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Ms. Bayo,

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Enclosed please find 25 copies of the 2007 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). The 2007 OUC TYSP was prepared for and submitted by Black & Veatch on behalf of OUC.

Should you require additional copies of the 2007 OUC TYSP, or have any other questions regarding the TYSP, please do not hesitate to contact me at (913) 458-7134.

Very truly yours,

Bradley Kushner

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OUC

The *Reliable* One®

2007 Ten-Year Site Plan
Orlando Utilities Commission

April 2007

B&V Project 143935

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1.0 Executive Summary

This report documents the 2007 Orlando Utilities Commission (OUC) Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-22.070 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule, and consists of the following additional sections:

- Utility System Description (Section 2.0)
- Strategic Issues (Section 3.0)
- Forecast of Peak Demand and Energy Consumption (Section 4.0)
- Demand-Side Management (Section 5.0)
- Forecast of Facilities Requirements (Section 6.0)
- Supply-Side Alternatives (Section 7.0)
- Economic Evaluation Criteria and Methodology (Section 8.0)
- Analysis and Results (Section 9.0)
- Environmental and Land Use Information (Section 10.0)
- Conclusions (Section 11.0)
- Ten-Year Site Plan Schedules (Section 12.0)

This Ten-Year Site Plan integrates the power sales, purchases, and loads for the City of St. Cloud (St. Cloud) into the analyses, as OUC and St. Cloud have entered into an Interlocal Agreement under which OUC has assumed responsibility for supplying all of St. Cloud's loads through 2032. Load forecasts for OUC and St. Cloud have been integrated into one forecast, and details of the aggregated load forecast are provided in Section 4.0. A banded forecast is provided with base case growth, high growth, and low growth scenarios.

OUC is a member of the Florida Municipal Power Pool (FMPP), which consists of OUC, Lakeland Electric (Lakeland), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Power for OUC is supplied by OUC jointly owned generation and power purchases. OUC's total installed generating capacity, including units in which it has joint ownership as well as St. Cloud's capacity entitlements, is 1,217 MW (summer) and 1,275 MW (winter), as of January 1, 2007. The existing supply system has a broad range of generation technology and fuel diversity.

OUC has received approval from the Florida Public Service Commission (FPSC) to construct Stanton Energy Center Unit B (Stanton B). The Stanton B project is the result of the proposal submitted by Southern Company Services (SCS) on behalf of its partners Southern Power Company (SPC), OUC, and Kellogg Brown & Root, Inc. (KBR) for funding of an air blown transport gasification combined cycle demonstration project to be located at OUC's Stanton Energy Center. The proposal was submitted June 15, 2004, in response to the Clean Coal Power Initiative (CCPI) of the US Department of Energy (DOE). Stanton B is planned to be a 1x1 combined cycle unit that will be capable of firing coal derived syngas or natural gas, and is planned for commercial operation on June 1, 2010. For purposes of the analysis presented in this Ten-Year Site Plan, Stanton B is considered to be a capacity resource for OUC beginning in the summer of 2010. It should be noted that various aspects of Stanton B are confidential, and as such, the amount of detail provided within this Ten-Year Site Plan for Stanton B is somewhat limited.

Four alternative power plant technologies, including combustion turbines, combined cycle, pulverized coal, and circulating fluidized bed units are considered for capacity additions in this Ten-Year Site Plan. As illustrated in Section 6.0 of this report, OUC is forecasted to require additional capacity to maintain a 15 percent reserve margin beginning in the summer of 2015 (with Stanton B considered as a committed unit with commercial operation planned for June 1, 2010). OUC's least-cost capacity expansion plans to satisfy forecast capacity requirements under the base case and numerous sensitivity scenarios are discussed in Section 9.0. OUC has made no commitments to the future generating capacity additions presented in Section 9.0, and they are presented for informational purposes only.

2.0 Utility System Description

At the turn of the 20th century, John M. Cheney, an Orlando, Florida judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kW generator. Twenty-four hour service began in 1903. The population of the City of Orlando (City) had grown to roughly 10,000 by 1922 and Cheney, realizing the need for wider services than his company was capable of supplying, urged his friends to work and vote for a $975,000 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately owned utility. The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando acquired Cheney's company and its 2,795 electricity and 5,000 water customers for a total initial investment of $1.5 million.

In 1923, OUC was created by an act of the state legislature and was granted full authority to operate electric and water municipal utilities. The business was a paying venture from the start. By 1924, the number of customers had more than doubled and OUC had contributed $53,000 to the City. When Orlando citizens took over operation of their utility, the City's population was less than 10,000; by 1925, it had grown to 23,000. In 1925, more than $165,000 was transferred to the City, and an additional $111,000 was transferred in 1926.

Today, OUC operates as a statutory commission created by the legislature of the State of Florida as a separate part of the government of the City. OUC has full authority over the management and control of the electric and waterworks plants in the City and has been approved by the Florida legislature to offer these services in Osceola County as well as Orange County. OUC's charter allows it to undertake, among other things, the construction, operation, and maintenance of electric generation, transmission, and distribution systems, chilled water systems, as well as water production, transmission, and distribution systems to meet the requirements of its customers.

In 1997, OUC entered into an Interlocal Agreement with the City of St. Cloud in which OUC assumed responsibility for supplying all of St. Cloud's loads for the 25 year term of the agreement, which added an additional 150 square miles of service area. OUC also assumed management of St. Cloud's existing generating units and purchase power contracts. This agreement has been extended through 2032.

2.1 Existing Generation System

Presently, OUC has ownership interests in five electric generating plants, which are described further in this section. Table 2-1 summarizes OUC's generating facilities, which include the following:

- Stanton Energy Center Units 1 and 2, and Stanton A.
- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Progress Energy Florida (formerly Florida Power Corporation) Crystal River Unit 3 Nuclear Generating Facility.
- Lakeland Electric McIntosh Unit 3.
- Florida Power & Light Company (FPL) St. Lucie Unit 2 Nuclear Generating Facility.

The Stanton Energy Center is located 12 miles southeast of Orlando, Florida. The 3,280 acre site contains Units 1 and 2, as well as Stanton A, and the necessary supporting facilities. Stanton Unit 1 was placed in commercial operation on July 1, 1987, followed by Stanton Unit 2, which was placed in commercial operation on June 1, 1996. Both units are fueled by pulverized coal and operate at emission levels that are within the Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) requirement standards for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulates. Stanton Unit 1 is a 444 MW net coal fired facility. OUC has a 68.6 percent ownership share of this unit, which provides 302 MW of capacity to the OUC system. Stanton Unit 2 is a 446 MW net coal fired generating facility. OUC maintains a 71.6 percent (319 MW) ownership share of this unit.

OUC has entered into an agreement with Kissimmee Utility Authority (KUA), FMPA, and Southern Company - Florida LLC (SCF) governing the ownership of Stanton A, a combined cycle unit at the Stanton Energy Center that began commercial operation on October 1, 2003. OUC, KUA, FMPA, and SCF are joint owners of Stanton A, with OUC maintaining a 28 percent ownership share, KUA and FMPA each maintaining 3.5 percent ownership shares, and SCF maintaining the remaining 65 percent of Stanton A's capacity.

Stanton A is a 2x1 combined cycle utilizing General Electric combustion turbines. Stanton A is dual fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. OUC maintains a 28 percent equity share of Stanton A, while purchasing 52 percent as described further in Section 2.2.

Table 2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Net Capability	
				Pri	Alt	Pri	Alt			Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	18(1)	23.4(1)
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	18(1)	23.4(1)
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	85.3(2)	100.3(2)
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	85.3(2)	100.3(2)
Stanton Energy Center	1	Orange	ST	BIT	--	RR	--	07/87	Unknown	301.6(3)	303.7(3)
Stanton Energy Center	2	Orange	ST	BIT	--	RR	--	06/96	Unknown	337.9(4)	337.9(4)
Stanton Energy Center	A	Orange	CC	NG	FO2	PL	TK	10/03	Unknown	173.6(5)	184.8(5)
McIntosh	3	Polk	ST	BIT	--	RR	--	09/82	Unknown	133(6)	136(6)
Crystal River	3	Citrus	NP	UR	--	TK	--	03/77	Unknown	13	13
St. Lucie(7)	2	St. Lucie	NP	UR	--	TK	--	06/83	Unknown	51	52

(1)Reflects an OUC ownership share of 48.8 percent.
(2)Reflects an OUC ownership share of 79.0 percent.
(3)Reflects an OUC ownership share of 68.6 percent.
(4)Reflects an OUC ownership share of 71.6 percent and St. Cloud entitlement of 4.2 percent.
(5)Reflects an OUC ownership share of 28.0 percent.
(6)Reflects an OUC ownership share of 40.0 percent.
(7)OUC owns approximately 6.1 percent of St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.

The Indian River Plant is located 4 miles south of Titusville on US Highway 1. The 160 acre Indian River Plant site contains three steam electric generating units (No. 1, 2, and 3) and four combustion turbine units (A, B, C, and D). The three steam turbine units were sold to Reliant in 1999. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent, or 36 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent (170 MW) in Indian River Units C and D.

Crystal River Unit 3 is an 835 MW net nuclear generating facility operated by Progress Energy Florida, formerly Florida Power Corporation. OUC has a 1.6015 percent ownership share in this facility, providing approximately 13 MW to the OUC system.

McIntosh Unit 3 is a 340 MW net coal fired unit operated by Lakeland Electric. McIntosh Unit 3 has supplementary oil and refuse-derived fuel burning capability and is capable of burning up to 20 percent petroleum coke. Lakeland Electric has ceased burning refuse-derived fuel at McIntosh Unit 3 for operational and landfill reasons. For purposes of the analyses performed in this application, it was assumed that McIntosh Unit 3 would burn coal priced identically to that used for Stanton Units 1 and 2. OUC has a 40 percent ownership share in McIntosh Unit 3, providing approximately 133 MW of capacity to the OUC system.

St. Lucie Unit 2 is a 853 MW net nuclear generating facility operated by FPL. OUC has a 6.08951 percent ownership share in this facility, providing approximately 51 MW of generating capacity to OUC. A reliability exchange with St. Lucie Unit 1 results in half of the capacity being supplied by St. Lucie Unit 1 and half by St. Lucie Unit 2.

As part of the Interlocal Agreement with St. Cloud, OUC has operating control of the generating units owned by St. Cloud. The St. Cloud internal combustion generating units were placed into standby in October 2006. St. Cloud also has an entitlement to capacity from Stanton Unit 2 associated with its purchase through FMPA. FMPA's ownership in Stanton Unit 2 is 28.41 percent and St. Cloud's purchase from FMPA's Stanton Unit 2 ownership is 14.67 percent, entitling St. Cloud to approximately 18.6 MW of capacity from Stanton Unit 2.

2.2 Purchase Power Resources

OUC has a purchase power agreement (PPA) with SCF for 80 percent of SCF's ownership share of Stanton A. Under the original Stanton A PPA OUC, KUA, and FMPA agreed to purchase all of SCF's 65 percent capacity share of Stanton A for 10 years, although the utilities retained the right to reduce the capacity purchased from SCF by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. The utilities originally had options to extend the PPA beyond its initial term. OUC, KUA, and FMPA have unilateral options to purchase all of Stanton A's capacity for the estimated 30 year useful life of the unit. Subsequent amendments to the original PPA continue OUC's capacity purchase through the 20th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC will maintain the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. Additionally, OUC has the option of terminating the PPA after the 20th contract year, which ends September 30, 2023. Rather than terminating the PPA, OUC may elect to continue the PPA for an additional 5 years under the Extended Term option beginning October 1, 2023, and ending September 30, 2028. OUC may subsequently continue the PPA for an additional 5 years under the Further Extension option beginning October 1, 2028, and ending September 30, 2033.

St. Cloud has a Partial Requirements (PR) contract with Tampa Electric Company (TECO) for 15 MW, which expires December 31, 2012. As a result of the Interlocal Agreement with St. Cloud, OUC may schedule the TECO PR purchase.

2.3 Power Sales Contracts

OUC has had a number of power sales contracts with various entities over the past several years. However, OUC is currently not contractually obligated to supply power under any power sales contracts.

2.4 Renewable Generating Capacity

OUC currently has several projects in development that focus on renewable technologies. OUC utilizes landfill gas from an Orange County landfill, burning the equivalent of 10 MW (approximately 1 percent of total existing summer generating capacity) of landfill gas at the Stanton Energy Center and offsetting coal burning by approximately 3 percent. OUC also works with local area high schools to educate students about renewable technologies, specifically photovoltaic (PV) energy. OUC has installed PV cells on school rooftops to provide power to the schools.

OUC will continue to evaluate renewable opportunities that benefit OUC, its customers, and the environment. OUC currently does not purchase any energy from renewable generation sources, and OUC's customers currently do not have any self-service renewable generating facilities.

2.5 Transmission System

OUC's existing transmission system consists of 28 substations interconnected through approximately 300 miles of 230 kV, 115 kV, and 69 kV lines and cables. OUC is fully integrated into the state transmission grid through its twenty-two 230 kV, one 115 kV, and one 69 kV metered interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC), as summarized in Table 2-2. Additionally, OUC is responsible for St. Cloud's four substations, as well as approximately 56 miles of 230 kV and 69 kV lines and cables. As presented in Table 2-3, the St. Cloud transmission system includes three interconnections. OUC's transmission system, including St. Cloud, is shown on Figure 2-1.

The addition of a distribution transformer to the existing Kaley substation (No. 13) was completed in December 2004, and the new Lake Nona 230/25/15 kV substation was placed into service in March 2005. The addition of the new 230/69/25 kV St. Cloud south substation and the associated 69 kV line to the central substation were completed in May 2006, while the 230/69 kV bus tie transformer and 230 kV line to the east substation were energized in early February 2007. The upgrade of the 69 kV tie line from the St. Cloud central substation to KUA has been delayed because of a road widening project along its path.

To increase reliability and relieve higher fault current levels resulting from the closing of the Stanton 230 kV bus, oil circuit breakers at three substations (No. 10, No. 11, and No. 12) were upgraded to gas insulated models, and two distribution transformers and switchgears at substation No. 9 were replaced with new units.

To maintain reliable and economic service, OUC is evaluating numerous upgrades to its transmission system. While these upgrades vary in scope and timing, the following identifies the higher priority, near-term transmission system upgrades planned by OUC:

- Relocating the bus tie transformer from the Stanton east bus to the Magnolia Ranch North 230/69 kV substation.
- Addition of a 230 kV line between Stanton and Lake Nona within the existing Taft-to-Stanton railroad/transmission corridor.
- Addition of a 69 kV line from Magnolia Ranch North to State Road (SR) 15 in Orange County, Florida. This new line segment will be part of the tie line to St. Cloud north substation.

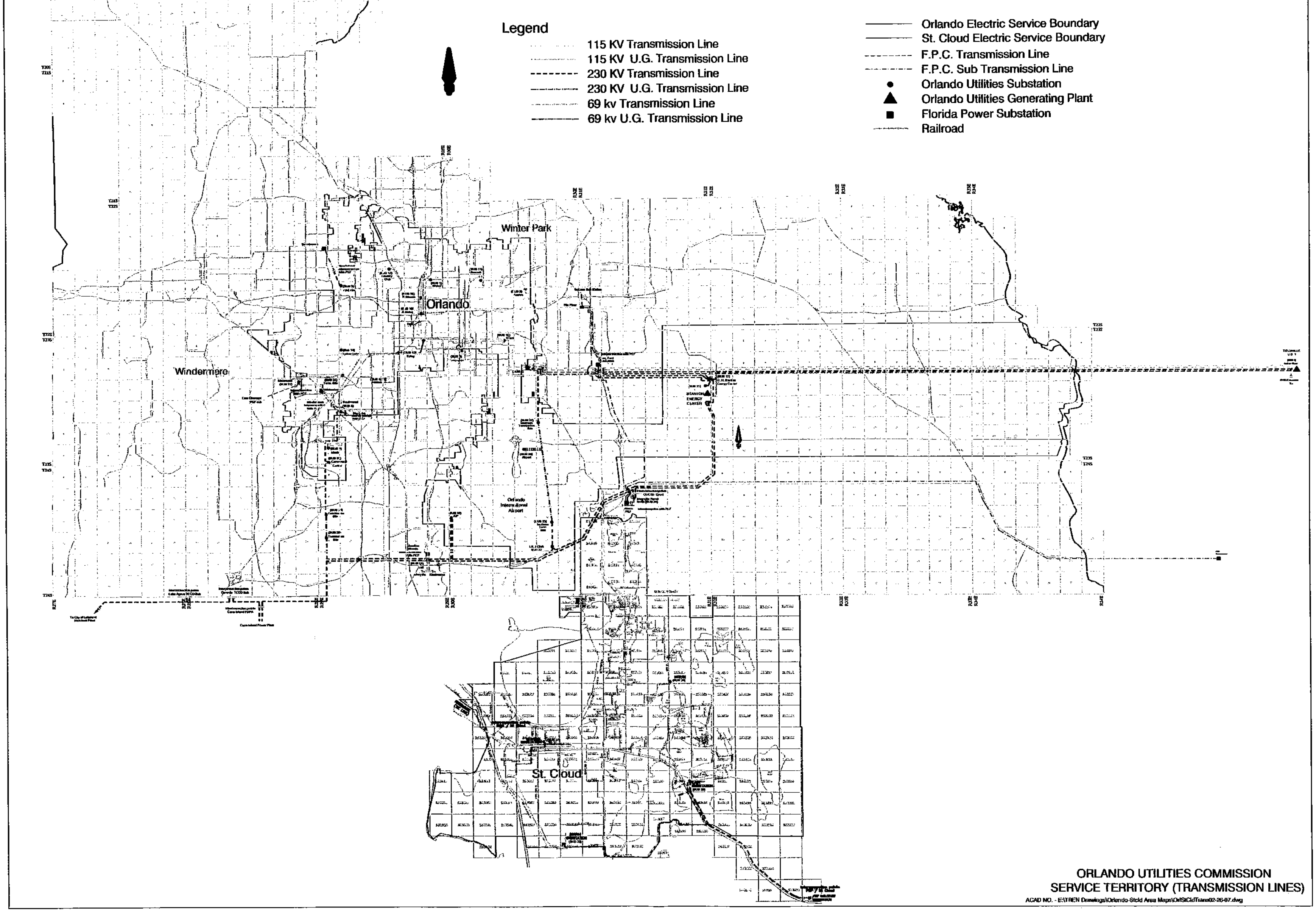
Table 2-2
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL	230	2
Progress Energy Florida (PEF)	230	8
KUA	230	2
KUA/FMPA	230	2
Lakeland Electric	230	1
TECO	230	2
TECO/Reedy Creek Improvement District	230	2
PEF	69	1
Southern Company	230	1
Reliant Energy	230	2
Reliant Energy	115	1

Table 2-3
St. Cloud Transmission Interconnections

Utility	kV	Number of Interconnections
OUC	69	1
PEF	230	1
KUA	69	1

Orlando Utilities Commission Transmission Lines



ORLANDO UTILITIES COMMISSION
SERVICE TERRITORY (TRANSMISSION LINES)

3.0 Strategic Issues

OUC incorporates a number of strategic considerations while planning for the electrical system. This section provides an overview of a number of these strategic considerations.

3.1 Strategic Business Units

As the entire electric utility industry faces deregulation, OUC is aggressively developing strategies to be competitive in a deregulated environment. One strategy already implemented was to reorganize OUC into the following strategic business units, which consist of the Power Resources Business Unit (PRBU) and the Energy Delivery Business Unit (EDBU).

3.1.1 Power Resources Business Unit

The PRBU has structured its operations based on a competitive environment that assumes that even OUC's customers are not captive. The PRBU will only be profitable if it can produce electricity that is competitively priced in the open market. In line with this strategy, OUC is continually studying strategic options to improve or reposition its generating assets, such as the sale of the Indian River Steam Units in 1999 and the addition of new units and power purchase agreements. In addition, OUC formally instituted its Energy Risk Management Program in 2000.

OUC's generating system has been designed over the years to take advantage of fuel diversity and the resultant system reliability and economic benefits. OUC's long-standing intent to achieve diversity in its fuel mix is evidenced by its participation in other generating facilities in the State of Florida. The first such endeavor occurred in 1977 when OUC secured a share of the Crystal River Unit 3 nuclear plant, followed by the acquisition of an ownership share in Lakeland Electric's McIntosh Unit 3 coal fired unit in 1982. In 1983, OUC also acquired a share of the St. Lucie Unit 2 nuclear unit. OUC's current capacity mix is summarized in Table 3-1.

Coal represents approximately 60 percent of the winter generating capacity (approximately 63 percent summer) either wholly or jointly owned by OUC. This strategy ensures against interruptions in supply and increases in the cost of oil and natural gas. Additional details of OUC's generating facilities are presented in Schedule 1 of Section 12.0.

Table 3-1
Generation Capacity (MW) Owned by OUC by Fuel Type (as of January 1, 2007)

Plant Name	Winter Capacity				Summer Capacity			
	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Stanton	623		185	808	621		174	795
Indian River			248	248			207	207
Crystal River		13		13		13		13
C.D. McIntosh Jr.	136			136	133			133
St. Lucie		52		52		51		51
Total (MW)	759	65	433	1,257	754	64	381	1,199
Total (percent)	60.4	5.2	34.4	100.0	62.9	5.3	31.8	100.0

OUC's use of alternative or renewable fuels is enhanced by burning a mixture of petroleum coke in McIntosh Unit 3, along with coal. Petroleum coke is a waste by-product of the refining industry and in addition to the benefits of using a waste product, petroleum coke's lower price results in significant savings over coal. Tests have been done that indicate the unit has the ability to use petroleum coke for approximately 20 percent of the fuel input. Permits have been modified and approved for this level of use and petroleum coke is being burned in the unit.

OUC's fuel diversity and use of renewable and waste fuels is further enhanced through the burning of landfill gas from the Orange County Landfill at Stanton Energy Center. The use of landfill gas not only reduces fuel costs, but also reduces the emission of greenhouse gases.

OUC's diversified mix of generating units provides protection against disruption of supply while simultaneously providing economic opportunities to reduce cost to customers. OUC's fuel diversity will be further enhanced through the addition of Stanton B, which will be capable of burning either coal derived syngas or natural gas once it becomes commercial (assumed to be June 1, 2010).

3.1.2 Energy Delivery Business Unit

OUC's EDBU focuses on providing OUC's customers with the most reliable electric service possible. Formerly called the Electric Distribution Business Unit, the unit was renamed after merging with OUC's Electric Transmission Business Unit, which was being phased out with the anticipated creation of a regional independent transmission organization.

OUC's leadership in providing reliable electric distribution service is demonstrated by its commitment to making initial investments in high quality material and equipment. Additionally, nearly 50 percent of OUC's distribution system is underground, protecting it from trees and high winds. OUC's dependability is also attributable to its proactive maintenance programs to identify and correct potential problems, proactive replacement of old equipment, and a tree trimming program that minimizes tree-related service disruptions. OUC's reliability is demonstrated by the fact that during 2006, the average annual customer interruption for the combined Orlando-St. Cloud service area was well below that of OUC's competition. For the fifth consecutive year, OUC ranked at the top in the state for reliability of electric service. OUC finished well ahead of Florida's investor-owned utilities in both L-Bar (the average number of minutes a customer is out of power during an outage) and system average interruption duration indices (SAIDI, a measure of average amount of time a customer is without power during the course of a year).

3.2 Reposition of Assets

As a strategic consideration, OUC has been working on repositioning its assets. One major issue is the sale of its Indian River power plant steam units to Reliant Energy in 1999. The sale of the Indian River steam units allowed OUC to take positions in Stanton A and B and to update and diversify its generation portfolio. The sale offered OUC the ability to replace the less competitive oil and gas steam units with more competitive combined cycle generation.

3.3 Florida Municipal Power Pool

In 1988, OUC joined with Lakeland Electric and the FMPA's All-Requirements Project members to form the FMPP. Later, KUA joined FMPP. Over time, FMPA's All-Requirements Project has added members as well. FMPP is an operating-type electric pool, which dispatches all the pool members' generating resources in the most economical manner to meet the total load requirements of the pool. The central dispatch is providing savings to all parties because of reduced commitment costs and lower overall fuel costs. OUC serves as the FMPP dispatcher and handles all accounting for the allocation of fuel expenses and savings. The term of the pool agreement is 1 year and automatically renews from year to year until terminated by the consent of all participants.

OUC's participation in FMPP provides significant savings from the joint commitment and dispatch of FMPP's units. Participation in FMPP also provides OUC with a ready market for any excess energy available from OUC's generating units.

3.4 Security of Power Supply

OUC currently maintains interchange agreements with other utilities in Florida to provide electrical energy during emergency conditions. The reliability of the power supply is also enhanced by metered interconnections with other Florida utilities including nine interconnections with Progress Energy Florida (formerly Florida Power Corporation), four with KUA, two each with Tampa Electric Company and Reedy Creek Improvement District, two with FPL, and one each with Lakeland Electric and St. Cloud. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida.

3.5 Environmental Performance

As the quality of the environment is important to Florida, and especially important to the tourist-attracted economy in Central Florida, OUC is committed to protecting human health and preserving the quality of life and the environment in Central Florida. To demonstrate this commitment, OUC has chosen to operate their generating units with emission levels below those required by permits and licenses by equipping its power plants with the best available environmental protection systems. As a result, even with a second unit in operation, the Stanton Energy Center is one of the cleanest coal fired generating stations in the nation. Unit 2 is the first of its size and kind in the nation to use selective catalytic reduction (SCR) to remove nitrogen oxides (NO_x). Using SCR and low-NO_x burner technology, Stanton 2 successfully meets the stringent air quality requirements imposed upon it. Stanton A, OUC's newest generating unit, incorporates the most environmentally advanced technology available and enables OUC to diversify its fuel mix while adding more flexibility to OUC's portfolio of owned generation and purchased power. Stanton B is expected to be one of the most efficient and lowest polluting coal fired power plants in the United States.

This superior environmental performance not only preserves the environment, but also results in many economic benefits, which help offset the costs associated with the superior environmental performance. For example, the high quality coal burned at Stanton contributes to the high availability of the units as well as their low heat rates.

Further demonstrating its environmental commitment to clean air, OUC has signed a contract to burn the methane gas collected from the Orange County landfill adjacent to Stanton Energy Center. Methane gas, when released into the atmosphere, is considered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Stanton 1 and Stanton 2 both have the capability of burning methane.

In 2006, OUC created two new environmental vice presidential positions – Environmental Affairs and Strategic Planning (who is responsible for renewable energy programs). These positions will enhance OUC's efforts to increase investments in renewables, conservation, energy efficiency, and other environmental initiatives.

OUC has also voluntarily implemented a product substitution program not only to protect workers' health and safety but also to minimize hazardous waste generation and to prevent environmental impacts. The Environmental Affairs and the Safety Divisions constantly review and replace products to eliminate the use of hazardous substances. To further prevent pollution and reduce waste generation, OUC also reuses and recycles many products.

3.6 Community Relations

Owned by the City of Orlando and its citizens, OUC is especially committed to being a good corporate citizen and neighbor in the areas it serves or impacts.

In Orange, Osceola, and Brevard Counties, where OUC serves customers and/or has generating units, OUC gives its wholehearted support to education, diversity, the arts, and social-service agencies. An active Chamber of Commerce participant in all three counties, OUC also supports area Hispanic Chambers and the Metropolitan Orlando Urban League. As a United Arts trustee, OUC has allowed its historic Lake Ivanhoe Power Plant to be turned into a performing arts center. OUC is also a corporate donor for WMFE public television and a co-sponsor of the "Power Station" exhibit at the Orlando Science Center. OUC has also donated $100,000 to the Orlando Science Center to help sponsor the alternative-energy exhibit "Our Energy Future" that includes a permanent exhibit in Orlando and a component that travels to museums throughout the country.

Events sponsored by OUC have included the annual OUC Downtown Orlando Triathlon and the OUC Half Marathon & 5K. OUC also participated in the Junior Achievement Bowl-A-Thon. OUC also partnered with the Florida Interactive Entertainment Academy at the University of Central Florida (UCF), continuing the long-standing partnership between OUC and UCF.

During 2006, OUC's Project CARE – the bill payment assistance program – continued to provide financial support to customers in need. Since 1994, Project CARE has helped more than 5,000 families by raising more than $900,000. OUC has previously matched customer donations to Project CARE dollar for dollar. OUC has increased its commitment to Project CARE, and now donates $2 for every dollar contributed by OUC customers.

4.0 Forecast of Peak Demand and Energy Consumption

OUC retained Itron, formerly Regional Economic Research, Inc. (RER), to assist in the development of forecasts of peak demand and energy consumption. The project scope was to develop a set of sales, energy, and demand forecast models that could support OUC's budgeting and financial planning process as well as long-term planning requirements. OUC utilized its internal knowledge of the service area with the expertise of Itron in the development of the forecast models.

4.1 Forecast Methodology

There are two primary forecasting approaches used in forecasting electricity requirements: econometric-based modeling (such as linear regression) and end-use models (such as EPRI REEPS and COMMEND models). In general, econometric forecast models provide better forecasts in the short-term time frame, and end-use models are better at capturing long-term structural change resulting from competition across fuels, and changes in appliance stock and efficiency.

The difficulty of end-use modeling is that these models are extremely data-intensive and provide relatively poor short-term forecasts. End-use models require detailed information on appliance ownership, efficiency of the existing stock, new purchase behavior, utilization patterns, commercial floor-stock estimates by building type, and commercial end-use saturations and intensities in both new and existing construction. It typically costs several hundred thousand dollars to update and to maintain such a detailed database. Lack of detailed end-use information precluded developing end-use forecasts for the OUC/St. Cloud service territories. Furthermore, since there is virtually no retail natural gas in the OUC service territory, end-use modeling would provide little information on cross-fuel competition - one of the primary benefits of end-use modeling.

Since end-use modeling was not an option, the approach adopted was to develop linear regression sales models. To capture long-term structural changes, end-use concepts are blended into the regression model specification. This approach, known as an SAE model, entails specifying end-use variables (heating, cooling, and other use) and utilizing these variables in sales regression models. While the SAE approach loses some end-use detail, it adequately forecasts short-term energy requirements, and it provides a reasonable structure for forecasting long-term energy requirements.

4.1.1 Residential Sector Model

The residential model consists of both an average use per household model and a customer forecast model. Monthly average use models were estimated over the period encompassing 1996 to 2006. This provides at least 10 years of historical data, with more than enough observations to estimate strong regression models. Once models were estimated, the residential energy requirement in month T was calculated as the product of the customer and average use forecast:

$$\text{Residential Sales}_T = \text{Average User Per Household}_T \times \text{Number of Customers}_T$$

4.1.1.1 Residential Customer Forecast. The number of customers was forecasted as a simple function of household projections for the Orlando Metropolitan Statistical Area (MSA). Models were estimated using MSA-level data, since county level economic data is only available on an annual basis. Not surprisingly, the historical relationship between OUC customers and households in the Orlando MSA is extremely strong. The OUC customer forecast model had an adjusted R^2 of 0.99, with an in-sample Mean Absolute Percent Error (MAPE) of 0.2 percent. For St. Cloud, the model performance was not as strong, given the "noise" in the historical monthly billing data. The adjusted R^2 was 0.91, with an in-sample MAPE of 2.9 percent. Since St. Cloud is a relatively small part of OUC's service territory, the 2.9 percent average customer forecast error represents a relatively small number of total system customers.

4.1.1.2 Average Use Forecast. The SAE modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$), depicted as follows:

$$\text{Use}_{y,m} = \text{Heat}_{y,m} + \text{Cool}_{y,m} + \text{Other}_{y,m}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for end-use elements provides the following econometric equation:

$$\text{Use}_m = a + b_1 \times \text{XHeat}_m + b_2 \times \text{XCool}_m + b_3 \times \text{XOther}_m + \varepsilon_m$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. The estimated model can then be thought of as an SAE model, where the estimated slopes are the adjustment factors.

XHeat captures the factors that affect residential space heating. These variables include the following:

- Heating degree-days.
- Heating equipment saturation levels.
- Heating equipment operating efficiencies.
- Average number of days in the billing cycle for each month.
- Thermal integrity and footage of homes.
- Average household size, household income, and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier as follows:

$$\mathbf{XHeat}_{y,m} = \mathbf{HeatIndex}_{y} \times \mathbf{HeatUse}_{y,m}$$

where:

$XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m).
$HeatIndex_y$ is the annual index of heating equipment.
$HeatUse_{y,m}$ is the monthly usage multiplier.

The heat index is defined as a weighted average energy intensity measured in kWh. Given a set of starting end-use energy intensities (EI), the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), and building structural index (*StructuralIndex*). Formally, the heating equipment index is defined as follows:

$$\mathbf{HeatIndex}_y = \mathbf{StructuralIndex}_y \times \sum_{Type} \mathbf{EI}^{Type} \times \frac{\left(\mathbf{Sat}_y^{Type} / \mathbf{Eff}_y^{Type} \right)}{\left(\mathbf{Sat}_{98}^{Type} / \mathbf{Eff}_{98}^{Type} \right)}$$

StructuralIndex is based on EIA square footage projections and thermal shell efficiency for the southeast census region. EIA's current projections show average square footage increasing slightly faster than thermal shell integrity improvements.

Electric heating saturation in the OUC service area is relatively high with approximately 85 percent of the homes using electric space heat. Heat pumps account for nearly half the existing stock and are projected to increase as a share of heating equipment over time. Given that heat pumps are significantly more efficient than resistance heat, efficiency gains are expected to outstrip increasing heat saturation, which in turn slows expected residential heating sales growth.

Heating sales are also driven by the factors that impact utilization of the appliance stock. Heating use depends on weather conditions, household size, household income, and prices. The heat use variable is constructed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{98}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{98}}\right)^{0.20} \times \left(\frac{Income_{y}}{Income_{98}}\right)^{0.20} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.15}$$

where:

HDD is the number of heating degree days in year (y) and month (m).
HHSize is the average household size in a year (y).
Income is the average real income per household in a year (y).
Price is the average real price of electricity in month (m) and year (y).

By construction, $HeatUse_{y,m}$ has an annual sum that is close to 1.0 in the base year (1998). The index changes over time with changes in HDD, HHSize, Income, and Price. In this form, the coefficients represent end-use elasticity estimates. The elasticity estimates are based on short-term estimates embedded in the Electric Power Research Institute (EPRI) end-use forecasting model Residential End-Use Planning System (REEPS) and elasticities used by EIA in their long-term energy forecast model. The elasticities are also validated by evaluating out-of-sample model fit statistics using different elasticity estimates.

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days.
- Cooling equipment saturation levels.
- Cooling equipment operating efficiencies.

- Thermal integrity and footage of homes.
- Average household size, household income, and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier as follows:

$$\mathbf{XCool}_{y,m} = \mathbf{CoolIndex}_{y} \times \mathbf{CoolUse}_{y,m}$$

where:

$XCool_{y,m}$ is the estimated cooling energy use in year (y) and month (m).
$CoolIndex_y$ is the cooling equipment index.
$CoolUse_{y,m}$ is the monthly usage multiplier.

The cooling equipment index is calculated as follows:

$$\mathbf{CoolIndex}_y = \mathbf{StructuralIndex}_y \times \sum_{\mathbf{Type}} \mathbf{EI}^{\mathbf{Type}} \times \frac{\left(\mathbf{Sat}_y^{\mathbf{Type}} \Big/ \mathbf{Eff}_y^{\mathbf{Type}}\right)}{\left(\mathbf{Sat}_{98}^{\mathbf{Type}} \Big/ \mathbf{Eff}_{98}^{\mathbf{Type}}\right)}$$

As air conditioning saturation increases, the index increases. As efficiency increases, the index decreases. Again, because of the high current saturation of air conditioning, the index is largely driven by increasing overall air conditioning efficiency. A slight increase in the structural index (as a result of increasing square footage) results in a small increase in the cooling equipment index over time.

The cooling utilization variable is constructed similar to that of the heating use variable. *CoolUse* is defined as follows:

$$\mathbf{CoolUse}_{y,m} = \left(\frac{\mathbf{CDD}_{y,m}}{\mathbf{CDD}_{98}}\right) \times \left(\frac{\mathbf{HHSize}_y}{\mathbf{HHSize}_{98}}\right)^{0.20} \times \left(\frac{\mathbf{Income}_y}{\mathbf{Income}_{98}}\right)^{0.20} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}}\right)^{-0.15}$$

where:

CDD is the number of cooling degree days in year (y) and month (m).

Monthly estimates of nonweather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by the following:

- Appliance and equipment saturation levels.
- Appliance efficiency levels.
- Average household size, real income, and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathbf{XOther}_{y,m} = \mathbf{OtherEqpIndex}_{y,m} \times \mathbf{OtherUse}_{y,m}$$

The first term on the right hand side of this expression ($OtherEqpIndex_{y,m}$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term ($OtherUse$) captures the impact of changes in price, income, and household size on appliance utilization. The appliance index is defined as follows:

$$\mathbf{OtherIndex}_{y,m} = \mathbf{EI}^{\mathbf{Type}} \times \frac{\left(\mathbf{Sat}_y^{\mathbf{Type}} \Big/ \frac{1}{\mathbf{Eff}_y^{\mathbf{Type}}} \right)}{\left(\mathbf{Sat}_{98}^{\mathbf{Type}} \Big/ \frac{1}{\mathbf{Eff}_{98}^{\mathbf{Type}}} \right)} \times \mathbf{MoMult}_m^{\mathbf{Type}}$$

where:

EI is the energy intensity for each appliance (annual kWh).
Sat represents the fraction of households who own an appliance type.
$MoMult_m$ is a monthly multiplier for the appliance type in month (m).
Eff is the average operating efficiency for water heaters.

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration. Saturation and efficiency trends are based on EIA projections for the southeast census region.

Economic activity is captured through the *OtherUse* variable, where *OtherUse* is defined as follows:

$$\text{OtherUse}_{y,m} = \left(\frac{\text{HHSize}_y}{\text{HHSize}_{98}}\right)^{0.20} \times \left(\frac{\text{Income}_y}{\text{Income}_{98}}\right)^{0.20} \times \left(\frac{\text{Price}_{y,m}}{\text{Price}_{98}}\right)^{-0.15}$$

Increase in household income translates into an increase in XOther, while increases in electricity prices result in a decrease in XOther. Decreasing household size (number per household) translates into a decrease in XOther.

4.1.1.3 Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on XCool, XHeat, and XOther. Lagged *Use* values of XCool and Xheat are also included in the specification since these variables are constructed with calendar-month weather data, but the dependent variable (residential average use) is based on revenue-month sales. July residential sales, for example, reflect usage in both calendar months June and July. The end-use variables worked extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.95 with an in-sample MAPE of approximately 3.9 percent. The mean absolute deviation (MAD) is 40.2 kWh compared to a residential monthly average usage of 1,084 kWh. All the model coefficients are highly significant (exhibited by t-statistics greater than 2.0). The St. Cloud model also explains average usage well with an R^2 of 0.91. The model coefficients are highly significant.

4.1.2 Nonresidential Sector Models

The nonresidential sector is segmented into two revenue classes:

- *Small General Service (GS Nondemand or GSND).*
- *Large General Service (GS Demand or GSD).*

The GSND class consists of small commercial customers with a measured demand of less than 50 kW. The GSD class consists of those customers with monthly maximum demand exceeding 50 kW.

The SAE approach is also used to develop models to forecast electricity sales for commercial nondemand and demand classes. The commercial SAE model framework begins by defining energy use ($Use_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$) as follows:

$$\textbf{Sales}_{y,m} = \textbf{Heat}_{y,m} + \textbf{Cool}_{y,m} + \textbf{Other}_{y,m}$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation:

$$\mathbf{Sales}_m = \mathbf{a} + \mathbf{b}_1 \times \mathbf{XHeat}_m + \mathbf{b}_2 \times \mathbf{XCool}_m + \mathbf{b}_3 \times \mathbf{XOther}_m + \varepsilon_m$$

The model parameters are then estimated using linear regression.

The constructed variables XHeat, XCool, and XOther capture structural as well as market condition changes. The end-use variables include the following:

- Heating and cooling degree days.
- End-use saturation and efficiency trends.
- Real regional output.
- Price.

The end-use variables are represented as the product of an annual equipment index (Index) and a monthly usage multiplier (Use). The variables are defined as follows:

$$\mathbf{XHeat}_{y,m} = \mathbf{HeatIndex}_y \times \mathbf{HeatUse}_{y,m}$$

$$\mathbf{XCool}_{y,m} = \mathbf{HeatIndex}_y \times \mathbf{HeatUse}_{y,m}$$

$$\mathbf{XOther}_{y,m} = \mathbf{OtherIndex}_{y,m} \times \mathbf{OtherUse}_{y,m}$$

The heating equipment index captures change in end-use saturation and efficiency. The heating index is defined as follows:

$$\mathbf{HeatIndex}_y = \mathbf{HeatSales}_{98} \times \frac{\left(\mathbf{HeatShare}_y / \mathbf{Eff}_y\right)}{\left(\mathbf{HeatShare}_{98} / \mathbf{Eff}_{98}\right)}$$

In this expression, 1998 is defined as the base year. The ratio on the right is equal to 1.0 in 1998. As end-use saturation increases, the index increases; as efficiency increases, the index decreases. The starting heating sales estimate (HeatSales98) is derived from the EIA end-use forecast database for the southeast census region.

Similarly, projections of saturation and efficiency changes are based on EIA's long-term outlook for the southeast region.

The heating variable *XHeat* is constructed by interacting the index variable (*HeatIndex*) with a variable that captures short-term stock utilization (*HeatUse*). Temperature data, prices, and regional output are incorporated into the HeatUse variable. The calculated heat utilization variable is computed as follows:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{98}}\right) \times \left(\frac{Output_y}{Output_{98}}\right)^{0.40} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.20}$$

where:

HDD is the number of heating degree days in year (y) and month (m).

Output is real gross regional product in year (y) and month (m).

Price is the average real price of electricity in year (y) and month (m).

As constructed, *HeatUse* is also an index value with a value of 1.0 in 1998. Furthermore, in this functional form, the coefficients of 0.4 and -0.2 can be interpreted as elasticities. A 1.0 percent change in output will translate into a 0.4 percent increase in the HeatUse index. A 1.0 percent increase in real price will translate into a -0.2 percent change in HeatUse.

The cooling variable (*XCool*) is constructed in a similar manner. Cooling requirements are driven by the following:

- Cooling degree days.
- Cooling equipment saturation levels.
- Cooling equipment operating efficiencies.
- Business activity (as captured by regional output).
- Price.

The following cooling variable is the product of an equipment-based index and monthly usage multiplier:

$$\text{CoolIndex}_y = \text{CoolSales}_{98} \times \frac{\left(\text{CoolShare}_y / \text{Eff}_y\right)}{\left(\text{CoolShare}_{98} / \text{Eff}_{98}\right)}$$

where:

CoolIndex$_y$ is an index of the cooling equipment.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Saturation and efficiency trends are derived from the EIA end-use database for the southeast census region. Given the nearly 100 percent saturation in air conditioning, the index is driven downwards by improving air conditioning efficiency.

The *CoolUse* variable is constructed similar to the *HeatUse* variable. *CoolUse* captures the interaction of temperature (*CDD*), regional output (*Output*), and price. The output and price elasticity are estimated be 0.4 and -0.2, respectively. The constructed use variable is defined as follows:

$$\mathbf{CoolUse}_{y,m} = \left(\frac{\mathbf{CDD}_{y,m}}{\mathbf{CDD}_{98}}\right) \times \left(\frac{\mathbf{Output}_{y}}{\mathbf{Output}_{98}}\right)^{0.40} \times \left(\frac{\mathbf{Price}_{y,m}}{\mathbf{Price}_{98}}\right)^{-0.20}$$

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (1998). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will vary to reflect changes in commercial output and prices.

Monthly estimates of nonweather sensitive sales can be derived in a similar fashion as space heating and cooling. Based on end-use concepts, other sales are driven by the following:

- Equipment saturation levels.
- Equipment efficiency levels.
- Average number of days in the billing cycle for each month.
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$\mathbf{XOther}_{y,m} = \mathbf{OtherIndex}_{y,m} \times \mathbf{OtherUse}_{y,m}$$

The first term embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$\text{OtherIndex}_{y,m} = \sum_{\text{Type}} \text{OtherSales}_{98}^{\text{Type}} \times \left(\frac{\text{Share}_{y}^{\text{Type}} \big/ \text{Eff}_{y}^{\text{Type}}}{\text{Share}_{98}^{\text{Type}} \big/ \text{Eff}_{98}^{\text{Type}}} \right)$$

where:

OtherSales represents starting base year non-heating, ventilating, and air conditioning (HVAC) sales.

Share represents saturation of other office equipment.

Eff is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the primary commercial non-HVAC end-uses. End-uses embedded in *OtherIndex* include lighting, water heating, cooking, refrigeration, office equipment, and miscellaneous equipment. The equipment categories are based on EIA categorizations. Economic drivers interact with the *OtherIndex* through the utilization variable *OtherUse*. *OtherUse* is defined as follows:

$$\text{OtherUse}_{y,m} = \left(\frac{\text{Output}_y}{\text{Output}_{98}} \right)^{0.40} \times \left(\frac{\text{Price}_{y,m}}{\text{Price}_{98}} \right)^{-0.20}$$

4.1.2.1 GSND Sales Forecast. The GSND sales forecast is derived from a total sales forecast model where sales are specified as a function of regional output, (real) price, heating and cooling degree days, and end-use indices to account for changes in commercial sector end-use saturation and efficiency.

4.1.2.2 GSND Sales Models. GSND sales models are estimated for OUC and St. Cloud. Both models explain historical monthly sales variations. The adjusted R^2 for the OUC GSND sales model is 0.98 and the adjusted R^2 for St. Cloud is 0.91. The estimated end-use variable coefficients are statistically significant at the 5 percent level of confidence in both models.

4.1.2.3 GSD Models. The GSD class represents the largest nonresidential customer class. Over the last 5 years, OUC has seen its strongest sales gains in this customer class, with GSD sales growth averaging 2.6 percent annually for the combined OUC and St. Cloud service territories. While overall sales growth will slow significantly over the forecast period, GSD sales are expected to continue a relatively strong sales growth through the forecast horizon.

The GSD models include *XCool* and *XOther*. Low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class. In the OUC model, *XCool* and *XOther* are highly significant with t-statistics over 2.0. The adjusted R^2 is 0.94 with an in-sample MAPE of 3.2 percent. The St. Cloud end-use variables are also statistically significant with t-statistics over 2.0. The St. Cloud model has an adjusted R^2 of 0.88 with an MAPE of 5.2 percent.

The eight largest OUC customers (GSLD) are backed out of OUC GSD sales data and forecasted separately. The companies include a defense contractor, the Orlando International Airport (OIA), two regional medical centers, a sewage treatment facility, the convention center, and two theme parks. Forecasts are based on discussions with customer support staff. For all customers, except the airport and the convention center, the sales forecasts are held constant at the 2004 level. The OIA and convention center forecasts are based on airport and convention center expansion plans. The GSLD forecast is combined with the other GSD forecast to develop a total GSD forecast.

OUC's own electric use (OUC Use) is also forecasted separately. The forecast is primarily driven by expected demand for OUC's chilled water cooling plants in the metropolitan Orlando area. OUC chiller-related electricity requirements are backed out of the GSD sales forecast since chilled water sales are expected to directly displace GSD air conditioning load.

4.1.2.3.1 Street Lighting Sales. Street lighting sales are forecasted using a simple trend model. The forecast also includes sales from the *OUC Convenient Lighting Program*, which targets outdoor lighting use. It is assumed that the *Convenient Lighting Program* will grow by about 2.5 GWh a year through the forecast period.

4.1.3 Hourly Load and Peak Forecast

To capture the load diversity across the two retail companies, separate system hourly load forecasts are estimated for OUC and St. Cloud. The hourly load forecasts are then combined to generate a total system hourly load forecast. Summer and winter peak demands are then calculated from the combined utility system hourly load forecast.

The system load profiles are based on a set of hourly load models using load data covering the January 1996 to December 2006 period. Historical hourly loads are first expressed as a percentage of the total daily energy as follows:

$$\mathbf{Fraction_{dh} = Load_{hd} \div Energy_{d}}$$

where:

$Load_{hd}$ = the system load in hour (h) and day (d).

$Energy_{d}$ = the system energy in day (d).

Hourly fraction models are then estimated using the Ordinary Least Squares (OLS) regression where the hourly models are specified as a function of daily weather conditions, months, day of the week, and holidays. A second model is estimated for daily energy ($Energy_d$) where daily energy is specified as a function of daily temperatures, day of the week, holidays, seasons, and a trend variable to account for underlying growth over the estimation period.

The hourly fraction and daily energy models are used to simulate hourly fractions and daily energy for normal daily weather conditions. Normal daily temperatures are calculated by first ranking each year from the hottest to coldest day. The ranked data are then averaged to generate the hottest average temperature day to the coolest average temperature day. Daily normal temperatures are then mapped back to a representative calendar day based on a typical daily weather pattern. The hottest normal temperature is mapped to July and the coldest normal temperature to January.

Given weather normal hourly fractions (*WNFraction*) and weather normal daily energy (*WNDailyEnergy*), it is possible to calculate weather normal load for hour (h) in day (d) as follows:

$$\mathbf{WNLoad_{dh} = WNFraction_{dh} \times WNDailyEnergyt_{dh}}$$

The system 8,760 hourly load forecast is generated by combining the weather normal system load shape with the energy forecast using *MetrixLT*. The energy forecast is allocated to each hour based on the weather normal hourly profile. Separate hourly load forecasts are derived for OUC and St. Cloud.

Under normal daily weather conditions OUC is just as likely to experience a winter peak as it is a summer peak. OUC experiences a "needle-like" peak in the winter months on the 1 or 2 days where the low temperature falls below freezing. The needle peak is largely driven by backup resistant heat built into the residential heat pumps.

A separate hourly load forecast is estimated for St. Cloud. Given that St. Cloud is dominated by the residential sector, St. Cloud is even more likely to peak during the winter season.

The hourly OUC and St. Cloud forecasts are aggregated to yield total system hourly load requirements. Forecasted seasonal peaks are then derived by finding the maximum hourly demand in January (for the winter peak) and July (for the summer peak).

4.2 Forecast Assumptions

The forecast is driven by a set of underlying demographic, economic, weather, and price assumptions. Given long-term economic uncertainty, the approach was to develop a set of reasonable, but conservative, set of forecast drivers.

4.2.1 Economics

The economic assumptions are derived from forecasts from Economy.com and the University of Florida. Economy.com's monthly economic forecast for the Orlando MSA is used to drive the forecast.

4.2.1.1 Employment and Regional Output. The nonresidential forecast models are driven by nonmanufacturing and regional output forecasts. Economy.com's employment forecasts were used. Table 4-1 shows the annual employment and gross state product projections.

4.2.1.2 Population, Households, and Income. The primary economic drivers in the residential forecast model are population, the number of households, and real personal income. Economy.com's projections for the Orlando MSA were used, and the projections are presented in Table 4-2.

4.2.2 Price Assumption

An aggregate retail price series was used as a proxy for effective prices in each of the model specifications. Since retail rates (across rate schedules) have generally moved in the same direction, an average retail price variable captures price movement across all the customer classes. The average annual price series is provided in Table 4-3.

Table 4-1
Employment and Gross Regional Output Projections – Orlando MSA

Year	Total Employment (thousands)	Nonmanufacturing Employment (thousands)	Gross Product (billion $)
1990	595.9	505.3	36.0
1995	696.6	613.7	45.6
2000	886.0	779.4	60.3
2005	1,012.1	888.9	77.9
2010	1,153.4	1,012.1	94.7
2015	1,309.4	1,153.5	112.2
2020	1,527.8	1,349.5	135.9
2025	1,775.3	1,571.9	165.0
Average Annual Increase			
90-95	3.2%	4.0%	4.8%
95-00	4.9%	4.9%	5.8%
00-05	2.7%	2.7%	5.3%
05-10	2.7%	2.6%	4.0%
10-15	2.6%	2.7%	3.5%
15-20	3.1%	3.2%	3.9%
20-25	3.1%	3.1%	4.0%

Table 4-2
Population, Household, and Income Projections – Orlando MSA

Year	Real Income per Household	Households (thousands)	Population (thousands)
1990	$59,822	471.2	1,240.6
1995	$60,512	542.7	1,428.3
2000	$71,067	629.7	1,656.3
2005	$74,659	734.8	1,933.1
2010	$78,998	843.4	2,185.6
2015	$81,417	991.4	2,516.5
2020	$87,266	1,175.1	2,948.6
2025	$94,852	1,368.7	3,426.9
Average Annual Increase			
90-95	0.2%	2.9%	2.9%
95-00	3.3%	3.0%	3.0%
00-05	1.0%	3.1%	3.1%
05-10	1.1%	2.8%	2.5%
10-15	0.6%	3.3%	2.9%
15-20	1.4%	3.5%	3.2%
20-25	1.7%	3.1%	3.1%

Table 4-3
Historical and Forecasted Price Series
Average Annual Price

Year	Real Price (cents/kWh)
2000	5.3
2005	6.1
2010	5.5
2015	5.5
2020	5.5
2025	5.5
Annual Increase	
00-05	2.9%
05-10	-2.1%
10-15	0.0%
15-20	0.0%
20-25	0.0%

The price series is calculated by first deflating historical monthly revenues by the Consumer Price Index. Real revenues are then divided by retail sales to yield a monthly revenue per kWh value. Since revenue is itself a function of sales, it is inappropriate to regress sales directly on revenue per kWh. To generate a price series, a 12 month moving average of the real revenue per kWh series is calculated. This is a more appropriate price variable, as it assumes that households and businesses respond to changes in electricity prices that have occurred over the prior year.

4.2.3 Weather

Weather is a key factor affecting electricity consumption for indoor cooling and heating. Monthly cooling degree days (CDDs) are used to capture cooling requirements while heating degree days (HDDs) account for variation in usage because of electric heating needs. CDDs and HDDs are calculated from the daily average temperatures for Orlando.

CDD is calculated using a 65° F base. First, a daily CDD is calculated as follows:

$$\mathbf{CDD_d = (AvgTemp_d - 65) \text{ when } AvgTemp_d \rangle = 65}$$

CDD_d has a value equal to the average daily temperature minus 65 when the average daily temperature is greater than or equal to 65° F, and equals zero if average daily temperature is less than 65° F. The daily CDD values are then aggregated to yield a monthly CDD as follows:

$$\mathbf{CCD_m = \Sigma\, CDD_{md}}$$

For each month, a normal CDD estimate is calculated using a 10 year average of the monthly values calculated from 1995 through 2004:

$$\mathbf{CDD_{nm} = \Sigma\, CDD_m \div 10}$$

Heating degree days are calculated in a similar manner. Daily HDD is first derived using a base temperature of 65° F as follows:

$$\mathbf{HDD_d = (65 - AvgTemp_d) \text{ when } AvgTemp_d \langle = 65}$$

HDD_d equals 65° F minus the average daily temperature if the average daily temperature is less than or equal to 65° F, and equals zero if the daily temperature is greater than 65° F. Aggregate monthly HDD (HDD_m) is then calculated by summing daily HDD over each month:

$$HDD_m = \Sigma HDD_{md}$$

The monthly normal HDD is calculated as a 10 year average of the calendar month HDD as follows:

$$HDD_{nm} = \Sigma HDD_m \div 10$$

4.3 Base Case Load Forecast

A long-term annual budget forecast was developed through 2025. As outlined in the methodology section, the sales forecast is developed from a set of structured regression models that can be used for forecasting both monthly sales and customers for the forecast horizon. Forecast models are estimated for each of the major rate classifications including the following:

- Residential.
- GSND (small commercial customers).
- GSD (large commercial and industrial customers).
- Street lighting.

Models are estimated using monthly sales data covering the 1996 through 2006 period for the OUC residential model as well as for the OUC nonresidential models. St. Cloud residential, GSD, and GSND sales models are estimated using monthly data from 1996 through 2005.

To support production-costing modeling, an 8,760 hourly load forecast is derived for each of the forecast years. The hourly load forecasts are based on a set of hourly and daily energy statistical models. The models are estimated from hourly system load data over the January 1996 to December 2006 period. A separate set of models is estimated for OUC and St. Cloud. Seasonal peak demand forecasts are derived as the maximum hourly demand forecast occurring in the summer and winter months. Table 4-4 summarizes the annual net energy for load and seasonal peak demand forecasts for the combined OUC and St. Cloud service territories.

Table 4-4
System Peak (Summer and Winter) and
Net Energy for Load (Total of OUC and St. Cloud)

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)	Load Factor (%)
1995	861	876	4,377	57.0%
2000	1,025	1,007	5,290	58.9%
2005	1,206	1,079	6,071	57.5%
2010	1,369	1,381	7,011	58.0%
2015	1,556	1,569	7,951	57.8%
2020	1,776	1,792	9,085	57.9%
2025	2,028	2,047	10,322	57.6%
Average Annual Increase				
95-00	3.5%	2.8%	3.9%	-
00-05	3.3%	1.4%	2.8%	-
05-10	2.6%	5.1%	2.9%	-
10-15	2.6%	2.6%	2.6%	-
15-20	2.7%	2.7%	2.7%	-
20-25	2.7%	2.7%	2.6%	-

4.3.1 Base Case Economic Outlook

Between 1995 and 2005, the population has grown at an average annual rate of 2.8 percent, and gross output has grown at an average annual rate of 4.4 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and the nation. Orlando is expected to exceed overall state economic growth through the next 10 years.

Much of this growth has been fueled by significant gains in the service sector, which has seen employment expand by nearly 100 percent since 1990. Moreover, employment in the service sector accounts for over half of total employment. Hotels and tourism-related activities, as well as call centers, have continued to grow.

Two of the largest regional employers are Walt Disney and Universal Studios. Universal Studios has doubled in size with the addition of *Islands of Adventure*, *CityWalk*, and the related hotel complex. The expanded Orange County convention center opened in 2003, which will help increase regional convention and tourism activity.

To accommodate growing convention, tourism, and regional business activity, the OIA is anticipating a major expansion program that will ultimately double the capacity of the airport. In 2001, OIA served 28 million passengers. The airport saw a decrease in the number of passengers after September 11, 2001. In 2003, OIA served 27.3 million passengers, which was a 2.5 percent increase over the prior year and almost at pre-September 2001 levels. In 2005, OIA served 34.1 million passengers, exceeding pre-September 2001 levels. The level of passengers grew to 34.8 million passengers or 2.1 percent, in 2006. The OIA expects strong growth (in excess of 3.0 percent a year) over the next decade.

4.3.1.1 Economic Projections. Relatively inexpensive labor and housing costs and strong in-migration from both other states and other nations will continue to fuel the regional economic expansion long into the future. The number of households in the Orlando MSA is projected to increase from 629,700 in 2000 to 1,368,700 by 2025, representing an average annual growth rate of 3.2 percent. Employment is projected to grow at 2.8 percent over the same period.

Traditionally, the cost of doing business in Orlando has been below the average cost throughout the United States, with the cost of living in Orlando slightly lower than the average cost of living in the United States. The combination of these and other factors will sustain Orlando as one of the fastest growing metropolitan areas in the United States. Long-term growth will be driven by the high quality of life, the relatively low costs of both doing business and living, strong net migration, and an environment that is conducive to business development. Increasing concentrations of high-tech and medical-related industries will help to diversify the local economy.

Economic projections are based on Economy.com's economic outlook for Orlando and the State of Florida. Projections are in line with economic projections by the University of Florida.

4.3.2 Forecast Results

Based upon the previously discussed economic assumptions, total retail sales for OUC are expected to increase from 4,696 GWh in 2000 to 8,710 GWh by 2025. St. Cloud sales are projected to increase from 343 GWh to 1,206 GWh over this same time period.

4.3.2.1 Residential Forecast. With high electric end-use saturation and projected appliance efficiency-gains, residential average use is projected to increase relatively slowly over the forecast period. For OUC, average use per customer is forecasted to grow at 0.1 percent. Residential sales growth will be driven largely by the addition of new customers. With relatively strong population projections for the region, residential customers are expected to increase at an average annual rate of 2.9 percent for OUC and at 5.1 percent for St. Cloud between 2000 and 2025. The OUC and St. Cloud residential sales forecasts are shown in Tables 4-5 through 4-8, respectively.

4.3.2.2 Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 1.3 percent and 5.3 percent for OUC and St. Cloud, respectively, between 2000 and 2025. Projected GSND sales are driven by regional non-manufacturing employment and output growth. Average use is projected to be relatively flat, particularly for OUC. Average use growth is partly constrained by size limitation; as customers exceed the 50 kW rate class cutoff, they migrate to the appropriate GSD rate. For OUC, average GSND use has actually trended downward over the last few years. Small commercial customer growth accounts for most of the GSND sales gains. The GSND customer forecast is driven by regional non-manufacturing employment projections. The number of GSND customers is projected to grow at an average annual growth rate of 1.9 percent and 4.5 percent, respectively, for OUC and St. Cloud from 2000 through 2025. Tables 4-5 through 4-8 show annual GSND forecasts for OUC and St. Cloud.

4.3.2.3 Large Nonresidential Sales Forecast. GSD represents the largest commercial and industrial customers. GSD sales grew 3.2 percent between 2000 and 2006. Sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall strong regional output growth. Average use actually declines over the forecast period as smaller customers migrate from GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 4-5 through 4-8 summarize the annual GSD forecasts for OUC and St. Cloud.

Table 4-5
OUC Long-Term Sales Forecast (GWh)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,380	316	2,157	27	--	55	3,935
2000	1,583	293	2,705	31	--	84	4,696
2005	1,858	282	3,081	37	9	106	5,373
2010	2,101	324	3,500	43	19	110	6,097
2015	2,424	349	3,879	47	29	114	6,842
2020	2,843	375	4,288	52	39	120	7,717
2025	3,331	405	4,744	57	49	124	8,710
Average Annual Increase							
95-00	2.8%	-1.5%	4.6%	2.8%	--	8.8%	3.6%
00-05	3.3%	-0.8%	2.6%	3.6%	--	4.8%	2.7%
05-10	2.5%	2.8%	2.6%	3.1%	16.1%	0.7%	2.6%
10-15	2.9%	1.5%	2.1%	1.8%	8.8%	0.7%	2.3%
15-20	3.2%	1.5%	2.0%	2.0%	6.1%	1.0%	2.4%
20-25	3.2%	1.6%	2.0%	1.9%	4.7%	0.7%	2.5%

Table 4-6
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108,805	14,590	2,946	126,341
2000	125,523	15,626	4,262	145,411
2005	143,477	17,345	5,327	166,149
2010	162,364	18,944	6,025	187,333
2015	188,354	20,726	6,710	215,790
2020	219,561	22,727	7,562	249,850
2025	254,960	24,896	8,583	288,339
Average Annual Increase				
95-00	2.9%	1.4%	7.7%	2.9%
00-05	2.7%	2.1%	4.6%	2.7%
05-10	2.5%	1.8%	2.5%	2.4%
10-15	3.0%	1.8%	2.2%	2.9%
15-20	3.1%	1.9%	2.4%	3.0%
20-25	3.0%	1.8%	2.6%	2.9%

Table 4-7
St. Cloud Long-Term Sales Forecast (GWh)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
1995	180	19	56	2	257
2000	238	27	76	3	344
2005	345	40	102	5	492
2010	453	56	126	5	640
2015	573	70	148	8	799
2020	723	84	171	11	989
2025	898	99	195	14	1,206
Average Annual Increase					
95-00	5.7%	7.3%	6.3%	8.5%	6.0%
00-05	7.5%	8.2%	6.1%	10.8%	7.4%
05-10	7.7%	7.0%	4.3%	0.0%	5.4%
10-15	4.8%	4.6%	3.3%	9.9%	4.5%
15-20	4.8%	3.7%	2.9%	6.6%	4.4%
20-25	4.4%	3.3%	2.7%	4.9%	4.1%

Table 4-8 St. Cloud Average Number of Customers Forecast				
Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	14,546	1,363	126	16,035
2000	16,470	1,610	158	18,238
2005	22,201	2,422	234	24,857
2010	28,822	2,956	295	32,073
2015	36,646	3,467	356	40,469
2020	46,040	4,107	417	50,564
2025	56,696	4,796	477	61,969
Average Annual Increase				
95-00	2.5%	3.4%	4.6%	2.6%
00-05	6.2%	8.5%	8.2%	6.4%
05-10	5.4%	4.1%	4.7%	5.2%
10-15	4.9%	3.2%	3.8%	4.8%
15-20	4.7%	3.5%	3.2%	4.6%
20-25	4.3%	3.2%	2.7%	4.2%

4.4 Net Peak Demand and Net Energy for Load

Hourly load models are used to forecast the 8,760 hours of each of the forecast years. Underlying hourly load growth is driven by the aggregate energy forecast. Thus, forecasted peaks grow at roughly the same rate as the energy forecast. Tables 4-9 and 4-10 show seasonal peak demands and net energy for load forecasts for OUC and St. Cloud, respectively.

4.5 High and Low Load Scenarios

In addition to the base case, two long-term forecast scenarios contributed to the potential demand outcome. High and low case scenarios are based on long-term population trends projected by the University of Florida. The high and low forecast scenarios are based on the University of Florida's population projections for counties served by Orlando and St. Cloud. In the high case scenario, the population is forecasted to increase 3.1 percent on a compounded basis between 2005 and 2025. This compares with the University of Florida's base case population projections of 2.1 percent. The high growth scenario results in a forecasted long-term annual energy growth rate of 3.7 percent, with system peak demand that is 399 MW higher than the base case by 2025. In the low case scenario, energy increases 1.7 percent on a compounded basis through 2025. Peak demand is 324 MW lower than the base case by 2025. Table 4-11 presents a summary of the high, base, and low load scenarios.

Table 4-9
OUC Net Peak Demand (Summer and Winter) and
Net Energy for Load (History and Forecast)

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2000	941	913	4,922
2005	1,076	965	5,555
2010	1,210	1,218	6,339
2015	1,358	1,367	7,321
2020	1,531	1,542	8,044
2025	1,729	1,741	9,056
Average Annual Increase			
95-00	2.7%	1.1%	2.4%
00-05	2.7%	1.1%	2.4%
05-10	2.4%	4.8%	2.7%
10-15	2.3%	2.3%	2.9%
15-20	2.4%	2.4%	1.9%
20-25	2.5%	2.5%	2.4%

Table 4-10
St. Cloud Net Peak Demand (Summer and Winter) and
Net Energy for Load (History and Forecast)

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2000	84	94	369
2005	130	114	516
2010	159	162	672
2015	198	202	838
2020	245	251	1,041
2025	299	306	1,266
Average Annual Increase			
00-05	9.1%	3.9%	6.9%
05-10	4.1%	7.3%	5.4%
10-15	4.5%	4.5%	4.5%
15-20	4.4%	4.4%	4.4%
20-25	4.1%	4.0%	4.0%

Table 4-11
Scenario Peak Forecasts
OUC and St. Cloud

High Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2005	1,206	1,079	6,071
2010	1,406	1,418	7,208
2015	1,686	1,701	8,644
2020	2,022	2,040	10,366
2025	2,425	2,446	12,431
Average Annual Increase			
05-10	3.1%	5.6%	3.5%
10-15	3.7%	3.7%	3.7%
15-20	3.7%	3.7%	3.7%
20-25	3.7%	3.7%	3.7%
Base Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2005	1,206	1,079	6,071
2010	1,369	1,381	7,011
2015	1,556	1,569	7,951
2020	1,776	1,792	9,085
2025	2,028	2,047	10,322
Average Annual Increase			
05-10	2.6%	5.1%	2.9%
10-15	2.6%	2.6%	2.6%
15-20	2.7%	2.7%	2.7%
20-25	2.7%	2.7%	2.6%
Low Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2005	1,206	1,079	6,071
2010	1,327	1,338	6,799
2015	1,443	1,456	7,397
2020	1,571	1,584	8,048
2025	1,709	1,723	8,755
Average Annual Increase			
05-10	1.9%	4.4%	2.3%
10-15	1.7%	1.7%	1.7%
15-20	1.7%	1.7%	1.7%
20-25	1.7%	1.7%	1.7%

5.0 Demand-Side Management

Throughout its history, OUC has demonstrated a strong commitment to serve its customers' conservation needs. OUC has undertaken many conservation programs to meet customer needs and expectations. OUC's 2005 Demand-Side Management (DSM) Plan was approved by the Florida Public Service Commission (FPSC) on September 1, 2004 (Docket No. 040035-EG). The FPSC determined that there were no cost-effective conservation measures available for use by OUC, and therefore established zero DSM and conservation goals for OUC's residential, commercial, and industrial sectors through 2014. Although OUC's FPSC-approved DSM and conservation goals are zero, OUC recognizes the importance of energy efficiency and conservation in today's market. Therefore, OUC has voluntarily maintained and continued to offer those programs that have shown high customer demand and participation. The FPSC goals for OUC and the programs currently offered by OUC are presented briefly in this section and in greater detail in OUC's 2005 DSM Plan.

Table 5-1
Total Conservation Goals Approved by the FPSC

	Residential			Commercial / Industrial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
2005	0	0	0	0	0	0
2006	0	0	0	0	0	0
2007	0	0	0	0	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	0	0	0	0	0	0
2011	0	0	0	0	0	0
2012	0	0	0	0	0	0
2013	0	0	0	0	0	0
2014	0	0	0	0	0	0

The DSM programs voluntarily continued and offered by OUC to its customers during 2006 included programs that result in energy and/or demand reductions that are quantifiable, as well as programs that are not quantifiable but aid OUC's customers in reliability, energy conservation, and education. The quantifiable DSM and conservation programs voluntarily continued and offered to OUC's customers in 2006 included the following:

- Residential Energy Survey Program (Walk-Through, Video or DVD, and On-Line).
- Residential Energy Efficiency Rebate Program (Duct Repair, Attic Insulation, Weatherization).
- Residential Low-Income Home Energy Fix-Up Program.
- Residential Insulation Billed Solution Program.
- Residential Efficient Electric Heat Pump Program.
- Residential Gold Ring Home Program.
- Commercial Energy Survey Program.
- Commercial Indoor Lighting Retrofit Program.

In addition, OUC continues additional programs that are not quantifiable, but aid OUC's customers in reliability, energy conservation, and education. The programs that are not quantifiable which were offered by OUC to its customers in 2006 include the following:

- Residential Energy Conservation Rate.
- Commercial OUConsumption Online Program.
- Commercial OUConvenient Lighting Program.
- Commercial Power Quality Analysis Program.
- Commercial Infrared Inspections Program.
- OUCooling.
- Green Pricing Initiative Program.
- Photovoltaic Generation Pilot Program.

In general, many things have changed over the last few years leading to a decrease in customer participation and decreased cost-effectiveness of DSM and conservation programs. As each program continues, participation tends to gradually decrease because the market for the program becomes saturated. Most of the customers that want to and are willing to participate will have done so early in the program.

The decrease in cost-effectiveness of DSM and conservation programs is a result of numerous factors. Government mandates have forced manufacturers to increase their efficiency standards, thereby decreasing the incremental amount of energy savings achievable; the efficiency of new generation has increased and the cost of installing new generation has decreased; and with interest rates near all-time lows, the carrying costs of power plants have been greatly reduced. All of these factors have resulted in it becoming more difficult for DSM and conservation programs to be cost-effective and to achieve high levels of customer participation.

The remainder of this section describes each of the quantifiable and non-quantifiable DSM and conservation programs voluntarily continued and offered by OUC to its customers during 2006.

5.1 Quantifiable Conservation Programs

5.1.1 Residential Energy Survey Program

This program is designed to provide residential customers with recommended energy efficiency measures and practices. The Residential Energy Survey Program consists of three measures, including the Residential Energy Walk-Through Survey, the Residential Energy Survey Video and DVD, and an interactive On-Line Energy Survey.

The Residential Energy Walk-Through Survey includes a complete examination of the attic; HVAC system; air duct and air returns; window caulking; weather stripping; water heater; faucets; toilets; and lawn sprinkler systems. Literature on other OUC programs is also provided to residential customers. The participant is given a choice to receive either a low-flow showerhead or a compact fluorescent bulb. OUC Conservation Specialists are presently using this walk-through type audit as a means of motivating OUC customers to participate in other conservation programs and qualify for appropriate rebates.

The Residential Energy Survey Video was first offered in 2000 by OUC and is now available to OUC customers in an interactive DVD format. The video (or DVD) is free and is distributed either in the English or Spanish version to OUC customers by request. The measure was developed to further assist OUC customers in surveying their homes for potential energy saving opportunities. The video walks the customer through a complete visual assessment of energy and water efficiency in his or her home. A checklist brochure to guide the customer through the audit accompanies the video. The video has many benefits over the walk-through survey, including the convenience of viewing the video at any time without a scheduled appointment and the ability to watch the video numerous times.

In addition to the Energy Walk-Through and the Video Surveys, OUC offers customers an interactive Online Home Energy Audit. The interactive Online Home Energy Audit is available on OUC's Web site, www.OUC.com.

One of the primary benefits of the Residential Energy Survey Program is the education it provides to customers on energy conservation measures and ways their lifestyle can directly affect their energy use. Customers participating in the Energy Survey Program are informed about conservation measures that they can implement.

Customers will benefit from the increased efficiency in their homes, which will decrease their electric and water bills.

Participation in the Walk-Through Energy Survey has been consistently strong over the past 10 years and interest in both the Energy Survey Video and DVD, as well as the interactive Online Home Energy Audit, has been high since the measures were first introduced. Feedback from customers that have taken advantage of the surveys has been very positive.

5.1.2 Residential Energy Efficiency Rebate Program

This program rewards customers who have invested in energy-efficient heat pumps, weather stripping, insulation, duct repairs, or other energy-saving measures for their single-family homes. Under this program, OUC will give specific tips to customers on conserving electricity and water, and offer details on the following customer rebate programs:

- OUC will rebate up to $300 on customer's purchase of an energy-efficient heat pump.
- OUC will rebate customers up to $75 for the purchase of caulking, weather stripping, window tinting, and solar screening.
- OUC will rebate up to $100 to upgrade the customer's attic insulation to R-19 or higher.
- OUC will rebate up to $75 on repairs made to leaking ducts.

5.1.3 Residential Low-Income Home Energy Fix-Up Program

This program targets residential customers with a total annual family income of $35,000 or less. Each customer must request a free Residential Energy Survey. Ordinarily, Energy Survey recommendations require a customer to spend money replacing or adding energy conservation measures, which low-income customers may not have the discretionary income to implement. To be eligible for this program, the customer must be equipped with all electric appliances.

OUC pays 85 percent of the total cost, not to exceed $2,000, for home weatherization for the following measures:

- Attic insulation.
- Exterior and interior caulking.
- Weather-stripping of doors and windows.
- Minor air conditioning/heating supply and return air duct repairs.
- Water heater and hot water pipe insulation.

- Minor water leakage repair.
- Installation of water flow restrictors.

Under this program, OUC will arrange for a licensed, approved contractor to perform the necessary repairs and will pay 85 percent of the total cost, not to exceed $2,000. The remaining 15 percent can be paid directly or over an interest-free 12-month period on the participant's monthly electric bill. The purpose of the program is to reduce the energy cost for low-income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy community.

Through this program, OUC helps to lower the bills of low-income customers who may have difficulty paying their bills. Reducing the bill of the low-income customer may improve the customer's ability to pay the bill, thereby decreasing costly service disconnect fees and late charges. OUC believes that this program will help achieve and maintain high customer satisfaction.

5.1.4 Residential Insulation Billed Solutions Program

This measure is available to OUC residential customers who utilize some type of electric heat and/or air conditioning. To qualify, customers must request a free Residential Energy Survey. To qualify for financing, customers must have a satisfactory credit rating with OUC. The program allows customers who insulate their attics to a minimum R-19 level to pay for the insulation on their monthly utility bills for up to 2 years interest-free with no money down. In addition, the customer will receive a $100 rebate to be deducted from the financed amount. OUC directly pays the total cost for installation when the customer makes payments to OUC as part of their monthly utility bill. The maximum amount that can be financed is $600. Feedback from customers that have taken advantage of the program has been very positive.

5.1.5 Residential Efficient Electric Heat Pump Program

This program provides rebates to qualifying customers who install heat pumps having a seasonal energy efficiency ratio (SEER) of 14.0 or higher. Customers will be able to obtain a rebate of $100, $200 or $300, if they install heat pumps with a SEER rating of 14, 15, or 16 respectively. A qualified, licensed, and insured air conditioner contractor must perform the work. In addition, OUC will require proof of purchase or invoice documenting the eligibility of heat pump installation. Customers will benefit from the increased energy conservation in their homes, which will decrease their electric bills. One of the main benefits of this program is the ductwork and insulation level improvements made by contractors when installing energy efficient heat pumps.

5.1.6 Residential Gold Ring Home Program

The Residential Gold Ring Home Program is closely aligned with Energy Star Ratings. In developing the program, OUC partnered with local home builders to construct new homes according to Energy Star standards. Features may include high efficiency heat pumps, heat recovery water heaters, R-30 attic insulation, interior air ducts, double pane windows, window shading, etc.

The contractor is required to qualify its homes to Energy Star standards by having the homes rated by a certified rater. In return for each Energy Star home certification, the builder receives a rebate of $200 ($100 for townhomes). In addition, OUC will help support the builder's efforts through additional advertising and other promotional strategies.

Gold Ring Homes can use 20 to 30 percent less energy than other homes. Gold Ring homeowners benefit from lower energy bills and qualification for all Federal Housing Administration (FHA), Veterans Affairs (VA), and Energy Efficient Mortgage Programs. This allows the homeowner to increase his or her income-to-debt ratio by 2 percent and makes it easier to qualify for a mortgage.

5.1.7 Commercial Energy Survey Program

This program is focused on increasing the energy efficiency and energy conservation of commercial buildings and includes a survey comprised of a physical walk-through inspection of the commercial facility performed by highly trained and experienced energy experts. The commercial customer who has a Commercial Energy Survey receives a report at the time of the survey and the book *Business Energy Efficiency Guide* which shows more ways for businesses to profit from energy management. Within approximately 30 days of the audit, the customer receives a written report detailing cost-effective recommendations to make the facility more energy and water efficient. Customers are encouraged to participate in other OUC commercial programs and directly benefit from energy conservation, which decreases their electric and water bills.

5.1.8 Commercial Indoor Lighting Retrofit Program

This program reduces energy consumption for the commercial customer through the replacement of older fluorescent and incandescent lighting with newer, more efficient lighting technologies. A special alliance between OUC and the lighting contractor enables OUC to offer the customer a discounted project cost. An additional feature of the program allows the customer to pay for the retrofit through the monthly savings that the project generates. Upfront capital funding is not required to participate in this program. The project payment appears on the participating customer's utility bill as a line-item. After the project has been completely paid, the participating customer's annual energy bill will decrease by the approximate amount of projected energy cost savings.

5.2 Additional Conservation Programs

The following programs were offered by OUC to its customers in 2006, resulting in energy savings and increased reliability. Although the programs are neither directly nor easily quantifiable, each program provides a valuable service to OUC's customers.

5.2.1 Residential Energy Conservation Rate

Beginning in October 2002, OUC modified its residential rate structure to a two-tiered block structure to encourage energy conservation. Residential customers using more than 1,000 kWh per month pay a higher rate for the additional energy usage. The purpose of this rate structure is to make OUC customers more energy-conscientious and to encourage conservation of energy resources.

5.2.2 Commercial OUConsumption Online Program

This program enables businesses to check their energy usage and demand from a desktop computer, thereby allowing businesses to manage their energy load. Customers are able to analyze the metered interval load data for multiple locations, compare energy usage among facilities, and measure the effectiveness of various energy efficiency efforts. The data can also be downloaded for further analysis. Participants must cover a one-time program set-up fee of $45, the cost of additional infrastructure (can range between $0 and $500) at the meters, and a $45 monthly fee per meter for this service.

5.2.3 Commercial OUConvenient Lighting Program

OUConvenient Lighting provides complete outdoor lighting services for commercial applications, including industrial parks, sports complexes, and residential developments. Each lighting package is customized for each participant, allowing the participant to choose among light fixtures. OUC handles all of the upfront financial costs and maintenance. The participant then pays a low monthly fee for each fixture. OUC also retrofits existing fixtures to new light sources or higher output units, increasing efficiency as well as providing preventive and corrective maintenance.

During 2006, OUConvenient Lighting had more than 5,900 new lights put under contract. OUConvenient Lighting projects include the Rosen Hotels & Resorts, Baldwin Park Development Co., and the Orange County Convention Center, among many others.

In St. Cloud, OUConvenient Lighting worked with developers to provide lighting solutions to the Stevens Plantation project, which is planned to include 800 single-family homes, up to 250,000 square feet of neighborhood retail, and a 100 acre business park with up to 1 million square feet of office and light manufacturing space.

5.2.4 Commercial Power Quality Analysis Program

This program enables OUC to ensure the highest possible power quality to commercial customers. There are five general categories of power irregularities, including overvoltage, undervoltage, outages, electric noise, and harmonic distortion. Under the Power Quality Analysis program, trained and experienced service personnel help the customer isolate any problems and find appropriate solutions. The goals of this program include making the maximum effort to solve power quality problems through monitoring and interpretive analysis, identifying solutions that will lead to corrective action, and providing ongoing follow-up services to monitor results.

5.2.5 Commercial Infrared Inspections Program

This program was developed to help customers uncover potential reliability and power quality problems. A highly trained and experienced technician performs the inspection using state-of-the-art equipment. The infrared inspection detects thermal energy and measures the temperature of wires, breakers, and other electrical equipment components. The information is transferred into actual images, and those images reveal potential problem areas and hot spots that are invisible to the naked eye. This information allows the customer to make repairs to faulty equipment and prevent untimely breakdowns, equipment damage, and lost profits. Following the inspection, the customer receives a detailed analysis and written report, which includes a complete description of diagnostic recommendations..

5.2.6 OUCooling

OUCooling was originally formed in 1997 as a partnership between OUC and Trigen-Cinergy Solutions, and helps to lower air conditioning-related electric charges and reduce capital and operating costs. During 2004, OUC bought Trigen-Cinergy's rights and is now the sole owner of OUCooling. OUCooling will fund, install, and maintain a central chiller plant for each business district participating in the program. The main benefits to the businesses are lower energy consumption, increased reliability, and no environmental risks associated with the handling of chemicals. Other benefits for the businesses include avoided initial capital cost, lower maintenance costs, a smaller mechanical room (therefore more rental space), no insurance requirements, improved property resale value, and availability of maintenance personnel for other duties.

OUCooling operates two chilled water plants that serve customers in downtown Orlando, outside of downtown Orlando, and in Parramore. Underground "loops" run from each facility to buildings partnered with OUCooling. In Parramore and downtown Orlando alone, about 10 miles of underground pipes have the capacity to deliver 15,000 tons of chilled water to businesses – enough chilled water to cool about 6,000 residential homes. The 17.6 million gallon chilled water storage tank at the Orange County Convention Center is the largest in the world. The tank works in tandem with 20 water chillers and feeds a cooling loop that can handle more than 33,000 gallons of 37° F water per minute.

OUC's first chiller plant was installed at Lockheed Martin Corp. The plant was built in 1999 and serves eight customers. After that project, OUC began operation of a chilled water system serving downtown Orlando. In 1999, the downtown project won three awards. In 2000, the Downtown Orlando Partnership gave its Award of Excellence to OUC, based on the chilled water plant. The downtown Orlando "district cooling" division now provides air conditioning service to more than a dozen large commercial customers with a combined 2 million square feet of space.

In 2002, the International District Energy Association (IDEA) presented OUCooling a first-place award for signing up more customer square footage for its chilled-water business than any other company in 2001. OUCooling signed up 9 million square feet of new customer space in 2001. IDEA is an association representing more than 900 district heating and cooling executives, managers, engineers, consultants, and equipment suppliers from 20 countries.

OUC envisions building other chiller plants serving commercial campuses, hotels, retail shopping centers, and tourist attractions. During 2006, OUCooling maintained its strong growth. Three new development projects came on line during 2006, and new cooling contracts were put into place on upcoming projects.

OUC recently received three awards from the Associated Builders and Contractors Inc. for one of the top construction projects in Orlando. The awards included the Eagle Award for mechanical work, General Contractor Award of Merit, and the Subcontractor Award of Merit. OUCooling was also featured in the January-February 2003 issue of *Relay*, Florida's energy and electric utility magazine.

5.2.7 Green Pricing Initiative Program

OUC offers its customers an opportunity to participate in its Green Pricing Initiative, a program developed to increase the role of renewable energy among OUC's customers. Participation in this program helps add renewable energy to OUC's generation portfolio, improves regional air and water quality, and assists OUC in developing additional renewable energy resources. Program participants pay an additional $5.00 on their monthly utility bills in return for 200 kWh to support funding to add additional renewable energy to OUC's portfolio. Participation will help OUC develop cleaner alternative energy resources, such as solar, wind, and biomass. The annual per customer participation of 2,400 kWh is equivalent to the environmental benefit of planting 3 acres of forest, taking three cars off the road, preventing the use of 27 barrels of oil, or bicycling more than 30,575 miles instead of driving.

5.2.8 Photovoltaic Generation Pilot Program

OUC has initiated its Photovoltaic Generation Pilot Program to customers on standby service in which onsite generation consists of photovoltaic (PV) capacity. A PV system is a solar electric generating system that contains solar PV panels, batteries (optional), a static power converter, wiring, fuses, wiring devices, conduit, circuit breakers, transfer or disconnect switches, etc., for making the physical connections required to install the PV system and connect it to the normal wiring system. The program is available to the first 150 kW of residential PV generation and 350 kW of general service PV generation located in either the OUC or City of St. Cloud service territories.

Participating customers will be reimbursed for any export power supplied by the PV system at a rate equal to the applicable per kWh standby base and fuel energy charges in the event that the PV system is grid-integrated. If the customer qualifies for buyback credits, OUC will furnish and install such metering facilities as OUC determines to be appropriate to measure the electricity delivered by the customer to OUC's delivery system. The customer will receive both a monthly per kW credit as well as a flat monthly credit for the ownership and use of the PV system.

6.0 Forecast of Facilities Requirements

6.1 Existing Capacity Resources and Requirements

6.1.1 Existing and Planned Generating Capacity

Tables 6-1 and 6-2, which are presented at the end of this section, indicate that OUC and St. Cloud currently have a combined installed generating capability of 1,275 MW in the winter and 1,217 MW in the summer. OUC's existing generating capability (described in more detail in Section 2.0) consists of the following:

- A joint ownership share in the Stanton Energy Center (Units 1, 2, and Stanton A).
- Joint ownership shares of the Indian River combustion turbine units.
- Joint ownership shares of Crystal River Unit 3, McIntosh Unit 3, and St. Lucie Unit 2.

Additionally, St. Cloud's entitlement to capacity from Stanton Unit 2 is included as generating capability, consistent with the Interlocal Agreement described in Section 2.0.

As discussed throughout this Ten-Year Site Plan, it has been assumed that Stanton B will begin commercial operation June 1, 2010. Stanton B is expected to provide 275 MW of winter capacity and 249 MW of summer capacity. Including the capacity from Stanton B will increase the combined OUC and St. Cloud installed generating capability to 1,550 MW in the winter and 1,466 MW in the summer.

6.1.2 Power Purchase Agreements

As described in Section 2.2, OUC schedules St. Cloud's power purchase from TECO. Corresponding with the construction of Stanton A, OUC entered into a PPA with SCF to purchase capacity from SCF's 65 percent ownership share of Stanton A. The original Stanton A PPA was for a term of 10 years and allowed OUC, KUA, and FMPA to purchase all of SCF's 65 percent capacity share of Stanton A for 10 years. The utilities retained the right to reduce the capacity purchased from SCF by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased did not exceed 200 MW. The utilities originally had options to extend the PPA beyond its initial term. OUC, KUA, and FMPA have unilateral options to purchase all of Stanton A's capacity for the estimated 30 year useful life of the unit. Subsequent amendments to the original PPA continue OUC's capacity purchase until the 16th year of the PPA. Beginning with the 16th contract year and ending with the 20th contract year, OUC will maintain the irrevocable right to reduce the amount of capacity purchased by either 20 MW or 40 MW per year, as long as the total reduction in purchased capacity does not exceed 160 MW. OUC has the option of terminating the PPA on September 30, 2023, or extending the PPA up to an additional 10 years through two separate 5 year extensions.

6.1.3 Power Sales Agreements

As described in Section 2.3, OUC currently has no firm contractual power sales.

6.1.4 Retirements of Generating Facilities

OUC has not scheduled any unit retirements over the planning horizon, but will continue to evaluate options on an ongoing basis. The internal combustion units owned by St. Cloud were placed into standby in October 2006.

By the end of the Ten-Year Site Plan planning period, McIntosh 3 will be 34 years old and, therefore, increasing consideration should be given to life extension costs or its possible retirement.

An additional factor affecting potential unit modifications and/or retirements is the US Environmental Protection Agency (EPA)'s Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR). CAIR and CAMR are discussed in more detail in Section 8.0. OUC has not made final decisions on its compliance strategy for the regulatory requirements under CAIR and CAMR but continues to actively evaluate its options as part of its planning process.

6.2 Reserve Margin Criteria

The Florida Public Service Commission (FPSC) has established a minimum planned reserve margin criterion of 15 percent in 25-6.035 (1) Florida Administrative Code for the purposes of sharing responsibility for grid reliability. The 15 percent minimum planned reserve margin criterion is generally consistent with practice throughout much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning criterion.

6.3 Future Resource Needs

6.3.1 Generator Capabilities and Requirements Forecast

OUC has applied a minimum 15 percent reserve margin criterion to its own load and to St. Cloud's load, as well as the TECO partial requirements purchase. Tables 6-1 and 6-2 (presented at the end of this section) display the forecast reserve margins for the combined OUC and St. Cloud systems for the winter and summer seasons, respectively. The capacity associated with Stanton B is included in Tables 6-1 and 6-2, beginning in the summer of 2010.

Table 6-1 and Table 6-2 indicate that additional capacity is required to maintain the 15 percent reserve margin beginning in the summer of 2015.

6.3.2 Transmission Capability and Requirements Forecast

OUC continuously monitors and upgrades the bulk power transmission system as necessary to provide reliable electric service to its customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for electric power transmission system planning for its needs and those of the City of St. Cloud. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. Criteria of 95 percent and 105 percent of nominal system voltage establish the lower and upper limits of acceptable voltage. Transmission lines are not allowed to exceed 100 percent of their continuous ratings during normal conditions or 100 percent of their emergency ratings during contingency outages. The bus tie transformer loading guideline is 100 percent of the unit's 65° C rating.

OUC's transmission group uses the following planning criteria to review the need and options for increasing the capability of the transmission system. During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis that involves an outage of each of the 69 kV through 230 kV transmission lines. Bus tie transformers, tie lines with neighboring utilities, and off-system facilities known to cause internal problems are also included. If a violation of the voltage or loading criteria occurs, a permanent solution may be an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to ensure that no voltage or loading violations remain. OUC has recently changed its planning philosophy in situations where voltage or loading criteria are exceeded. Instead of using an operational procedure as the first step to correcting the problem, OUC will investigate permanent solutions such as new construction. As a short-term solution, operational remedies will continue to be used until new facilities can be put into service.

Table 6-1
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Base Case

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin(4) (MW)
	OUC	STC			Installed(1)	SEC A PPA	SEC B	TECO P.R.	Total	Required(2)	Available(3)	
2006/07	1,130	142	0	1,272	1,275	343	0	15	1,633	191	364	173
2007/08	1,165	149	0	1,313	1,275	343	0	15	1,633	197	322	125
2008/09	1,191	155	0	1,346	1,275	343	0	15	1,633	202	289	87
2009/10	1,218	162	0	1,381	1,275	343	0	15	1,633	207	255	47
2010/11	1,245	170	0	1,415	1,275	343	275	15	1,908	212	495	283
2011/12	1,272	177	0	1,449	1,275	343	275	15	1,908	217	461	243
2012/13	1,302	185	0	1,487	1,275	343	275	0	1,893	223	406	183
2013/14	1,333	193	0	1,527	1,275	343	275	0	1,893	229	366	137
2014/15	1,367	202	0	1,569	1,275	343	275	0	1,893	235	323	88
2015/16	1,403	212	0	1,615	1,275	343	275	0	1,893	242	278	35

(1) Includes existing net capability to serve OUC and St. Cloud.
(2) "Required Reserves" include 15 percent reserve margin on OUC retail peak demand, and STC retail peak demand.
(3) "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 percent of the TECO P.R. purchase.
(4) Calculated as the difference between available reserves and required reserves.

Table 6-2
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Base Case

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)	Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin(4) (MW)
	OUC	STC			Installed(1)	SEC A PPA	SEC B	TECO P.R.	Total	Required(2)	Available(3)	
2007	1,122	139	0	1,261	1,217	322	0	15	1,554	189	295	106
2008	1,156	146	0	1,302	1,217	322	0	15	1,554	195	254	59
2009	1,182	152	0	1,334	1,217	322	0	15	1,554	200	222	22
2010	1,210	159	0	1,369	1,217	322	249	15	1,803	205	436	231
2011	1,236	166	0	1,402	1,217	322	249	15	1,803	210	403	192
2012	1,263	173	0	1,437	1,217	322	249	15	1,803	215	368	153
2013	1,293	181	0	1,474	1,217	322	249	0	1,788	221	314	93
2014	1,324	189	0	1,513	1,217	322	249	0	1,788	227	275	48
2015	1,358	198	0	1,556	1,217	322	249	0	1,788	233	232	(1)
2016	1,393	207	0	1,601	1,217	322	249	0	1,788	240	187	(53)

(1) Includes existing net capability to serve OUC and St. Cloud.
(2) "Required Reserves" include 15 percent reserve margin on OUC retail peak demand, and STC retail peak demand.
(3) "Available Reserves" equals the difference between total available capacity and total peak demand, plus 15 percent of the TECO P.R. purchase.
(4) Calculated as the difference between available reserves and required reserves.

7.0 Supply-Side Alternatives

This section presents the supply-side alternatives evaluated to satisfy OUC's forecast capacity requirements throughout this Ten-Year Site Plan. The supply-side alternatives considered include a simple cycle combustion turbine alternative (GE 7FA) assumed to operate on ultra-low sulfur fuel oil, a combined cycle alternative (GE 1x1 7FA) assumed to operate on natural gas, a subcritical pulverized coal alternative (similar to Stanton 2) assumed to operate on low sulfur Central Appalachian coal, and a circulating fluidized bed (CFB) alternative assumed to operate on a blend of 80 percent high-Btu Powder River Basin (PRB) coal and 20 percent petroleum coke.

The remainder of this section presents the performance, emission, capital cost, operating and maintenance (O&M) cost, construction schedule, and availability estimates for each of the supply-side alternatives.

7.1 Performance and Emission Estimates

Tables 7-1 through 7-8 present performance and emission estimates for the simple cycle, combined cycle, pulverized coal, and CFB alternatives.

7.1.1 7FA Simple Cycle Combustion Turbine

Table 7-1
GE 7FA Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)(1)	Full Load Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Summer (Full Load)(3)	157.5	11,253
Average (Full Load)(3)	166.6	11,132
Average (90% Load)(3)	149.9	11,338
Average (70% Load)(3)	116.3	12,427
Average (50% Load) (3)	82.8	14,335

(1)Net capacity and net plant heat rate include degradation factors, and performance is preliminary.
(2)Heat rate and net capacity assume operation on fuel oil.
(3)Includes evaporative cooling.

Table 7-2 GE 7FA Estimated Emissions[1]	
NO_x, lb/MBtu (HHV)	0.008
SO_2, lb/MBtu (HHV)	0.0012
Hg, lb/MBtu (HHV)	N/A
CO_2, lb/MBtu (HHV)	159.8
CO, lb/MBtu (HHV)	0.034

(1)Emissions are at full load at average ambient conditions, ultra-low sulfur fuel oil operation, and include the effects of selective catalytic reduction (SCR).

7.1.2 1x1 7FA Combined Cycle

Table 7-3
GE 7FA Combined Cycle Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1, 2]
Summer (Full Load)	286.6	7,545
Average (Full Load)	298.8	7,492
Average (75% Load)[3]	191.6	7,350
Average (50% Load)[3]	141.1	7,968

(1)Net capacity and net plant heat rate include degradation factors, and performance is preliminary. Summer and average full load net capacity and net plant heat rate include supplemental firing.
(2)Heat rate presented assumes operation on natural gas.
(3)Part load performance percent load is based on gas turbine load point.

Table 7-4 GE 7FA 1x1 Combined Cycle Estimated Emissions(1)	
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0005
Hg, lb/MBtu	N/A
CO, lb/MBtu	0.0036
CO_2, lb/MBtu	114.8

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

7.1.3 Pulverized Coal

Table 7-5
Pulverized Coal Unit Characteristics

Ambient Condition	Net Capacity (MW)(1)	Full Load Net Plant Heat Rate (Btu/kWh, HHV)(1, 2)
Summer (Full Load)	445.0	9,555
Average (Full Load)	446.9	9,510
Average (90% Load)	400.5	9,595
Average (70% Load)	307.8	9,809
Average (min% Load)	215.1	10,224

(1)Performance assumes operation on 100 percent bituminous coal.
(2) Net capacity and net plant heat rate include degradation factors, and performance is preliminary.

Table 7-6 Pulverized Coal Estimated Emissions[(1)]	
NO_x, lb/MBtu	0.07
SO_2, lb/MBtu	0.10
Hg, lb/TBtu	1.29
CO_2, lb/MBtu	204.5
CO, lb/MBtu	0.10

[(1)]Emissions include the effects of SCR and SO_2 emissions control.

7.1.4 Circulating Fluidized Bed

Table 7-7
250 MW CFB Characteristics

	Net Capacity (MW)[(1)]	Net Plant Heat Rate (Btu/kWh, HHV)[(1)]
Summer (Full Load)	250.0	9,529
Average (Full Load)	250.6	9,505
Average (75% Load)	184.9	9,750
Average (50% Load)	119.2	10,264
Average (min Load)	92.9	10,682

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

Table 7-8
250 MW CFB Unit Estimated Emissions[1]

NO_x, lb/MBtu	0.09
SO_2, lb/MBtu	0.11
Hg, lb/TBtu	1.55
CO, lb/MBtu	0.115
CO_2, lb/MBtu	207.7

[1]Emissions at full load at average ambient conditions.

7.2 Capital and O&M Cost, Construction Schedule, and Availability Estimates

Table 7-9 presents the capital cost, O&M cost, construction schedule, and availability estimates for the simple cycle, combined cycle, pulverized coal, and CFB alternatives.

Table 7-9
Capital Costs, O&M Costs, Schedules, and Availability for the Self-Build Generating Alternatives

Supply Alternative	Total Cost[1] ($Millions)	Total Cost[2] ($/kW)	Fixed O&M[2] ($/kW-yr)	Variable O&M[2] ($/MWh)	Construction/ Development Schedule[3] (Months)	Maintenance[4] (Days)	Forced Outage (Percent)
7FA SC	83.1	499	4.40[5]	30.67[5]	14	10	2.0
1x1 7FA CC	235.5	788	6.28	4.47	30	14	3.0
CFB	694.1	2,770	33.10	3.73	41	21	5.0
Subcritical PC	936.9	2,097	26.15	1.94	50	20	7.0

(1)All costs are presented in 2007 dollars and include EPC and Owner's costs. Total costs do not include interest during construction.
(2)Costs reflect operation at average ambient conditions.
(3)Includes time for equipment procurement and planning.
(4)Reflects an average maintenance schedule.
(5)O&M costs are presented in 2007 dollars for all alternatives and reflect operation on fuel oil for the 7FA simple cycle combustion turbine. The fixed O&M for the combined cycle alternative does not include fixed costs for incremental firm natural gas transportation (which are discussed in Section 9.0).

8.0 Economic Evaluation Criteria and Methodology

This section presents the economic evaluation criteria and methodology used throughout this Ten-Year Site Plan. The economic analysis was performed for a 10 year evaluation period encompassing 2007 through 2016.

8.1 Economic Parameters

The economic parameters used in this analysis are summarized below and are presented on an annual basis. These parameters are applied consistently throughout this Ten-Year Site Plan.

8.1.1 Inflation and Escalation Rates

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

8.1.2 Cost of Capital

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio (approximately 65/35), the embedded rate for new debt (projected to be 5.25 percent), and the return on equity (approximately 10.3 percent). OUC's weighted average cost of capital is approximately 7.0 percent.

8.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to OUC's weighted average cost of capital of 7.0 percent.

8.1.4 Interest During Construction Rate

The interest during construction (IDC) rate is assumed to be equal to the embedded debt rate of 5.25 percent.

8.1.5 Levelized Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year FCR. The FCR calculation includes 0.10 percent for property insurance. Bond issuance fees and insurance costs are not included in the calculation of the levelized FCR, since these are already considered in OUC's embedded debt rate. Assuming a 30 year financing term, the resulting levelized FCR is 8.159 percent.

8.2 Fuel Price Forecasts

Fuel price projections for coal, natural gas, and No. 2 fuel oil were developed for OUC by Energy Ventures Analysis, Inc. (EVA). The fuel price projections were provided for fuels currently being used by OUC, as well as for fuels that might be used by future units considered in the economic analysis described in Section 9.0. The following subsections present the annual price projections for coal, natural gas, and No. 2 fuel oil provided by EVA.

8.2.1 Coal and Petroleum Coke

Low sulfur (1.6 lb SO_2/MBtu) Central Appalachian coal fuels the existing Stanton Units 1 and 2 and was assumed to be the fuel for the pulverized coal alternative considered in this analysis (described in Section 7.0). A blend of 80 percent PRB coal and 20 percent petroleum coke is used for the CFB alternative, while Stanton B will use PRB coal. The price forecasts (in real 2007 dollars per ton) provided by EVA for low sulfur Central Appalachian and PRB coals are presented in Table 8-1 and represent the commodity cost of each coal, excluding railcars and other delivery costs which are accounted for elsewhere in the analysis. The costs for railcars are accounted for separately in the capital cost estimates of the coal fired alternatives considered in this analysis. Other delivery costs for Central Appalachian and PRB coals were provided by OUC and are discussed in Section 8.3.1.

EVA did not provide petroleum coke price forecasts, and therefore, the delivered petroleum coke price forecast was taken directly from the Taylor Energy Center Need for Power Application (filed with the Florida Public Service Commission in September 2006). The delivered petroleum coke price forecast is discussed later in this section.

Table 8-1
Coal Price Forecasts (Commodity Only, Real 2007 $/Ton)

Calendar Year	Low Sulfur Central Appalachian (1.6 lb SO_2/MBtu, 12,500 Btu/lb)	High-Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)
2007	36.88	7.48
2008	37.23	8.19
2009	39.79	9.30
2010	40.94	9.64
2011	42.18	9.68
2012	43.42	9.73
2013	44.68	9.80
2014	44.94	9.87
2015	45.27	9.94
2016	45.68	10.03

8.2.2 Natural Gas

Natural gas is the primary fuel for Stanton A and OUC's Indian River combustion turbines, and will also be the primary fuel for the 1x1 7FA combined cycle alternative considered in this analysis (described in Section 7.0). The price forecast (in real 2006 dollars) provided by EVA for natural gas is presented in Table 8-2 and considers the Florida Gas Transmission (FGT) Zone 3 basis adder for Henry Hub, as well as fuel loss and usage charges. The methodology used to develop the natural gas transportation charges for delivery to the Stanton Energy Center is discussed in Section 8.3.

8.2.3 No. 2 Fuel Oil

No. 2 fuel oil is the secondary fuel for Stanton A, as well as for OUC's Indian River combustion turbines, and will also be used as the primary fuel for the simple cycle combustion turbines considered in this analysis (described in Section 7.0). The forecasts for low sulfur No. 2 fuel oil (0.05 percent sulfur) provided by EVA (in real 2005 cents per gallon) are presented in Table 8-3.

Table 8-2
Natural Gas Price Forecast
(Real 2006 \$/MBtu)

Calendar Year	Natural Gas[1] (\$/MBtu)
2007	6.48
2008	6.45
2009	5.75
2010	5.75
2011	5.79
2012	5.86
2013	5.93
2014	5.97
2015	6.04
2016	6.12

[1]Includes FGT Zone 3 basis adder, fuel losses, and usage charges.

Table 8-3
No. 2 Fuel Price Forecast
(0.05 Percent Sulfur, Real 2005 Cents/Gallon)

Calendar Year	No. 2 Fuel Oil (cents/gallon)
2007	140.3
2008	134.4
2009	134.4
2010	134.3
2011	135.7
2012	138.5
2013	141.3
2014	144.1
2015	146.9
2016	148.3

8.3 Economic Evaluation Methodology

This section discusses the methodology applied by Black & Veatch and OUC to the fuel price forecasts provided by EVA to develop the fuel costs used in the economic analysis in Section 9.0.

8.3.1 Coal and Petroleum Coke

EVA provided forecasts for the commodity costs of low sulfur (1.6 lb SO_2/MBtu) Central Appalachian and high-Btu PRB coals in real 2007 dollars per ton. The Central Appalachian coal forecast is used for Stanton Units 1 and 2 as well as McIntosh Unit 3, and it has been assumed that this coal would be burned by the pulverized coal alternative described in Section 7.0. A blend of 80 percent PRB coal and 20 percent petroleum coke was assumed for the CFB alternative. Stanton B will use the PRB coal. The delivered, nominal forecasts for low sulfur Central Appalachian and PRB coals are presented in Table 8-4 and were developed by applying the 2.5 percent annual inflation rate to the real 2007 dollar price projections provided by EVA. Costs for delivery of each coal to the Stanton Energy Center were provided by OUC and added to the commodity price forecasts, and the heat content of each coal was used to determine the delivered, nominal cost on a dollar per MBtu basis. The petroleum coke price forecast presented in Table 8-4 was taken from the Taylor Energy Center Need for Power Application (filed with the Florida Public Service Commission in September 2006) and is also based on a 2.5 percent annual inflation rate.

8.3.2 Natural Gas

Black & Veatch used the natural gas price forecast provided by EVA, which did not include delivery charges to the Stanton Energy Center. This is appropriate because OUC has already contracted for firm natural gas delivery for Stanton A and the Indian River combustion turbines through FGT. For the 1x1 7FA combined cycle alternative considered in this analysis (described in Section 7.0), the FGT firm transportation service charges will be added as a fixed cost rather than included in the cost per MBtu of natural gas. Section 9.0 describes how the amount of incremental natural gas transportation capacity required for the combined cycle alternative was determined. The delivered, nominal natural gas price forecast presented in Table 8-4 was developed by applying the 2.5 percent annual inflation rate to the real 2006 dollar natural gas price projections provided by EVA.

8.3.3 No. 2 Fuel Oil

EVA provided price projections for low sulfur No. 2 fuel oil (0.05 percent sulfur) on a cent per gallon basis, exclusive of delivery charges to the Stanton Energy Center. Based on recent historical information provided by OUC, a basis adder for delivery of fuel oil to Stanton Energy Center was developed. This adder was estimated to be $0.28 per barrel, or approximately 0.67 cents per gallon (assuming 42 gallons per barrel).

Low sulfur fuel oil would not likely meet the air permitting requirements of any new combustion turbine constructed by OUC. Ultra-low sulfur diesel (ULSD) is currently required for vehicle use, and power plants have recently been permitted on ULSD. Based on this information, it was determined that ULSD, with a sulfur content of 0.0015 percent, would be more appropriate for use in this analysis. Black & Veatch developed an incremental cost for ULSD that was added to the EVA projections of low sulfur No. 2 fuel oil. Data from the US Department of Energy's Energy Information Administration (EIA) was used to develop an incremental cost of approximately 6.1 cents/gallon.

After adjusting the EVA forecast to include the delivery adder and the incremental cost for ULSD, Black & Veatch converted the forecast prices (provided in cents/gallon) to $/MBtu by assuming a heat content of 140,000 Btu/gallon. The resulting annual forecasts were then converted from real 2005 dollars to nominal dollars, assuming the 2.5 percent annual inflation rate. The resulting delivered, nominal fuel price forecast is shown in Table 8-4.

8.3.4 Nuclear

EVA did not provide projections for nuclear fuel, which are required for OUC's ownership shares of St. Lucie Units 1 and 2 and Crystal River Unit 3. OUC provided historical prices for nuclear fuel, which Black & Veatch used as the basis for developing the forecasts presented in Table 8-4. The price projections for nuclear fuel used in this study are identical to those used in the Stanton B Need for Power Application.

Table 8-4
Delivered Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb)	High-Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)	Petroleum Coke US Gulf Coast (High S, Low Grind, 14,000 Btu/lb)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2007	2.42	2.57	1.28	6.65	13.84	0.51
2008	2.60	2.72	1.41	6.77	13.73	0.523
2009	2.78	2.87	1.49	6.19	14.07	0.54
2010	2.91	2.99	1.49	6.34	14.42	0.55
2011	3.04	3.07	1.49	6.55	14.89	0.57
2012	3.18	3.16	1.42	6.79	15.50	0.58
2013	3.32	3.21	1.43	7.05	16.13	0.59
2014	3.42	3.26	1.49	7.28	16.79	0.61
2015	3.53	3.32	1.63	7.55	17.46	0.62
2016	3.65	3.38	1.68	7.83	18.03	0.64

8.3.5 Emission Allowance Price Forecasts

The analyses presented in this Ten-Year Site Plan include consideration of the economic effects of future regulatory programs through inclusion of forecast allowance prices for emissions of SO_2 and NO_x under CAIR. On May 12, 2005, the EPA published the final CAIR, mandating reductions in SO_2 and NO_x emissions in 28 states and the District of Columbia. The EPA structured CAIR to compel emissions reductions from electric generating units (EGUs) and to encourage participation in an interstate cap-and-trade market to address the interstate transport of precursor emissions that significantly contribute to downwind nonattainment areas for the new 8 hour ozone and $PM_{2.5}$ national ambient air quality standards. Regulated EGUs are defined in CAIR as stationary fossil fuel fired boilers, or stationary fossil fuel fired combustion turbines, serving (at any time) a generator with a nameplate capacity of more than 25 MW producing electricity for sale. While modeling was performed to determine the geographical extent of individual sources contributing to these downwind nonattainment areas, the EPA designated entire states (and thereby all EGUs situated within these states) as being subject to regulation under CAIR. Thus, while it is debatable whether some or all of their emissions significantly contribute to downwind ozone and $PM_{2.5}$ nonattainment areas, all individual EGUs located within the State of Florida have been included in and are subject to CAIR. NO_x emissions will be regulated under CAIR beginning in 2009, and SO_2 emissions will be regulated under CAIR beginning in 2010.

The analyses presented in this Ten-Year Site Plan also take into consideration forecast allowance prices for emissions of mercury (Hg) under the CAMR. On March 15, 2005, the EPA issued the final CAMR. The rule is intended to limit the emissions of Hg from affected coal fired utility units (greater than 25 MW) located in all 50 states from current levels of 48 tons per year (tpy) eventually to 15 tpy. Like the various CAIR programs, CAMR is a two-phase emissions reduction program with the first phase (effective in 2010) capping nationwide Hg emissions to 38 tpy, and the second phase (effective in 2018) capping total nationwide Hg emissions at 15 tpy.

Similar to the framework of CAIR, each state is assigned an Hg emissions budget under CAMR and must submit a state implementation plan (SIP) detailing the control programs that will be implemented to meet its specified state budget for coal fired utility units. Collectively, the budgets for all 50 states establish the "cap" for each phase of the emissions trading program. The initial Phase I cap of 38 tons scheduled to take effect in 2010 was based on the maximum reduction in Hg emissions that could be achieved through installation of flue gas desulfurization (FGD) and SCR, otherwise known as the "co-benefit" of Hg reduction achieved through control of SO_2 and NO_x emissions under the proposed CAIR rulemaking. The Phase II cap of 15 tons of Hg emissions per year scheduled to take effect in 2018 is based on additional controls being installed, and allows for commercial development of emerging Hg control technologies.

The SO_2 and NO_x emission rates for OUC's existing units are the same as those used in the Stanton B Need for Power Application, and Hg emissions rates for OUC's existing units are consistent with those used in internal evaluations. SO_2, NO_x, and Hg emission rates for all unit additions considered in this analysis are presented in Section 7.0 of this report.

Table 8-5 presents the SO_2, NO_x, and Hg emission allowance price forecasts in nominal dollars per ton (nominal dollars per pound for Hg) used in this study. The forecasts were taken from those presented in the Taylor Energy Center Need for Power Application. The emission allowance price forecasts were converted from real 2005 dollars to nominal dollars by applying the 2.5 percent annual inflation rate.

The forecast SO_2, NO_x, and Hg emission allowance prices were used to calculate a fuel cost adder for both existing units and candidate units based on each unit's emission rates. As a result, each unit was modeled using different prices for fuel because of differences in emission rates. The value of allowances allocated to OUC's existing units was not included in the economic analysis since it would be the same for every capacity expansion plan considered.

Table 8-5
Forecast SO_2, NO_x, and Hg Allowance Prices

Calendar Year	SO_2 Allowances (Nominal $/ton)	NO_x Allowances (Nominal $/ton)	Hg Allowances (Nominal $/lb)
2009	-	2,292	-
2010	384	3,195	16,883
2011	392	3,350	17,192
2012	453	3,486	13,915
2013	464	3,571	18,194
2014	603	3,866	10,839
2015	860	6,176	20,932
2016	997	6,677	13,965

9.0 Analysis and Results

Detailed economic analyses were performed to determine the least-cost capacity expansion plan to satisfy OUC's forecast capacity requirements for the 2007 through 2016 evaluation period for a number of different scenarios. This section presents the methodology utilized in the economic analyses. The cumulative present worth cost (CPWC) is presented for the base case evaluation, as well as for sensitivities addressing high and low load forecasts, high and low natural gas and coal price forecasts, a constant differential between natural gas and coal prices, and high and low present worth discount rates. All of the economic analyses performed have considered Stanton B as a committed resource, with commercial operation beginning June 1, 2010. Due to the confidential nature of information related to Stanton B, this section minimizes presentation of details related to the Stanton B project (i.e., costs, availability, contractual arrangements, Department of Energy funding, etc.). This information was presented in the Stanton B Need for Power Application, and the Stanton B project parameters used in this study are consistent with those used in the Need for Power Application with few exceptions. The exceptions relate to net plant output and net plant heat rate, which have been updated to reflect the current estimates provided to OUC by Southern Power Company - Orlando Gasification LLC (SPC-OG).

As illustrated in Section 6.0, the capacity associated with Stanton B is only sufficient to satisfy OUC's forecast capacity requirements until the summer of 2015. Generating unit additions subsequent to construction of Stanton B were selected from among the supply-side alternatives described in Section 7.0.

9.1 Expansion Planning and Production Costing Methodology

The expansion planning and production costing methodology used in this study is consistent with that used in the Stanton B Need for Power Application. For convenience, the methodology is described in this section.

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model 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. POWROPT and its detailed chronological production costing module, POWRPRO, have both been used in numerous Need for Power Applications approved by the Florida Public Service Commission, including FMPA's Treasure Coast Energy Center Unit 1 Need for Power Application (approved in July 2005) and the Stanton Energy Center Unit 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 10 year period from 2007 through 2016.

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 O&M costs, and the number of starts and associated costs. Fixed O&M costs were included only for new unit additions, as the fixed O&M costs for existing units are generally considered sunk costs that will not vary from one expansion plan to another. The annual capacity charges for the Stanton A and the TECO Partial Requirements purchase power agreements likewise were not included, as they also represent sunk costs. Similarly, fixed costs for firm natural gas transportation capacity from FGT for existing units are considered sunk costs and are not included. The operating costs of each unit are aggregated to determine annual operating costs for each year of the expansion plan. Capital costs, fixed O&M costs, and fixed costs for incremental natural gas transportation (for combined cycle additions) are then added for each capacity addition selected, at which point the CPWC of each expansion plan can be calculated.

The CPWC calculation accounts for annual system costs (fuel and energy, fixed O&M for capacity additions, non-fuel variable O&M, startup costs, and levelized capital costs for capacity additions) for each year of the expansion planning period and discounts each back to 2007 at the present worth discount rate of 7.0 percent. These annual present worth costs are then summed over the 2007 through 2016 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.

9.2 Least-Cost Capacity Expansion Analysis

As described previously in this section, Black & Veatch first used its optimum generation expansion program, POWROPT, to select unit additions from among the supply-side alternatives presented in Section 7.0. Once the least-cost expansion plan was determined, POWRPRO was used to determine the annual total system costs and develop a comparison of CPWCs associated with each expansion plan.

For all capacity expansion plan evaluations, it was necessary to account for natural gas transportation capacity associated with new combined cycle unit alternatives. OUC currently has contracts in place with FGT for firm natural gas transportation to fuel Stanton A as well as the Indian River combustion turbines. For the 1x1 7FA combined cycle option included in Section 7.0, it was assumed that OUC would purchase 40,000 MBtu per day of firm natural gas transportation on a year-round basis. Using a Firm Transportation Service reservation charge of \$0.78 per MBtu, firm transportation costs of \$11,388,000 per year were added to the fixed O&M costs of the 1x1 7FA combined cycle alternative. It has been assumed that OUC will not purchase firm natural gas transportation capacity from FGT for Stanton B 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 provided in Section 8.0. Any natural gas required in addition to the firm natural gas transportation for existing and new units is priced at the interruptible service rate.

As described in Section 7.0, the 7FA simple cycle combustion turbine supply-side alternative is assumed to operate on ultra-low sulfur diesel fuel oil and has the capability to operate on natural gas as well. Since these units will not burn natural gas as a primary fuel, no firm natural gas transportation costs were added to the fixed O&M costs for the 7FA simple cycle combustion turbine.

To reflect the economic effects of the future CAIR and CAMR regulatory programs, the costs of emission allowances for SO_2, NO_X, and Hg were incorporated into the fuel costs for each unit, including existing units, at the start of the first phases of CAIR (2009) and CAMR (2010). The emission allowance price forecasts presented in Section 8.0 provide forecast annual emission allowance costs on a dollar per ton basis (dollar per pound for Hg). These costs were used to calculate a fuel cost adder for both existing units and candidate units based on each unit's emission rates. As a result, each unit was modeled using different prices for fuel because of differences in emission rates. The value of allowances allocated to OUC's existing units was not included in the economic analysis since it would be the same for each expansion plan evaluated. Variable O&M and estimated emission allowance costs were included in the unit dispatch modeling in POWROPT and POWRPRO along with fuel costs. These costs were included in the dispatch modeling to ensure the most cost-effective dispatch of both existing and new generating units.

9.3 Base Case Cumulative Present Worth Cost Analysis

The previous section described how POWROPT was used to select the least-cost capacity expansion plan to satisfy forecast capacity requirements for the 2007 through 2016 evaluation period. Once the least-cost capacity expansion plan was identified, POWRPRO was used to determine the total annual system costs and to develop the associated CPWC.

The least-cost capacity expansion plan under the base case assumptions (economic parameters, load forecast, and fuel forecasts) includes construction of a 7FA simple cycle combustion turbine for operation in June 2015. The CPWC of this capacity expansion plan is approximately $2,187.5 million.

9.4 Sensitivity Analyses

Several sensitivity scenarios were evaluated as part of the detailed economic analyses. The methodology used to determine the least-cost capacity expansion plan for the sensitivity scenarios is identical to that described previously in this section. The sensitivities address high and low load forecasts, high and low natural gas and coal price forecasts, a constant differential between natural gas and coal prices, and high and low present worth discount rates. Each of these sensitivity scenarios is discussed in more detail in the following sections, and the least-cost capacity expansion plan and associated CPWC are also presented for each sensitivity.

9.4.1 High Load Forecast Sensitivity

The high load forecast is presented in Section 4.0, and under the high load forecast OUC will initially require additional capacity to maintain the 15 percent reserve margin in 2013. The least-cost capacity expansion plan under the high load forecast sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2013, followed by construction of a second 7FA simple cycle combustion turbine for operation in June 2016. The CPWC of this capacity expansion plan is approximately $2,320.3 million.

9.4.2 Low Load Forecast Sensitivity

The low load forecast is presented in Section 4.0. Assuming the low load forecast, no capacity additions are required beyond construction of Stanton B. The CPWC for the low load forecast sensitivity is based on dispatching OUC's existing system (including Stanton B) to meet the annual energy requirements of the low load forecast and is approximately $2,071.7 million.

9.4.3 High Natural Gas and Coal Price Forecast Sensitivity

The high natural gas and coal price forecasts were developed by increasing the delivered natural gas price forecasts presented in Section 8.0 by 40 percent, and by increasing the delivered coal price forecasts presented in Section 8.0 by 15 percent. The resulting high natural gas and coal price forecasts are shown in Table 9-1. It should be noted that OUC's contractual arrangements for coal delivery will mitigate the effects of volatility in coal prices; however, for purposes of this analysis this factor was not considered. The least-cost capacity expansion plan under the high natural gas and coal price forecast sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2015. The CPWC of this capacity expansion plan is approximately $2,547.4 million.

9.4.4 Low Natural Gas and Coal Price Forecast Sensitivity

The low natural gas and coal price forecasts were developed by decreasing both the delivered natural gas price and delivered coal price forecasts presented in Section 8.0 by 20 percent. The resulting low natural gas and coal price forecasts are shown in Table 9-2. It should be noted that OUC's contractual arrangements for coal delivery will mitigate the effects of volatility in coal prices; however, for purposes of this analysis this factor was not considered. The least-cost capacity expansion plan under the low natural gas and coal price forecast sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2015. The CPWC of this capacity expansion plan is approximately $1,850.8 million.

Table 9-1
High Natural Gas and Coal Price Sensitivity - Delivered Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb)	High-Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)	Petroleum Coke US Gulf Coast (High S, Low Grind, 14,000 Btu/lb)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2007	2.78	2.96	1.28	9.31	13.84	0.51
2008	2.99	3.13	1.41	9.48	13.73	0.523
2009	3.20	3.30	1.49	8.67	14.07	0.54
2010	3.35	3.44	1.49	8.88	14.42	0.55
2011	3.50	3.53	1.49	9.17	14.89	0.57
2012	3.66	3.63	1.42	9.51	15.50	0.58
2013	3.82	3.69	1.43	9.87	16.13	0.59
2014	3.93	3.75	1.49	10.19	16.79	0.61
2015	4.06	3.82	1.63	10.57	17.46	0.62
2016	4.20	3.89	1.68	10.96	18.03	0.64

Table 9-2
Low Natural Gas and Coal Price Sensitivity - Delivered Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb)	High-Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)	Petroleum Coke US Gulf Coast (High S, Low Grind, 14,000 Btu/lb)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2007	1.94	2.06	1.28	5.32	13.84	0.51
2008	2.08	2.18	1.41	5.42	13.73	0.523
2009	2.22	2.30	1.49	4.95	14.07	0.54
2010	2.33	2.39	1.49	5.07	14.42	0.55
2011	2.43	2.46	1.49	5.24	14.89	0.57
2012	2.54	2.53	1.42	5.43	15.50	0.58
2013	2.66	2.57	1.43	5.64	16.13	0.59
2014	2.74	2.61	1.49	5.82	16.79	0.61
2015	2.82	2.66	1.63	6.04	17.46	0.62
2016	2.92	2.70	1.68	6.26	18.03	0.64

9.4.5 Constant Differential Natural Gas and Coal Price Forecast Sensitivity

The constant differential natural gas and coal price forecast sensitivity assumes that the delivered natural gas price and delivered coal price forecast for 2007 presented in Section 8.0 would remain constant in real terms. The constant differential price forecasts shown in Table 9-3 were developed by applying the general inflation rate (2.5 percent) to the base case natural gas and coal price forecasts to convert from real to nominal dollars. The least-cost capacity expansion plan under the constant differential natural gas and coal price forecast sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2015. The CPWC of this capacity expansion plan is approximately $2,092.3 million.

9.4.6 High Present Worth Discount Rate Sensitivity

The high present worth discount rate sensitivity assumes that the present worth discount rate is increased from the base case assumption (7.0 percent) to 8.0 percent. The least-cost capacity expansion plan under the high present worth discount rate sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2015. The CPWC of this capacity expansion plan is approximately $2,095.2 million.

9.4.7 Low Present Worth Discount Rate Sensitivity

The low present worth discount rate sensitivity assumes that the present worth discount rate is decreased from the base case assumption (7.0 percent) to 6.0 percent. The least-cost capacity expansion plan under the low present worth discount rate sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2015. The CPWC of this capacity expansion plan is approximately $2,286.4 million.

Table 9-3
Constant Differential Natural Gas and Coal Price Sensitivity - Delivered Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian (1.8 lb SO_2/MBtu, 12,500 Btu/lb)	High-Btu Gillette PRB (0.8 lb SO_2/MBtu, 8,800 Btu/lb)	Petroleum Coke US Gulf Coast (High S, Low Grind, 14,000 Btu/lb)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2007	2.42	2.57	1.28	6.65	13.84	0.51
2008	2.48	2.63	1.41	6.82	13.73	0.523
2009	2.54	2.70	1.49	6.99	14.07	0.54
2010	2.61	2.77	1.49	7.16	14.42	0.55
2011	2.67	2.84	1.49	7.34	14.89	0.57
2012	2.74	2.91	1.42	7.52	15.50	0.58
2013	2.81	2.98	1.43	7.71	16.13	0.59
2014	2.88	3.05	1.49	7.90	16.79	0.61
2015	2.95	3.13	1.63	8.10	17.46	0.62
2016	3.02	3.21	1.68	8.30	18.03	0.64

10.0 Environmental and Land Use Information

The Stanton Energy Center, originally certified for 2,000 MW, currently consists of two pulverized coal units (Stanton Units 1 and 2), which went into service in 1987 and 1996, and a 2x1 combined cycle unit (Stanton A), which began commercial operation in 2003. Extensive environmental and land use information was filed with the Site Certification Application for Stanton 1, and additional information was filed with the Supplemental Site Certification Applications for Stanton 2 and Stanton A as well as the recently filed Supplemental Site Certification Application for Stanton B. The original and Supplemental Site Certification Applications were submitted to all the agencies and for the sake of brevity have not been reproduced for inclusion in this Ten-Year Site Plan.

10.1 Status of Site Certification

Ultimate certification for 2,000 MW was obtained with the Site Certification for Stanton 1. Stanton 2, Stanton A, and Stanton B were certified under the Supplemental Site Certification provisions of the Florida Electrical Power Plant Siting Act.

10.2 Land and Environmental Features

The Stanton Energy Center is located in Orange County, Florida, and consists of approximately 3,280 acres. The Econlockhatchee River is about three-fourths of 1 mile east of the northeast corner of the site boundary. The Orange County Solid Waste Disposal facility is adjacent to the site along the west boundary.

A natural gas pipeline connects the Stanton Site to the FGT system. The pipeline is 2.5 miles in total length, connecting with FGT's system south of the Stanton Site. The pipeline is routed in the existing transmission and railroad spur right-of-way. The pipeline has been sized to accommodate additional natural gas fired generation at the Stanton Site.

The Stanton Site is served by an approximately 18 mile rail spur from the CSX railroad.

Extensive details regarding land and environmental features are contained in the Site Certification Application for Stanton 1 and the Supplemental Site Certification Applications for Stanton 2, Stanton A, and Stanton B.

10.3 Air Emissions

OUC is currently evaluating emission reduction strategies applicable to Stanton Energy Center Units 1 and 2 to ensure compliance with the EPA's CAIR and CAMR regulations. Stanton B will be subject to Florida Department of Environmental Protection's Prevention of Significant Deterioration (PSD) permitting program, which requires Best Available Control Technology (BACT) for the emissions of various pollutants. The combined cycle unit will include postcombustion emissions controls. Moreover, SCR will be demonstrated during the unit's 4 year demonstration phase to further reduce NO_x emissions. Taken together, these design features will make Stanton B one of the most efficient and lowest polluting coal fired power plants in the United States.

10.4 Water and Wastewater

Water for cooling tower makeup for Stanton B will be reclaimed water (treated wastewater). Reclaimed water will be supplied from the existing Eastern Water Reclamation Facility, Orange County wastewater treatment plant. A maximum of 2.6 million gallons per day (mgd) of makeup water is expected to be required for Stanton B. The majority of this water supply will be for cooling tower makeup, which will utilize treated effluent.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator/crystallizer; thus, the Stanton site is truly a zero discharge site.

There will be five major sources of wastewater from Stanton B: sanitary waste, HRSG blowdown, oil/water separator effluent, cooling tower blowdown, and other plant wastewaters from the combined cycle unit. Sanitary wastewaters will be directed to a new onsite septic system. HRSG blowdown will be routed to the cooling tower basin. Wastewaters with the potential for oil contamination will be routed to a new oil/water separator. Effluent from the oil/water separator and other combined cycle plant wastewaters will be combined and discharged to OUC's existing recycle basin. Cooling tower blowdown will be routed separately to the existing zero-discharge wastewater system.

Gasification wastewaters will consist of oil/water separator effluent, sanitary wastes, and rainwater runoff. Sanitary wastes will be directed to the combined cycle septic system. Rainwater runoff will be collected and sent to the existing Stanton Energy Center collection pond and then discharged to natural drainage courses. Oil/water separator effluent will be discharged to the combined cycle wastewater system.

11.0 Conclusions

As discussed throughout this Ten-Year Site Plan, it has been assumed that Stanton B will begin commercial operation in June 2010. The Stanton B project is the result of the proposal submitted by Southern Company Services (SCS) on behalf of its partners Southern Power Company (SPC), OUC, and Kellogg Brown & Root, Inc. (KBR) for funding of an air blown Transport Gasification combined cycle demonstration project to be located at OUC's Stanton Energy Center. The proposal was submitted June 15, 2004, in response to the Clean Coal Power Initiative (CCPI) of the US Department of Energy (DOE). Stanton B is planned as a 1x1 F-class IGCC unit that will be capable of firing coal derived syngas or natural gas, and is planned for commercial operation on June 1, 2010. For purposes of the analyses presented in this Ten-Year Site Plan, Stanton B is considered to be a capacity resource for OUC beginning in the summer of 2010. It should be noted that significant detail related to the Stanton B project is presented in the Stanton B Need for Power Application, and the information pertaining to Stanton B presented in this Ten-Year Site Plan is intended to be an overview for the sake of brevity.

The addition of Stanton B satisfies forecast capacity requirements through the summer of 2015 under the base case load forecast. Detailed economic analyses were performed under base case assumptions – as well as numerous sensitivity scenarios related to load forecasts, fuel price projections, and economic parameters – to determine the least-cost capacity expansion plan to meet forecast capacity requirements through 2016. Under all scenarios evaluated, OUC can meet its forecast capacity requirements for the 2007 through 2016 period with the addition of simple cycle combustion turbines. However, OUC has made no final decisions related to construction of new generation resources, and the economic evaluations presented in this Ten-Year Site Plan are intended for informational purposes only.

12.0 Ten-Year Site Plan Schedules

This section presents the schedules required by the Ten-Year Site Plan rules for the Florida Public Service Commission (FPSC). For each table the FPSC Schedule number is included in parenthesis. The information contained within the FPSC Schedules is representative of the combined OUC and City of St. Cloud systems, consistent with all sections of the 2007 OUC Ten-Year Site Plan.

Table 12-1 (Schedule 1)
OUC and St. Cloud Existing Generating Facilities as of December 31, 2006

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
				Primary Fuel		Alternate Fuel		Alt Fuel	Commercial. In-	Expected	Gross Capability[1]		Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Fuel Type	Transport Method	Fuel Type	Transport Method	Storage (Days Burn)	Service MM/YYYY	Retirement MM/YYYY	Summer MW	Winter MW	Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	PL	DFO	TK	0.2	06/1989	Unknown	18.30	23.50	18.00	23.30
Indian River	B	Brevard	GT	NG	PL	DFO	TK	0.2	07/1989	Unknown	18.30	23.50	18.00	23.30
Indian River	C	Brevard	GT	NG	PL	DFO	TK	0.2	08/1992	Unknown	86.10	101.10	85.30	100.30
Indian River	D	Brevard	GT	NG	PL	DFO	TK	0.2	10/1992	Unknown	86.10	101.10	85.30	100.30
Stanton Energy Center	1	Orange	ST	BIT	RR	NA	UN	UN	07/1987	Unknown	320.13	322.19	301.62	303.68
Stanton Energy Center	2	Orange	ST	BIT	RR	NA	UN	UN	06/1996	Unknown	351.70	351.70	334.45	334.45
Stanton Energy Center	A	Orange	CC	NG	PL	DFO	TK	3	10/2001	Unknown	180.60	198.00	173.60	184.80
McIntosh	3	Polk	ST	BIT	REF	NA	UN	UN	09/1982	Unknown	146.00	146.00	136.80	136.80
Crystal River	3	Citrus	ST	NUC	TK	NA	UN	UN	03/1977	Unknown	14.03	14.27	13.36	13.64
St. Lucie[2]	2	St. Lucie	ST	NUC	TK	NA	UN	UN	08/1983	Unknown	54.20	54.20	51.09	51.94
St. Cloud	1	Osceola	IC	NG	PL	DFO	TK	5	07/1982	Standby	2.000	2.000	2.000	2.000
St. Cloud	2	Osceola	IC	NG	PL	DFO	TK	5	12/1974	Standby	5.000	5.000	5.000	5.000
St. Cloud	3	Osceola	IC	NG	PL	DFO	TK	5	09/1982	Standby	2.000	2.000	2.000	2.000
St. Cloud	4	Osceola	IC	NG	PL	DFO	TK	5	08/1961	Standby	3.000	3.000	3.000	3.000
St. Cloud	6	Osceola	IC	NG	PL	DFO	TK	5	03/1967	Standby	3.000	3.000	3.000	3.000
St. Cloud	7	Osceola	IC	NG	PL	DFO	TK	5	09/1982	Standby	6.000	6.000	6.000	6.000
St. Cloud[3]	8	Osceola	IC	NG	PL	DFO	TK	5	04/1977	Standby	6.000	6.000	6.000	6.000

(1)Reflects capability to serve OUC and St. Cloud.
(2)Reliability exchange divides 50% power from Unit 1 and 50% power from Unit 2.
(3)St. Cloud Unit 8 has never been connected to the grid and, therefore, is not included in the summation of existing generating capacity.

Table 12-2 (Schedule 2.1)
OUC and St. Cloud History and Forecast of Energy Consumption and Number of Customers by Customer Class[(1)]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural and Residential					General Service Non-Demand		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1997	330,000	2.57	1,569	128,504	12,210	341	16,353	20,852
1998	341,000	2.57	1,804	132,824	13,582	331	16,597	19,943
1999	351,400	2.56	1,725	137,317	12,562	330	17,058	19,346
2000	362,000	2.55	1,821	141,993	12,825	320	17,236	18,566
2001	372,200	2.55	1,893	145,838	12,980	316	17,184	18,389
2002	383,200	2.55	1,973	150,194	13,136	315	17,669	17,828
2003	391,500	2.55	2,033	153,708	13,226	299	18,011	16,601
2004	403,900	2.54	2,082	158,755	13,115	300	18,866	15,902
2005	421,100	2.54	2,198	165,545	13,277	320	19,672	16,267
2006	436,000	2.55	2,241	170,765	13,125	340	20,034	16,960
Forecast								
2007	448,600	2.55	2,323	176,216	13,184	350	20,668	16,927
2008	459,900	2.55	2,414	180,630	13,366	363	21,054	17,228
2009	472,700	2.55	2,481	185,646	13,362	371	21,465	17,289
2010	486,805	2.55	2,555	191,187	13,363	380	21,899	17,343
2011	502,000	2.55	2,631	197,164	13,346	387	22,329	17,354
2012	518,200	2.55	2,714	203,507	13,336	394	22,760	17,333
2013	535,500	2.55	2,799	210,297	13,308	402	23,211	17,320
2014	553,600	2.55	2,894	217,427	13,308	410	23,690	17,313
2015	572,900	2.55	2,997	225,000	13,319	419	24,193	17,299
2016	593,320	2.55	3,109	232,996	13,344	427	24,719	17,287

[(1)]Historical and forecast data includes both OUC and the City of St. Cloud.

Table 12-3 (Schedule 2.2)
OUC and St. Cloud History and Forecast of Energy Consumption and Number of Customers by Customer Class[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	General Service Demand						
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1997	2,391	3,594	665,275	0	24	5	4,330
1998	2,569	3,956	649,393	0	25	5	4,734
1999	2,723	4,071	668,877	0	29	5	4,812
2000	2,861	4,420	647,358	0	28	6	5,036
2001	2,967	4,763	622,992	0	31	6	5,213
2002	3,033	4,980	609,036	0	40	6	5,367
2003	3,138	5,417	579,287	0	37	6	5,513
2004	3,221	5,500	585,636	0	42	6	5,651
2005	3,283	5,561	590,361	0	45	6	5,852
2006	3,347	5,675	589,871	0	49	6	5,984
Forecast							
2007	3,479	5,895	590,137	0	49	6	6,207
2008	3,574	6,036	592,060	0	53	6	6,410
2009	3,651	6,176	591,157	0	57	6	6,565
2010	3,731	6,320	590,412	0	60	6	6,732
2011	3,805	6,456	589,388	0	64	6	6,894
2012	3,879	6,589	588,756	0	67	6	7,061
2013	3,962	6,734	588,304	0	71	6	7,239
2014	4,045	6,893	586,797	0	74	6	7,429
2015	4,135	7,066	585,199	0	78	6	7,634
2016	4,229	7,254	582,979	0	82	6	7,853

[1]Historical and forecast data includes both OUC and the City of St. Cloud.

Table 12-4 (Schedule 2.3)
OUC and St. Cloud History and Forecast of Energy Consumption and Number of Customers by Customer Class[1]

(1) Year	(2) Sales for Resale[2] GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers[3]
1997	0	236	4,566	0	148,451
1998	0	175	4,909	0	153,377
1999	0	199	5,011	0	158,446
2000	0	255	5,291	0	163,648
2001	969	191	6,373	0	167,785
2002	821	208	6,396	0	172,843
2003	920	249	6,682	0	177,136
2004	714	234	6,599	0	183,121
2005	704	219	6,775	0	190,778
2006	18	248	6,250	0	196,474
Forecast					
2007	0	257	6,464	0	202,779
2008	0	265	6,675	0	207,721
2009	0	272	6,837	0	213,286
2010	0	279	7,011	0	219,406
2011	0	286	7,179	0	225,949
2012	0	292	7,353	0	232,856
2013	0	300	7,539	0	240,242
2014	0	308	7,737	0	248,010
2015	0	316	7,951	0	256,259
2016	0	324	8,177	0	264,969

(1)Historical and forecast data includes both OUC and the City of St. Cloud.
(2)To maintain consistency with the FRCC Forms, the historical "Sales for Resale" includes GWh sales to FMPA, KUA, Seminole Electric Cooperative, and Reedy Creek Improvement District (RCID) for 2001, 2002, 2003, 2004, 2005, and 2006, as in the FRCC forms.
(3)Total No. of Customers includes aggregate of Rural and Residential, General Service Non-Demand, and General Service Demand.

Table 12-5 (Schedule 3.1)
OUC and St. Cloud History and Forecast of Summer Peak Demand (Base Case)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1997	917	0	917	0	0	0	0	917
1998	988	0	988	1	0	0	0	987
1999	1055	0	1055	0	0	0	0	1055
2000	1,026	0	1,026	1	0	0	0	1,025
2001	1,382	341	1,041	1	0	0	0	1,381
2002	1,408	319	1,089	1	0	0	0	1,407
2003	1,381	303	1,078	1	0	0	0	1,380
2004	1,311	231	1,080	1	0	0	0	1,310
2005	1,353	147	1,206	0	0	0	0	1,353
2006	1,230	22	1,208	0	0	0	0	1,230
Forecast								
2007	1,261	0	1,261	0	0	0	0	1,261
2008	1,302	0	1,302	0	0	0	0	1,302
2009	1,334	0	1,334	0	0	0	0	1,334
2010	1,369	0	1,369	0	0	0	0	1,369
2011	1,402	0	1,402	0	0	0	0	1,402
2012	1,437	0	1,437	0	0	0	0	1,437
2013	1,474	0	1,474	0	0	0	0	1,474
2014	1,513	0	1,513	0	0	0	0	1,513
2015	1,556	0	1,556	0	0	0	0	1,556
2016	1,601	0	1,601	0	0	0	0	1,601

[1]Historical and forecast data includes both OUC and the City of St. Cloud.
[2]Includes conservation.
[3] To maintain consistency with the FRCC Forms, historical "Wholesale" includes MW sales to FMPA, KUA, Seminole Electric Cooperative, and RCID for 2001, 2002, 2003, 2004, 2005, and 2006, as in the FRCC forms.

Table 12-6 (Schedule 3.2)
OUC and St. Cloud History and Forecast of Winter Peak Demand (Base Case)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
1996/97	851	0	851	0	0	0	0	851
1997/98	814	0	814	1	0	0	0	813
1998/99	1,030	0	1,030	1	0	0	0	1,029
1999/00	1,060	0	1,060	1	0	0	0	1,059
2000/01	1,066	0	1,066	1	0	0	0	1,065
2001/02	1,345	302	1,044	1	0	0	0	1,345
2002/03	1,414	277	1,137	1	0	0	0	1,413
2003/04	1,196	241	955	1	0	0	0	1,419
2004/05	1,203	123	1,080	1	0	0	0	1,202
2005/06	1,117	22	1,095	0	0	0	0	1,117
2006/07[4]	1,272	0	1,272	0	0	0	0	1,272
Forecast								
2007/08	1,313	0	1,313	0	0	0	0	1,313
2008/09	1,346	0	1,346	0	0	0	0	1,346
2009/10	1,381	0	1,381	0	0	0	0	1,381
2010/11	1,415	0	1,415	0	0	0	0	1,415
2011/12	1,449	0	1,449	0	0	0	0	1,449
2012/13	1,487	0	1,487	0	0	0	0	1,487
2013/14	1,527	0	1,527	0	0	0	0	1,527
2014/15	1,569	0	1,569	0	0	0	0	1,569
2015/16	1,615	0	1,615	0	0	0	0	1,615
2016/17	1,664	0	1,664	0	0	0	0	1,664

[1]Historical and forecast data includes both OUC and the City of St. Cloud.
[2]Includes conservation.
[3]To maintain consistency with the FRCC Forms, historical "Wholesale" includes MW sales to FMPA, KUA, Seminole Electric Cooperative, and RCID for 2001/02, 2002/03, 2003/04, 2004/05, and 2005/06, as in the FRCC forms.
[4]2006/07 is a forecast as actual information was not available at time of publication.

Table 12-7 (Schedule 3.3)
OUC and St. Cloud History and Forecast of Annual Net Energy for Load - GWH (Base Case)[1]

(1) Year	(2) Total[2]	(3) Conservation	(4) Retail	(5) Wholesale[3]	(6) Utility Use and Losses	(7) Net Energy for Load	(8) Load Factor[4] (%)
1997	4,566	0	4,330	0	236	4,566	56.8%
1998	4,909	0	4,734	0	175	4,909	56.8%
1999	5,011	0	4,812	0	199	5,011	54.2%
2000	5,291	0	5,036	0	255	5,291	57.0%
2001	6,373	0	5,213	969	191	6,373	52.7%
2002	6,396	0	5,367	821	208	6,396	51.9%
2003	6,682	0	5,513	920	249	6,682	54.0%
2004	6,599	0	5,651	714	234	6,599	53.1%
2005	6,775	0	5,852	704	219	6,775	57.2%
2006	6,250	0	5,984	18	248	6,250	57.5%
Forecast							
2007	6,464	0	6,207	0	257	6,464	58.5%
2008	6,675	0	6,410	0	265	6,675	58.0%
2009	6,837	0	6,565	0	272	6,837	58.0%
2010	7,011	0	6,732	0	279	7,011	58.0%
2011	7,179	0	6,894	0	286	7,179	57.9%
2012	7,353	0	7,061	0	292	7,353	57.9%
2013	7,539	0	7,239	0	300	7,539	57.9%
2014	7,737	0	7,429	0	308	7,737	57.9%
2015	7,951	0	7,634	0	316	7,951	57.8%
2016	8,177	0	7,853	0	324	8,177	57.8%

(1)Historical and forecast data includes both OUC and the City of St. Cloud.
(2)Includes conservation.
(3)To maintain consistency with the FRCC Forms, historical "Wholesale" includes GWh sales to FMPA, KUA, Seminole Electric Cooperative, and RCID for 2001, 2002, 2003, 2004, 2005, and 2006, as in the FRCC Forms.
(4)Forecast load factor calculation considers all retail and wholesale peak demand and energy. Calculated as ratio of annual NEL to the product of the annual peak demand times 8,760 hours.

Table 12-8 (Schedule 4)
OUC and St. Cloud Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual - 2006[2]		2007 Forecast		2008 Forecast	
Month	Peak Demand[3] (MW)	NEL GWh	Peak Demand[3] (MW)	NEL GWh	Peak Demand[3] (MW)	NEL GWh
January	893	452	1,272	515	1,313	531
February	1,117	423	936	420	975	431
March	906	454	894	480	924	498
April	1,067	493	1,007	493	1,040	515
May	1,097	556	1,119	566	1,155	583
June	1,162	583	1,157	572	1,195	588
July	1,198	624	1,261	633	1,302	660
August	1,230	652	1,186	636	1,224	657
September	1,148	578	1,190	627	1,229	649
October	1,108	527	1,153	577	1,191	586
November	870	445	975	465	1,007	477
December	855	463	824	481	851	499

[1]Includes OUC and City of St. Cloud peak demand and NEL as well as wholesale sales to FMPA (MW and NEL) for historical 2006.
[2]Actual 2006 Peak Demand may not correspond to Schedule 3.1 due to coincidence issues between OUC native load, City of St. Cloud native load, and wholesale power sales.
[3]Includes Load Management, Conservation, and Interruptible Load.

Table 12-9 (Schedule 5)
Fuel Requirements[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Nuclear		Trillion BTU	5	6	6	5	6	6	5	6	6	5	6	6
(2)	Coal		1,000 Ton	2,198	2,162	1,917	1,949	1,968	2,270	2,431	2,495	2,548	2,582	2,668	2,724
(3)	Residual[2]	Total	1,000 BBL	9	6	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1,000 BBL	9	6	0	0	0	0	0	0	0	0	0	0
(5)		CC	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate[3]	Total	1,000 BBL	5	2	0	0	0	0	0	0	0	0	19	21
(8)		Steam	1,000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	1,000 BBL	2	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	1,000 BBL	3	2	0	0	0	0	0	0	0	0	19	21
(11)	Natural Gas	Total	1,000 MCF	15,614	15,967	8,067	9,159	9,912	7,431	6,511	6,551	7,113	8,413	8,385	9,122
(12)		Steam	1,000 MCF	34	33	0	0	0	0	0	0	0	0	0	0
(13)		CC	1,000 MCF	15,406	15,612	7,310	8,129	8,491	6,257	6,040	6,100	6,561	7,701	7,556	8,388
(14)		CT	1,000 MCF	174	321	758	1,030	1,421	1,174	472	451	552	712	829	734
(15)	Other		Trillion BTU	1	1	0	0	0	0	0	0	0	0	0	0

[1]Includes fuel required for OUC and the City of St. Cloud. Forecast 2007 through 2016 represents results of production cost modeling to serve combined OUC and City of St. Cloud loads and contracted wholesale sales only.
[2]Residual includes No. 4, No. 5, and No. 6 oil.
[3]Distillate includes No. 1, No. 2 oil, kerosene, jet fuel, and amounts used at coal burning plants for flame stabilization and on startup.

Table 12-10 (Schedule 6.1)
Energy Sources (GWh)[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Inter-region Interchange		GWh	0	0	0	0	0	0	0	0	0	0	0	
(2)	Nuclear		GWh	471	514	518	489	512	518	488	517	537	489	518	518
(3)	Residual	Total	GWh	6	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWh	6	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Total	GWh	2	2	0	0	0	0	0	0	0	0	9	9
(8)		Steam	GWh	0	1	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWh	2	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWh	0	1	0	0	0	0	0	0	0	0	9	9
(12)	Natural Gas	Total	GWh	2,234	2,249	1,017	1,154	1,238	918	831	831	902	1,072	1,072	1,181
(12)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	GWh	2,221	2,226	957	1,069	1,121	821	795	797	861	1,016	1,007	1,123
(14)		CT	GWh	13	23	61	85	118	96	36	34	41	56	66	58
(15)	Coal	Steam	GWh	5,590	5,483	4,907	4,996	5,041	5,545	5,847	5,988	6,099	6,170	6,347	6,469
(16)	NUG		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Other	Purchases	GWh	0	1	22	36	45	31	13	17	1	6	4	0
		Sales	GWh	68	0	0	0	0	0	0	0	0	0	0	0
		Total	GWh	68	1	22	36	45	31	13	17	1	6	4	0
(19)	Net Energy for Load[2]		GWh	8,371	8,249	6,464	6,675	6,837	7,011	7,180	7,353	7,538	7,737	7,951	8,177

[1] Forecast 2007 through 2016 represents results of production cost modeling to serve combined OUC and City of St. Cloud loads and contracted wholesale sales only.
[2] Variation in Net Energy for Load between Schedule 3.3 and Schedule 6.1 can be attributed to rounding error.

Table 12-11 (Schedule 6.2)
Energy Sources (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2005	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Inter-region Interchange		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	Nuclear		GWh	5.63%	6.23%	8.01%	7.33%	7.50%	7.38%	6.80%	7.03%	7.12%	6.32%	6.51%	6.33%
(3)	Residual	Total	GWh	0.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(4)		Steam	GWh	0.07%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)	Distillate	Total	GWh	0.02%	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.11%
(8)		Steam	GWh	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWh	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWh	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.12%	0.11%
(11)	Natural Gas	Total	GWh	26.69%	27.27%	15.74%	17.29%	18.11%	13.09%	11.57%	11.30%	11.96%	13.86%	13.49%	14.44%
(12)		Steam	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(13)		CC	GWh	26.53%	26.98%	14.80%	16.02%	16.39%	11.72%	11.08%	10.84%	11.42%	13.13%	12.66%	13.73%
(14)		CT	GWh	0.16%	0.28%	0.94%	1.27%	1.72%	1.38%	0.49%	0.46%	0.55%	0.73%	0.82%	0.70%
(15)	Coal	Steam	GWh	66.78%	66.47%	75.90%	74.84%	73.73%	79.09%	81.44%	81.43%	80.90%	79.75%	79.83%	79.12%
(16)	NUG		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	Hydro		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	Other	Purchases	GWh	0.00%	0.01%	0.35%	0.53%	0.66%	0.44%	0.19%	0.24%	0.02%	0.08%	0.05%	0.00%
		Sales	GWh	0.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Total	GWh	0.81%	0.01%	0.35%	0.53%	0.66%	0.44%	0.19%	0.24%	0.02%	0.08%	0.05%	0.00%
(19)	Net Energy for Load		GWh	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 12-12 (Schedule 7.1)
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity[1]	Firm Capacity Import[2]	Firm Capacity Export[3]	QF	Total Capacity Available	System Firm Peak Demand[4]	Reserve Margin Before Maintenance[5, 6]		Scheduled Maintenance	Reserve Margin After Maintenance[5, 6]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2007	1,217	337	0	0	1,554	1,261	295	23.4%	0	295	23.4%
2008	1,217	337	0	0	1,554	1,302	254	19.5%	0	254	19.5%
2009	1,217	337	0	0	1,554	1,334	222	16.6%	0	222	16.6%
2010	1,465	337	0	0	1,803	1,369	436	31.9%	0	436	31.9%
2011	1,465	337	0	0	1,803	1,402	403	28.7%	0	403	28.7%
2012	1,465	337	0	0	1,803	1,437	368	25.7%	0	368	25.7%
2013	1,465	322	0	0	1,788	1,474	314	21.5%	0	314	21.5%
2014	1,465	322	0	0	1,788	1,513	275	18.3%	0	275	18.3%
2015	1,623	322	0	0	1,945	1,556	390	25.2%	0	390	25.2%
2016	1,623	322	0	0	1,945	1,601	345	21.7%	0	345	21.7%

(1)Installed capacity includes St. Cloud's entitlement to capacity from Stanton Unit 2.
(2)Firm capacity imports include capacity purchased from TECO and capacity purchased from Southern Company-Florida, LLC (from Stanton A).
(3)Firm capacity export includes all firm wholesale power sales contracts.
(4)Includes OUC peak demand and City of St. Cloud peak demand.
(5)Assumes TECO purchase (15 MW) includes reserves and that OUC must include reserves to meet its retail peak demand and the City of St. Cloud's retail peak demand.
(6)Reserve margin percentages are calculated as the sum of installed capacity and firm capacity import (plus an additional 15% of the TECO purchase) minus the sum of OUC peak demand, St. Cloud peak demand, and firm capacity export, all divided by the sum of the forecast OUC peak demand and St. Cloud peak demand.

Table 12-13 (Schedule 7.2)
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity(1)	Firm Capacity Import(2)	Firm Capacity Export(3)	QF	Total Capacity Available	System Firm Peak Demand(4)	Reserve Margin Before Maintenance(5,6)		Scheduled Maintenance	Reserve Margin After Maintenance(5,6)	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2007/08	1,275	358	0	0	1,633	1,313	322	24.5%	0	322	24.5%
2008/09	1,275	358	0	0	1,633	1,346	289	21.5%	0	289	21.5%
2009/10	1,275	358	0	0	1,633	1,381	255	18.4%	0	255	18.4%
2010/11	1,275	358	0	0	1,633	1,415	221	15.6%	0	221	15.6%
2011/12	1,549	358	0	0	1,908	1,449	461	31.8%	0	461	31.8%
2012/13	1,549	358	0	0	1,908	1,487	423	28.4%	0	423	28.4%
2013/14	1,549	343	0	0	1,893	1,527	366	24.0%	0	366	24.0%
2014/15	1,549	343	0	0	1,893	1,569	323	20.6%	0	323	20.6%
2015/16	1,735	343	0	0	2,078	1,615	463	28.7%	0	463	28.7%
2016/17	1,735	343	0	0	2,078	1,664	414	24.9%	0	414	24.9%

(1)Installed capacity includes St. Cloud's entitlement to capacity from Stanton Unit 2.
(2)Firm capacity imports include capacity purchased from TECO and capacity purchased from Southern Company-Florida, LLC (from Stanton A).
(3)Firm capacity export includes all firm wholesale power sales contracts.
(4)Includes OUC peak demand and City of St. Cloud peak demand.
(5)Assumes TECO purchase (15 MW) includes reserves and that OUC must include reserves to meet its retail peak demand and the City of St. Cloud's retail peak demand.
(6)Reserve margin percentages are calculated as the sum of installed capacity and firm capacity import (plus an additional 15% of the TECO purchase) minus the sum of OUC peak demand, St. Cloud peak demand, and firm capacity export, all divided by the sum of the forecast OUC peak demand and St. Cloud peak demand.

Table 12-14 (Schedule 8)
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Construction Start	Commercial In-Service	Expected Retirement	Gross Capability[1]		Net Capability[1]		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	Sum MW	Win MW	Sum MW	Win MW	
SEC[1]	B	Orange	CC	SUB	NG	RR	PL	01/08	06/10				249	275	P
SEC[2]	GT1	Orange	GT	DFO	NG	TK	PL	04/14	06/15		165	194	158	171	P

[1] Need for Power Application for Stanton Energy Center B (SEC B) approved by FPSC May 2006 (Docket No. 060155-EM).
[2] OUC has not committed to construction of this unit.

Table 12-15 (Schedule 9)
Status Report and Specifications of Proposed Generation Facilities

(1)	**Plant Name and Unit Number:**	Stanton Energy Center B[1]	Stanton Energy Combustion Turbine 1[2]
(2)	**Capacity**		
	a. Summer:	249	158
	b. Winter:	275	171
(3)	**Technology Type:**	IGCC	GT
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	01/2008	01/2008
	b. Commercial in-service date:	06/2010	06/2010
(5)	**Fuel**		
	a. Primary fuel:	SUB	SUB
	b. Alternate fuel:	NG	NG
(6)	**Air Pollution Control Strategy**	BACT compliant	Low NO_x burners
(7)	**Cooling Method**	Mechanical draft	NA
(8)	**Total Site Area**	Approximately 3,280 acres	Approximately 3,280 acres
(9)	**Construction Status**	P	P
(10)	**Certification Status**	Underway	N/A
(11)	**Status with Federal Agencies**	Underway	Not begun
(12)	**Projected Unit Performance Data**		
	Planned Outage Factor (POF):	N/A	2.7
	Forced Outage Factor (FOF):	N/A	2.0
	Equivalent Availability Factor (EAF):	N/A	95%
	Resulting Capacity Factor (%):	N/A	1%
	Average Net Operating Heat Rate (ANOHR):	N/A	13,040
(13)	**Projected Unit Financial Data**		
	Book Life (Years):	N/A	30
	Total Installed Cost (In-Service Year $/kW):	N/A	$623.5
	Direct Construction Cost ($/kW):	N/A	$498.8
	AFUDC Amount ($/kW):	N/A	$18.4
	Escalation ($/kW):	N/A	$106.4
	Fixed O&M ($/kW-Yr)[2]:	N/A	$4.40
	Variable O&M ($/MWH)[3]:	N/A	$30.67
	K Factor:	N/A	N/A

(1) Need for Power Application for Stanton Energy Center B (SEC B) filed February 22, 2006 (Docket No. 060155-EM). Certain details of the unit are confidential as indicated by "N/A." However, the unit will be located at Stanton Energy Center and is assumed to have a commercial operation date of June 1, 2010.
(2) Not authorized by OUC nor planned for construction. Represents capacity addition to satisfy forecast capacity requirements in this Ten-Year Site Plan.