,082
2030	$973,554	$105,941	$52,677	$1,132,173	$212,595	$1,228	$7,392	$0	$1,581	$222,796	$1,354,968	$10,699,214
2031	$991,076	$106,191	$53,994	$1,151,261	$212,595	$1,259	$7,392	$0	$1,653	$222,898	$1,374,159	$11,105,007
2032	$1,029,544	$109,715	$55,344	$1,194,603	$212,595	$1,290	$7,392	$0	$1,727	$223,004	$1,417,606	$11,503,695
2033	$1,062,663	$111,300	$56,728	$1,230,691	$212,595	$1,323	$7,392	$0	$1,805	$223,114	$1,453,805	$11,893,094
2034	$1,105,695	$114,482	$58,146	$1,278,323	$211,950	$1,356	$7,392	$0	$1,886	$222,583	$1,500,906	$12,275,966
2035	$1,149,541	$117,617	$59,600	$1,326,758	$205,005	$1,390	$7,392	$0	$1,971	$215,757	$1,542,515	$12,650,714

Table C.1-4 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Fuel Prices

Case Description	
Fuel Forecast:	Low Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
1x1 7FA CC BF	204,000	30	12/01/19	296,439	23,463
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
IGCC UNIT BF	712,900	38	12/01/22	1,124,589	81,578
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

Year	Production Cost				Capital Cost and Other Project Costs						Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Other Capital Cost ($1,000)	Other Capital Cost ($1,000)	*Total Capital Cost ($1,000)*		
2006	$429,193	$28,160	$0	$457,352	$0	$0	$0	$0	$0	$0	$457,352	$457,352
2007	$389,956	$28,802	$0	$418,758	$0	$0	$0	$0	$0	$0	$418,758	$856,169
2008	$394,585	$30,195	$0	$424,780	$0	$0	$0	$0	$0	$0	$424,780	$1,241,457
2009	$393,085	$35,615	$0	$428,701	$0	$0	$0	$0	$0	$0	$428,701	$1,611,785
2010	$433,528	$49,266	$0	$482,795	$0	$0	$0	$0	$0	$0	$482,795	$2,008,981
2011	$465,487	$61,498	$82	$527,067	$584	$0	$0	$0	$0	$584	$527,651	$2,422,410
2012	$501,477	$65,895	$1,777	$569,149	$11,024	$0	$0	$0	$0	$11,024	$580,172	$2,855,343
2013	$454,829	$61,343	$10,566	$526,738	$55,715	$0	$0	$0	$0	$55,715	$582,453	$3,269,282
2014	$497,371	$71,767	$11,663	$580,800	$60,073	$0	$0	$0	$0	$60,073	$640,873	$3,703,050
2015	$491,703	$72,268	$21,142	$585,113	$107,027	$0	$0	$0	$0	$107,027	$692,140	$4,149,209
2016	$510,292	$75,445	$21,670	$607,407	$107,027	$0	$0	$0	$0	$107,027	$714,434	$4,587,810
2017	$492,474	$68,114	$22,212	$582,800	$107,027	$0	$0	$0	$0	$107,027	$689,827	$4,991,137
2018	$543,135	$74,181	$22,767	$640,084	$107,027	$0	$0	$0	$0	$107,027	$747,110	$5,407,156
2019	$580,179	$78,407	$24,440	$683,026	$109,020	$0	$0	$0	$0	$109,020	$792,046	$5,827,195
2020	$609,716	$79,957	$36,982	$726,655	$130,490	$0	$0	$0	$0	$130,490	$857,145	$6,260,112
2021	$647,190	$83,394	$37,749	$768,333	$131,237	$0	$0	$0	$0	$131,237	$899,571	$6,692,821
2022	$679,565	$88,524	$41,064	$809,153	$146,220	$0	$0	$0	$0	$146,220	$955,373	$7,130,488
2023	$658,602	$97,690	$58,300	$814,592	$221,695	$0	$0	$0	$0	$221,695	$1,036,288	$7,582,617
2024	$727,067	$103,093	$61,251	$891,412	$231,446	$0	$0	$0	$0	$231,446	$1,122,858	$8,049,187
2025	$781,272	$107,109	$64,167	$952,548	$240,572	$0	$0	$0	$0	$240,572	$1,193,120	$8,521,345
2026	$794,009	$109,240	$65,509	$968,759	$240,572	$0	$0	$0	$0	$240,572	$1,209,331	$8,977,129
2027	$811,355	$111,966	$66,885	$990,205	$240,572	$0	$0	$0	$0	$240,572	$1,230,778	$9,418,908
2028	$843,284	$114,795	$68,295	$1,026,375	$240,572	$0	$0	$0	$0	$240,572	$1,266,947	$9,852,013
2029	$873,517	$117,065	$69,741	$1,060,323	$240,572	$0	$0	$0	$0	$240,572	$1,300,895	$10,275,547
2030	$927,045	$121,270	$71,223	$1,119,538	$240,572	$0	$0	$0	$0	$240,572	$1,360,110	$10,697,274
2031	$945,403	$122,348	$72,741	$1,140,492	$239,988	$0	$0	$0	$0	$239,988	$1,380,481	$11,104,934
2032	$979,458	$125,439	$74,298	$1,179,195	$233,697	$0	$0	$0	$0	$233,697	$1,412,892	$11,502,296
2033	$1,015,961	$128,341	$75,894	$1,220,195	$233,697	$0	$0	$0	$0	$233,697	$1,453,892	$11,891,719
2034	$1,056,170	$131,358	$77,529	$1,265,058	$233,697	$0	$0	$0	$0	$233,697	$1,498,754	$12,274,042
2035	$1,104,379	$135,760	$79,205	$1,319,344	$233,697	$0	$0	$0	$0	$233,697	$1,553,040	$12,651,347

Table C.1-5 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	High Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

	Generation Additions				
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
GE 7FA CT BF	71,700	14	12/01/07	76,236	6,840
GE 7FA CT BF	71,700	14	12/01/07	76,236	6,840
GE 7FA CT GF	76,700	14	12/01/07	81,552	7,317
GE 7FA CT GF	76,700	14	12/01/07	81,552	7,317
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
1x1 7FA CC BF	204,000	30	12/01/19	296,439	23,463
IGCC UNIT BF	712,900	38	12/01/21	1,097,160	79,588
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
		O&M										
Year	Fuel and Energy Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$539,151	$28,988	$0	$568,139	$0	$0	$0	$0	$0	$0	$568,139	$568,139
2007	$582,389	$34,088	$352	$616,829	$2,405	$0	$0	$0	$0	$2,405	$619,234	$1,157,885
2008	$555,103	$51,621	$4,246	$610,970	$28,314	$0	$0	$0	$0	$28,314	$639,283	$1,737,734
2009	$542,119	$55,739	$4,352	$602,209	$28,314	$0	$0	$0	$0	$28,314	$630,523	$2,282,403
2010	$594,432	$75,765	$4,460	$674,658	$28,314	$0	$0	$0	$0	$28,314	$702,971	$2,860,740
2011	$644,389	$93,072	$4,735	$742,197	$29,482	$0	$0	$0	$0	$29,482	$771,679	$3,465,370
2012	$634,162	$76,192	$11,108	$721,462	$68,870	$788	$4,928	$0	$418	$75,003	$796,464	$4,059,704
2013	$649,808	$75,474	$13,620	$738,901	$82,108	$807	$7,392	$0	$748	$91,055	$829,956	$4,649,538
2014	$709,529	$89,509	$14,793	$813,830	$86,466	$827	$7,392	$0	$782	$95,467	$909,297	$5,264,986
2015	$692,184	$86,927	$25,203	$804,314	$137,886	$848	$7,392	$0	$817	$146,943	$951,257	$5,878,175
2016	$651,415	$83,447	$35,250	$770,112	$186,014	$869	$7,392	$0	$854	$195,129	$965,241	$6,470,749
2017	$633,376	$78,312	$36,132	$747,820	$186,014	$891	$7,392	$0	$892	$195,189	$943,009	$7,022,107
2018	$691,339	$85,961	$37,035	$814,334	$186,014	$913	$7,392	$0	$933	$195,252	$1,009,586	$7,584,282
2019	$733,676	$88,648	$39,065	$861,389	$188,007	$936	$7,392	$0	$974	$197,309	$1,058,698	$8,145,732
2020	$778,626	$88,978	$51,972	$919,575	$209,477	$959	$7,392	$0	$1,018	$218,847	$1,138,422	$8,720,713
2021	$836,157	$96,628	$54,452	$987,237	$216,237	$983	$7,392	$0	$1,064	$225,676	$1,212,913	$9,304,145
2022	$807,341	$104,751	$71,479	$983,571	$289,065	$1,008	$7,392	$0	$1,112	$298,577	$1,282,148	$9,891,511
2023	$882,217	$111,598	$73,295	$1,067,110	$290,718	$1,033	$7,392	$0	$1,162	$300,305	$1,367,415	$10,488,110
2024	$1,002,239	$116,767	$78,376	$1,197,382	$310,219	$1,059	$7,392	$0	$1,214	$319,884	$1,517,267	$11,118,566
2025	$1,080,959	$120,802	$83,367	$1,285,127	$328,472	$1,086	$7,392	$0	$1,269	$338,218	$1,623,345	$11,760,979
2026	$1,146,266	$125,475	$85,189	$1,356,930	$328,472	$1,113	$7,392	$0	$1,326	$338,302	$1,695,232	$12,399,894
2027	$1,180,686	$128,658	$87,057	$1,396,401	$326,067	$1,141	$7,392	$0	$1,386	$335,985	$1,732,386	$13,021,720
2028	$1,239,221	$131,861	$88,972	$1,460,054	$300,158	$1,169	$7,392	$0	$1,448	$310,167	$1,770,221	$13,626,870
2029	$1,288,499	$134,903	$90,934	$1,514,337	$300,158	$1,198	$7,392	$0	$1,513	$310,261	$1,824,598	$14,220,907
2030	$1,371,263	$140,320	$92,946	$1,604,529	$300,158	$1,228	$7,392	$0	$1,581	$310,359	$1,914,888	$14,814,652
2031	$1,403,635	$141,259	$95,007	$1,639,902	$298,990	$1,259	$7,392	$0	$1,653	$309,293	$1,949,195	$15,390,255
2032	$1,463,748	$144,786	$97,121	$1,705,654	$286,407	$1,290	$7,392	$0	$1,727	$296,816	$2,002,470	$15,953,431
2033	$1,517,251	$147,700	$99,287	$1,764,238	$286,407	$1,323	$7,392	$0	$1,805	$296,926	$2,061,164	$16,505,510
2034	$1,590,175	$151,334	$101,507	$1,843,016	$286,407	$1,356	$7,392	$0	$1,886	$297,040	$2,140,056	$17,051,425
2035	$1,663,223	$156,929	$103,783	$1,923,935	$286,407	$1,390	$7,392	$0	$1,971	$297,159	$2,221,094	$17,591,032

Table C.1-6 Expansion Plan Economic Summary - Without Taylor Energy Center - High Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	High Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE 7FA CT BF	71,700	14	12/01/07	76,236	6,840
GE 7FA CT BF	71,700	14	12/01/07	76,236	6,840
GE 7FA CT GF	76,700	14	12/01/07	81,552	7,317
GE 7FA CT GF	76,700	14	12/01/07	81,552	7,317
1x1 7FA CC BF	204,000	30	12/01/11	243,301	19,257
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
IGCC UNIT BF	712,900	38	12/01/18	1,018,822	73,905
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
CFB UNIT GF	574,000	44	12/01/21	888,729	64,468
GE LMS100 CT BF	65,100	17	12/01/22	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/23	105,803	9,493
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Other Capital	Other Capital	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Cost ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$539,151	$28,988	$0	$568,139	$0	$0	$0	$0	$0	$0	$568,139	$568,139
2007	$582,389	$34,088	$352	$616,829	$2,405	$0	$0	$0	$0	$2,405	$619,234	$1,157,885
2008	$555,103	$51,621	$4,246	$610,970	$28,314	$0	$0	$0	$0	$28,314	$639,283	$1,737,734
2009	$542,119	$55,739	$4,352	$602,209	$28,314	$0	$0	$0	$0	$28,314	$630,523	$2,282,403
2010	$594,432	$75,765	$4,460	$674,658	$28,314	$0	$0	$0	$0	$28,314	$702,971	$2,860,740
2011	$643,453	$92,817	$5,638	$741,907	$29,949	$0	$0	$0	$0	$29,949	$771,857	$3,465,509
2012	$658,887	$85,020	$17,285	$761,192	$47,571	$0	$0	$0	$0	$47,571	$808,762	$4,069,020
2013	$685,940	$87,196	$18,266	$791,402	$51,823	$0	$0	$0	$0	$51,823	$843,225	$4,668,285
2014	$656,809	$88,949	$28,257	$774,014	$101,989	$0	$0	$0	$0	$101,989	$876,004	$5,261,198
2015	$655,397	$89,021	$37,889	$782,306	$148,943	$0	$0	$0	$0	$148,943	$931,249	$5,861,490
2016	$693,344	$93,692	$38,574	$825,610	$148,943	$0	$0	$0	$0	$148,943	$974,553	$6,459,781
2017	$664,847	$84,472	$39,277	$788,596	$148,943	$0	$0	$0	$0	$148,943	$937,539	$7,007,941
2018	$724,144	$93,726	$41,336	$859,206	$155,220	$0	$0	$0	$0	$155,220	$1,014,426	$7,572,811
2019	$700,174	$96,259	$56,898	$853,332	$222,848	$0	$0	$0	$0	$222,848	$1,076,180	$8,143,532
2020	$777,824	$107,077	$58,161	$943,061	$223,578	$0	$0	$0	$0	$223,578	$1,166,639	$8,732,764
2021	$815,729	$108,931	$61,655	$986,315	$245,712	$0	$0	$0	$0	$245,712	$1,232,027	$9,325,390
2022	$812,208	$109,742	$76,029	$997,979	$306,144	$0	$0	$0	$0	$306,144	$1,304,123	$9,922,824
2023	$886,061	$116,638	$79,142	$1,081,841	$306,338	$0	$0	$0	$0	$306,338	$1,388,178	$10,528,482
2024	$1,010,002	$121,914	$84,369	$1,216,286	$325,622	$0	$0	$0	$0	$325,622	$1,541,908	$11,169,176
2025	$1,070,923	$123,606	$89,510	$1,284,038	$343,874	$0	$0	$0	$0	$343,874	$1,627,912	$11,813,396
2026	$1,147,646	$130,794	$91,485	$1,369,925	$343,874	$0	$0	$0	$0	$343,874	$1,713,799	$12,459,309
2027	$1,187,013	$134,040	$93,511	$1,414,563	$341,469	$0	$0	$0	$0	$341,469	$1,756,032	$13,089,624
2028	$1,237,595	$137,169	$95,587	$1,470,351	$315,561	$0	$0	$0	$0	$315,561	$1,785,911	$13,700,137
2029	$1,290,092	$140,758	$97,714	$1,528,565	$315,561	$0	$0	$0	$0	$315,561	$1,844,125	$14,300,531
2030	$1,376,888	$146,825	$99,895	$1,623,609	$315,561	$0	$0	$0	$0	$315,561	$1,939,169	$14,901,806
2031	$1,400,249	$147,092	$102,131	$1,649,472	$315,561	$0	$0	$0	$0	$315,561	$1,965,032	$15,482,085
2032	$1,467,287	$151,349	$104,422	$1,723,059	$315,561	$0	$0	$0	$0	$315,561	$2,038,620	$16,055,428
2033	$1,521,526	$154,326	$106,771	$1,782,623	$315,561	$0	$0	$0	$0	$315,561	$2,098,184	$16,617,423
2034	$1,595,762	$158,398	$109,179	$1,863,339	$315,561	$0	$0	$0	$0	$315,561	$2,178,899	$17,173,246
2035	$1,666,555	$163,033	$111,646	$1,941,235	$315,561	$0	$0	$0	$0	$315,561	$2,256,795	$17,721,526

Table C.1-7 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Low Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
CFB UNIT BF	544,700	41	12/01/21	840,827	60,994
CFB UNIT BF	544,700	41	12/01/24	905,479	65,683

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing Capex	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Adder ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$421,345	$25,583	$0	$446,927	$0	$0	$0	$0	$0	$0	$446,927	$446,927
2007	$387,478	$26,127	$0	$413,605	$0	$0	$0	$0	$0	$0	$413,605	$840,837
2008	$401,021	$28,568	$0	$429,589	$0	$0	$0	$0	$0	$0	$429,589	$1,230,487
2009	$398,680	$31,507	$0	$430,187	$0	$0	$0	$0	$0	$0	$430,187	$1,602,098
2010	$451,636	$42,961	$0	$494,597	$0	$0	$0	$0	$0	$0	$494,597	$2,009,004
2011	$488,194	$52,252	$0	$540,446	$0	$0	$0	$0	$0	$0	$540,446	$2,432,457
2012	$497,171	$50,076	$4,451	$551,699	$26,805	$788	$4,928	$0	$418	$32,938	$584,636	$2,868,722
2013	$503,697	$49,055	$6,797	$559,548	$40,043	$807	$7,392	$0	$748	$48,990	$608,538	$3,301,199
2014	$550,866	$57,560	$6,967	$615,393	$40,043	$827	$7,392	$0	$782	$49,044	$664,437	$3,750,916
2015	$607,743	$61,844	$7,141	$676,729	$40,043	$848	$7,392	$0	$817	$49,100	$725,828	$4,218,791
2016	$648,168	$66,609	$7,320	$722,097	$40,043	$869	$7,392	$0	$854	$49,158	$771,255	$4,692,275
2017	$592,521	$55,574	$7,503	$655,598	$40,043	$891	$7,392	$0	$892	$49,218	$704,816	$5,104,366
2018	$656,261	$61,943	$7,690	$725,895	$40,043	$913	$7,392	$0	$933	$49,280	$775,175	$5,536,012
2019	$698,970	$64,924	$7,883	$771,777	$40,043	$936	$7,392	$0	$974	$49,345	$821,122	$5,971,471
2020	$768,810	$74,188	$8,080	$851,078	$40,043	$959	$7,392	$0	$1,018	$49,412	$900,490	$6,426,279
2021	$814,777	$78,125	$9,271	$902,172	$45,223	$983	$7,392	$0	$1,064	$54,662	$956,834	$6,886,533
2022	$768,109	$79,771	$20,423	$868,304	$101,036	$1,008	$7,392	$0	$1,112	$110,548	$978,852	$7,334,956
2023	$860,829	$88,771	$20,934	$970,534	$101,036	$1,033	$7,392	$0	$1,162	$110,623	$1,081,158	$7,806,662
2024	$987,473	$98,454	$22,522	$1,108,450	$106,615	$1,059	$7,392	$0	$1,214	$116,280	$1,224,730	$8,315,562
2025	$950,337	$97,958	$34,846	$1,083,141	$166,720	$1,086	$7,392	$0	$1,269	$176,466	$1,259,607	$8,814,032
2026	$981,311	$101,084	$35,717	$1,118,112	$166,720	$1,113	$7,392	$0	$1,326	$176,550	$1,294,663	$9,301,976
2027	$1,007,617	$101,965	$36,610	$1,146,193	$166,720	$1,141	$7,392	$0	$1,386	$176,638	$1,322,830	$9,776,796
2028	$1,050,525	$105,193	$37,526	$1,193,243	$166,720	$1,169	$7,392	$0	$1,448	$176,729	$1,369,972	$10,245,121
2029	$1,103,833	$108,861	$38,464	$1,251,157	$166,720	$1,198	$7,392	$0	$1,513	$176,823	$1,427,980	$10,710,030
2030	$1,175,628	$113,787	$39,425	$1,328,840	$166,720	$1,228	$7,392	$0	$1,581	$176,921	$1,505,761	$11,176,919
2031	$1,193,658	$111,991	$40,411	$1,346,059	$166,720	$1,259	$7,392	$0	$1,653	$177,023	$1,523,082	$11,626,689
2032	$1,248,520	$116,559	$41,421	$1,406,500	$166,720	$1,290	$7,392	$0	$1,727	$177,129	$1,583,629	$12,072,070
2033	$1,294,908	$117,230	$42,457	$1,454,594	$166,720	$1,323	$7,392	$0	$1,805	$177,239	$1,631,833	$12,509,154
2034	$1,348,837	$120,800	$43,518	$1,513,155	$166,720	$1,356	$7,392	$0	$1,886	$177,353	$1,690,508	$12,940,392
2035	$1,427,400	$126,802	$44,606	$1,598,808	$166,720	$1,390	$7,392	$0	$1,971	$177,472	$1,776,280	$13,371,932

Table C.1-8 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Load and Energy Growth

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Low Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
CFB UNIT BF	544,700	41	12/01/21	840,827	60,994
IGCC UNIT BF	712,900	38	12/01/24	1,181,521	85,708

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*				Other	Other	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Capital Cost ($1,000)	Capital Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$421,345	$25,583	$0	$446,927	$0	$0	$0	$0	$0	$0	$446,927	$446,927
2007	$387,478	$26,127	$0	$413,605	$0	$0	$0	$0	$0	$0	$413,605	$840,837
2008	$401,021	$28,568	$0	$429,589	$0	$0	$0	$0	$0	$0	$429,589	$1,230,487
2009	$398,680	$31,507	$0	$430,187	$0	$0	$0	$0	$0	$0	$430,187	$1,602,098
2010	$451,636	$42,961	$0	$494,597	$0	$0	$0	$0	$0	$0	$494,597	$2,009,004
2011	$488,194	$52,252	$0	$540,446	$0	$0	$0	$0	$0	$0	$540,446	$2,432,457
2012	$546,246	$60,850	$0	$607,096	$0	$0	$0	$0	$0	$0	$607,096	$2,885,482
2013	$563,718	$62,005	$0	$625,723	$0	$0	$0	$0	$0	$0	$625,723	$3,330,171
2014	$616,661	$73,521	$832	$691,014	$4,358	$0	$0	$0	$0	$4,358	$695,372	$3,800,827
2015	$588,998	$69,253	$10,040	$668,291	$51,312	$0	$0	$0	$0	$51,312	$719,603	$4,264,689
2016	$625,925	$73,751	$10,291	$709,967	$51,312	$0	$0	$0	$0	$51,312	$761,279	$4,732,048
2017	$573,931	$63,434	$10,549	$647,914	$51,312	$0	$0	$0	$0	$51,312	$699,225	$5,140,871
2018	$640,378	$70,489	$10,812	$721,679	$51,312	$0	$0	$0	$0	$51,312	$772,991	$5,571,301
2019	$679,285	$72,590	$11,083	$762,958	$51,312	$0	$0	$0	$0	$51,312	$814,269	$6,003,125
2020	$751,637	$82,027	$11,360	$845,024	$51,312	$0	$0	$0	$0	$51,312	$896,336	$6,455,836
2021	$799,861	$87,390	$12,633	$899,883	$56,492	$0	$0	$0	$0	$56,492	$956,376	$6,915,869
2022	$750,231	$88,754	$23,870	$862,854	$112,305	$0	$0	$0	$0	$112,305	$975,160	$7,362,601
2023	$834,871	$97,351	$24,466	$956,689	$112,305	$0	$0	$0	$0	$112,305	$1,068,994	$7,828,999
2024	$962,751	$106,957	$26,631	$1,096,339	$119,585	$0	$0	$0	$0	$119,585	$1,215,924	$8,334,241
2025	$924,615	$111,991	$44,450	$1,081,055	$198,013	$0	$0	$0	$0	$198,013	$1,279,068	$8,840,411
2026	$946,224	$113,947	$45,561	$1,105,731	$198,013	$0	$0	$0	$0	$198,013	$1,303,744	$9,331,779
2027	$972,127	$115,710	$46,700	$1,134,537	$198,013	$0	$0	$0	$0	$198,013	$1,332,550	$9,810,088
2028	$1,018,994	$119,390	$47,867	$1,186,251	$198,013	$0	$0	$0	$0	$198,013	$1,384,264	$10,283,298
2029	$1,063,318	$122,412	$49,064	$1,234,794	$198,013	$0	$0	$0	$0	$198,013	$1,432,807	$10,749,779
2030	$1,140,873	$127,565	$50,291	$1,318,729	$198,013	$0	$0	$0	$0	$198,013	$1,516,742	$11,220,072
2031	$1,151,569	$126,476	$51,548	$1,329,593	$198,013	$0	$0	$0	$0	$198,013	$1,527,606	$11,671,178
2032	$1,209,397	$131,555	$52,837	$1,393,788	$198,013	$0	$0	$0	$0	$198,013	$1,591,801	$12,118,858
2033	$1,252,488	$132,882	$54,158	$1,439,528	$198,013	$0	$0	$0	$0	$198,013	$1,637,541	$12,557,470
2034	$1,309,337	$136,900	$55,512	$1,501,749	$198,013	$0	$0	$0	$0	$198,013	$1,699,762	$12,991,069
2035	$1,396,487	$144,176	$56,899	$1,597,562	$198,013	$0	$0	$0	$0	$198,013	$1,795,575	$13,427,297

Table C.1-9 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	662,411	48,051
CFB UNIT BF	653,640	41	12/01/13	828,128	60,072
CFB UNIT BF	653,640	41	12/01/15	870,051	63,114
GE LMS100 CT BF	78,120	17	12/01/20	114,848	10,304
GE LMS100 CT BF	78,120	17	12/01/21	117,719	10,562
GE LMS100 CT GF	82,200	17	12/01/21	123,867	11,113
GE LMS100 CT GF	82,200	17	12/01/22	126,964	11,391
1x1 7FA CC BF	244,800	30	12/01/23	392,656	31,079

	Production Cost				Capital Cost and Other Project Costs							Cumulative
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,721,165
2012	$534,104	$57,858	$4,451	$596,413	$32,165	$788	$4,928	$2,100	$477	$40,458	$636,872	$3,196,408
2013	$542,117	$58,439	$7,609	$608,165	$53,153	$807	$7,392	$0	$748	$62,100	$670,265	$3,672,754
2014	$518,304	$62,774	$16,762	$597,841	$108,124	$827	$7,392	$0	$782	$117,125	$714,966	$4,156,670
2015	$574,301	$67,247	$18,034	$659,583	$113,484	$848	$7,392	$0	$817	$122,541	$782,123	$4,660,834
2016	$540,883	$67,840	$27,902	$636,626	$171,237	$869	$7,392	$0	$854	$180,352	$816,978	$5,162,388
2017	$522,631	$63,602	$28,600	$614,832	$171,237	$891	$7,392	$0	$892	$180,412	$795,244	$5,627,351
2018	$568,600	$69,235	$29,315	$667,150	$171,237	$913	$7,392	$0	$933	$180,475	$847,624	$6,099,340
2019	$609,429	$71,818	$30,048	$711,294	$171,237	$936	$7,392	$0	$974	$180,539	$891,834	$6,572,298
2020	$668,808	$78,510	$30,901	$778,219	$172,112	$959	$7,392	$0	$1,018	$181,482	$959,701	$7,057,012
2021	$708,681	$81,336	$33,042	$823,060	$183,382	$983	$7,392	$0	$1,064	$192,822	$1,015,881	$7,545,669
2022	$724,340	$82,044	$36,693	$843,077	$204,184	$1,008	$7,392	$0	$1,112	$213,696	$1,056,773	$8,029,788
2023	$794,922	$85,762	$40,304	$920,988	$217,247	$1,033	$7,392	$0	$1,162	$226,834	$1,147,823	$8,530,580
2024	$884,679	$88,214	$53,488	$1,026,381	$245,686	$1,059	$7,392	$0	$1,214	$255,351	$1,281,733	$9,063,166
2025	$959,126	$93,804	$54,564	$1,107,493	$245,686	$1,086	$7,392	$0	$1,269	$255,433	$1,362,925	$9,602,522
2026	$987,059	$95,505	$55,666	$1,138,229	$245,686	$1,113	$7,392	$0	$1,326	$255,517	$1,393,746	$10,127,810
2027	$1,015,876	$97,239	$56,796	$1,169,911	$245,686	$1,141	$7,392	$0	$1,386	$255,604	$1,425,516	$10,639,488
2028	$1,057,658	$99,715	$57,954	$1,215,327	$245,686	$1,169	$7,392	$0	$1,448	$255,695	$1,471,022	$11,142,357
2029	$1,110,705	$102,148	$59,141	$1,271,993	$245,686	$1,198	$7,392	$0	$1,513	$255,790	$1,527,783	$11,639,759
2030	$1,176,108	$105,960	$60,357	$1,342,426	$245,686	$1,228	$7,392	$0	$1,581	$255,888	$1,598,313	$12,135,345
2031	$1,196,723	$105,852	$61,604	$1,364,179	$245,686	$1,259	$7,392	$0	$1,653	$255,990	$1,620,168	$12,613,785
2032	$1,252,267	$109,440	$62,883	$1,424,590	$245,686	$1,290	$7,392	$0	$1,727	$256,095	$1,680,685	$13,086,462
2033	$1,304,449	$111,472	$64,193	$1,480,114	$245,686	$1,323	$7,392	$0	$1,805	$256,205	$1,736,320	$13,551,532
2034	$1,358,895	$114,417	$65,536	$1,538,848	$245,686	$1,356	$7,392	$0	$1,886	$256,320	$1,795,167	$14,009,468
2035	$1,434,115	$119,183	$66,912	$1,620,210	$245,686	$1,390	$7,392	$0	$1,971	$256,438	$1,876,649	$14,465,393

Table C.1-10 Expansion Plan Economic Summary - Without Taylor Energy Center - High Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	78,120	17	12/01/11	91,962	8,251
CFB UNIT BF	653,640	41	12/01/12	807,929	58,607
CFB UNIT BF	653,640	41	12/01/14	848,831	61,574
GE LMS100 CT BF	78,120	17	12/01/19	112,047	10,053
1x1 7FA CC BF	244,800	30	12/01/20	364,620	28,860
IGCC UNIT BF	855,480	38	12/01/22	1,349,507	97,893
GE LMS100 CT GF	82,200	17	12/01/23	130,138	11,676
GE LMS100 CT GF	82,200	17	12/01/24	133,391	11,968

	Production Cost				Capital Cost and Other Project Costs							Cumulative Present Worth Cost ($1,000)
	Fuel and Energy Cost	O&M		*Total Production Cost*	Unit Capital Cost	Community Contribution	Transmission Charge	Other Capital Cost	Other Capital Cost	*Total Capital Cost*	Total System Cost	
Year	($1,000)	Variable ($1,000)	Fixed ($1,000)	*($1,000)*	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	*($1,000)*	($1,000)	
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$533,799	$61,578	$82	$595,458	$701	$0	$0	$0	$0	$701	$596,159	$2,720,955
2012	$575,868	$65,675	$1,777	$643,321	$13,228	$0	$0	$0	$0	$13,228	$656,549	$3,210,882
2013	$514,377	$61,464	$10,566	$586,407	$66,858	$0	$0	$0	$0	$66,858	$653,265	$3,675,145
2014	$563,433	$71,101	$11,663	$646,197	$72,088	$0	$0	$0	$0	$72,088	$718,284	$4,161,308
2015	$551,272	$72,012	$21,142	$644,425	$128,432	$0	$0	$0	$0	$128,432	$772,857	$4,659,499
2016	$584,044	$74,841	$21,670	$680,556	$128,432	$0	$0	$0	$0	$128,432	$808,988	$5,156,147
2017	$548,068	$67,594	$22,212	$637,874	$128,432	$0	$0	$0	$0	$128,432	$766,306	$5,604,191
2018	$604,155	$73,800	$22,767	$700,722	$128,432	$0	$0	$0	$0	$128,432	$829,154	$6,065,895
2019	$647,276	$77,538	$23,436	$748,249	$129,286	$0	$0	$0	$0	$129,286	$877,535	$6,531,270
2020	$704,320	$82,148	$26,230	$812,698	$140,936	$0	$0	$0	$0	$140,936	$953,634	$7,012,921
2021	$722,639	$80,849	$38,875	$842,363	$167,345	$0	$0	$0	$0	$167,345	$1,009,708	$7,498,607
2022	$769,561	$88,070	$41,064	$898,695	$175,659	$0	$0	$0	$0	$175,659	$1,074,354	$7,990,781
2023	$751,723	$96,994	$58,300	$907,016	$266,230	$0	$0	$0	$0	$266,230	$1,173,246	$8,502,664
2024	$862,583	$102,531	$61,251	$1,026,365	$277,930	$0	$0	$0	$0	$277,930	$1,304,295	$9,044,626
2025	$922,486	$106,348	$64,167	$1,093,002	$288,882	$0	$0	$0	$0	$288,882	$1,381,883	$9,591,484
2026	$946,249	$108,351	$65,509	$1,120,109	$288,882	$0	$0	$0	$0	$288,882	$1,408,991	$10,122,518
2027	$978,619	$111,479	$66,885	$1,156,983	$288,882	$0	$0	$0	$0	$288,882	$1,445,865	$10,641,500
2028	$1,022,396	$114,332	$68,295	$1,205,023	$288,882	$0	$0	$0	$0	$288,882	$1,493,905	$11,152,191
2029	$1,063,303	$116,419	$69,741	$1,249,463	$288,882	$0	$0	$0	$0	$288,882	$1,538,345	$11,653,032
2030	$1,135,299	$120,928	$71,223	$1,327,450	$288,882	$0	$0	$0	$0	$288,882	$1,616,332	$12,154,205
2031	$1,162,448	$122,072	$72,741	$1,357,261	$288,181	$0	$0	$0	$0	$288,181	$1,645,442	$12,640,109
2032	$1,209,512	$125,185	$74,298	$1,408,995	$280,631	$0	$0	$0	$0	$280,631	$1,689,626	$13,115,300
2033	$1,261,713	$128,182	$75,894	$1,465,788	$280,631	$0	$0	$0	$0	$280,631	$1,746,419	$13,583,076
2034	$1,317,080	$131,240	$77,529	$1,525,850	$280,631	$0	$0	$0	$0	$280,631	$1,806,481	$14,043,897
2035	$1,384,780	$135,738	$79,205	$1,599,724	$280,631	$0	$0	$0	$0	$280,631	$1,880,355	$14,500,723

Table C.1-11 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	460,007	33,369
CFB UNIT BF	435,760	41	12/01/13	552,085	40,048
CFB UNIT BF	435,760	41	12/01/15	580,034	42,076
GE LMS100 CT BF	52,080	17	12/01/20	76,565	6,869
GE LMS100 CT BF	52,080	17	12/01/21	78,479	7,041
GE LMS100 CT GF	54,800	17	12/01/21	82,578	7,409
GE LMS100 CT GF	54,800	17	12/01/22	84,643	7,594
IGCC BF	577,520	38	12/01/23	933,805	67,738

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Adder ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,721,165
2012	$534,104	$57,858	$4,451	$596,413	$22,337	$788	$4,928	$2,100	$477	$30,630	$627,043	$3,189,074
2013	$542,117	$58,439	$7,609	$608,165	$36,770	$807	$7,392	$0	$748	$45,717	$653,882	$3,653,776
2014	$518,304	$62,774	$16,762	$597,841	$73,417	$827	$7,392	$0	$782	$82,418	$680,259	$4,114,203
2015	$574,301	$67,247	$18,034	$659,583	$76,991	$848	$7,392	$0	$817	$86,048	$745,630	$4,594,842
2016	$540,883	$67,840	$27,902	$636,626	$115,493	$869	$7,392	$0	$854	$124,608	$761,234	$5,062,174
2017	$522,631	$63,602	$28,600	$614,832	$115,493	$891	$7,392	$0	$892	$124,668	$739,500	$5,494,544
2018	$568,600	$69,235	$29,315	$667,150	$115,493	$913	$7,392	$0	$933	$124,730	$791,880	$5,935,493
2019	$609,429	$71,818	$30,048	$711,294	$115,493	$936	$7,392	$0	$974	$124,795	$836,089	$6,378,889
2020	$668,808	$78,510	$30,901	$778,219	$116,076	$959	$7,392	$0	$1,018	$125,446	$903,665	$6,835,301
2021	$708,681	$81,336	$33,042	$823,060	$123,590	$983	$7,392	$0	$1,064	$133,029	$956,089	$7,295,196
2022	$724,340	$82,044	$36,693	$843,077	$137,457	$1,008	$7,392	$0	$1,112	$146,969	$990,046	$7,748,748
2023	$787,122	$87,872	$42,697	$917,691	$150,160	$1,033	$7,392	$0	$1,162	$159,747	$1,077,438	$8,218,830
2024	$826,829	$97,534	$58,445	$982,808	$212,145	$1,059	$7,392	$0	$1,214	$221,810	$1,204,618	$8,719,374
2025	$896,942	$102,055	$59,906	$1,058,903	$212,145	$1,086	$7,392	$0	$1,269	$221,891	$1,280,794	$9,226,227
2026	$918,226	$103,768	$61,404	$1,083,398	$212,145	$1,113	$7,392	$0	$1,326	$221,975	$1,305,373	$9,718,209
2027	$948,901	$107,189	$62,939	$1,119,028	$212,145	$1,141	$7,392	$0	$1,386	$222,063	$1,341,091	$10,199,583
2028	$983,960	$109,369	$64,512	$1,157,841	$212,145	$1,169	$7,392	$0	$1,448	$222,154	$1,379,995	$10,671,334
2029	$1,037,064	$112,016	$66,125	$1,215,205	$212,145	$1,198	$7,392	$0	$1,513	$222,248	$1,437,453	$11,139,328
2030	$1,089,306	$115,507	$67,778	$1,272,591	$212,145	$1,228	$7,392	$0	$1,581	$222,346	$1,494,937	$11,602,860
2031	$1,109,608	$115,305	$69,473	$1,294,386	$212,145	$1,259	$7,392	$0	$1,653	$222,448	$1,516,834	$12,050,785
2032	$1,161,791	$119,167	$71,209	$1,352,167	$212,145	$1,290	$7,392	$0	$1,727	$222,554	$1,574,721	$12,493,661
2033	$1,219,040	$122,231	$72,990	$1,414,260	$212,145	$1,323	$7,392	$0	$1,805	$222,664	$1,636,924	$12,932,108
2034	$1,260,296	$124,494	$74,814	$1,459,604	$212,145	$1,356	$7,392	$0	$1,886	$222,778	$1,682,382	$13,361,273
2035	$1,328,869	$128,944	$76,685	$1,534,498	$212,145	$1,390	$7,392	$0	$1,971	$222,897	$1,757,395	$13,788,226

Table C.1-12 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Capital Costs

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	54,250	17	12/01/11	63,862	5,730
CFB UNIT BF	453,917	41	12/01/12	561,062	40,699
CFB UNIT BF	453,917	41	12/01/14	589,466	42,760
IGCC UNIT BF	594,083	38	12/01/19	870,244	63,127
GE LMS100 CT BF	54,250	17	12/01/21	81,749	7,335
GE LMS100 CT GF	57,083	17	12/01/22	88,169	7,911
GE LMS100 CT GF	57,083	17	12/01/22	88,169	7,911
1x1 7FA CC BF	170,000	30	12/01/23	272,678	21,582

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Other Capital	Other Capital	*Total Capital*	Total System	Cumulative Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Cost ($1,000)	Cost ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$533,799	$61,578	$82	$595,458	$487	$0	$0	$0	$0	$487	$595,945	$2,720,787
2012	$575,868	$65,675	$1,777	$643,321	$9,186	$0	$0	$0	$0	$9,186	$652,507	$3,207,698
2013	$514,377	$61,464	$10,566	$586,407	$46,429	$0	$0	$0	$0	$46,429	$632,836	$3,657,442
2014	$563,433	$71,101	$11,663	$646,197	$50,061	$0	$0	$0	$0	$50,061	$696,258	$4,128,697
2015	$551,272	$72,012	$21,142	$644,425	$89,189	$0	$0	$0	$0	$89,189	$733,614	$4,601,591
2016	$584,044	$74,841	$21,670	$680,556	$89,189	$0	$0	$0	$0	$89,189	$769,745	$5,074,148
2017	$548,068	$67,594	$22,212	$637,874	$89,189	$0	$0	$0	$0	$89,189	$727,063	$5,499,247
2018	$604,155	$73,800	$22,767	$700,722	$89,189	$0	$0	$0	$0	$89,189	$789,911	$5,939,099
2019	$644,200	$78,172	$24,709	$747,082	$94,551	$0	$0	$0	$0	$94,551	$841,632	$6,385,434
2020	$635,483	$86,690	$40,487	$762,661	$152,317	$0	$0	$0	$0	$152,317	$914,977	$6,847,560
2021	$673,370	$91,014	$41,604	$805,988	$152,939	$0	$0	$0	$0	$152,939	$958,927	$7,308,820
2022	$709,495	$95,174	$44,082	$848,751	$160,995	$0	$0	$0	$0	$160,995	$1,009,746	$7,771,397
2023	$762,068	$98,240	$48,464	$908,772	$177,305	$0	$0	$0	$0	$177,305	$1,086,077	$8,245,248
2024	$876,139	$103,822	$52,414	$1,032,375	$197,055	$0	$0	$0	$0	$197,055	$1,229,430	$8,756,102
2025	$915,688	$104,964	$65,966	$1,086,618	$197,055	$0	$0	$0	$0	$197,055	$1,283,673	$9,264,095
2026	$942,927	$107,594	$67,354	$1,117,875	$197,055	$0	$0	$0	$0	$197,055	$1,314,929	$9,759,678
2027	$969,595	$110,210	$68,776	$1,148,581	$197,055	$0	$0	$0	$0	$197,055	$1,345,635	$10,242,683
2028	$1,018,875	$113,420	$70,233	$1,202,529	$197,055	$0	$0	$0	$0	$197,055	$1,399,583	$10,721,131
2029	$1,059,059	$115,513	$71,727	$1,246,298	$197,055	$0	$0	$0	$0	$197,055	$1,443,353	$11,191,045
2030	$1,131,455	$119,858	$73,258	$1,324,572	$197,055	$0	$0	$0	$0	$197,055	$1,521,626	$11,662,852
2031	$1,151,411	$120,695	$74,828	$1,346,934	$196,568	$0	$0	$0	$0	$196,568	$1,543,502	$12,118,653
2032	$1,204,969	$124,299	$76,437	$1,405,705	$191,325	$0	$0	$0	$0	$191,325	$1,597,030	$12,567,803
2033	$1,250,139	$126,694	$78,086	$1,454,920	$191,325	$0	$0	$0	$0	$191,325	$1,646,244	$13,008,746
2034	$1,312,042	$130,237	$79,776	$1,522,055	$191,325	$0	$0	$0	$0	$191,325	$1,713,380	$13,445,819
2035	$1,371,428	$133,373	$81,509	$1,586,310	$191,325	$0	$0	$0	$0	$191,325	$1,777,635	$13,877,689

Table C.1-13 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - High Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
1x1 7FA CC BF	204,000	30	12/01/23	327,213	25,899

	Production Cost				Capital Cost and Other Project Costs							Cumulative
	Fuel and Energy	O&M		*Total Production*	Unit Capital	Community	Transmission	Seasonal	Ongoing Capex	*Total Capital*	Total System	Present Worth
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Contribution ($1,000)	Charge ($1,000)	Purchase ($1,000)	Adder ($1,000)	*Cost ($1,000)*	Cost ($1,000)	Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,993	$35,478	$0	$474,471	$0	$0	$0	$0	$0	$0	$474,471	$1,815,491
2010	$492,024	$48,593	$0	$540,617	$0	$0	$0	$0	$0	$0	$540,617	$2,260,259
2011	$539,422	$62,012	$0	$601,434	$0	$0	$0	$0	$0	$0	$601,434	$2,731,498
2012	$539,185	$57,856	$4,451	$601,492	$26,805	$788	$4,928	$2,100	$477	$35,097	$636,589	$3,206,530
2013	$547,868	$58,436	$7,609	$613,913	$44,294	$807	$7,392	$0	$748	$53,242	$667,154	$3,680,664
2014	$524,647	$62,763	$16,762	$604,173	$90,103	$827	$7,392	$0	$782	$99,104	$703,277	$4,156,670
2015	$584,612	$67,229	$18,034	$669,875	$94,570	$848	$7,392	$0	$817	$103,627	$773,502	$4,655,276
2016	$552,387	$67,783	$27,902	$648,072	$142,698	$869	$7,392	$0	$854	$151,813	$799,885	$5,146,336
2017	$534,964	$63,979	$28,600	$627,543	$142,698	$891	$7,392	$0	$892	$151,873	$779,415	$5,602,044
2018	$578,457	$68,748	$29,315	$676,520	$142,698	$913	$7,392	$0	$933	$151,935	$828,455	$6,063,359
2019	$625,206	$71,766	$30,048	$727,020	$142,698	$936	$7,392	$0	$974	$152,000	$879,020	$6,529,522
2020	$686,844	$78,446	$30,901	$796,191	$143,427	$959	$7,392	$0	$1,018	$152,796	$948,988	$7,008,825
2021	$726,655	$81,261	$33,042	$840,959	$152,819	$983	$7,392	$0	$1,064	$162,258	$1,003,217	$7,491,389
2022	$742,217	$81,984	$36,693	$860,894	$170,153	$1,008	$7,392	$0	$1,112	$179,665	$1,040,559	$7,968,081
2023	$818,828	$85,692	$40,304	$944,823	$181,039	$1,033	$7,392	$0	$1,162	$190,626	$1,135,450	$8,463,474
2024	$917,047	$88,132	$53,488	$1,058,667	$204,739	$1,059	$7,392	$0	$1,214	$214,404	$1,273,071	$8,992,462
2025	$996,759	$93,737	$54,564	$1,145,060	$204,739	$1,086	$7,392	$0	$1,269	$214,485	$1,359,544	$9,530,480
2026	$1,027,526	$95,435	$55,666	$1,178,627	$204,739	$1,113	$7,392	$0	$1,326	$214,569	$1,393,196	$10,055,561
2027	$1,054,636	$96,706	$56,796	$1,208,138	$204,739	$1,141	$7,392	$0	$1,386	$214,657	$1,422,794	$10,566,262
2028	$1,104,589	$99,639	$57,954	$1,262,182	$204,739	$1,169	$7,392	$0	$1,448	$214,747	$1,476,929	$11,071,150
2029	$1,155,530	$101,614	$59,141	$1,316,284	$204,739	$1,198	$7,392	$0	$1,513	$214,842	$1,531,126	$11,569,640
2030	$1,223,858	$105,246	$60,357	$1,389,461	$204,739	$1,228	$7,392	$0	$1,581	$214,940	$1,604,401	$12,067,114
2031	$1,254,749	$105,792	$61,604	$1,422,146	$204,739	$1,259	$7,392	$0	$1,653	$215,042	$1,637,187	$12,550,580
2032	$1,314,257	$109,377	$62,883	$1,486,517	$204,739	$1,290	$7,392	$0	$1,727	$215,148	$1,701,664	$13,029,157
2033	$1,364,488	$110,891	$64,193	$1,539,572	$204,739	$1,323	$7,392	$0	$1,805	$215,258	$1,754,830	$13,499,185
2034	$1,429,645	$114,398	$65,536	$1,609,579	$204,739	$1,356	$7,392	$0	$1,886	$215,372	$1,824,951	$13,964,718
2035	$1,504,646	$118,539	$66,912	$1,690,098	$204,739	$1,390	$7,392	$0	$1,971	$215,491	$1,905,588	$14,427,674

Table C.1-14 Expansion Plan Economic Summary - Without Taylor Energy Center - High Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
GE LMS100 CT BF	65,100	17	12/01/19	93,372	8,377
1x1 7FA CC BF	204,000	30	12/01/20	303,850	24,050
IGCC UNIT BF	712,900	38	12/01/22	1,124,589	81,578
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*				Other	Other	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Capital Cost ($1,000)	Capital Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,993	$35,478	$0	$474,471	$0	$0	$0	$0	$0	$0	$474,471	$1,815,491
2010	$492,024	$48,593	$0	$540,617	$0	$0	$0	$0	$0	$0	$540,617	$2,260,259
2011	$538,814	$61,575	$82	$600,470	$584	$0	$0	$0	$0	$584	$601,054	$2,731,200
2012	$580,789	$65,671	$1,777	$648,237	$11,024	$0	$0	$0	$0	$11,024	$659,261	$3,223,151
2013	$520,037	$61,450	$10,566	$592,053	$55,715	$0	$0	$0	$0	$55,715	$647,768	$3,683,507
2014	$569,417	$71,083	$11,663	$652,162	$60,073	$0	$0	$0	$0	$60,073	$712,235	$4,165,576
2015	$561,539	$71,969	$21,142	$654,651	$107,027	$0	$0	$0	$0	$107,027	$761,677	$4,656,560
2016	$594,989	$74,781	$21,670	$691,441	$107,027	$0	$0	$0	$0	$107,027	$798,467	$5,146,750
2017	$558,701	$67,517	$22,212	$648,430	$107,027	$0	$0	$0	$0	$107,027	$755,456	$5,588,449
2018	$616,118	$73,747	$22,767	$712,632	$107,027	$0	$0	$0	$0	$107,027	$819,659	$6,044,866
2019	$662,298	$77,474	$23,436	$763,208	$107,738	$0	$0	$0	$0	$107,738	$870,946	$6,506,748
2020	$721,538	$82,073	$26,230	$829,841	$117,447	$0	$0	$0	$0	$117,447	$947,288	$6,985,192
2021	$739,692	$80,782	$38,875	$859,350	$139,454	$0	$0	$0	$0	$139,454	$998,803	$7,465,634
2022	$786,421	$88,000	$41,064	$915,485	$146,382	$0	$0	$0	$0	$146,382	$1,061,867	$7,952,087
2023	$774,763	$96,919	$58,300	$929,983	$221,858	$0	$0	$0	$0	$221,858	$1,151,840	$8,454,632
2024	$893,586	$102,448	$61,251	$1,057,285	$231,609	$0	$0	$0	$0	$231,609	$1,288,893	$8,990,193
2025	$958,899	$106,280	$64,167	$1,129,345	$240,735	$0	$0	$0	$0	$240,735	$1,370,080	$9,532,381
2026	$985,605	$108,289	$65,509	$1,159,403	$240,735	$0	$0	$0	$0	$240,735	$1,400,138	$10,060,078
2027	$1,021,173	$111,404	$66,885	$1,199,462	$240,735	$0	$0	$0	$0	$240,735	$1,440,197	$10,577,025
2028	$1,065,503	$113,869	$68,295	$1,247,667	$240,735	$0	$0	$0	$0	$240,735	$1,488,402	$11,085,835
2029	$1,112,602	$116,350	$69,741	$1,298,693	$240,735	$0	$0	$0	$0	$240,735	$1,539,427	$11,587,029
2030	$1,186,898	$120,861	$71,223	$1,378,981	$240,735	$0	$0	$0	$0	$240,735	$1,619,716	$12,089,251
2031	$1,219,018	$122,009	$72,741	$1,413,768	$240,151	$0	$0	$0	$0	$240,151	$1,653,919	$12,577,658
2032	$1,269,738	$125,115	$74,298	$1,469,151	$233,859	$0	$0	$0	$0	$233,859	$1,703,010	$13,056,613
2033	$1,326,450	$128,130	$75,894	$1,530,474	$233,859	$0	$0	$0	$0	$233,859	$1,764,333	$13,529,187
2034	$1,385,739	$131,212	$77,529	$1,594,481	$233,859	$0	$0	$0	$0	$233,859	$1,828,340	$13,995,585
2035	$1,459,135	$135,744	$79,205	$1,674,085	$233,859	$0	$0	$0	$0	$233,859	$1,907,944	$14,459,113

Table C.1-15 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Low Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
IGCC BF	721,900	38	12/01/23	1,167,256	84,673

	Production Cost				Capital Cost and Other Project Costs							
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$436,130	$35,604	$0	$471,734	$0	$0	$0	$0	$0	$0	$471,734	$1,813,127
2010	$481,054	$48,601	$0	$529,656	$0	$0	$0	$0	$0	$0	$529,656	$2,248,876
2011	$529,443	$62,018	$0	$591,461	$0	$0	$0	$0	$0	$0	$591,461	$2,712,301
2012	$529,041	$57,861	$4,451	$591,352	$26,805	$788	$4,928	$2,100	$477	$35,097	$626,450	$3,179,767
2013	$537,953	$58,793	$7,609	$604,355	$44,294	$807	$7,392	$0	$748	$53,242	$657,596	$3,647,109
2014	$512,817	$62,922	$16,762	$592,501	$90,103	$827	$7,392	$0	$782	$99,104	$691,605	$4,115,214
2015	$564,004	$67,262	$18,034	$649,300	$94,570	$848	$7,392	$0	$817	$103,627	$752,926	$4,600,558
2016	$529,440	$67,887	$27,902	$625,229	$142,698	$869	$7,392	$0	$854	$151,813	$777,042	$5,077,594
2017	$511,642	$63,678	$28,600	$603,920	$142,698	$891	$7,392	$0	$892	$151,873	$755,792	$5,519,490
2018	$556,226	$69,292	$29,315	$654,833	$142,698	$913	$7,392	$0	$933	$151,935	$806,769	$5,968,729
2019	$594,125	$71,884	$30,048	$696,056	$142,698	$936	$7,392	$0	$974	$152,000	$848,056	$6,418,471
2020	$652,034	$78,483	$30,901	$761,418	$143,427	$959	$7,392	$0	$1,018	$152,796	$914,214	$6,880,212
2021	$693,372	$81,820	$33,042	$808,235	$152,819	$983	$7,392	$0	$1,064	$162,258	$970,493	$7,347,035
2022	$706,485	$82,110	$36,693	$825,288	$170,153	$1,008	$7,392	$0	$1,112	$179,665	$1,004,953	$7,807,416
2023	$766,920	$86,533	$40,693	$894,146	$186,031	$1,033	$7,392	$0	$1,162	$195,618	$1,089,764	$8,282,876
2024	$793,368	$97,670	$58,445	$949,483	$263,512	$1,059	$7,392	$0	$1,214	$273,178	$1,222,660	$8,790,917
2025	$858,359	$102,143	$59,906	$1,020,408	$263,512	$1,086	$7,392	$0	$1,269	$273,259	$1,293,666	$9,302,865
2026	$877,004	$103,884	$61,404	$1,042,292	$263,512	$1,113	$7,392	$0	$1,326	$273,343	$1,315,635	$9,798,714
2027	$904,233	$107,277	$62,939	$1,074,449	$263,512	$1,141	$7,392	$0	$1,386	$273,430	$1,347,879	$10,282,525
2028	$936,555	$109,516	$64,512	$1,110,583	$263,512	$1,169	$7,392	$0	$1,448	$273,521	$1,384,104	$10,755,681
2029	$985,684	$112,123	$66,125	$1,163,931	$263,512	$1,198	$7,392	$0	$1,513	$273,616	$1,437,547	$11,223,705
2030	$1,034,059	$115,635	$67,778	$1,217,473	$263,512	$1,228	$7,392	$0	$1,581	$273,714	$1,491,186	$11,686,074
2031	$1,050,761	$115,409	$69,473	$1,235,642	$263,512	$1,259	$7,392	$0	$1,653	$273,816	$1,509,457	$12,131,821
2032	$1,098,822	$119,280	$71,209	$1,289,311	$263,512	$1,290	$7,392	$0	$1,727	$273,921	$1,563,232	$12,571,465
2033	$1,150,614	$122,331	$72,990	$1,345,935	$263,512	$1,323	$7,392	$0	$1,805	$274,031	$1,619,966	$13,005,370
2034	$1,187,762	$124,534	$74,814	$1,387,110	$263,512	$1,356	$7,392	$0	$1,886	$274,146	$1,661,256	$13,429,146
2035	$1,254,025	$128,893	$76,685	$1,459,603	$263,512	$1,390	$7,392	$0	$1,971	$274,264	$1,733,868	$13,850,383

Table C.1-16 Expansion Plan Economic Summary - Without Taylor Energy Center - Low Allowance Prices

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
GE LMS100 CT BF	65,100	17	12/01/19	93,372	8,377
1x1 7FA CC BF	204,000	30	12/01/20	303,850	24,050
IGCC UNIT BF	712,900	38	12/01/22	1,124,589	81,578
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy Cost	O&M		*Total Production Cost*	Unit Capital Cost	Community Contribution	Transmission Charge	Other Capital Cost	Other Capital Cost	*Total Capital Cost*	Total System Cost	Cumulative Present Worth Cost
Year	($1,000)	Variable ($1,000)	Fixed ($1,000)	*($1,000)*	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	*($1,000)*	($1,000)	($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$436,130	$35,604	$0	$471,734	$0	$0	$0	$0	$0	$0	$471,734	$1,813,127
2010	$481,054	$48,601	$0	$529,656	$0	$0	$0	$0	$0	$0	$529,656	$2,248,876
2011	$528,823	$61,581	$82	$590,486	$584	$0	$0	$0	$0	$584	$591,070	$2,711,994
2012	$570,957	$65,681	$1,777	$638,415	$11,024	$0	$0	$0	$0	$11,024	$649,438	$3,196,615
2013	$508,718	$61,476	$10,566	$580,760	$55,715	$0	$0	$0	$0	$55,715	$636,475	$3,648,946
2014	$557,466	$71,119	$11,663	$640,248	$60,073	$0	$0	$0	$0	$60,073	$700,321	$4,122,951
2015	$541,087	$72,052	$21,142	$634,281	$107,027	$0	$0	$0	$0	$107,027	$741,308	$4,600,805
2016	$575,539	$75,272	$21,670	$672,480	$107,027	$0	$0	$0	$0	$107,027	$779,507	$5,079,354
2017	$537,379	$67,667	$22,212	$627,258	$107,027	$0	$0	$0	$0	$107,027	$734,285	$5,508,676
2018	$592,193	$73,856	$22,767	$688,816	$107,027	$0	$0	$0	$0	$107,027	$795,843	$5,951,831
2019	$632,593	$77,612	$23,436	$733,641	$107,738	$0	$0	$0	$0	$107,738	$841,379	$6,398,032
2020	$686,091	$82,127	$26,230	$794,448	$117,447	$0	$0	$0	$0	$117,447	$911,894	$6,858,601
2021	$705,617	$80,928	$38,875	$825,421	$139,454	$0	$0	$0	$0	$139,454	$964,875	$7,322,722
2022	$751,567	$88,109	$41,064	$880,739	$146,382	$0	$0	$0	$0	$146,382	$1,027,122	$7,793,258
2023	$727,632	$96,986	$58,300	$882,919	$221,858	$0	$0	$0	$0	$221,858	$1,104,776	$8,275,268
2024	$830,515	$102,679	$61,251	$994,446	$231,609	$0	$0	$0	$0	$231,609	$1,226,054	$8,784,719
2025	$885,751	$106,422	$64,167	$1,056,340	$240,735	$0	$0	$0	$0	$240,735	$1,297,075	$9,298,016
2026	$906,813	$108,428	$65,509	$1,080,750	$240,735	$0	$0	$0	$0	$240,735	$1,321,485	$9,796,070
2027	$935,712	$111,556	$66,885	$1,114,153	$240,735	$0	$0	$0	$0	$240,735	$1,354,887	$10,282,396
2028	$977,000	$114,422	$68,295	$1,159,717	$240,735	$0	$0	$0	$0	$240,735	$1,400,452	$10,761,141
2029	$1,013,630	$116,489	$69,741	$1,199,860	$240,735	$0	$0	$0	$0	$240,735	$1,440,595	$11,230,157
2030	$1,082,721	$120,999	$71,223	$1,274,942	$240,735	$0	$0	$0	$0	$240,735	$1,515,677	$11,700,120
2031	$1,105,498	$122,142	$72,741	$1,300,382	$240,151	$0	$0	$0	$0	$240,151	$1,540,533	$12,155,043
2032	$1,149,361	$125,242	$74,298	$1,348,901	$233,859	$0	$0	$0	$0	$233,859	$1,582,760	$12,600,180
2033	$1,195,941	$128,209	$75,894	$1,400,044	$233,859	$0	$0	$0	$0	$233,859	$1,633,903	$13,037,818
2034	$1,245,909	$131,296	$77,529	$1,454,734	$233,859	$0	$0	$0	$0	$233,859	$1,688,593	$13,468,567
2035	$1,313,302	$135,690	$79,205	$1,528,197	$233,859	$0	$0	$0	$0	$233,859	$1,762,056	$13,896,653

Table C.1-17 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Regulated - CO_2

Case Description	
Fuel Forecast:	Carbon Tax Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	551,508	40,006
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
1x1 7FA CC BF	204,000	30	12/01/23	327,213	23,736

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total Production*					Ongoing	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capex Adder ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$488,177	$28,156	$0	$516,334	$0	$0	$0	$0	$0	$0	$516,334	$516,334
2007	$436,780	$28,666	$0	$465,446	$0	$0	$0	$0	$0	$0	$465,446	$959,616
2008	$442,801	$30,091	$0	$472,892	$0	$0	$0	$0	$0	$0	$472,892	$1,388,543
2009	$436,068	$35,603	$0	$471,671	$0	$0	$0	$0	$0	$0	$471,671	$1,795,990
2010	$480,580	$48,594	$0	$529,173	$0	$0	$0	$0	$0	$0	$529,173	$2,231,342
2011	$527,402	$62,017	$0	$589,419	$0	$0	$0	$0	$0	$0	$589,419	$2,693,168
2012	$593,767	$57,852	$4,451	$656,071	$26,780	$788	$4,928	$2,100	$477	$35,073	$691,143	$3,208,910
2013	$679,762	$58,464	$7,609	$745,835	$44,258	$807	$7,392	$0	$748	$53,205	$799,040	$3,776,773
2014	$709,141	$62,816	$16,762	$788,719	$90,067	$827	$7,392	$0	$782	$99,068	$887,787	$4,377,662
2015	$755,090	$67,324	$18,034	$840,448	$94,534	$848	$7,392	$0	$817	$103,591	$944,039	$4,986,198
2016	$737,385	$67,786	$27,902	$833,073	$142,661	$869	$7,392	$0	$854	$151,776	$984,849	$5,590,809
2017	$706,992	$63,269	$28,600	$798,861	$142,661	$891	$7,392	$0	$892	$151,836	$950,697	$6,146,662
2018	$600,339	$68,730	$29,315	$698,384	$142,661	$913	$7,392	$0	$933	$151,899	$850,283	$6,620,132
2019	$658,486	$69,838	$30,048	$758,373	$142,661	$936	$7,392	$0	$974	$151,964	$910,336	$7,102,902
2020	$691,871	$76,157	$30,901	$798,929	$143,391	$959	$7,392	$0	$1,018	$152,760	$951,689	$7,583,570
2021	$744,875	$79,827	$33,042	$857,745	$169,311	$983	$7,392	$0	$1,064	$178,750	$1,036,495	$8,082,141
2022	$856,628	$80,455	$36,693	$973,777	$170,749	$1,008	$7,392	$0	$1,112	$180,261	$1,154,038	$8,610,820
2023	$959,290	$85,043	$40,304	$1,084,636	$185,378	$1,033	$7,392	$0	$1,162	$194,965	$1,279,602	$9,169,106
2024	$996,354	$87,797	$53,488	$1,137,639	$180,819	$1,059	$7,392	$0	$1,214	$190,484	$1,328,124	$9,720,968
2025	$1,081,104	$92,316	$54,564	$1,227,984	$202,539	$1,086	$7,392	$0	$1,269	$212,286	$1,440,269	$10,290,932
2026	$1,110,411	$93,688	$55,666	$1,259,765	$202,539	$1,113	$7,392	$0	$1,326	$212,370	$1,472,135	$10,845,764
2027	$1,155,982	$95,215	$56,796	$1,307,993	$202,539	$1,141	$7,392	$0	$1,386	$212,457	$1,520,450	$11,391,518
2028	$1,221,858	$98,326	$57,954	$1,378,138	$202,539	$1,169	$7,392	$0	$1,448	$212,548	$1,590,686	$11,935,294
2029	$1,289,081	$100,650	$59,141	$1,448,872	$202,539	$1,198	$7,392	$0	$1,513	$212,643	$1,661,515	$12,476,236
2030	$1,372,708	$104,650	$60,357	$1,537,715	$202,539	$1,228	$7,392	$0	$1,581	$212,741	$1,750,456	$13,018,996
2031	$1,417,492	$104,498	$61,604	$1,583,594	$202,539	$1,259	$7,392	$0	$1,653	$212,843	$1,796,437	$13,549,489
2032	$1,502,974	$108,809	$62,883	$1,674,666	$202,539	$1,290	$7,392	$0	$1,727	$212,948	$1,887,614	$14,080,363
2033	$1,577,194	$110,308	$64,193	$1,751,695	$202,539	$1,323	$7,392	$0	$1,805	$213,058	$1,964,753	$14,606,618
2034	$1,668,998	$114,002	$65,536	$1,848,536	$202,539	$1,356	$7,392	$0	$1,886	$213,173	$2,061,709	$15,132,547
2035	$1,769,113	$118,299	$66,912	$1,954,324	$202,539	$1,390	$7,392	$0	$1,971	$213,291	$2,167,616	$15,659,161

Table C.1-18 Expansion Plan Economic Summary - Without Taylor Energy Center - Regulated - CO_2

Case Description	
Fuel Forecast:	Carbon Tax Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
GE LMS100 CT BF	65,100	17	12/01/19	93,372	8,377
1x1 7FA CC BF	204,000	30	12/01/20	303,850	24,050
CFB UNIT GF	574,000	44	12/01/22	910,948	66,080
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*				Other	Other	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Capital Cost ($1,000)	Capital Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$488,177	$28,156	$0	$516,334	$0	$0	$0	$0	$0	$0	$516,334	$516,334
2007	$436,780	$28,666	$0	$465,446	$0	$0	$0	$0	$0	$0	$465,446	$959,616
2008	$442,801	$30,091	$0	$472,892	$0	$0	$0	$0	$0	$0	$472,892	$1,388,543
2009	$436,068	$35,603	$0	$471,671	$0	$0	$0	$0	$0	$0	$471,671	$1,795,990
2010	$480,580	$48,594	$0	$529,173	$0	$0	$0	$0	$0	$0	$529,173	$2,231,342
2011	$526,781	$61,580	$82	$588,443	$584	$0	$0	$0	$0	$584	$589,027	$2,692,860
2012	$634,739	$65,674	$1,777	$702,190	$11,024	$0	$0	$0	$0	$11,024	$713,214	$3,225,071
2013	$652,565	$61,455	$10,566	$724,586	$55,715	$0	$0	$0	$0	$55,715	$780,301	$3,779,616
2014	$747,361	$71,121	$11,663	$830,145	$60,073	$0	$0	$0	$0	$60,073	$890,218	$4,382,151
2015	$731,783	$72,090	$21,142	$825,015	$107,027	$0	$0	$0	$0	$107,027	$932,042	$4,982,953
2016	$775,198	$74,801	$21,670	$871,669	$107,027	$0	$0	$0	$0	$107,027	$978,696	$5,583,788
2017	$728,893	$67,277	$22,212	$818,382	$107,027	$0	$0	$0	$0	$107,027	$925,409	$6,124,855
2018	$636,335	$73,276	$22,767	$732,379	$107,027	$0	$0	$0	$0	$107,027	$839,406	$6,592,267
2019	$694,918	$76,780	$23,436	$795,133	$107,738	$0	$0	$0	$0	$107,738	$902,871	$7,071,079
2020	$724,678	$81,376	$26,230	$832,284	$117,447	$0	$0	$0	$0	$117,447	$949,731	$7,550,758
2021	$757,405	$80,322	$38,875	$876,602	$139,454	$0	$0	$0	$0	$139,454	$1,016,056	$8,039,498
2022	$899,380	$86,861	$40,791	$1,027,032	$145,066	$0	$0	$0	$0	$145,066	$1,172,098	$8,576,450
2023	$952,332	$89,305	$55,006	$1,096,643	$206,360	$0	$0	$0	$0	$206,360	$1,303,004	$9,144,946
2024	$995,519	$93,909	$57,875	$1,147,303	$216,111	$0	$0	$0	$0	$216,111	$1,363,414	$9,711,473
2025	$1,077,038	$97,900	$60,706	$1,235,644	$225,237	$0	$0	$0	$0	$225,237	$1,460,881	$10,289,593
2026	$1,101,452	$99,233	$61,962	$1,262,646	$225,237	$0	$0	$0	$0	$225,237	$1,487,883	$10,850,361
2027	$1,155,604	$101,999	$63,249	$1,320,852	$225,237	$0	$0	$0	$0	$225,237	$1,546,089	$11,405,318
2028	$1,213,335	$104,201	$64,569	$1,382,104	$225,237	$0	$0	$0	$0	$225,237	$1,607,342	$11,954,787
2029	$1,278,479	$107,137	$65,921	$1,451,537	$225,237	$0	$0	$0	$0	$225,237	$1,676,775	$12,500,697
2030	$1,372,468	$111,655	$67,307	$1,551,429	$225,237	$0	$0	$0	$0	$225,237	$1,776,667	$13,051,584
2031	$1,422,151	$112,387	$68,728	$1,603,266	$224,653	$0	$0	$0	$0	$224,653	$1,827,919	$13,591,374
2032	$1,491,937	$115,188	$70,184	$1,677,309	$218,362	$0	$0	$0	$0	$218,362	$1,895,671	$14,124,514
2033	$1,574,825	$118,271	$71,677	$1,764,773	$218,362	$0	$0	$0	$0	$218,362	$1,983,135	$14,655,693
2034	$1,655,693	$120,824	$73,207	$1,849,724	$218,362	$0	$0	$0	$0	$218,362	$2,068,085	$15,183,248
2035	$1,760,458	$125,180	$74,775	$1,960,413	$218,362	$0	$0	$0	$0	$218,362	$2,178,774	$15,712,574

Table C.1-19 Expansion Plan Economic Summary - With Joint 3x1 CC in 2012

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
JOINT 3x1 7FA CC	154,004	36	05/01/12	193,467	15,313
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
IGCC UNIT BF	721,900	38	12/01/20	1,083,913	78,627
GE LMS100 CT BF	65,100	17	12/01/22	100,552	9,021
GE LMS100 CT BF	65,100	17	12/01/23	103,065	9,247
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy Cost	O&M		*Total Production Cost*	Unit Capital Cost	Community Contribution	Transmission Charge	Seasonal Purchase	Other Capital Cost	*Total Capital Cost*	Total System Cost	Cumulative Present Worth Cost
Year	($1,000)	Variable ($1,000)	Fixed ($1,000)	*($1,000)*	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	*($1,000)*	($1,000)	($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,721,165
2012	$556,953	$61,088	$7,487	$625,528	$10,250	$788	$5,841	$2,100	$0	$18,979	$644,507	$3,202,106
2013	$566,278	$60,010	$12,008	$638,296	$19,565	$807	$8,761	$0	$0	$29,133	$667,429	$3,676,435
2014	$546,788	$65,313	$21,034	$633,136	$65,373	$827	$8,761	$0	$0	$74,962	$708,097	$4,155,703
2015	$602,362	$70,253	$22,176	$694,791	$69,840	$848	$8,761	$0	$0	$79,450	$774,240	$4,654,786
2016	$568,282	$70,393	$31,910	$670,585	$117,968	$869	$8,761	$0	$0	$127,598	$798,184	$5,144,801
2017	$542,759	$65,357	$32,471	$640,587	$117,968	$891	$8,761	$0	$0	$127,620	$768,207	$5,593,956
2018	$599,160	$71,535	$33,045	$703,741	$117,968	$913	$8,761	$0	$0	$127,642	$831,383	$6,056,901
2019	$638,075	$74,283	$33,634	$745,992	$117,968	$936	$8,761	$0	$0	$127,665	$873,657	$6,520,220
2020	$702,263	$81,847	$35,645	$819,756	$124,646	$959	$8,761	$0	$0	$134,367	$954,122	$7,002,117
2021	$673,395	$88,561	$51,838	$813,794	$196,595	$983	$8,761	$0	$0	$206,340	$1,020,134	$7,492,818
2022	$712,436	$94,185	$53,004	$859,625	$197,361	$1,008	$8,761	$0	$0	$207,130	$1,066,755	$7,981,511
2023	$776,361	$99,789	$55,530	$931,681	$207,228	$1,033	$8,761	$0	$0	$217,023	$1,148,703	$8,482,687
2024	$873,560	$103,289	$59,649	$1,036,499	$225,440	$1,059	$8,761	$0	$0	$235,261	$1,271,759	$9,011,129
2025	$935,728	$106,942	$62,550	$1,105,220	$234,567	$1,086	$8,761	$0	$0	$244,413	$1,349,633	$9,545,225
2026	$957,889	$108,546	$63,876	$1,130,311	$234,567	$1,113	$8,761	$0	$0	$244,441	$1,374,752	$10,063,354
2027	$988,852	$111,280	$65,236	$1,165,369	$234,567	$1,141	$8,761	$0	$0	$244,468	$1,409,837	$10,569,405
2028	$1,035,394	$114,349	$66,630	$1,216,373	$234,567	$1,169	$8,761	$0	$0	$244,497	$1,460,870	$11,068,803
2029	$1,076,292	$116,630	$68,058	$1,260,980	$234,567	$1,198	$8,761	$0	$0	$244,526	$1,505,506	$11,558,952
2030	$1,147,734	$121,142	$69,522	$1,338,399	$234,567	$1,228	$8,761	$0	$0	$244,556	$1,582,955	$12,049,776
2031	$1,182,151	$122,581	$71,023	$1,375,755	$234,567	$1,259	$8,761	$0	$0	$244,587	$1,620,342	$12,528,267
2032	$1,224,164	$125,401	$72,562	$1,422,126	$234,567	$1,290	$8,761	$0	$0	$244,618	$1,666,745	$12,997,024
2033	$1,273,834	$127,866	$74,138	$1,475,838	$234,567	$1,323	$8,761	$0	$0	$244,651	$1,720,489	$13,457,854
2034	$1,332,507	$131,317	$75,755	$1,539,578	$234,567	$1,356	$8,761	$0	$0	$244,684	$1,784,262	$13,913,008
2035	$1,392,113	$135,456	$77,411	$1,604,981	$234,567	$1,390	$8,761	$0	$0	$244,718	$1,849,698	$14,362,385

Table C.1-20 Expansion Plan Economic Summary - With Joint IGCC in 2012

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
JOINT IGCC	474,642	53	05/01/12	592,273	42,963
CFB UNIT BF	*544,700*	*41*	*12/01/13*	*690,106*	*50,060*
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
1x1 7FA CC BF	204,000	30	12/01/20	303,850	24,050
GE LMS100 CT BF	65,100	17	12/01/22	100,552	9,021
GE LMS100 CT BF	65,100	17	12/01/23	103,065	9,247
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*					Other	*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Capital Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,721,165
2012	$522,563	$65,605	$7,958	$596,127	$28,760	$788	$5,601	$2,100	$0	$37,248	$633,375	$3,193,799
2013	$521,669	$68,437	$12,964	$603,070	$47,215	$807	$8,401	$0	$0	$56,423	$659,494	$3,662,489
2014	$498,963	$72,381	$22,252	$593,595	$93,024	$827	$8,401	$0	$0	$102,252	$695,847	$4,133,466
2015	$559,500	$77,540	$23,661	$660,701	$97,491	$848	$8,401	$0	$0	$106,740	$767,440	$4,628,165
2016	$527,999	$77,611	$33,670	$639,279	$145,618	$869	$8,401	$0	$0	$154,889	$794,168	$5,115,715
2017	$507,350	$72,107	$34,511	$613,968	$145,618	$891	$8,401	$0	$0	$154,910	$768,879	$5,565,262
2018	$548,306	$79,145	$35,374	$662,825	$145,618	$913	$8,401	$0	$0	$154,933	$817,758	$6,020,621
2019	$597,463	$81,973	$36,259	$715,695	$145,618	$936	$8,401	$0	$0	$154,956	$870,650	$6,482,345
2020	$655,382	$88,030	$38,274	$781,687	$147,661	$959	$8,401	$0	$0	$157,022	$938,708	$6,956,456
2021	$669,353	$87,514	$51,221	$808,088	$169,668	$983	$8,401	$0	$0	$179,053	$987,141	$7,431,288
2022	$707,556	$93,146	$52,347	$853,049	$170,434	$1,008	$8,401	$0	$0	$179,843	$1,032,893	$7,904,468
2023	$776,309	$99,654	$54,686	$930,650	$179,475	$1,033	$8,401	$0	$0	$188,909	$1,119,559	$8,392,928
2024	$877,406	$103,494	$57,302	$1,038,202	$189,631	$1,059	$8,401	$0	$0	$199,091	$1,237,293	$8,907,049
2025	$935,283	$106,091	$61,766	$1,103,141	$207,883	$1,086	$8,401	$0	$0	$217,370	$1,320,510	$9,429,620
2026	$959,539	$108,573	$63,048	$1,131,160	$207,883	$1,113	$8,401	$0	$0	$217,397	$1,348,557	$9,937,877
2027	$998,115	$111,968	$64,363	$1,174,445	$207,883	$1,141	$8,401	$0	$0	$217,425	$1,391,870	$10,437,478
2028	$1,035,437	$114,214	$65,710	$1,215,361	$207,883	$1,169	$8,401	$0	$0	$217,453	$1,432,814	$10,927,285
2029	$1,091,118	$117,468	$67,091	$1,275,676	$207,883	$1,198	$8,401	$0	$0	$217,482	$1,493,158	$11,413,415
2030	$1,148,103	$120,736	$68,506	$1,337,345	$207,883	$1,228	$8,401	$0	$0	$217,512	$1,554,858	$11,895,526
2031	$1,183,641	$122,240	$69,957	$1,375,838	$207,883	$1,259	$8,401	$0	$0	$217,543	$1,593,381	$12,366,056
2032	$1,226,686	$125,557	$71,444	$1,423,687	$207,883	$1,290	$8,401	$0	$0	$217,575	$1,641,262	$12,827,645
2033	$1,286,760	$128,683	$72,968	$1,488,411	$207,883	$1,323	$8,401	$0	$0	$217,607	$1,706,018	$13,284,600
2034	$1,335,095	$131,274	$74,531	$1,540,899	$207,883	$1,356	$8,401	$0	$0	$217,640	$1,758,539	$13,733,192
2035	$1,394,115	$135,202	$76,132	$1,605,450	$207,883	$1,390	$8,401	$0	$0	$217,674	$1,823,123	$14,176,113

Table C.1-21 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Second PC Unit Available

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
JOINT OWNERSHIP PC UNIT	NA	NA	12/01/20	678,616	49,227
GE LMS100 CT BF	65,100	17	12/01/22	100,552	9,021
GE LMS100 CT BF	65,100	17	12/01/22	100,552	9,021
GE LMS100 CT GF	68,500	17	12/01/23	108,448	9,730
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							Cumulative
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,186	$28,657	$0	$482,844	$0	$0	$0	$0	$0	$0	$482,844	$976,465
2008	$444,311	$30,125	$0	$474,436	$0	$0	$0	$0	$0	$0	$474,436	$1,406,792
2009	$439,692	$35,465	$0	$475,157	$0	$0	$0	$0	$0	$0	$475,157	$1,817,250
2010	$487,406	$48,606	$0	$536,012	$0	$0	$0	$0	$0	$0	$536,012	$2,258,228
2011	$534,317	$61,938	$0	$596,255	$0	$0	$0	$0	$0	$0	$596,255	$2,725,410
2012	$534,132	$57,875	$4,451	$596,458	$26,805	$788	$4,928	$2,100	$477	$35,097	$631,555	$3,196,686
2013	$541,844	$58,484	$7,609	$607,937	$44,294	$807	$7,392	$0	$748	$53,242	$661,178	$3,666,573
2014	$518,948	$62,754	$16,762	$598,464	$90,103	$827	$7,392	$0	$782	$99,104	$697,568	$4,138,715
2015	$574,249	$67,328	$18,034	$659,612	$94,570	$848	$7,392	$0	$817	$103,627	$763,239	$4,630,705
2016	$547,824	$68,974	$27,902	$644,701	$142,698	$869	$7,392	$0	$854	$151,813	$796,514	$5,119,696
2017	$520,732	$63,401	$28,600	$612,733	$142,698	$891	$7,392	$0	$892	$151,873	$764,606	$5,566,745
2018	$568,089	$69,179	$29,315	$666,583	$142,698	$913	$7,392	$0	$933	$151,935	$818,518	$6,022,527
2019	$609,163	$71,916	$30,048	$711,126	$142,698	$936	$7,392	$0	$974	$152,000	$863,126	$6,480,261
2020	$673,451	$78,922	$31,485	$783,858	$146,879	$1,919	$8,008	$0	$1,103	$157,908	$941,766	$6,955,917
2021	$667,229	$75,755	$39,851	$782,835	$191,924	$1,967	$14,783	$0	$2,128	$210,803	$993,638	$7,433,874
2022	$709,505	$81,292	$41,061	$831,858	$193,457	$2,016	$14,783	$0	$2,224	$212,480	$1,044,338	$7,912,297
2023	$763,177	$81,712	$44,599	$889,487	$210,794	$2,067	$14,783	$0	$2,324	$229,968	$1,119,455	$8,400,712
2024	$853,589	$84,273	$47,618	$985,481	$221,391	$2,118	$14,783	$0	$2,429	$240,722	$1,226,202	$8,910,224
2025	$914,880	$87,418	$52,102	$1,054,400	$239,644	$2,171	$14,783	$0	$2,538	$259,136	$1,313,536	$9,430,035
2026	$940,922	$89,590	$53,404	$1,083,916	$239,644	$2,225	$14,783	$0	$2,652	$259,305	$1,343,221	$9,936,281
2027	$970,605	$91,593	$54,740	$1,116,938	$239,644	$2,281	$14,783	$0	$2,772	$259,480	$1,376,418	$10,430,336
2028	$1,018,399	$94,322	$56,108	$1,168,829	$239,644	$2,338	$14,783	$0	$2,896	$259,662	$1,428,490	$10,918,665
2029	$1,058,378	$95,291	$57,511	$1,211,180	$239,644	$2,397	$14,783	$0	$3,027	$259,850	$1,471,031	$11,397,590
2030	$1,105,753	$98,041	$58,948	$1,262,743	$239,644	$2,456	$14,783	$0	$3,163	$260,046	$1,522,789	$11,869,758
2031	$1,140,956	$99,062	$60,422	$1,300,440	$239,644	$2,518	$14,783	$0	$3,305	$260,250	$1,560,690	$12,330,635
2032	$1,190,207	$102,328	$61,933	$1,354,468	$239,644	$2,581	$14,783	$0	$3,454	$260,462	$1,614,930	$12,784,819
2033	$1,241,015	$104,051	$63,481	$1,408,547	$239,644	$2,645	$14,783	$0	$3,609	$260,682	$1,669,229	$13,231,919
2034	$1,297,186	$106,851	$65,068	$1,469,105	$239,644	$2,711	$14,783	$0	$3,772	$260,910	$1,730,015	$13,673,235
2035	$1,355,984	$110,535	$66,695	$1,533,214	$239,644	$2,779	$14,783	$0	$3,941	$261,148	$1,794,362	$14,109,168

Table C.1-22 Expansion Plan Economic Summary - Without Taylor Energy Center - All Gas

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

	Generation Additions				
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
1x1 7FA CC BF	204,000	30	12/01/11	243,301	19,257
GE LMS100 CT BF	65,100	17	12/01/13	80,515	7,224
GE LMS100 CT BF	65,100	17	12/01/14	82,527	7,404
1x1 7FA CC GF	219,600	33	12/01/15	289,968	22,951
GE LMS100 CT GF	68,500	17	12/01/20	100,705	9,035
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
1x1 7FA CC GF	219,600	33	12/01/22	344,681	27,281
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
		O&M										
Year	Fuel and Energy Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Other Capital Cost ($1,000)	Other Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,848
2011	$532,443	$61,489	$1,066	$594,997	$1,636	$0	$0	$0	$0	$1,636	$596,633	$2,721,326
2012	$543,583	$57,505	$12,598	$613,686	$19,257	$0	$0	$0	$0	$19,257	$632,943	$3,193,638
2013	$566,391	$59,366	$12,737	$638,494	$19,871	$0	$0	$0	$0	$19,871	$658,365	$3,661,526
2014	$608,308	$64,718	$13,829	$686,854	$27,110	$0	$0	$0	$0	$27,110	$713,964	$4,144,765
2015	$660,425	$66,847	$16,061	$743,333	$35,835	$0	$0	$0	$0	$35,835	$779,168	$4,647,023
2016	$669,146	$63,524	$28,938	$761,608	$56,836	$0	$0	$0	$0	$56,836	$818,444	$5,149,477
2017	$636,278	$58,211	$29,138	$723,626	$56,836	$0	$0	$0	$0	$56,836	$780,463	$5,605,797
2018	$700,593	$62,941	$29,343	$792,877	$56,836	$0	$0	$0	$0	$56,836	$849,713	$6,078,950
2019	$741,754	$65,811	$29,552	$837,118	$56,836	$0	$0	$0	$0	$56,836	$893,954	$6,553,033
2020	$815,002	$72,394	$29,903	$917,299	$57,604	$0	$0	$0	$0	$57,604	$974,902	$7,045,424
2021	$867,292	$75,952	$31,895	$975,139	$67,445	$0	$0	$0	$0	$67,445	$1,042,584	$7,546,925
2022	$913,254	$77,649	$36,458	$1,027,361	$86,711	$0	$0	$0	$0	$86,711	$1,114,072	$8,057,294
2023	$979,380	$80,453	$50,182	$1,110,015	$111,675	$0	$0	$0	$0	$111,675	$1,221,690	$8,590,314
2024	$1,110,809	$87,768	$50,800	$1,249,378	$112,522	$0	$0	$0	$0	$112,522	$1,361,900	$9,156,211
2025	$1,178,251	$91,213	$52,931	$1,322,395	$121,649	$0	$0	$0	$0	$121,649	$1,444,043	$9,727,668
2026	$1,227,277	$93,768	$53,469	$1,374,515	$121,649	$0	$0	$0	$0	$121,649	$1,496,164	$10,291,557
2027	$1,264,186	$94,832	$54,020	$1,413,038	$121,649	$0	$0	$0	$0	$121,649	$1,534,687	$10,842,421
2028	$1,330,206	$98,407	$54,585	$1,483,199	$121,649	$0	$0	$0	$0	$121,649	$1,604,848	$11,391,038
2029	$1,377,871	$100,014	$55,164	$1,533,050	$121,649	$0	$0	$0	$0	$121,649	$1,654,698	$11,929,760
2030	$1,475,711	$104,319	$55,758	$1,635,787	$121,649	$0	$0	$0	$0	$121,649	$1,757,436	$12,474,685
2031	$1,499,751	$104,732	$56,366	$1,660,849	$121,649	$0	$0	$0	$0	$121,649	$1,782,498	$13,001,061
2032	$1,579,803	$108,732	$56,990	$1,745,525	$121,649	$0	$0	$0	$0	$121,649	$1,867,174	$13,526,186
2033	$1,632,273	$109,950	$57,629	$1,799,852	$121,035	$0	$0	$0	$0	$121,035	$1,920,887	$14,040,693
2034	$1,719,705	$114,096	$58,284	$1,892,086	$113,796	$0	$0	$0	$0	$113,796	$2,005,882	$14,552,380
2035	$1,786,957	$116,715	$58,956	$1,962,628	$107,020	$0	$0	$0	$0	$107,020	$2,069,648	$15,055,194

Table C.1-23 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 - Direct-Fired Biomass in 2011

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	552,009	40,043
BIOMASS UNIT	84,555		12/01/11	97,852	7,098
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
1x1 7FA CC BF	204,000	30	12/01/23	327,213	25,899

Year	Production Cost				Capital Cost and Other Project Costs							Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	Biomass Unit Total Cost ($1,000)	*Total Capital Cost ($1,000)*		
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,091	$30,091	$0	$473,182	$0	$0	$0	$0	$0	$0	$0	$473,182	$1,405,629
2009	$439,816	$35,476	$0	$475,292	$0	$0	$0	$0	$0	$0	$0	$475,292	$1,816,204
2010	$487,458	$48,596	$0	$536,055	$0	$0	$0	$0	$0	$0	$0	$536,055	$2,257,218
2011	$533,720	$61,934	$0	$595,654	$603	$0	$0	$0	$0	$11,484	$12,086	$607,740	$2,733,398
2012	$522,393	$55,839	$4,451	$582,683	$33,903	$788	$4,928	$1,200	$477	$11,771	$53,066	$635,749	$3,207,804
2013	$528,956	$56,336	$7,609	$592,901	$51,393	$807	$7,392	$0	$748	$12,065	$72,405	$665,306	$3,680,624
2014	$505,524	$60,815	$16,762	$583,102	$97,201	$827	$7,392	$0	$782	$12,367	$118,569	$701,671	$4,155,543
2015	$564,620	$66,212	$18,034	$648,865	$101,668	$848	$7,392	$0	$817	$12,676	$123,401	$772,266	$4,653,352
2016	$532,896	$66,722	$27,902	$627,520	$149,796	$869	$7,392	$0	$854	$12,993	$171,903	$799,423	$5,144,129
2017	$511,585	$62,527	$28,600	$602,712	$149,796	$891	$7,392	$0	$892	$13,317	$172,288	$775,000	$5,597,255
2018	$555,881	$67,632	$29,315	$652,828	$149,796	$913	$7,392	$0	$933	$13,650	$172,684	$825,511	$6,056,931
2019	$597,702	$70,500	$30,048	$698,249	$149,796	$936	$7,392	$0	$974	$13,992	$173,090	$871,339	$6,519,021
2020	$652,436	$76,299	$30,901	$759,636	$150,525	$959	$7,392	$0	$1,018	$14,341	$174,236	$933,872	$6,990,689
2021	$696,437	$79,806	$32,904	$809,147	$159,130	$983	$7,392	$0	$1,064	$14,700	$183,269	$992,416	$7,468,059
2022	$722,015	$82,938	$35,164	$840,117	$168,797	$1,008	$7,392	$0	$1,112	$15,067	$193,376	$1,033,493	$7,941,514
2023	$773,776	$83,636	$40,304	$897,715	$188,369	$1,033	$7,392	$0	$1,162	$15,444	$213,400	$1,111,116	$8,426,290
2024	$869,307	$86,699	$53,488	$1,009,494	$212,068	$1,059	$7,392	$0	$1,214	$15,830	$237,564	$1,247,058	$8,944,468
2025	$938,441	$91,562	$54,564	$1,084,567	$212,068	$1,086	$7,392	$0	$1,269	$16,226	$238,041	$1,322,608	$9,467,869
2026	$971,617	$93,847	$55,666	$1,121,129	$212,068	$1,113	$7,392	$0	$1,326	$16,632	$238,531	$1,359,659	$9,980,310
2027	$998,684	$96,113	$56,796	$1,151,592	$212,068	$1,141	$7,392	$0	$1,386	$17,047	$239,034	$1,390,626	$10,479,465
2028	$1,042,237	$98,689	$57,954	$1,198,880	$212,068	$1,169	$7,392	$0	$1,448	$17,474	$239,551	$1,438,431	$10,971,192
2029	$1,090,665	$101,016	$59,141	$1,250,822	$212,068	$1,198	$7,392	$0	$1,513	$17,911	$240,082	$1,490,904	$11,456,588
2030	$1,149,765	$103,499	$60,357	$1,313,621	$212,068	$1,228	$7,392	$0	$1,581	$18,358	$240,628	$1,554,249	$11,938,510
2031	$1,178,911	$104,833	$61,604	$1,345,347	$212,068	$1,259	$7,392	$0	$1,653	$18,817	$241,189	$1,586,536	$12,407,019
2032	$1,236,655	$108,050	$62,883	$1,407,588	$212,068	$1,290	$7,392	$0	$1,727	$19,288	$241,765	$1,649,353	$12,870,884
2033	$1,281,110	$110,064	$64,193	$1,455,367	$212,068	$1,323	$7,392	$0	$1,805	$19,770	$242,357	$1,697,724	$13,325,617
2034	$1,339,604	$113,186	$65,536	$1,518,326	$212,068	$1,356	$7,392	$0	$1,886	$20,264	$242,966	$1,761,292	$13,774,911
2035	$1,398,360	$116,206	$66,912	$1,581,478	$212,068	$1,390	$7,392	$0	$1,971	$20,771	$243,591	$1,825,069	$14,218,305

Table C.1-24 Expansion Plan Economic Summary - Without Taylor Energy Center - Direct-Fired Biomass in 2011

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.972%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions					
Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
BIOMASS UNIT	84,555		12/01/11	97,852	7,098
GE LMS100 CT BF	65,100	17	12/01/11	76,635	6,876
CFB UNIT BF	544,700	41	12/01/12	673,274	48,839
CFB UNIT BF	544,700	41	12/01/14	707,359	51,312
GE LMS100 CT BF	65,100	17	12/01/19	93,372	8,377
1x1 7FA CC BF	204,000	30	12/01/20	303,850	24,050
IGCC UNIT BF	712,900	38	12/01/22	1,124,589	81,578
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

	Production Cost				Capital Cost and Other Project Costs							
	Fuel and Energy	O&M		*Total*				Other		*Total*	Total	Cumulative Present
Year	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	*Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Capital Cost ($1,000)	Biomass Unit Total Cost ($1,000)	*Capital Cost ($1,000)*	System Cost ($1,000)	Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,091	$30,091	$0	$473,182	$0	$0	$0	$0	$0	$0	$473,182	$1,405,629
2009	$439,816	$35,476	$0	$475,292	$0	$0	$0	$0	$0	$0	$475,292	$1,816,204
2010	$487,458	$48,596	$0	$536,055	$0	$0	$0	$0	$0	$0	$536,055	$2,257,218
2011	$532,268	$61,565	$82	$593,915	$1,187	$0	$0	$0	$11,484	$12,670	$606,586	$2,732,493
2012	$559,143	$63,292	$1,777	$624,213	$18,122	$0	$0	$0	$11,771	$29,893	$654,105	$3,220,597
2013	$501,927	$59,646	$10,566	$572,140	$62,813	$0	$0	$0	$12,065	$74,878	$647,018	$3,680,420
2014	$545,867	$68,089	$11,663	$625,618	$67,171	$0	$0	$0	$12,367	$79,538	$705,156	$4,157,698
2015	$534,332	$69,463	$21,142	$624,936	$114,125	$0	$0	$0	$12,676	$126,801	$751,737	$4,642,274
2016	$573,429	$73,773	$21,670	$668,873	$114,125	$0	$0	$0	$12,993	$127,118	$795,991	$5,130,943
2017	$533,818	$65,795	$22,212	$621,824	$114,125	$0	$0	$0	$13,317	$127,442	$749,267	$5,569,024
2018	$592,293	$72,929	$22,767	$687,988	$114,125	$0	$0	$0	$13,650	$127,775	$815,764	$6,023,272
2019	$633,745	$76,034	$23,436	$733,216	$114,837	$0	$0	$0	$13,992	$128,828	$862,044	$6,480,432
2020	$686,327	$80,031	$26,230	$792,588	$124,545	$0	$0	$0	$14,341	$138,886	$931,474	$6,950,890
2021	$703,841	$79,209	$38,875	$821,926	$146,552	$0	$0	$0	$14,700	$161,252	$983,178	$7,423,815
2022	$747,739	$85,597	$41,064	$874,400	$153,481	$0	$0	$0	$15,067	$168,548	$1,042,948	$7,901,602
2023	$740,104	$95,676	$58,155	$893,934	$228,130	$0	$0	$0	$15,444	$243,574	$1,137,508	$8,397,893
2024	$847,924	$101,564	$59,645	$1,009,133	$229,824	$0	$0	$0	$15,830	$245,654	$1,254,787	$8,919,283
2025	$908,466	$104,631	$64,167	$1,077,264	$248,076	$0	$0	$0	$16,226	$264,302	$1,341,566	$9,450,186
2026	$933,053	$106,958	$65,509	$1,105,520	$248,076	$0	$0	$0	$16,632	$264,708	$1,370,228	$9,966,611
2027	$962,515	$109,552	$66,885	$1,138,952	$248,076	$0	$0	$0	$17,047	$265,124	$1,404,076	$10,470,593
2028	$1,004,139	$112,621	$68,295	$1,185,055	$248,076	$0	$0	$0	$17,474	$265,550	$1,450,605	$10,966,482
2029	$1,047,774	$114,756	$69,741	$1,232,270	$248,076	$0	$0	$0	$17,911	$265,987	$1,498,257	$11,454,272
2030	$1,113,093	$118,743	$71,223	$1,303,058	$248,076	$0	$0	$0	$18,358	$266,435	$1,569,493	$11,940,921
2031	$1,141,718	$119,893	$72,741	$1,334,352	$247,492	$0	$0	$0	$18,817	$266,309	$1,600,662	$12,413,601
2032	$1,192,354	$123,557	$74,298	$1,390,209	$241,201	$0	$0	$0	$19,288	$260,488	$1,650,697	$12,877,844
2033	$1,238,954	$125,792	$75,894	$1,440,640	$241,201	$0	$0	$0	$19,770	$260,970	$1,701,610	$13,333,617
2034	$1,293,574	$129,203	$77,529	$1,500,305	$241,201	$0	$0	$0	$20,264	$261,465	$1,761,770	$13,783,033
2035	$1,365,226	$133,834	$79,205	$1,578,266	$241,201	$0	$0	$0	$20,771	$261,971	$1,840,237	$14,230,112

Table C.1-25 Expansion Plan Economic Summary - With Taylor Energy Center in 2012 on PRB

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/12	550,371	39,924
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
IGCC BF	721,900	38	12/01/23	1,138,786	82,608
GE LMS100 CT GF	68,500	17	12/01/24	111,159	9,973

Year	Production Cost				Capital Cost and Other Project Costs						Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
	Fuel and Energy Cost ($1,000)	O&M		*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	*Total Capital Cost ($1,000)*		
		Variable ($1,000)	Fixed ($1,000)									
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,662	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,087	$30,091	$0	$473,178	$0	$0	$0	$0	$0	$0	$473,178	$1,405,626
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,917
2010	$487,458	$48,596	$0	$536,055	$0	$0	$0	$0	$0	$0	$536,055	$2,255,931
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,723,247
2012	$530,939	$57,901	$4,450	$593,291	$26,725	$788	$4,928	$2,100	$477	$35,018	$628,309	$3,192,101
2013	$538,831	$58,490	$7,608	$604,929	$44,176	$807	$7,392	$0	$748	$53,123	$658,052	$3,659,766
2014	$514,294	$62,826	$16,761	$593,881	$89,984	$827	$7,392	$0	$782	$98,985	$692,866	$4,128,725
2015	$570,262	$67,291	$18,033	$655,586	$94,451	$848	$7,392	$0	$817	$103,508	$759,094	$4,618,044
2016	$538,090	$67,878	$27,901	$633,869	$142,579	$869	$7,392	$0	$854	$151,694	$785,563	$5,100,312
2017	$521,375	$63,640	$28,599	$613,614	$142,579	$891	$7,392	$0	$892	$151,754	$765,368	$5,547,807
2018	$568,403	$69,289	$29,314	$667,006	$142,579	$913	$7,392	$0	$933	$151,816	$818,822	$6,003,757
2019	$609,244	$71,853	$30,047	$711,144	$142,579	$936	$7,392	$0	$974	$151,881	$863,025	$6,461,438
2020	$668,025	$78,555	$30,900	$777,480	$143,308	$959	$7,392	$0	$1,018	$152,678	$930,158	$6,931,231
2021	$709,106	$81,375	$33,041	$823,521	$152,700	$983	$7,392	$0	$1,064	$162,139	$985,660	$7,405,350
2022	$722,783	$82,926	$38,028	$843,738	$176,244	$1,008	$7,392	$0	$1,112	$185,756	$1,029,494	$7,876,973
2023	$722,743	$93,112	$55,305	$871,161	$251,836	$1,033	$7,392	$0	$1,162	$261,423	$1,132,583	$8,371,115
2024	$835,472	$100,251	$56,837	$992,560	$252,683	$1,059	$7,392	$0	$1,214	$262,348	$1,254,908	$8,892,556
2025	$899,253	$103,341	$59,904	$1,062,498	$261,809	$1,086	$7,392	$0	$1,269	$271,555	$1,334,053	$9,420,486
2026	$920,640	$105,094	$61,402	$1,087,137	$261,809	$1,113	$7,392	$0	$1,326	$271,639	$1,358,776	$9,932,594
2027	$952,145	$108,606	$62,937	$1,123,688	$261,809	$1,141	$7,392	$0	$1,386	$271,727	$1,395,415	$10,433,468
2028	$989,151	$110,745	$64,511	$1,164,407	$261,809	$1,169	$7,392	$0	$1,448	$271,818	$1,436,225	$10,924,441
2029	$1,040,227	$114,004	$66,123	$1,220,354	$261,809	$1,198	$7,392	$0	$1,513	$271,912	$1,492,266	$11,410,280
2030	$1,092,951	$116,970	$67,776	$1,277,697	$261,809	$1,228	$7,392	$0	$1,581	$272,010	$1,549,708	$11,890,795
2031	$1,116,337	$117,660	$69,471	$1,303,468	$261,809	$1,259	$7,392	$0	$1,653	$272,112	$1,575,580	$12,356,068
2032	$1,174,380	$121,415	$71,208	$1,367,002	$261,809	$1,290	$7,392	$0	$1,727	$272,218	$1,639,220	$12,817,083
2033	$1,226,240	$124,847	$72,988	$1,424,075	$261,809	$1,323	$7,392	$0	$1,805	$272,328	$1,696,403	$13,271,462
2034	$1,270,479	$127,162	$74,812	$1,472,454	$261,809	$1,356	$7,392	$0	$1,886	$272,442	$1,744,896	$13,716,574
2035	$1,342,250	$131,452	$76,683	$1,550,385	$261,809	$1,390	$7,392	$0	$1,971	$272,561	$1,822,946	$14,159,452

Table C.1-26 Expansion Plan Economic Summary - With Taylor Energy Center in May of 2013

Case Description	
Fuel Forecast:	Base Case
Load Forecast	Base Case

Economic Parameters	
CPW Discount Rate:	5.0%
Final Capital Escalation Rate:	2.5%
Base Year for CPW $	2006

Financial Parameters	
Interest During Construction:	5.00%
Fixed Charge Rate CT: (20 year)	8.97%
Fixed Charge Rate CC: (25 year)	7.92%
Fixed Charge Rate Coal: (30 year)	7.25%

Generation Additions

Unit Addition	2006 Capital Cost ($1,000)	Construction and Development Period (months)	Month/Day/Year Installed (mm/dd/yy)	Installed Cost ($1,000)	Levelized Cost ($1,000)
TEC	NA	NA	05/01/13	565,262	41,004
CFB UNIT BF	544,700	41	12/01/13	690,106	50,060
CFB UNIT BF	544,700	41	12/01/15	725,043	52,595
GE LMS100 CT BF	65,100	17	12/01/20	95,706	8,587
GE LMS100 CT BF	65,100	17	12/01/21	98,099	8,801
GE LMS100 CT GF	68,500	17	12/01/21	103,223	9,261
GE LMS100 CT GF	68,500	17	12/01/22	105,803	9,493
IGCC BF	721,900	38	12/01/23	1,167,256	84,673

	Production Cost				Capital Cost and Other Project Costs							Cumulative
Year	Fuel and Energy Cost ($1,000)	O&M Variable ($1,000)	O&M Fixed ($1,000)	*Total Production Cost ($1,000)*	Unit Capital Cost ($1,000)	Community Contribution ($1,000)	Transmission Charge ($1,000)	Seasonal Purchase ($1,000)	Ongoing Capex Adder ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Present Worth Cost ($1,000)
2006	$488,458	$28,156	$0	$516,614	$0	$0	$0	$0	$0	$0	$516,614	$516,614
2007	$454,155	$28,661	$0	$482,816	$0	$0	$0	$0	$0	$0	$482,816	$976,439
2008	$443,091	$30,091	$0	$473,182	$0	$0	$0	$0	$0	$0	$473,182	$1,405,629
2009	$438,205	$35,601	$0	$473,806	$0	$0	$0	$0	$0	$0	$473,806	$1,814,921
2010	$484,925	$48,598	$0	$533,524	$0	$0	$0	$0	$0	$0	$533,524	$2,253,852
2011	$534,412	$62,015	$0	$596,427	$0	$0	$0	$0	$0	$0	$596,427	$2,721,168
2012	$591,682	$70,555	$0	$662,237	$0	$0	$0	$2,100	$0	$2,100	$664,337	$3,216,907
2013	$563,225	$62,551	$5,374	$631,150	$31,775	$807	$4,928	$5,550	$489	$43,549	$674,699	$3,696,403
2014	$518,304	$62,774	$16,762	$597,841	$91,064	$827	$7,392	$0	$767	$100,050	$697,892	$4,168,764
2015	$574,301	$67,247	$18,034	$659,582	$95,531	$848	$7,392	$0	$802	$104,573	$764,155	$4,661,345
2016	$540,883	$67,840	$27,902	$636,626	$143,659	$869	$7,392	$0	$838	$152,758	$789,384	$5,145,958
2017	$522,631	$63,602	$28,600	$614,832	$143,659	$891	$7,392	$0	$875	$152,817	$767,649	$5,594,787
2018	$568,600	$69,235	$29,315	$667,150	$143,659	$913	$7,392	$0	$915	$152,879	$820,028	$6,051,409
2019	$609,429	$71,818	$30,048	$711,294	$143,659	$936	$7,392	$0	$956	$152,943	$864,237	$6,509,732
2020	$668,856	$78,515	$30,901	$778,272	$144,388	$959	$7,392	$0	$999	$153,738	$932,010	$6,980,461
2021	$708,734	$81,344	$33,042	$823,120	$153,780	$983	$7,392	$0	$1,044	$163,199	$986,319	$7,454,897
2022	$724,320	$82,046	$36,693	$843,060	$171,115	$1,008	$7,392	$0	$1,091	$180,605	$1,023,665	$7,923,850
2023	$790,851	$86,459	$40,693	$918,003	$186,992	$1,033	$7,392	$0	$1,140	$196,557	$1,114,560	$8,410,129
2024	$828,308	$97,712	$58,445	$984,464	$264,474	$1,059	$7,392	$0	$1,191	$274,116	$1,258,580	$8,933,095
2025	$897,877	$102,032	$59,906	$1,059,815	$264,474	$1,086	$7,392	$0	$1,245	$274,196	$1,334,011	$9,461,008
2026	$913,905	$103,818	$61,404	$1,079,127	$264,474	$1,113	$7,392	$0	$1,301	$274,279	$1,353,406	$9,971,092
2027	$948,149	$107,237	$62,939	$1,118,325	$264,474	$1,141	$7,392	$0	$1,359	$274,365	$1,392,690	$10,470,988
2028	$983,955	$109,369	$64,512	$1,157,837	$264,474	$1,169	$7,392	$0	$1,420	$274,455	$1,432,292	$10,960,617
2029	$1,037,355	$112,036	$66,125	$1,215,516	$264,474	$1,198	$7,392	$0	$1,484	$274,548	$1,490,065	$11,445,739
2030	$1,088,432	$114,962	$67,778	$1,271,172	$264,474	$1,228	$7,392	$0	$1,551	$274,645	$1,545,817	$11,925,047
2031	$1,109,501	$115,363	$69,473	$1,294,336	$264,474	$1,259	$7,392	$0	$1,621	$274,745	$1,569,082	$12,388,401
2032	$1,161,920	$119,122	$71,209	$1,352,251	$264,474	$1,290	$7,392	$0	$1,694	$274,850	$1,627,101	$12,846,008
2033	$1,219,014	$122,286	$72,990	$1,414,290	$264,474	$1,323	$7,392	$0	$1,770	$274,958	$1,689,248	$13,298,471
2034	$1,260,340	$124,494	$74,814	$1,459,648	$264,474	$1,356	$7,392	$0	$1,850	$275,071	$1,734,719	$13,740,986
2035	$1,328,933	$128,941	$76,685	$1,534,558	$264,474	$1,390	$7,392	$0	$1,933	$275,188	$1,809,747	$14,180,658