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April 15, 2008

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0688

080000

Ms. Cole,

Enclosed please find an original plus 25 copies of the 2008 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). The 2008 OUC TYSP was prepared for and submitted by Black & Veatch on behalf of OUC.

Should you require additional copies of the 2008 OUC TYSP, or have any other questions regarding the TYSP, please do not hesitate to contact me at (913) 458-7134.

Very truly yours,

BLACK & VEATCH CORPORATION

Bradley Kushner

Enclosure[s]

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OUC

The *Reliable* One®

2008 Ten-Year Site Plan
Orlando Utilities Commission

April 2008

B&V Project 161100

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The Reliable One®

2008 Ten-Year Site Plan
Orlando Utilities Commission

B&V File Number
161100

April 2008

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1.0 Executive Summary

This report documents the 2008 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 1,238 MW (summer) and 1,296 MW (winter), as of January 1, 2008. Considering the March 2008 retirement of St. Cloud's internal combustion units that were previously grid-connected decreases the total installed capacity (including OUC's units as well as St. Cloud's entitlement to capacity from Stanton Energy Center Unit 2) to 1,217 MW (summer) and 1,275 MW (winter). 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) and the Florida Department of Environmental Protection (FEDP) to construct Stanton Energy Center Unit B (Stanton B). Originally proposed to be an integrated gasification combined cycle (IGCC) unit, Stanton B was designed to be able to run as a stand alone natural gas unit with the gasification portion as an alternative fuel source. In 2007, OUC made the decision not to move forward with the gasification portion of Stanton B, and the unit is currently planned to be a 1x1 combined cycle unit operating on natural gas as the primary fuel with the capability to utilize fuel oil as a secondary fuel source. 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. 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.

As illustrated in Section 6.0 of this report, following commercial operation of Stanton B (assumed to be June 1, 2010) OUC is forecasted to require additional capacity to maintain a 15 percent reserve margin beginning in the summer of 2017. It should be noted that four new nuclear generating units have been proposed to the FPSC since October 2007, including Florida Power & Light's Turkey Point Units 6 and 7 (Docket No. 070650) and Progress Energy Florida's Levy Units 1 and 2 (Docket No. 080148), with Turkey Point Units 6 and 7 having received recommendation for approval from the FPSC Staff. OUC is aware of and closely monitoring opportunities to participate in new nuclear generating units and will continue to work diligently towards approaching the owners of these potential new units to secure allocations if possible and deemed appropriate as OUC continues its planning processes. Given OUC's projected need for additional capacity beyond Stanton B during the term of this Ten-Year Site Plan and the potential opportunities to participate in and receive capacity from new nuclear generating units in the State, the capacity expansion plans discussed throughout this report include the addition of a simple cycle combustion turbine in the 2017 timeframe to maintain forecasted reserve margin requirements. OUC has made no commitments to future generating capacity additions beyond Stanton B and will continue to evaluate alternatives as part of its planning processes.

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
(As of January 1, 2008)

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 (approximately 171 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 (totaling 21 MW of grid-connected capacity, and an additional 6 MW that has never been connected to the grid) were retired as of March 2008. 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 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 is actively working to increase customer awareness of opportunities to increase the role of renewable energy among its customers. One such initiative is OUC's Green Pricing Program. 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 may pay an additional $5.00 on their monthly utility bills for each 200 kWh block of bio-energy, solar and wind power; or $10.00 for each 200 kWh of all solar energy. There is no limit to the number of 200kWh blocks that a participant may acquire to support funding of 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.

Further examples of OUC's commitment to renewable energy are OUC's environmentally friendly solar programs. Two such programs were recently launched to residential and commercial customers – a solar PV program which generates electricity and a Solar Thermal program which generates heat for domestic water heating systems. Participating customers install a solar PV system, a solar thermal system, or both systems, on their homes and sign an agreement allowing OUC to retain the rights to the environmental benefits or attributes. Participating customers receive a monthly production credit on their utility bills for the energy the systems produce. Any excess electricity generated by the solar systems back to OUC's electric grid will be credited at the full applicable standard rate.

The solar PV systems will be metered in kWh, while the solar thermal systems will be metered in British Thermal Units (BTU) and converted to kWh. Participating customers save on normal electric consumption and also receives a monthly credit for the kWh production of the solar systems. The monthly production credit is $0.03 and $0.05 for each equivalent kWh produced for solar thermal and solar PV systems, respectively.

Residential customers may benefit from OUC's partnership with the Orlando Federal Credit Union to provide low interest loan options for solar installations, helping to keep the net monthly cost low, all of which can be included on the OUC bill. Additional Florida state rebates and federal tax credits may also be available to help minimize costs.

To further facilitate development of solar energy, OUC supported Orange County in its efforts to obtain an award of a $2.5 million grant from the Florida Department of Environmental Protection to install a 1 MW solar array on the Orange County Convention Center. This solar project will be the largest in the Southeast US, and OUC will receive all of the renewable energy credits (RECs) from the array.

In April 2007, OUC broke ground on what will become the greenest building in downtown Orlando. OUC's new administration building is designed to meet the requirements for Gold LEED (Leadership in Energy and Environmental Design) Certification, Scheduled to open in late 2008, OUC customers will be able to learn about energy and water saving features of the new administration building while paying their utility bills. The administration building will include a ground-floor public education center to educate customers on how new features (such as a 2,000 square-foot solar photovoltaic array, a solar hot water system, high efficiency windows, sub-floor heating and cooling, daylight sensitive lighting systems, low-flow water fixtures, and a roof storm water collection system for irrigation) save energy, water, and money.

2.5 Transmission System

OUC's existing transmission system consists of 30 substations interconnected through approximately 341 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 57 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.. The 230/69 kV "bus tie" AutoTransformer was relocated from the Stanton east bus to the Magnolia Ranch North 230/69 kV substation, which enabled the addition of a 230 kV line between Stanton and Lake Nona within the existing Taft-to-Stanton railroad/transmission corridor. Additionally, the move of the 230/69 kV AutoTransformer accommodated a new 69 kV line from Magnolia Ranch North to Progress Energy Magnolia Ranch substation, and retermination of the St. Cloud tie line that is alongside State Road (SR) 15 in Orange County, which remains connected to the St. Cloud north substation

To maintain reliable and economic service and proactively plan for the future at key locations, 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:

- Upgrade of thirty 230 kV power circuit breakers at the Stanton Substation to increase the site rating from 44 kA to a minimum of 63 kA.
- Continued conceptual permitting and design for the future Stanton South 230kV Substation for future generation needs. The site will address system stability and available fault current issues.
- Replacement and upgrade of aging transmission infrastructure within the corridor from Pershing to Stanton to Indian River. The 115kV line from Pershing to Stanton will be upgraded from 150-MVA to 400-MVA. The Stanton to Progress Energy Curry Ford (to Rio Pinar) transmission line will be upgraded to match or exceed the Progress Energy line rating.
- Addition of a 115kV substation denoted as Stanton North that will serve distribution load, provide electrical separation of the localized Stanton-area distribution and generation, and provide a bus position for a generator step-up that could be used for black-start generation.
- Various 115 kV transmission projects to more effectively move power to the downtown Orlando region. Among lines under consideration are the transmission lines from Pershing to Stanton, Pershing to Michigan, and Pershing to Grant Substation.

Table 2-2
OUC Transmission Interconnections

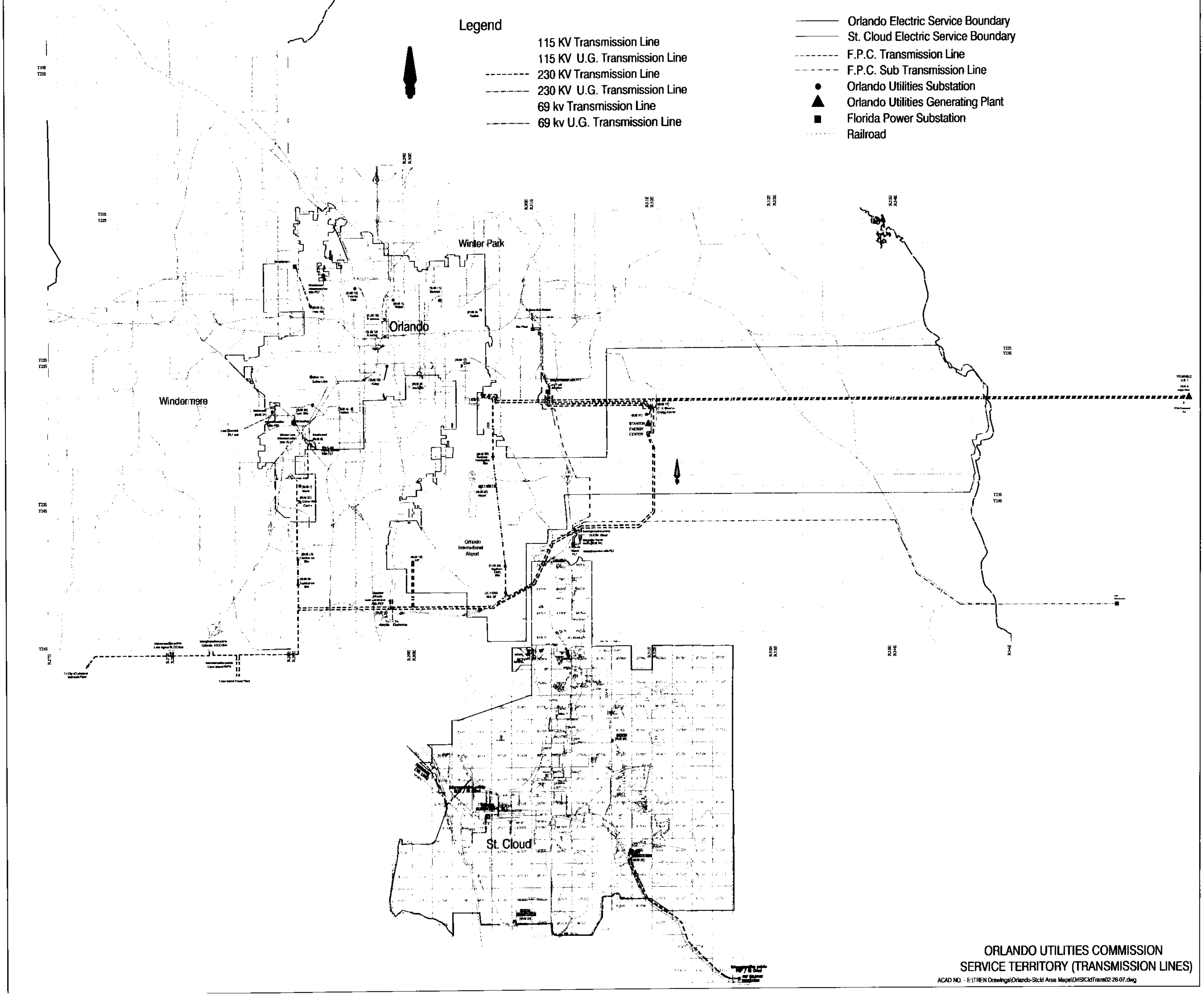
Utility	kV	Number of Interconnections
FPL	230	2
Progress Energy Florida (PEF)	230	8
KUA	230	2
KUA/FMPA	230	2
Lakeland Electric	230	1
TECO	230	2
TECO/Reedy Creek Improvement District	230	2
PEF	69	1
Southern Company	230	1
Reliant Energy	230	2
Reliant Energy	115	1

Table 2-3
St. Cloud Transmission Interconnections

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

Figure 2-1
OUC Service Area and
Transmission System

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

OUC is currently organized into two strategic business units - 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, 2008)

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 will further diversify its fuel supply through the addition of the natural gas combined cycle Stanton B, which is assumed to begin commercial operation in June 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, 60 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 2007, the average annual customer interruption for the combined Orlando-St. Cloud service area was well below that of OUC's competition. For the sixth 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).

PA Consulting Group recognized OUC as the winner of the 2007 ReliabilityOne™ Award in the Southeast region, which is awarded annually to the utilities that have excelled in delivering reliable electric service to their customers. The recognition by PA Consulting Group in 2007 represented the fourth straight year in which OUC has received the award for outstanding service.

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. In 2007 OUC broke ground on the Stanton B project[1] and, as part of the agreement associated with the termination of the gasification portion of Stanton B, acquired a 165 acre track of land in its service territory situated near it highest growth areas. The land is in an industrial area and is ideal for a new power generation site, having access to important infrastructure including a rail spur, natural gas lines, and OUC-owned and operated transmission lines.

[1] Originally proposed to be an integrated gasification combined cycle (IGCC) unit, Stanton B was designed to be able to run as a stand alone natural gas unit with the gasification portion as an alternative fuel source. In 2007, OUC made the decision not to move forward with the gasification portion of Stanton B, and the unit is currently planned to be a 1x1 combined cycle unit operating on natural gas as the primary fuel with the capability to utilize fuel oil as a secondary fuel source.

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 will further contribute to OUC's environmentally responsible portfolio of generating resources.

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.

In 2007, OUC's indoor lighting partnership with Orange County Public Schools completed work on Cypress Creek High School – the 20th school to benefit from new energy saving fixtures. At participating schools, OUC replaces old lighting fixtures with more energy-efficient retrofits. The schools benefit immediately as the up-front costs of the lighting retrofits are spread over multiple billing periods, and the costs of retrofits are ultimately balanced out by lower power bills.

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 and in 2007 achieved an important milestone by reaching more than $1,000,000 in total customer and OUC donations. OUC had initially matched customer donations to Project CARE dollar for dollar, but has increased its commitment to Project CARE and now donates $2 for every dollar contributed by OUC customers.

During 2007, OUC Conservation Support personnel participated in 27 community events to help promote OUC's conservation programs. Conservation Specialists conducted presentations, provided face-to-face consultations, scheduled audits, and provided information on OUC's conservation programs. Examples of the events that OUC representatives attended include Hispanic Business Expos, the Southeast Building Conference (SEBC), various home owner associations meetings, civic group meetings, Central Florida Hotel & Lodging Association (CFHLA) events, Florida Green Lodging events, corporate employee events, and various YMCA, City, and County events. OUC also helped to educate customers through its commitment to alternative fleet services. Every OUC Conservation Specialist drives a hybrid vehicle, generates discussion between customers and contributes to increased awareness of alternative fuel vehicles.

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. 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 2007. 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:

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

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 0.1 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 0.94, with an in-sample MAPE of 3.0 percent. Since St. Cloud is a relatively small part of OUC's service territory, the 3.0 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:

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

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:

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

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:

$$\mathbf{XHeat_{y,m} = HeatIndex_{y} \times HeatUse_{y,m}}$$

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:

$$\mathbf{HeatIndex_y = StructuralIndex_y \times \sum_{Type} EI^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type} \right)}{\left(Sat_{98}^{Type} / Eff_{98}^{Type} \right)}}$$

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 a study performed by OUC's consultants. 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:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m}$$

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:

$$OtherIndex_{y,m} = EI^{Type} \times \frac{\left(Sat_{y}^{Type} \Big/ \frac{1}{Eff_{y}^{Type}} \right)}{\left(Sat_{98}^{Type} \Big/ \frac{1}{Eff_{98}^{Type}} \right)} \times MoMult_{m}^{Type}$$

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:

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

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 0.94 with an in-sample MAPE of approximately 4.1 percent. The mean absolute deviation (MAD) is 41.7 kWh compared to a residential monthly average usage of 1,069 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 0.93. 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:

$$Sales_{y,m} = Heat_{y,m} + Cool_{y,m} + \text{Other}_{y,m}$$

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:

$$Sales_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m$$

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:

$$HeatIndex_y = HeatSales_{98} \times \frac{\left(HeatShare_y \middle/ Eff_y \right)}{\left(HeatShare_{98} \middle/ Eff_{98} \right)}$$

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:

$$\mathbf{CoolIndex_{y} = CoolSales_{98} \times \frac{\left(CoolShare_{y} / Eff_{y}\right)}{\left(CoolShare_{98} / Eff_{98}\right)}}$$

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:

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

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:

$$OtherIndex_{y,m} = \sum_{Type} OtherSales_{98}^{Type} \times \left(\frac{Share_{y}^{Type} / Eff_{y}^{Type}}{Share_{98}^{Type} / Eff_{98}^{Type}} \right)$$

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:

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

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 2.3 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 at a solid level of 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 3.1 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 5.8 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:

$$\text{Fraction}_{\text{dh}} = \text{Load}_{\text{hd}} \div \text{Energy}_{\text{d}}$$

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:

$$WNLoad_{dh} = \text{WNFraction}_{\text{dh}} \times \text{WNDailyEnergyt}_{\text{dh}}$$

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 $)
2010	1,157.3	1,018.0	93.1
2015	1,320.2	1,166.5	111.2
2020	1,534.6	1,356.2	133.0
2025	1,782.6	1,575.4	159.5
Average Annual Increase			
10-15	2.7%	2.8%	3.6%
15-20	3.1%	3.1%	3.6%
20-25	3.0%	3.0%	3.7%

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

Year	Real Income per Household	Households (thousands)	Population (thousands)
2010	$79,413	839.5	2,178.6
2015	$82,073	988.1	2,512.8
2020	$88,257	1,170.4	2,947.8
2025	$96,431	1,359.9	3,433.7
Average Annual Increase			
10-15	0.7%	3.3%	2.9%
15-20	1.5%	3.4%	3.2%
20-25	1.8%	3.0%	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	6.1
2015	6.2
2020	6.2
2025	6.2
Annual Increase	
00-05	2.9%
05-10	0.0%
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:

$$CDD_d = (AvgTemp_d - 65)\ when\ \ AvgTemp_d \rangle = 65$$

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:

$$HDD_d = (65 - AvgTemp_d)\ when\ AvgTemp_d \langle = 65$$

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:

$$\mathbf{HDD_{nm} = \Sigma HDD_m + 10}$$

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 2007 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 2007.

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 (%)
2010	1,354	1,346	6,918	58.1%
2015	1,526	1,516	7,909	59.2%
2020	1,738	1,723	9,133	60.0%
2025	1,984	1,965	10,496	60.4%
Average Annual Increase				
10-15	2.4%	2.4%	2.7%	-
15-20	2.6%	2.6%	2.9%	-
20-25	2.7%	2.7%	2.8%	-

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 36.5 million passengers or 4.7 percent, in 2007. 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 1,359,900 by 2025, representing an average annual growth rate of 3.1 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 8,730 GWh by 2025. St. Cloud sales are projected to increase from 343 GWh to 1,280 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 2.8 percent for OUC and at 5.4 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 1.2 percent and 5.5 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 1.6 percent and 3.9 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 2.6 percent between 2000 and 2007. Sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall increasing 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
2010	2,049	312	3,456	43	19	109	5,988
2015	2,355	337	3,869	47	29	112	6,748
2020	2,784	362	4,309	52	39	115	7,661
2025	3,276	393	4,835	57	49	121	8,730
Average Annual Increase							
10-15	2.8%	1.6%	2.2%	1.8%	8.8%	0.5%	2.4%
15-20	3.4%	1.4%	2.2%	2.0%	6.1%	0.5%	2.6%
20-25	3.3%	1.7%	2.3%	1.9%	4.7%	1.0%	2.6%

Table 4-6
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
2010	161,088	18,785	6,022	185,895
2015	186,450	20,140	6,717	213,307
2020	217,550	21,623	7,602	246,775
2025	249,878	23,226	8,625	281,729
Average Annual Increase				
10-15	3.0%	1.4%	2.2%	2.8%
15-20	3.1%	1.4%	2.5%	3.0%
20-25	2.8%	1.4%	2.6%	2.7%

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

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
2010	460	55	122	5	642
2015	594	70	145	6	815
2020	771	85	169	8	1,033
2025	970	102	197	11	1,280
Average Annual Increase					
10-15	5.3%	4.9%	3.5%	3.7%	4.9%
15-20	5.4%	4.0%	3.1%	5.9%	4.9%
20-25	4.7%	3.7%	3.1%	6.6%	4.4%

Table 4-8
St. Cloud Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
2010	29,675	2,508	259	32,442
2015	38,565	2,958	296	41,819
2020	49,466	3,546	334	53,346
2025	60,799	4,225	372	65,396
Average Annual Increase				
10-15	5.4%	3.4%	2.7%	5.2%
15-20	5.1%	3.7%	2.5%	5.0%
20-25	4.2%	3.6%	2.2%	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 3.6 percent on a compounded basis between 2005 and 2025. This compares with the University of Florida's base case population projections of 2.2 percent. The high growth scenario results in a forecasted long-term annual energy growth rate of 3.8 percent, with system peak demand that is 364 MW higher than the base case by 2025. In the low case scenario, energy increases 1.8 percent on a compounded basis through 2025. Peak demand is 352 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 Forecast Net Peak Demand (Summer and Winter) and
Net Energy for Load

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	1,190	1,183	6,242
2015	1,317	1,307	7,045
2020	1,472	1,458	8,029
2025	1,654	1,636	9,131
Average Annual Increase			
10-15	2.1%	2.0%	2.5%
15-20	2.3%	2.2%	2.7%
20-25	2.4%	2.3%	2.6%

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

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	164	163	677
2015	209	209	864
2020	266	265	1,103
2025	330	329	1,365
Average Annual Increase			
10-15	5.0%	5.1%	5.0%
15-20	4.9%	4.9%	5.0%
20-25	4.4%	4.4%	4.4%

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

High Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	1,386	1,383	7,131
2015	1,653	1,644	8,522
2020	1,971	1,953	10,266
2025	2,350	2,320	12,343
Average Annual Increase			
10-15	3.6%	3.5%	3.7%
15-20	3.6%	3.5%	3.7%
20-25	3.6%	3.5%	3.7%
Base Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	1,354	1,346	6,918
2015	1,526	1,516	7,909
2020	1,738	1,723	9,133
2025	1,984	1,965	10,496
Average Annual Increase			
10-15	2.4%	2.4%	2.7%
15-20	2.6%	2.6%	2.9%
20-25	2.7%	2.7%	2.8%
Low Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	1,328	1,325	6,839
2015	1,422	1,414	7,387
2020	1,523	1,509	7,979
2025	1,709	1,610	8,618
Average Annual Increase			
10-15	1.4%	1.3%	1.6%
15-20	1.4%	1.3%	1.6%
20-25	1.4%	1.3%	1.6%

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. This decision is reflected in Table 5-1 below. 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 DSM and conservation programs currently offered by OUC are discussed in this section.

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

Recent increases in fuel costs have led to increases in the cost of electricity to consumers, which in turn has led to higher levels of customer interest in DSM and conservation programs. OUC has been increasingly emphasizing its DSM and conservation programs to increase customer awareness of such programs. This is beneficial to the customers, and also represents one way in which OUC is helping to reduce its emissions of greenhouse gases, consistent with Governor Crist's Executive Order 07-127.

It should also be noted that government mandates have forced manufacturers to increase their efficiency standards, thereby decreasing the incremental amount of energy savings achievable; and the efficiency of new generation has increased. These appliance and generating unit efficiency improvements have to some degree mitigated the effectiveness of DSM and conservation programs, as the incremental benefit of such programs is partially offset by overall efficiency increases in the marketplace as a whole.

The DSM and conservation programs voluntarily continued and offered by OUC to its customers during 2007 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 educations. The quantifiable DSM and conservation programs voluntarily continued and offered to OUC's customers in 2007 included the following:

- Residential Energy Survey Program (Walk-Through, Video or DVD, and On-Line).
- Residential Energy Efficiency Rebate Program (Duct Repair, Insulation, Weatherization).
- Residential Home Energy Fix-Up Program.
- Residential Financed Insulation 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 2007 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..

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 2007. In addition to offering such programs, OUC continues to play an active role in promoting conservation through community relations as discussed in Section 3.6 of this Ten-Year Site Plan.

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; heating, ventilation, and air conditioning (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. 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.

Customers who participate in the Walk-Through Energy Surveys receive a free compact fluorescent light bulb and a free home water conservation kit that includes a low-flow showerhead, die tabs, an aerator, a water flow measurement device and instructions on its use, plumbing tape, and additional water saving tips. Customers also receive a booklet titled *Do-It-Yourself Home Water Audit Kit – the Complete Guide to Water Conservation.*

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 is available to 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 to achieve and maintain high customer satisfaction.

5.1.4 Residential Financed Insulation Program

This program 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 in the form of a credit on their bill 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 for single-family homes and $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 FHA, 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. 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. 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 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 2007, 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, a $45 monthly fee per meter for this service, and the cost of additional infrastructure (can range between $0 and $500) at the meters which may be required.

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. New interlocal agreements have allowed this program to expand into neighboring communities like Clermont, Oviedo, and Brevard County.

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.

OUC currently has four chilled water districts: downtown Orlando, the Mall at Millenia, the Starwood Resort, and the Orange County Convention Center including Lockheed Martin and neighboring hotels. OUC envisions building other chiller plants serving commercial campuses, hotels, retail shopping centers, and tourist attractions.

OUC will be adding a fifth district at Lake Nona, with the potential to provide up to 65,000 tons of chilled water to the medical complexes and research facilities located in the area. At full build out, this central chilled water system may be one of the largest in the US. 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 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.

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. The seasonal capacity available takes into account the March 2008 retirement of St. Cloud's internal combustion units that were previously grid-connected. 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 approximately 312 MW of winter capacity and 287 MW of summer capacity. Including the capacity from Stanton B will increase the combined OUC and St. Cloud installed generating capability to approximately 1,587 MW in the winter and approximately 1,504 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

The internal combustion units owned by St. Cloud were retired as of March 2008. OUC has not scheduled any additional unit retirements over the planning horizon, but will continue to evaluate options on an ongoing basis.

By the end of the Ten-Year Site Plan planning period, McIntosh 3 will be 35 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 possible future regulations of emissions of mercury that may replace the EPA's Clean Air Mercury Rule (CAMR) following the recent US District Court of Appeals decision that vacated 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 or mercury emissions regulations 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 OUC is projected to have adequate generating capacity to maintain the 15 percent reserve margin requirements until the summer of 2017. This projection considers the impending commercial operation of Stanton B as well as OUC's capacity allocations associated to planned upgrades to the existing Crystal River and St. Lucie nuclear generating units.

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]	
2007/08	1,141	150	0	1,297	1,275	343	0	15	1,633	195	338	144
2008/09	1,166	156	0	1,322	1,275	343	0	15	1,633	198	313	115
2009/10	1,183	163	0	1,346	1,275	343	0	15	1,633	202	289	87
2010/11	1,203	171	0	1,374	1,275	343	312	15	1,945	206	574	367
2011/12	1,226	179	0	1,405	1,278	343	312	15	1,948	211	546	335
2012/13	1,251	188	0	1,439	1,283	343	312	0	1,939	216	500	284
2013/14	1,278	198	0	1,476	1,283	343	312	0	1,939	221	463	241
2014/15	1,307	209	0	1,516	1,283	343	312	0	1,939	227	423	195
2015/16	1,336	219	0	1,555	1,283	343	312	0	1,939	233	384	151
2016/17	1,367	230	0	1,597	1,283	343	312	0	1,939	240	342	102

(1) Includes existing net capability to serve OUC and St. Cloud. Reflects OUC's share of the increased capacity associated with the planned upgrades of the existing Crystal River and St. Lucie nuclear generating units.
(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]	
2008	1,142	150	0	1,303	1,217	322	0	15	1,554	195	253	58
2009	1,172	157	0	1,329	1,217	322	0	15	1,554	199	227	28
2010	1,190	164	0	1,354	1,217	322	287	15	1,841	203	489	286
2011	1,211	171	0	1,382	1,217	322	287	15	1,841	207	461	254
2012	1,234	180	0	1,414	1,226	322	287	15	1,850	212	437	225
2013	1,260	189	0	1,449	1,226	322	287	0	1,850	217	402	185
2014	1,287	199	0	1,486	1,226	322	287	0	1,835	223	348	125
2015	1,317	209	0	1,526	1,226	322	287	0	1,835	229	308	79
2016	1,348	220	0	1,568	1,226	322	287	0	1,835	235	266	31
2017	1,379	231	0	1,610	1,226	322	287	0	1,835	242	224	(17)

(1) Includes existing net capability to serve OUC and St. Cloud. Reflects OUC's share of the increased capacity associated with the planned upgrades of the existing Crystal River and St. Lucie nuclear generating units.
(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

As discussed previously, OUC's current expansion plan to meet forecast capacity requirements through the 10 year horizon considered in this Ten-Year Site Plan includes the installation of Stanton B as a natural gas 1x1 combined cycle in the summer of 2010. As discussed in Section 1.0, OUC has made no commitments to future generating capacity additions beyond Stanton B, and has included the addition of a simple cycle combustion turbine in June 2017 to satisfy forecast reserve margin requirements beyond Stanton B. OUC will continue to evaluate alternatives as part of its planning processes, including possible opportunities to participate in future nuclear generating units if such participation is deemed appropriate.

The remainder of this section presents performance, emissions, cost, availability, and construction schedule estimates for the 1x1 combined cycle (representative of Stanton B) and the simple cycle combustion turbine.

7.1 Performance and Emission Estimates

Tables 7-1 through 7-4 present performance and emission estimates for the combined cycle and simple cycle technologies.

7.1.1 1x1 7FA Combined Cycle

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

Ambient Condition	Net Capacity (MW)(1)	Full Load Net Plant Heat Rate (Btu/kWh, HHV)(1.)
Summer (Full Load with Supplemental Firing)	286.6	7,545
Average (Full Load with Supplemental Firing)	307.2	7,420
Average (Full Load without Supplemental Firing)	247.0	6,969
Average (Part Load)	192.1	7,289
Average (Part Load)	117.7	8,398

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

Table 7-2 GE 1x1 7FA Combined Cycle Estimated Emissions[1]	
NO_x, lb/MBtu (HHV)	0.0072
SO_2, lb/MBtu (HHV)	0.0002
Hg, lb/MBtu (HHV)	Neglible
CO_2, lb/MBtu (HHV)	114.8
CO, lb/MBtu (HHV)	0.0036

[1]Emissions are at full load at average ambient conditions and include the effects of selective catalytic reduction (SCR) and CO catalyst.

7.1.2 GE 7FA Simple Cycle Combustion Turbine

Table 7-3
GE 7FA Simple Cycle Combustion Turbine Characteristics

Ambient Condition	Net Capacity (MW)[1]	Net Plant Heat Rate (Btu/kWh, HHV)[1.]
Summer (Full Load)	148.5	11,065
Average (Full Load)	160.0	10,826
Average (75% Load)	119.8	11,816
Average (50% Load)	79.6	14,223

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

Table 7-4 GE 7FA Simple Cycle Combustion Turbine Estimated Emissions[1]	
NO_x, lb/MBtu	0.0072
SO_2, lb/MBtu	0.0002
Hg, lb/MBtu	Neglible
CO, lb/MBtu	114.8
CO_2, lb/MBtu	0.0165

[1]Emissions are at full load at average ambient conditions and include the effects of SCR.

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

Table 7-5 presents the capital cost, O&M cost, construction schedule, and availability estimates for the combined cycle and simple cycle technologies.

Table 7-5
Capital Costs, O&M Costs, Schedules, and Availability for the 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)
1x1 7FA CC	304.7	1,063	5.10	4.60	24	14	3.0
7FA CT	97.6	657	5.20	5.90	12	10	2.0

(1)All costs are presented in 2008 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.

8.0 Economic Evaluation Criteria and Methodology

This section presents the economic evaluation criteria and methodology used by OUC in its current planning processes.

8.1 Economic Parameters

The economic parameters are summarized below and are presented on an annual basis.

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

The weighted average cost of capital used by OUC for economic evaluations is 8.0 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 8.0 percent.

8.1.4 Interest During Construction Rate

The interest during construction (IDC) used by OUC for economic evaluations is 4.3 percent.

8.2 Fuel Price Forecasts

8.2.1 Coal

Low sulfur (1.6 lb SO_2/MBtu) Central Appalachian coal fuels the existing Stanton Units 1 and 2. Energy ventures Analysis, Inc. (EVA) developed and provided to OUC annual projections of minemouth prices for low sulfur Central Appalachian coal in real 2007 dollars. Costs for delivery of low sulfur Central Appalachian coal to the Stanton Energy Center were developed by OUC and added to the minemouth price projections provided by EVA. The annual minemouth price projections, annual delivery cost projections, and resulting total delivered annual price projections for low sulfur Central Appalachian coal delivered to the Stanton Energy Center are presented in Table 8-1.

Table 8-1
Low Sulfur Central Appalachian Coal Price Projections
(Real 2007 $/MBtu)

Calendar Year	Minemouth (Commodity)	Delivery to Stanton Energy Center	Delivered Price
2008	1.95	0.93	2.88
2009	1.85	0.94	2.79
2010	1.90	0.95	2.85
2011	1.94	0.96	2.90
2012	1.97	0.97	2.94
2013	2.00	0.98	2.98
2014	2.01	0.99	3.00
2015	2.03	1.00	3.03
2016	2.05	1.01	3.06
2017	2.07	1.02	3.09

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 Stanton B as well as the 7FA simple cycle combustion turbine alternative considered in this analysis (described in Section 7.0). The price forecast (in real 2007 dollars) for Henry Hub natural gas is presented in Table 8-2, in addition to Florida Gas Transmission (FGT) Zone 3 basis adder for Henry Hub and fuel loss and usage charges. Projected costs for natural gas transmission for firm delivery under FGT's proposed Phase VIII expansion (FTS-3) are not included in the price projections shown in Table 8-2, although these costs were assumed by OUC to be approximately $1.20/MBtu (in real 2007$). Natural gas transmission costs for existing units served under FGT's FTS-2 rate are not presented since such costs are associated with OUC's existing units and would not affect future resource decisions as they are considered to be "sunk costs."

Table 8-2
Natural Gas Price Projections
(Real 2007 $/MBtu)

Calendar Year	Henry Hub	FGT Z3 Basis	FGT Losses	FGT Usage	Total Price (Excluding FTS-2 and FTS-3 Firm Transportation Costs)
2008	7.93	0.20	0.25	0.04	8.42
2009	7.63	0.19	0.24	0.04	8.11
2010	7.43	0.19	0.24	0.04	7.90
2011	7.26	0.18	0.23	0.04	7.71
2012	7.15	0.18	0.23	0.04	7.60
2013	7.08	0.18	0.22	0.04	7.53
2014	7.01	0.18	0.22	0.04	7.45
2015	6.96	0.18	0.22	0.04	7.40
2016	6.97	0.18	0.22	0.04	7.41
2017	7.07	0.18	0.22	0.04	7.51

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. Since fuel oil is not considered a primary fuel source for OUC's existing units nor for units that OUC may add in the planning horizon considered in this Ten-Year Site Plan, a forecast for fuel oil was not developed. For informational purposes, the fuel oil forecast presented in OUC's Stanton B Need for Power Application is presented in Table 8-4.

8.2.4 Nuclear

Forecast annual prices for nuclear fuel, which are required for OUC's ownership shares of St. Lucie Units 1 and 2 and Crystal River Unit 3, were developed based on OUC's historical costs.

8.2.5 Nominal Fuel Price Projections

Subsections 8.2.1 through 8.2.4 presented OUC's current projected annual fuel prices for coal, natural gas, fuel oil, and nuclear (in real 2007 dollars). Table 8-4 summarizes these fuel price forecasts and presents the price projections in nominal dollars, which were developed by converting the real 2007 dollar price projections assuming the 2.5 percent annual inflation rate.

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

Calendar Year	Low Sulfur Central Appalachian Coal (Delivered to Stanton Energy Center)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2008	2.95	8.63	13.73	0.54
2009	2.93	8.52	14.07	0.56
2010	3.07	8.51	14.42	0.59
2011	3.20	8.51	14.89	0.62
2012	3.32	8.59	15.50	0.65
2013	3.45	8.73	16.13	0.68
2014	3.56	8.85	16.79	0.71
2015	3.69	9.02	17.46	0.75
2016	3.82	9.26	18.03	0.78
2017	3.95	9.62	18.61	0.82

8.3.5 Emission Allowance Price Forecasts

OUC's planning processes 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. Further reductions in both NO_x and SO_2 emissions will be required under CAIR in 2015. Each state must develop a State Implementation plan

(SIP) to implement the emissions reduction requirements of CAIR. The Florida Department of Environmental Protection is responsible for implementing CAIR in Florida.

On March 15, 2005, the EPA issued the final CAMR. The rule was intended to limit the emissions of mercury (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. As finalized by EPA, CAMR would establish a cap-and-trade program (beginning in 2010) to regulate mercury emissions from coal-fired power plants greater than 25 MW in all 50 states, and also established performance standards for mercury emissions from new coal-fired units constructed or modified after January 30, 2004. In a decision issued on February 8, 2008, the federal District of Columbia Circuit Court of Appeals vacated CAMR. The Court found that in adopting CAMR, the EPA had unlawfully delisted (removed) electric generating units from regulation under Section 112 of the Clean Air Act, which invalidated the underlying basis for EPA to implement CAMR.

Table 8-5 presents the SO_2 and NO_x, emission allowance price forecasts in nominal dollars per ton used by OUC in their current planning processes.

OUC has assumed that appropriate measures would be taken to ensure its coal-fired generating resources (Stanton Energy Center Units 1 and 2 and McIntosh Unit 3) would operate within the mercury emissions allocations each unit receives, and therefore no cost was included for the cost of mercury emissions allowances.

Table 8-5
Forecast SO_2 and NO_x Emission Allowance Prices

Calendar Year	SO_2 Allowances (Nominal $/ton)	NO_x Annual Allowances (Nominal $/ton)	NO_x Seasonal Allowances (Nominal $/ton)
2009	-	998	2,600
2010	1,041	1,066	2,786
2011	1,115	1,138	2,984
2012	1,185	1,216	3,196
2013	1,270	1,299	3,423
2014	1,302	1,387	3,668
2015	1,349	1,482	3,929
2016	1,429	1,582	4,209
2017	1,534	1,690	4,508

9.0 Analysis and Results

Detailed economic analyses were performed by OUC using the GenTrader software package to evaluate the system costs associated with an expansion plan to meet projected capacity requirements for the 2008 through 2017 evaluation period. As discussed throughout this Ten-Year Site Plan, OUC is proceeding with construction of Stanton B as a natural gas combined cycle scheduled for commercial operation in the summer of 2010. Beyond Stanton B, OUC is forecast to require a minimal amount of incremental capacity to maintain a 15 percent reserve margin (summer and winter), and the projected capacity requirements have been assumed to be met through construction of a simple cycle combustion turbine in the summer of 2017, although OUC has made no commitments to future generating unit additions. OUC will continue to evaluate alternatives to meet forecast capacity requirements during the timeframe considered in this Ten-Year Site Plan as well as beyond 2017, and in doing so will evaluate possible participation in new nuclear generating units if deemed appropriate.

9.1 Sensitivity Analyses

As part of its capacity planning process, OUC considers a number of sensitivity analyses to measure the impact of variations to critical assumptions. Among the numerous scenarios that OUC may consider in its planning processes are high and low fuel prices, high and low load and energy growth projections, a scenario in which the differential between natural gas and coal price projections is held constant over time, and high and low present worth discount rates. Of these sensitivities only the high and low load and energy growth projection sensitivities would impact the timing of unit additions beyond Stanton B. For informational purposes, the following subsections describe the high and low load and energy growth, the high and low fuel price, and the constant differential fuel price sensitivity scenarios.

9.1.1 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 beyond Stanton B to maintain the 15 percent reserve margin in the summer of 2014. The capacity expansion plan under the high load forecast sensitivity scenario includes construction of a 7FA simple cycle combustion turbine for operation in June 2014, followed by construction of a second 7FA simple cycle combustion turbine for operation in June 2017.

9.1.2 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 to maintain the 15 percent reserve margin.

9.1.3 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 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 2017.

9.1.4 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 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 2017.

9.1.5 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 2008 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 2008 natural gas and coal price forecasts to convert from real to nominal dollars. The 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 2017.

Table 9-1
Delivered Fuel Price Forecasts – High Fuel Price Sensitivity
(Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian Coal (Delivered to Stanton Energy Center)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2008	3.39	12.08	13.73	0.54
2009	3.37	11.93	14.07	0.56
2010	3.53	11.91	14.42	0.59
2011	3.68	11.91	14.89	0.62
2012	3.82	12.03	15.5	0.65
2013	3.97	12.22	16.13	0.68
2014	4.09	12.39	16.79	0.71
2015	4.24	12.63	17.46	0.75
2016	4.39	12.96	18.03	0.78
2017	4.54	13.47	18.61	0.82

Table 9-2
Delivered Fuel Price Forecasts – Low Fuel Price Sensitivity
(Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian Coal (Delivered to Stanton Energy Center)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2008	2.46	7.19	13.73	0.54
2009	2.44	7.10	14.07	0.56
2010	2.56	7.09	14.42	0.59
2011	2.67	7.09	14.89	0.62
2012	2.77	7.16	15.5	0.65
2013	2.88	7.28	16.13	0.68
2014	2.97	7.38	16.79	0.71
2015	3.08	7.52	17.46	0.75
2016	3.18	7.72	18.03	0.78
2017	3.29	8.02	18.61	0.82

Table 9-3
Delivered Fuel Price Forecasts – Constant Differential Fuel Price Sensitivity
(Nominal $/MBtu)

Calendar Year	Low Sulfur Central Appalachian Coal (Delivered to Stanton Energy Center)	Natural Gas (Including FGT Zone 3 Basis Adder, Fuel Losses, and Usage Charges)	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2008	2.95	8.63	13.73	0.54
2009	3.02	8.85	14.07	0.56
2010	3.10	9.07	14.42	0.59
2011	3.18	9.29	14.89	0.62
2012	3.26	9.53	15.5	0.65
2013	3.34	9.76	16.13	0.68
2014	3.42	10.01	16.79	0.71
2015	3.51	10.26	17.46	0.75
2016	3.59	10.51	18.03	0.78
2017	3.68	10.78	18.61	0.82

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 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. Stanton B will utilize selective catalytic reduction (SCR) to control NO_x emissions.

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.

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 addition of Stanton B satisfies forecast capacity requirements through the summer of 2017 under the base case load forecast. To meet forecast capacity requirements in 2017, it has been assumed that OUC would construct a simple cycle combustion turbine. Under various load forecast sensitivities, the addition of such a unit could be either accelerated or delayed given the relatively short lead time associated with permitting and constructing a simple cycle combustion turbine.

Various discussions related to unit additions and the potential for participation in new nuclear generating additions, if deemed appropriate, have been presented throughout this Ten-Year Site Plan. However, OUC has made no final decisions related to construction of new generation resources, and OUC will continue to evaluate alternative unit additions, including possible participation in new nuclear generating units, through its on-going planning efforts. Therefore, the discussion of future generating unit additions presented in this Ten-Year Site Plan is 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 2008 OUC Ten-Year Site Plan.

Table 12-1 (Schedule 1)
OUC and St. Cloud Existing Generating Facilities as of December 31, 2007

(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	03/2008	2.000	2.000	2.000	2.000
St. Cloud	2	Osceola	IC	NG	PL	DFO	TK	5	12/1974	03/2008	5.000	5.000	5.000	5.000
St. Cloud	3	Osceola	IC	NG	PL	DFO	TK	5	09/1982	03/2008	2.000	2.000	2.000	2.000
St. Cloud	4	Osceola	IC	NG	PL	DFO	TK	5	08/1961	03/2008	3.000	3.000	3.000	3.000
St. Cloud	6	Osceola	IC	NG	PL	DFO	TK	5	03/1967	03/2008	3.000	3.000	3.000	3.000
St. Cloud	7	Osceola	IC	NG	PL	DFO	TK	5	09/1982	03/2008	6.000	6.000	6.000	6.000
St. Cloud[3]	8	Osceola	IC	NG	PL	DFO	TK	5	04/1977	03/2008	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 & 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
2007	451,696	2.56	2,223	176,435	12,599	363	20,230	17,922
Forecast								
2008	459,600	2.55	2,387	180,232	13,244	355	20,614	17,221
2009	472,300	2.55	2,447	185,220	13,211	362	20,946	17,283
2010	486,400	2.55	2,509	190,763	13,152	367	21,293	17,236
2011	501,700	2.55	2,581	196,740	13,119	375	21,633	17,335
2012	518,100	2.55	2,665	203,175	13,117	382	21,975	17,383
2013	535,700	2.55	2,750	210,068	13,091	390	22,332	17,464
2014	554,100	2.55	2,845	217,307	13,092	399	22,707	17,572
2015	573,800	2.55	2,949	225,015	13,106	407	23,098	17,621
2016	594,500	2.55	3,061	233,134	13,130	416	23,500	17,702
2017	615,700	2.55	3,176	241,447	13,154	424	23,905	17,737

[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				Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Consumers
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	GWh	GWh	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
2007	3,434	5,843	587,637	0	54	6	6,079
Forecast							
2008	3,535	5,999	589,265	0	44	15	6,336
2009	3,610	6,141	587,852	0	46	17	6,482
2010	3,682	6,281	586,212	0	47	19	6,624
2011	3,754	6,412	585,465	0	48	21	6,779
2012	3,838	6,544	586,491	0	49	23	6,957
2013	3,928	6,687	587,408	0	50	25	7,143
2014	4,021	6,844	587,522	0	52	27	7,344
2015	4,120	7,013	587,480	0	53	29	7,558
2016	4,217	7,192	586,346	0	55	31	7,780
2017	4,317	7,370	585,753	0	56	33	8,006

[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 & 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	153,377
1998	0	175	4,909	0	158,446
1999	0	199	5,011	0	163,648
2000	0	255	5,291	0	167,785
2001	969	191	6,373	0	172,843
2002	821	208	6,396	0	177,136
2003	920	249	6,682	0	183,121
2004	714	234	6,599	0	190,778
2005	704	219	6,775	0	196,474
2006	18	248	6,250	0	196,474
2007	0	262	6,341	0	202,508
Forecast					
2008	0	295	6,631	0	206,845
2009	0	286	6,767	0	212,307
2010	0	294	6,918	0	218,337
2011	0	304	7,083	0	224,785
2012	0	334	7,291	0	231,694
2013	0	326	7,470	0	239,087
2014	0	337	7,681	0	246,858
2015	0	351	7,909	0	255,126
2016	0	387	8,166	0	263,826
2017	0	376	8,382	0	272,722

(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" data includes GWh sales to entities with which OUC had contractual power sales agreements.

(3) Total No. of Customers includes aggregate of Rural & 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)
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Residential Load Management	Commercial/Industrial 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	1,055
2000	1026	0	1026	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
2007	1,256	0	1,256	0	0	0	0	1,256
Forecast								
2008	1,303	0	1,303	0	0	0	0	1,303
2009	1,329	0	1,329	0	0	0	0	1,329
2010	1,354	0	1,354	0	0	0	0	1,354
2011	1,382	0	1,382	0	0	0	0	1,382
2012	1,414	0	1,414	0	0	0	0	1,414
2013	1,449	0	1,449	0	0	0	0	1,449
2014	1,486	0	1,486	0	0	0	0	1,486
2015	1,526	0	1,526	0	0	0	0	1,526
2016	1,568	0	1,568	0	0	0	0	1,568
2017	1,610	0	1,610	0	0	0	0	1,610

(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, the "Wholesale" data includes MW sales to entities with which OUC had contractual power sales agreements.

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)
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Residential Load Management	Commercial/Industrial Load Management	Conservation	Net Firm Demand
1996/97	851	0	851	0	0	0	0	969
1997/98	814	0	814	1	0	0	0	851
1998/99	1030	0	1030	1	0	0	0	813
1999/00	1,060	0	1,060	1	0	0	0	1,029
2000/01	1,066	0	1,066	1	0	0	0	1,059
2001/02	1,345	302	1,044	1	0	0	0	1,065
2002/03	1,414	277	1,137	1	0	0	0	1,345
2003/04	1,196	241	955	1	0	0	0	1,413
2004/05	1,203	123	1,080	1	0	0	0	1,419
2005/06	1,117	22	1,095	0	0	0	0	1,117
2006/07	951	0	951	0	0	0	0	951
2007/08[4]	1,297	0	1,297	0	0	0	0	1,297
Forecast								
2008/09	1,322	0	1,322	0	0	0	0	1,322
2009/10	1,346	0	1,346	0	0	0	0	1,346
2010/11	1,374	0	1,374	0	0	0	0	1,374
2011/12	1,405	0	1,405	0	0	0	0	1,405
2012/13	1,439	0	1,439	0	0	0	0	1,439
2013/14	1,476	0	1,476	0	0	0	0	1,476
2014/15	1,516	0	1,516	0	0	0	0	1,516
2015/16	1,555	0	1,555	0	0	0	0	1,555
2016/17	1,597	0	1,597	0	0	0	0	1,597
2017/18	1,638	0	1,638	0	0	0	0	1,638

(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, the historical "Wholesale" data includes MW sales to entities with which OUC had contractual power sales agreements.
(4)2007/08 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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total[2]	Conservation	Retail	Wholesale[3]	Utility Use & Losses	Net Energy for Load	Load Factor[4] (%)
1997	4,566	0	4,330	0	236	4,566	53.8%
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	58.7%
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	55.3%
2004	6,599	0	5,651	714	234	6,599	53.3%
2005	6,775	0	5,852	704	219	6,775	54.5%
2006	6,250	0	5,984	18	248	6,250	58.0%
2007	6,341	0	6,079	0	262	6,341	57.6%
Forecast							
2008	6,631	0	6,336	0	295	6,631	58.1%
2009	6,767	0	6,482	0	286	6,767	58.1%
2010	6,918	0	6,624	0	294	6,918	58.3%
2011	7,083	0	6,779	0	304	7,083	58.5%
2012	7,291	0	6,957	0	334	7,291	58.9%
2013	7,470	0	7,143	0	326	7,470	58.8%
2014	7,681	0	7,344	0	337	7,681	59.0%
2015	7,909	0	7,558	0	351	7,909	59.2%
2016	8,166	0	7,780	0	387	8,166	59.5%
2017	8,382	0	8,006	0	376	8,382	59.5%

(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, the historical "Wholesale" data includes GWH sales to entities with which OUC had contractual power sales agreements.
(4)Forecast load factor calculation considers all retail and wholesale peak demand and energy.

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 – 2007[2]		2008 Forecast		2009 Forecast	
Month	Peak Demand[3] MW	NEL GWh	Peak Demand[3] MW	NEL GWh	Peak Demand[3] MW	NEL GWh
January	951	467	1,297	528	1,322	540
February	948	428	1,026	454	1,040	446
March	870	460	935	496	958	507
April	963	472	1,052	510	1,075	511
May	1,104	534	1,179	572	1,204	581
June	1,164	584	1,214	587	1,240	604
July	1,227	634	1,303	654	1,329	657
August	1,256	681	1,237	649	1,263	664
September	1,172	592	1,219	638	1,245	651
October	1,113	572	1,182	578	1,205	609
November	897	450	1,020	474	1,042	496
December	851	467	913	492	935	502

(1)Includes OUC and City of St. Cloud peak demand and NEL.
(2)Actual 2007 Peak Demand may not correspond to Schedule 3.1 due to coincidence issues between OUC native load and City of St. Cloud native load.
(3)Includes Load Management, Conservation and Interruptible Load.

Table 12-9 (Schedule 5.1)
Fuel Requirements[1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2,017
(1)	Nuclear		Trillion BTU	5	6	6	6	5	6	6	6	5	6	6
(2)	Coal		1000 Ton	1,878	1,862	2,004	2,001	1,976	1,988	2,035	2,017	2,026	2,054	2,065
(3)	Residual[2]	Total	1000 BBL	9	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	9	0	0	0	0	0	0	0	0	0	0
(7)	Distillate[3]	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		Steam	1000 BBL	2	0	0	0	0	0	0	0	0	0	0
(9)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	1000 BBL	2	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	19	0	0	0	0	0	0	0	0	0	0
(12)		Steam	1000 MCF	7,083	7,313	6,463	8,151	9,942	10,936	11,862	13,328	14,870	15,589	16,693
(13)		CC	1000 MCF	7,405	8,639	7,787	8,980	10,609	11,486	12,585	14,168	15,795	17,463	18,117
(14)		CT	1000 MCF	303	1,326	1,324	829	667	550	723	841	925	1,875	1,423
(15)	Other		Trillion BTU	1	0	0	0	0	0	0	0	0	0	0

[1] Includes fuel required for OUC and the City of St. Cloud.
[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 start up.

Table 12-10 (Schedule 6.1)
Energy Sources (GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2,017
(1)	Annual Firm Inter-Region Interchange		GWH	0	78	78	77	18	0	0	0	0	0	0
(2)	Nuclear		GWH	521	544	506	484	502	535	520	533	498	497	553
(3)	Residual	Total	GWH	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWH	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
(6)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Total	GWH	1	0	0	0	0	0	0	0	0	0	0
(8)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	1	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWH	1,048	1,128	994	1,184	1,417	1,569	1,696	1,948	2,156	2,339	2,487
(12)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	GWH	1,030	1,035	903	1,128	1,375	1,534	1,649	1,894	2,094	2,203	2,377
(14)		CT	GWH	18	93	91	57	42	35	47	55	62	136	110
(15)	Coal	Steam	GWH	4,771	4,792	5,156	5,147	5,076	5,109	5,245	5,191	5,214	5,291	5,325
(16)	NUG		GWH	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
(18)	Other		GWH	0	90	34	25	70	78	9	9	41	38	16
(19)	Net Energy for Load[1]		GWH	6,341	6,631	6,767	6,919	7,082	7,291	7,470	7,681	7,909	8,166	8,382

[1]Variation in Net Energy for Load between Schedule 3.3 and Schedule 6.1 can be attributed to rounding error.
[2]Includes Net Energy for Load for both OUC and the City of St. Cloud.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
(1)	Annual Firm Inter-Region Interchange		GWH	0.00%	1.17%	1.15%	1.12%	0.25%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	Nuclear		GWH	8.22%	8.20%	7.47%	7.00%	7.08%	7.34%	6.96%	6.93%	6.29%	6.09%	6.60%
(3)	Residual	Total	GWH	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	0.00%	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%
(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%
(7)	Distillate	Total	GWH	0.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(8)		Steam	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWH	0.01%	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%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(12)	Natural Gas	Total	GWH	16.53%	17.01%	14.68%	17.12%	20.01%	21.52%	22.71%	25.37%	27.26%	28.65%	29.68%
(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%
(13)		CC	GWH	16.25%	15.61%	13.34%	16.30%	19.41%	21.04%	22.08%	24.66%	26.47%	26.98%	28.36%
(14)		CT	GWH	0.28%	1.41%	1.35%	0.82%	0.60%	0.48%	0.63%	0.71%	0.79%	1.67%	1.32%
(15)	Coal	Steam	GWH	75.23%	72.26%	76.19%	74.40%	71.67%	70.07%	70.22%	67.58%	65.93%	64.80%	63.53%
(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%
(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%
(18)	Other		GWH	0.00%	1.35%	0.51%	0.37%	0.99%	1.07%	0.12%	0.12%	0.52%	0.47%	0.19%
(19)	Net Energy for Load		GWH	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

(1)Includes Net Energy for Load for both OUC and the City of St. Cloud.

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	%
2008	1,217	337	0	0	1,554	1,303	253	20.46	0	253	20.46
2009	1,217	337	0	0	1,554	1,329	227	17.11	0	227	17.11
2010	1,504	337	0	0	1,841	1,354	489	36.11	0	489	36.11
2011	1,504	337	0	0	1,841	1,382	461	33.35	0	461	33.35
2012	1,512	337	0	0	1,849	1,414	437	30.94	0	437	30.94
2013	1,512	322	0	0	1,849	1,449	402	27.77	0	402	27.77
2014	1,512	322	0	0	1,834	1,486	348	23.43	0	348	23.43
2015	1,512	322	0	0	1,834	1,526	308	20.20	0	308	20.20
2016	1,512	322	0	0	1,834	1,568	266	16.98	0	266	16.98
2017	1,660	322	0	0	1,982	1,609	372	23.12	0	372	23.12

(1)Installed capacity reflects commercial operation of Stanton B (June 2010), OUC's share of the incremental capacity associated with the upgrades of the existing Crystal River and St. Lucie nuclear generating units, and the addition of a simple cycle combustion turbine in June 2017.
(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	%
2008/09	1,275	358	0	0	1,633	1,322	115	23.69	0	115	23.69
2009/10	1,275	358	0	0	1,633	1,346	87	21.49	0	87	21.49
2010/11	1,587	358	0	0	1,945	1,374	367	41.75	0	367	41.75
2011/12	1,590	358	0	0	1,948	1,405	335	38.84	0	335	38.84
2012/13	1,596	343	0	0	1,939	1,439	284	34.74	0	284	34.74
2013/14	1,596	343	0	0	1,939	1,476	241	31.36	0	241	31.36
2014/15	1,596	343	0	0	1,939	1,516	195	27.89	0	195	27.89
2015/16	1,596	343	0	0	1,939	1,555	151	24.68	0	151	24.68
2016/17	1,596	343	0	0	1,939	1,597	102	21.40	0	102	21.40
2017/18	1,773	343	0	0	2,116	1,638	232	29.17	0	232	29.17

(1)Installed capacity reflects commercial operation of Stanton B (June 2010), OUC's share of the incremental capacity associated with the upgrades of the existing Crystal River and St. Lucie nuclear generating units, and the addition of a simple cycle combustion turbine in June 2017.
(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)
				Fuel		Fuel Transport		Construction Start	Commercial In-Service	Expected Retirement	Gross Capability[1]		Net Capability[1]		
Plant Name	Unit No	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	Sum MW	Win MW	Sum MW	Win MW	Status
SEC[1]	B	ORANGE	CC	NG	DFO	PL	TK	8/2008	6/2010	N/A	304	329	287	312	T
Unknown[2]	1	ORANGE	GT	NG	DFO	PL	TK	6/2016	6/2017	N/A	155	185	148	177	OT
ST. CLOUD	1	OSCEOLA	IC	NG	DFO	PL	TK	N/A	N/A	3/2008	-2	-2	-2	-2	RT
ST. CLOUD	2	OSCEOLA	IC	NG	DFO	PL	TK	N/A	N/A	3/2008	-5	-5	-5	-5	RT
ST. CLOUD	3	OSCEOLA	IC	NG	DFO	PL	TK	N/A	N/A	3/2008	-2	-2	-2	-2	RT
ST. CLOUD	4	OSCEOLA	IC	NG	DFO	PL	TK	N/A	N/A	3/2008	-3	-3	-3	-3	RT
ST. CLOUD	6	OSCEOLA	IC	NG	DFO	PL	TK	N/A	N/A	3/2008	-3	-3	-3	-3	RT
ST. CLOUD	7	OSCEOLA	IC	NG	DFO	PL	TK	N/A	N/A	3/2008	-6	-6	-6	-6	RT

(1) Originally proposed to be an integrated gasification combined cycle (IGCC) unit, Stanton B was designed to be able to run as a stand alone natural gas unit with the gasification portion as an alternative fuel source. In 2007, OUC made the decision not to move forward with the gasification portion of Stanton B, and the unit is currently planned to be a 1x1 combined cycle unit operating on natural gas as the primary fuel with the capability to utilize fuel oil as a secondary fuel source.
(2) Not authorized by OUC nor planned for construction. Represents capacity addition to satisfy forecast capacity requirements in this Ten-Year Site Plan.

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

(1)	**Plant Name and Unit Number:**	Stanton Energy Center Unit B [1]	Stanton Energy Center Combustion Turbine [2]
(2)	**Capacity**		
	a. Summer:	287	148
	b. Winter:	321	177
(3)	**Technology Type:**	Combined Cycle	Combustion Turbine
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	Aug-08	Jun-16
	b. Commercial in-service date:	June-10	Jun-17
(5)	**Fuel**		
	a. Primary fuel:	Natural Gas	Natural Gas
	b. Alternate fuel:	Distillate Fuel Oil	Distillate Fuel Oil
(6)	**Air Pollution Control Strategy**	BACT Compliant	Low-NO_x Burners
(7)	**Cooling Method**	Mechanical Draft	N/A
(8)	**Total Site Area**	Approximately 3,200 acres	Approximately 3,200 acres
(9)	**Construction Status**	T	OT
(10)	**Certification Status**	Complete	Not Begun
(11)	**Status with Federal Agencies**	Complete	Not Begun
(12)	**Projected Unit Performance Data**		
	Planned Outage Factor (POF):	3.8	2.7
	Forced Outage Factor (FOF):	3.0	2.0
	Equivalent Availability Factor (EAF):	93	95
	Resulting Capacity Factor (%):	39	2.2
	Average Net Operating Heat Rate (ANOHR):	7,067	10,826
(13)	**Projected Unit Financial Data**		
	Book Life (Years):	30	25
	Total Installed Cost (In-Service Year $/kW):	1,148	820
	Direct Construction Cost ($/kW):	1,063	657
	AFUDC Amount ($/kW):	43	16
	Escalation ($/kW):	42	146
	Fixed O&M ($/kW-Yr) [3]:	5.1	5.2
	Variable O&M ($/MWH)[3]:	5.2	25.9
	K Factor:	N/A	N/A

(1) Originally proposed to be an integrated gasification combined cycle (IGCC) unit, Stanton B was designed to be able to run as a stand alone natural gas unit with the gasification portion as an alternative fuel source. In 2007, OUC made the decision not to move forward with the gasification portion of Stanton B, and the unit is currently planned to be a 1x1 combined cycle unit operating on natural gas as the primary fuel with the capability to utilize fuel oil as a secondary fuel source.
(2) Not authorized by OUC nor planned for construction. Represents capacity addition to satisfy forecast capacity requirements in this Ten-Year Site Plan.
(2) Fixed and variable O&M stated in 2008 dollars.