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April 2, 2009

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

Ms. Cole,

Enclosed please find an original plus 25 copies of the 2009 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). The 2009 OUC TYSP was prepared by Black & Veatch and is being submitted by Black & Veatch on behalf of OUC.

Should you require additional copies of the 2009 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

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The *Reliable* One®

2009 Ten-Year Site Plan
Orlando Utilities Commission

April 2009

B&V Project 164153

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OUC

The *Reliable* One®

2009 Ten-Year Site Plan
Orlando Utilities Commission

B&V File Number
164153

April 2009

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1.0 Executive Summary

This report documents the 2009 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) and the partial requirements power sale to the City of Vero Beach (Vero Beach) into the analyses, as OUC has power supply agreements with St. Cloud and Vero Beach. OUC has assumed responsibility for supplying all of St. Cloud's loads through 2032 and supplementing Vero Beach's loads through 2029 (with provisions for further extension upon contract expiration). 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. The capacity OUC is currently planning on providing to Vero Beach is discussed in Section 2.0.

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. 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 as of January 1, 2009. 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 February 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 February 2010) OUC is not forecasted to require any additional capacity to maintain a 15 percent reserve margin over the 10-year planning horizon considered in this report. It should be noted that four new nuclear generating units have been proposed to and approved by 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). 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.

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, 2009)

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. OUC is currently contractually obligated to supply supplementary power to Vero Beach starting January 1, 2010 under a partial requirements power sales contract. The duration of the contract is twenty years with provisions for further extension upon contract expiration. Under the agreement, OUC will be the exclusive power provider and marketer for Vero Beach. Vero Beach will benefit from OUC's large system and generation fuel diversity to keep rates lower.

For purposes of this 10-Year Site Plan, OUC has assumed the winter and summer capacities presented in Table 2-2 will be provided to Vero Beach. For purposes of reserve margin calculations and capacity planning, OUC is assumed to provide an additional 15 percent reserve margin above the capacities presented in Table 2-2.

Table 2-2
Annual Summer and Winter Peak Capacity (MW) and
Annual Net Energy for Load (GWh) Sold to Vero Beach

Calendar Year	Summer Capacity (MW) (1)	Winter Capacity (MW) (1)	Annual Net Energy for Load (GWh)
2010	63	83	357
2011	64	85	368
2012	66	87	378
2013	70	91	395
2014	73	95	411
2015	75	97	421
2016	77	99	432
2017	79	102	443
2018	82	105	454

(1)Seasonal peak capacity does not include the 15 percent reserves OUC is planning on providing to Vero Beach and represents capacity at time of OUC's seasonal peaks.

2.4 Renewable Generating Technologies

Since 1998, OUC has utilized 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 and Orange County executed a new landfill gas agreement whereby OUC will purchase landfill gas from Orange County's Young Pine Road facility for an initial 30 year term. OUC expects to begin receiving this landfill gas in 2010.

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 promote customer awareness of opportunities to increase the role of renewable energy. 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 blend of local bio-energy (75 percent), local solar energy (20 percent) and purchased wind power (5 percent); or $10.00

for each 200 kWh block of 100 percent solar energy. There is no limit to the number of 200 kWh blocks that a participant may acquire to support funding of additional renewable energy to OUC's portfolio. Participation helps 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, which are available to both residential and commercial customers: These programs include the Solar Photovoltaic (PV) program (which generates electricity) and the 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 customers' solar systems goes back to OUC's electric grid and is credited at the full applicable standard rate.

The solar PV systems are metered in kWh, while the solar thermal systems are metered in British Thermal Units (BTU) and converted to kWh. Participating customers save on normal electric consumption and also receive a monthly credit for the kWh production of the solar systems. The current 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. In 2008, the City of Orlando was designated a "Solar American City" by the US DOE. The ongoing partnership between OUC, City of Orlando and Orange County received $450,000 in funding and technical expertise to help develop solar projects in OUC's community that can be replicated across the country.

In addition, in 2008 OUC committed $1 million toward the Dr. Phillips Orlando Performing Art Center in south downtown. This contribution will help the performing arts center with its green initiatives, specifically energy and water efficiency. With OUC's help, the facility's designers are keeping sustainability in mind and hope to incorporate green features and programs such as solar panels, energy efficient lighting and chilled water for air conditioning.

In 2008, OUC's commitment to efficiency and sustainability was further demonstrated by the completion of Reliable Plaza, OUC's new energy and water efficient center in south downtown which replaces OUC's previous South Orange Avenue home. Reliable Plaza, the "Greenest Building in Downtown Orlando," is designed to meet Gold Leadership in Energy and Environmental Design (LEED) certification. Reliable Plaza showcases a number of environmentally friendly features and uses 28 percent less energy and 40 percent less water than a similarly sized facility. One of the more innovative offerings at Reliable Plaza is the interactive conservation education center. With a live link to the building's conservation systems, the center's touch screen gives customers real time data on how Reliable Plaza uses – and saves – energy and water. The center also can give information on green building ideas and conservation tips customers can use at home.

In 2008, OUC partnered with the Disney Entrepreneur Center for a pilot efficiency program that will offer conservation credits to small businesses that may be experiencing financial difficulties. OUC also began its "Power to Save" campaign, which allowed customers to view OUC conservation and education videos on demand on Bright House Networks. Viewers could access information around the clock and at no cost. The campaign provided access that customers requested and OUC saved money and resources by offering a waste-free alternative to mailing out conservation DVDs. OUC also used digital billboards along major thoroughfares as a low-cost means to deliver conservation messages to commuters in the community.

OUC also continues to play an active role in the local community. During 2008, OUC Conservation Support personnel participated in 46 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, various home owner associations meetings, civic group meetings, Central Florida Hotel & Lodging Association (CFHLA) events, Florida Green Lodging events, Earth Day events, corporate employee events, and various other community events. OUC also helped to educate customers through its commitment to alternative fleet services. Every OUC Conservation

Specialist drives a hybrid vehicle, which is also wrapped. The wrapped hybrid cars help generate discussion between customers and contributes to increased awareness of alternative fuel vehicles within the community.

2.5 Transmission System

OUC's existing transmission system consists of 31 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 2-3. 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 2-4, the St. Cloud transmission system includes three interconnections. OUC's transmission system, including St. Cloud, is shown on Figure 2-1.

The St. Could 69/25 kV Central Substation upgrade project was completed in late 2008 which completely upgraded the sites 25 kV distribution equipment and 69 kV and 25 kV protective relaying. 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.

The upgrade of the Taft-Lakeland 230 kV transmission line from the existing 954 ACSR conductor to 1272 ACSS/TW conductor is in progress. The conductor is be upgraded to increase the power transfer capability of the 230 kV transmission line sections. To date the Osceola Substation to Lake Agnes Substation line section conductor upgrade is complete and work is ongoing on the Taft Substation to Cane Island Tap line section. The Cane Island Tap to Osceola Substation line section conductor upgrade will be beginning construction in late 2009.

Due to increased distribution load in the area adjacent to the Stanton Energy Center the new 115/12.47 kV Stanton North Substation (Sub 35) is being built, three distribution transformers will provide added distribution capacity. The Stanton North Substation will be feed from a new 230/115 kV autotransformer being installed in the 230 kV Stanton Substation which connected to Sub 35 via a short 115 kV transmission line. Sub 35 will also be interconnected to the 115 kV transmission line system by 115 kV transmission line connections to the Pershing Substation and the Indian River Substation. The Stanton North Substation and associated transmission line interconnections will be completed in 2009.

At the Stanton Substation, 25 230 kV power circuit breakers are in the process of being replaced to increase the substation fault withstand capabilities from 44 kA to 63 kA. This project is scheduled to be completed in 2010.

Table 2-3
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 2-4
St. Cloud Transmission Interconnections

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

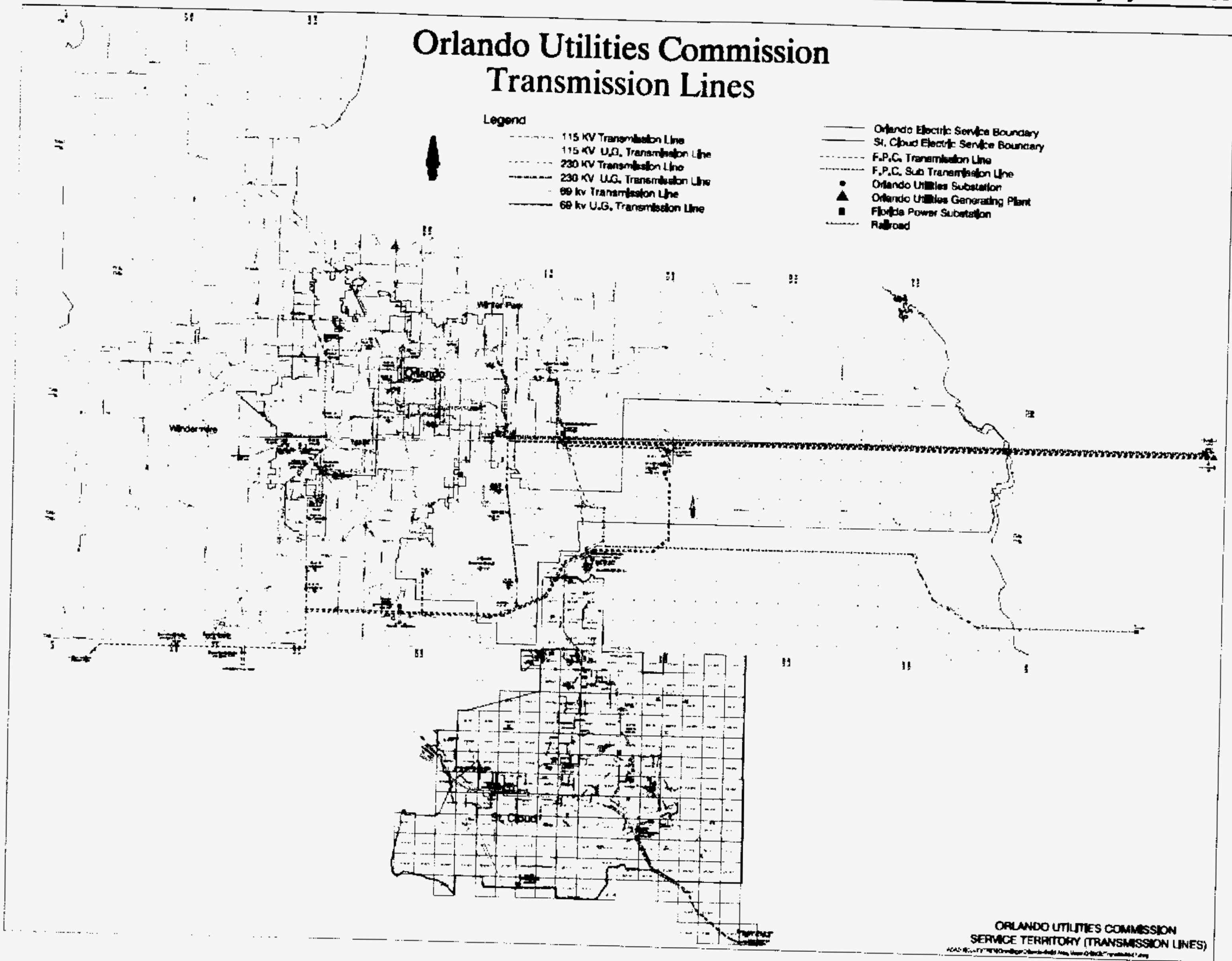

Figure 2-1
OUC Service Area and Transmission System

A new 230 kV transmission line is being added to the 230 kV Stanton Substation that will connect to the new 230 kV Stanton Energy Center Generator B Substation (Sub 36) located on the Stanton Energy Center power plant property. Sub 36 is configured as a collector bus for the new Combustion Turbine Generator and Steam Generator being installed on the Generator B site. The new 230 kV transmission line and Sub 36 are scheduled to be placed in-service in 2009.

A third distribution transformer is in the process of be added to the 230/12.47 kV Lake Nona Substation due to expected distribution load increases in the Lake Nona area. This distribution transformer will be in service in 2009.

The 115/12.47 kV America Substation protective relaying and station power systems are in the process of being completely upgraded to increase system reliability and support modifications to the substation that must be completed to allow for the next phase of the FDOT I-4/408 interchange project. The America upgrade project will be completed in 2010.

A new OUC – Progress Energy 230 kV tie line with terminals located the OUC Stanton Substation and the Progress Energy Bithlo Substation is currently in the permitting phase. Construction on the Stanton Substation line terminal is planned to begin in 2009 and be completed in 2010.

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:

- Continued conceptual permitting and design for the future Stanton South 230 kV 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 115 kV 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.
- 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.
- Addition of several distribution transformer additions to existing substation may be required; load growth will determine when these transformer additions will be required.

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 61 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, 2009)

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. OUC and Orange County executed a new landfill gas agreement whereby OUC will purchase landfill gas from Orange County's Young Pine Road facility for an initial 30 year term. OUC expects to begin receiving this landfill gas in 2010. 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 February 2010.

In 2008 OUC completed a comprehensive Electric Integrated Resource Plan (IRP) performed by the Strategic Planning team. The IRP analyzed OUC's position in the light of current and possible future governmental regulation. The IRP covered all potential resources, including opportunities in energy efficiency, renewable energy, and conventional generation. The report will be a basis for future plans in power production, demand side management, and other business processes.

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 2008, the average annual customer interruption for the combined Orlando-St. Cloud service area was below that of OUC's competition. For the seventh consecutive year, OUC ranked at or near 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. PA Consulting did not present a ReliabilityOne™ Award in the Southeast region in 2008.

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.

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.

In addition, OUC recently entered into a five-year contract for the storage of natural gas to manage price volatility and provide backup fuel for emergency situations. The fuel will provide up to 30,000 MBtu/day to help ensure power reliability.

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[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.

3.5 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.

3.5.1 Emphasis on Sustainability

OUC completed a greenhouse gas inventory for the entire company in 2008. This report was prepared to help OUC analyze how it impacts the environment, detailing both operating emissions and ways to reduce greenhouse gases. The greenhouse gas inventory was only a part of a larger initiative to perform a comprehensive sustainability audit of every department in the company. The goal of this effort is to understand both short-term and long-term opportunities to reduce the corporate carbon footprint in all departments and business functions.

The comprehensive sustainability audit will be completed in 2009 and will serve as a guide to help OUC develop new environmental initiatives.

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 has been 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.

OUC is actively involved in improving local schools. For example, 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.

During 2008, OUC Conservation Support personnel participated in 46 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, various home owner associations meetings, civic group meetings, Central Florida Hotel & Lodging Association (CFHLA) events, Florida Green Lodging events, Earth Day events, corporate employee events, and various other community 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.

Partnering with the Disney Entrepreneurship Center, OUC donated $100,000 in 2008 for a pilot efficiency program that will provide conservation credits to local small businesses that are experiencing financial difficulties. Partnering with St. Cloud, OUC authorized the expenditure of up to $1.3 million to help create a business, technology and research incubator in the Stevens Plantation Corporate Campus. St. Cloud will use the funding to work with the University of Central Florida to attract new businesses to the St. Cloud area.

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. A full-time administrator was hired in 2008 to streamline the application and approval process to help applicants pay their utility bills.

To proactively help customers avoid the inability to pay utility bills, OUC has experimented with programs to reduce hardship. For example, a pilot program was tested using wireless meter monitors to display customer monthly energy usage. These wireless monitors allow communication between OUC and the customer's meter. This program will continue roll-out in 2009 and is expected to track real-time energy usage and potentially reduce energy theft.

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 1998 to 2008. This provides at least 10 years of historical data, with more than enough observations to estimate strong regression models. Once models were estimated, the residential energy requirement in month T was calculated as the product of the customer and average use forecast:

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

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 0.15 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 0.97, with an in-sample MAPE of 2.1 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:

$$\mathbf{Use_{y,m} = Heat_{y,m} + Cool_{y,m} + Other_{y,m}}$$

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

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

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

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

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

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

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

where:

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

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

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

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:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{98}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{98}}\right)^{0.20} \times \left(\frac{Income_{y}}{Income_{98}}\right)^{0.25} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.13}$$

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:

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

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:

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

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:

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

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:

$$OtherUse_{y,m} = \left(\frac{HHSize_y}{HHSize_{98}}\right)^{0.20} \times \left(\frac{Income_y}{Income_{98}}\right)^{0.25} \times \left(\frac{Price_{y,m}}{Price_{98}}\right)^{-0.13}$$

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 41.2 kWh compared to a residential monthly average usage of 1,008 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:

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

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:

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

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

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

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

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

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:

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

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:

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

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 0.93. 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 solid sales gains in this customer class. 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 0.90 with an in-sample MAPE of 3.3 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 0.87 with an MAPE of 5.6 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 1997 to December 2008 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:

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

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 August (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.

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.

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

Year	Total Employment (thousands)	Non-manufacturing Employment (thousands)	Gross Product (billion $)
2010	1,053.4	942.5	83.1
2015	1,193.1	1,064.7	102.1
2020	1,347.4	1,209.4	123.6
2025	1,508.9	1,360.0	146.7
Average Annual Increase			
10-15	2.5%	2.5%	4.2%
15-20	2.5%	2.6%	3.9%
20-25	2.3%	2.4%	3.5%

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

Year	Real Income per Household	Households (thousands)	Population (thousands)
2010	$69,980	810.8	2,111.3
2015	$73,660	930.6	2,385.8
2020	$77,360	1,085.5	2,765.8
2025	$85,770	1,230.0	3,147.2
Average Annual Increase			
10-15	1.0%	2.8%	2.5%
15-20	1.0%	3.1%	3.0%
20-25	1.1%	2.5%	2.6%

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

Year	Real Price (cents/kWh)
2000	5.3
2005	5.5
2010	5.4
2015	5.6
2020	5.7
2025	5.9
Annual Increase	
00-05	0.7%
05-10	-0.3%
10-15	0.7%
15-20	0.3%
20-25	0.7%

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:

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

4.3 Base Case Load Forecast

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

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

Models are estimated using monthly sales data covering the 1998 through 2008 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 1998 through 2008.

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 1997 to December 2008 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.

4.3.1 Base Case Economic Outlook

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. The economic downturn has impacted all of the major rate sectors for both OUC and St. Cloud. Growth has slowed or stalled significantly for all areas of employment. Foreclosures in both service areas have affected the growth of residential usage and customers. OUC will continue to closely monitor the economic impact on sales and customer growth.

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 7,682 GWh by 2025. St. Cloud sales are projected to increase from 343 GWh to 995 GWh over this same time period.

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	1,241	1,115	6,336	58.3%
2015	1,400	1,302	7,150	58.3%
2020	1,583	1,483	8,074	58.2%
2025	1,775	1,673	9,050	58.2%
Average Annual Increase				
10-15	2.4%	2.4%	2.4%	-
15-20	2.5%	2.6%	2.5%	-
20-25	2.3%	2.4%	2.3%	-

4.3.2.1 Residential Forecast. With high electric end-use saturation and projected appliance efficiency-gains, residential average use is projected to remain about flat over the forecast period. Since OUC average residential use is flat, residential sales growth will be driven largely by the addition of new customers. With slow population projections for the region, residential customers are expected to increase at an average annual rate of 1.2 percent for OUC and at 0.7 percent for St. Cloud for the next few years. The ten year residential sales average annual growth rate is 2.4 percent for OUC and 3.7 percent for St. Cloud. 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 0.9 percent and 5.5 percent for OUC and St. Cloud, respectively, between 2010 and 2020. 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 2.9 percent and 3.1 percent, respectively, for OUC and St. Cloud from 2010 through 2020. 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 solid gains as a result of new major developments such as the UCF medical school, Burnham institute, VA hospital, and other related medical businesses coming on line. 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	1,855	337	3,161	43	19	108	5,523
2015	2,104	353	3,526	47	29	112	6,171
2020	2,448	367	3,879	52	39	116	6,901
2025	2,804	386	4,266	57	49	120	7,682
Average Annual Increase							
10-15	2.6%	0.9%	2.2%	1.8%	8.8%	0.7%	2.2%
15-20	31%	0.8%	1.9%	2.0%	6.1%	0.7%	2.3%
20-25	2.8%	1.0%	1.9%	1.9%	4.7%	0.7%	2.2%

Table 4-6
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
2010	153,307	18,835	5,729	177,871
2015	173,685	21,830	6,247	201,762
2020	199,905	24,966	6,913	231,784
2025	224,380	28,342	7,606	260,328
Average Annual Increase				
10-15	2.5%	3.0%	1.7%	2.6%
15-20	2.9%	2.7%	2.0%	2.8%
20-25	2.3%	2.6%	1.9%	2.4%

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

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
2010	393	48	110	4	555
2015	477	66	137	6	686
2020	587	82	163	8	840
2025	697	98	189	11	995
Average Annual Increase					
10-15	4.0%	6.6%	4.5%	8.4%	4.3%
15-20	4.2%	4.4%	3.5%	5.9%	4.1%
20-25	3.5%	3.6%	3.0%	6.6%	3.4%

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

Year	Residential	GS Nondemand	GS Demand	Total Retail
2010	27,768	2,191	225	30,184
2015	33,670	2,557	245	36,472
2020	40,948	2,960	264	44,172
2025	47,701	3,380	282	51,363
Average Annual Increase				
10-15	3.9%	3.1%	1.7%	3.9%
15-20	4.0%	3.0%	1.5%	3.9%
20-25	3.1%	2.7%	1.3%	3.1%

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 economy.com. The high and low forecast scenarios are based on bands around the most likely economy.com population forecast for the Orlando MSA. In the high case scenario, the population is forecasted to increase 3.5 percent on a compounded basis between 2005 and 2025. This is in comparison to the base case population projections of 2.4 percent. The high growth scenario results in a forecasted long-term annual energy growth rate of 3.5 percent, with system peak demand that is 342 MW higher than the base case by 2025. In the low case scenario, energy increases 1.3 percent on a compounded basis through 2025. Peak demand is 296 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	1,091	1,010	5,748
2015	1,222	1,129	6,423
2020	1,371	1,274	7,183
2025	1,528	1,427	7,996
Average Annual Increase			
10-15	2.3%	2.3%	2.2%
15-20	2.3%	2.4%	2.3%
20-25	2.2%	2.3%	2.2%

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	150	145	588
2015	178	173	727
2020	212	209	890
2025	247	246	1,054
Average Annual Increase			
10-15	3.5%	3.6%	4.3%
15-20	3.6%	3.9%	4.1%
20-25	3.1%	3.3%	3.4%

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

Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
High Load Scenario			
2010	1,246	1,162	6,367
2015	1,491	1,389	7,624
2020	1,788	1,681	9,113
2025	2,117	2,005	10,797
Average Annual Increase			
10-15	3.7%	3.6%	3.7%
15-20	3.7%	3.9%	3.6%
20-25	3.4%	3.6%	3.4%
Base Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	1,241	1,155	6,336
2015	1,400	1,302	7,150
2020	1,583	1,483	8,074
2025	1,775	1,673	9,050
Average Annual Increase			
10-15	2.4%	2.4%	2.4%
15-20	2.5%	2.6%	2.5%
20-25	2.3%	2.4%	2.3%
Low Load Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
2010	1,237	1,148	6,305
2015	1,314	1,219	6,701
2020	1,397	1,300	7,117
2025	1,479	1,380	7,536
Average Annual Increase			
10-15	1.2%	1.2%	1.2%
15-20	1.2%	1.3%	1.2%
20-25	1.1%	1.2%	1.2%

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. 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

Several factors continue to contribute to increases in the cost of electricity to consumers, which in turn has led to continued 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 and meet future climate regulations. It should also be noted that the Florida Legislature enacted House Bill 7135, creating the Florida Climate Protection Act, which authorizes the FDEP to adopt rules for cap and trade regulatory program to reduce greenhouse gas emissions (including CO_2) from major emitters (including electric utilities).

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 2008 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 2008 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 2008 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 2008. 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 Customers can implement. 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 around doors; faucets and toilets; and lawn sprinkler systems. OUC provides participating customers specific tips on conserving electricity and water as well as details on customer rebate programs. OUC Conservation Specialists are presently using this walk-through type audit as a means of motivating OUC customers to participate in other conservation programs and qualify for appropriate rebates.

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

One of the primary benefits of the Residential Energy Survey Program is the education it provides to customers on energy conservation measures and ways their lifestyle can directly affect their energy use. Customers participating in the Energy Survey Program are informed about conservation measures that they can implement. Customers will benefit from the increased efficiency in their homes, which will decrease their electric and water bills.

Participation in the Walk-Through Energy Survey has been consistently strong over the past several 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 offers financial incentives \to residential customers who implement efficiency measures including energy-efficient heat pumps, weather stripping, insulation, duct repairs, and 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 and complete 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. 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. To be eligible for this program, the customer's account must be in good credit standing. Measures covered under this program include:

- 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.

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 reduce their living expenses. 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 customers afford other important living expenses.

5.1.4 Residential Financed Insulation Program

This measure is available to OUC residential customers who utilize some type of electric heat and/or air conditioning. To qualify, customers must request and complete 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 $1,000. 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 and above 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. An additional benefit 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. After obtaining the Energy Star certification, OUC will help support the builder's efforts through additional advertising and other promotional strategies.

Gold Ring Homes use less energy than other homes, allowing 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. However, due to the past years' housing crisis, local builder and customer demand for this program has significantly diminished.

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 free survey comprised of a physical walk-through inspection of the commercial facility performed by highly trained and experienced energy experts. The survey will examine heating and air conditioning systems including duct work, refrigeration equipment, lighting, water heating, motors, process equipments, and the thermal characteristics of the building including insulation. Following the inspection 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 also receives 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 2008, 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 (which 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 and poles. 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 or replace 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 electric 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 five chilled water districts: downtown Orlando, the Mall at Millenia, the Starwood Resort, Lake Nona, 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 recently added its 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 thermal storage tank at the Orange County Convention Center is one of the largest in the world. The tank works in tandem with 18 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 in February 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 a contractual power sales contract to supplement Vero Beach's loads starting January 1, 2010. The duration of the agreement is 20 years with provisions for further extension upon contract expiration.

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 36 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 announced final decisions on its compliance strategy for the regulatory requirements under CAIR or mercury emissions regulations, but OUC is prepared to meet strict interpretation of the CAIR requirements. OUC has planned for $150 million to ensure compliance for Stanton Energy Center Units 1 and 2.

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, St. Cloud's load, the supplemental power to be supplied to Vero Beach, and 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 for both winter and summer through 2018, or the end of the planning horizon considered in this Ten-Year Site Plan. These projections consider the impending commercial operation of Stanton B as well as OUC's capacity allocations associated with 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)		Vero Beach PR Power Sale (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]	
2008/09	996	145	0	1,141	1,275	343	312	15	1,633	171	494	323
2009/10	1,010	145	83	1,238	1,275	343	312	15	1,633	186	398	212
2010/11	1,021	148	85	1,254	1,275	343	312	15	1,946	188	694	506
2011/12	1,045	153	87	1,285	1,277	343	312	15	1,948	193	665	472
2012/13	1,071	159	91	1,321	1,283	343	312	0	1,939	198	618	420
2013/14	1,099	166	95	1,360	1,283	343	312	0	1,939	204	579	375
2014/15	1,129	173	97	1,399	1,283	343	312	0	1,939	210	540	330
2015/16	1,159	180	99	1,438	1,283	343	312	0	1,939	216	501	285
2016/17	1,187	187	102	1,476	1,283	343	312	0	1,939	221	463	242
2017/18	1,215	194	105	1,514	1,283	343	312	0	1,939	227	426	199

(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, STC retail peak demand, and capacity sold to Vero Beach.
(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)		Vero Beach PR Capacity Sale (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]	
2009	1,084	148	0	1,232	1,217	322	0	15	1,554	185	324	140
2010	1,091	150	63	1,304	1,217	322	287	15	1,841	196	540	344
2011	1,107	153	64	1,324	1,217	322	287	15	1,841	199	519	320
2012	1,134	158	66	1,358	1,225	322	287	15	1,849	204	493	290
2013	1,162	165	70	1,397	1,225	322	287	0	1,834	210	438	228
2014	1,191	172	73	1,436	1,225	322	287	0	1,834	215	398	183
2015	1,222	178	75	1,475	1,225	322	287	0	1,834	221	359	138
2016	1,251	185	77	1,513	1,225	322	287	0	1,834	227	321	94
2017	1,281	191	79	1,551	1,225	322	287	0	1,834	233	283	50
2018	1,310	198	82	1,590	1,225	322	287	0	1,834	238	245	6

[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, STC retail peak demand, and capacity sold to Vero Beach.
[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 February 2010. As discussed in Section 1.0, OUC has made no commitments to future generating capacity additions beyond Stanton B and is expecting to have adequate capacity to satisfy forecast reserve margin requirements beyond Stanton B throughout the planning horizon considered in this Ten-Year Site Plan. 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. Given that OUC is not expected to add capacity beyond Stanton B, no generating unit alternatives have been characterized in this report.

8.0 Economic Evaluation Criteria and Methodology

This section presents the economic evaluation criteria and methodology used for OUC's 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

OUC uses a weighted average cost of capital for economic evaluations. The weighted average cost of capital is based on the debt/equity ratio (approximately 65/35), the embedded rate for new debt (projected to be 5.5 percent), and the return on equity (approximately 10.3 percent). The resulting weighted average cost of capital is approximately 7.2 percent.

8.1.3 Present Worth Discount Rate

The present worth discount rate is assumed to be equal to OUC's weighted average cost of capital of 7.2 percent.

8.1.4 Interest During Construction Rate

The interest during construction (IDC) rate used by OUC for economic evaluations is 5.5 percent.

8.1.5 Fixed Charge Rate

The fixed charge rate (FCR) represents the sum of a project's fixed charges as a percent of the initial investment cost. When the FCR is applied to the initial investment, the product equals the revenue requirements needed to offset the fixed charges during a given year. A separate FCR can be calculated and applied to each year of an economic analysis, but it is common practice to use a single, levelized FCR that has the same present value as the year-by-year FCR. The FCR calculation includes 0.10 percent for property insurance. Bond issuance fees and insurance costs are not included in the calculation of the levelized FCR, since these are already considered in OUC's embedded debt rate. Assuming a 20 year financing term, the resulting levelized FCR is 9.672 percent. Assuming a 30 year financing term, the resulting levelized FCR is 8.305 percent.

8.2 Fuel Price Forecasts

8.2.1 Coal

Low sulfur Central Appalachian coal fuels the existing Stanton Units 1 and 2. OUC developed projections of delivered coal prices to the Stanton Energy Center based on input provided by Energy Ventures Analysis, Inc. (EVA). The delivered annual price projections for low sulfur Central Appalachian coal delivered to the Stanton Energy Center are presented in Table 8-1.

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. The forecasted price for natural gas delivered to the Indian River and Stanton Energy Center sites is presented in Table 8-1. The gas price includes the Florida Gas Transmission (FGT) Zone 3 basis adder for Henry Hub and fuel loss and usage charges. Firm natural gas transmission costs for existing firm natural gas transportation capacity are not included 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."

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. 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, OUC's current fuel oil price projections are presented in Table 8-1.

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 carried forward from those presented in OUC's 2008 Ten-Year Site Plan and are presented in Table 8-1.

Table 8-1
Delivered Fuel Price Forecasts (Nominal $/MBtu)

Calendar Year	Stanton Energy Center Coal - Delivered	Delivered Natural Gas	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2009	$3.24	$5.59	$10.47	$0.56
2010	$3.37	$6.56	$12.66	$0.59
2011	$3.73	$7.32	$15.07	$0.62
2012	$3.94	$7.96	$15.81	$0.65
2013	$4.03	$8.36	$16.36	$0.68
2014	$4.12	$8.75	$16.93	$0.71
2015	$4.23	$9.19	$17.54	$0.75
2016	$4.35	$9.56	$18.91	$0.78
2017	$4.51	$9.94	$21.80	$0.82
2018	$4.64	$10.31	$22.58	$0.86

8.2.5 Overview of CAIR and CAMR

On May 12, 2005, the EPA published the final CAIR, mandating reductions in SO_2 and NO_x emissions in 28 states (including Florida) 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.

CAIR sought to maintain SO_2 and NO_x emissions within the program caps through the establishment of emissions "budgets." Each affected state expected to receive a proportional distribution of the overall cap for each phase of each program. States could individually choose which sources to regulate, as well as whether to mandate controls or allow participation in the EPA's recommended model cap-and-trade program.

States that chose to participate in the proposed interstate cap-and-trade program could also decide how to allocate allowances from their respective NO_x annual and seasonal budgets. States would then ultimately set forth their chosen measures for achieving compliance with the emission budgets in individual State Implantation Plans (SIPs).

The CAIR SO_2 cap-and-trade program was expected to rely on the existing Acid Rain program allowance allocations. However, the Acid Rain SO_2 allowances would have reduced value, dependent on the allowance vintage year, for use in complying with the CAIR SO_2 cap-and-trade program.

Florida also proposed to join the NO_x annual and ozone season cap-and-trade program. Each state involved with these programs was also required to develop a State Implementation Plan (SIP) to implement the emissions reduction requirements of CAIR. The Florida Department of Environmental Protection (FDEP) was responsible for implementing CAIR in Florida.

Different aspects of CAIR were challenged by multiple litigants, including the State of Florida. In July 2008, the U.S. Court of Appeals for the District of Columbia (DC Circuit) issued a decision vacating the entire rule, which effectively eliminated both the annual and ozone season NO_x programs, as well as the annual CAIR SO_2 program. Subsequently, after reviewing petitions for rehearing, the DC Circuit court essentially reversed its decision to vacate and temporarily reinstated CAIR, allowing it to remain in effect until EPA replaces it with a rule consistent with its July 2008 ruling.

EPA must now promulgate a new CAIR that addresses all the flaws and concerns identified in the DC Circuit court's July ruling, which realistically could take two or more years to finalize. Alternatively, Congress could enact legislation that implements CAIR's proposed SO_2 and NO_X emission reduction programs, but EPA would still likely have to develop rules to implement the new legislative program. In the meantime, affected units in Florida will be subject to the requirements of the initial phase of CAIR that for NO_x emissions began on January 1, 2009, and for SO_2 emissions will begin on January 1, 2010. Accordingly, OUC will now remain subject to the original CAIR rules.

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.

CAMR was challenged, and was vacated by the federal District of Columbia Circuit Court of Appeals in a decision issued February 8, 2008. The DC Circuit court found that 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. Both the EPA and Utility Air Regulatory Group (UARG) appealed this ruling to the full DC Circuit Court, and subsequently to the US Supreme Court. After the change in administrations, EPA withdrew its appeal on February 6, 2009, and the Supreme Court officially declined to hear UARG's appeal on February 23, 2009.

When the rule was finalized in 2005, states were required to enact and adopt laws and rules to implement the CAMR program through State Implementation Plans (SIPs). Although EPA offered model rules to follow, many states adopted different (often more stringent non-trading) programs in developing their individual SIPs. Even though CAMR has now been vacated at the federal level with no chance of reinstatement, many of these states still have their own mercury reduction programs on the books. Florida's Department of Environmental Protection has stated that it will initiate a new rulemaking project to remove provisions related to the federal mercury trading program.

At the federal level, EPA has announced its intention to develop new regulations that impose strict limits on mercury emissions from power plants under a non-trading program. In the meantime, new coal plant projects and modifications to existing coal plants must establish specific mercury emission limits a case-by-case basis.

9.0 Analysis and Results

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 February 2010. Beyond Stanton B, no additional capacity additions are necessary to satisfy OUC's percent reserve margin (summer and winter) criteria over the planning horizon considered in this Ten-Year Site Plan. OUC will continue to evaluate power supply alternatives during the timeframe considered in this Ten-Year Site Plan as well as beyond 2018, and in doing so will evaluate possible participation in new nuclear generating units if deemed appropriate.

For informational purposes, Black & Veatch's POWRPRO was used to obtain the annual production costs associated with various expansion plans (i.e. base case and several load, fuel, and other sensitivities). POWRPRO is a computer-based chronological production costing model developed for use in power supply system planning. POWRPRO simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs include the performance characteristics of generating units, fuel costs, and the system hourly load profile for each year. POWRPRO has been used in numerous Need for Power Applications approved by the Florida Public Service Commission, including FMPA's Treasure Coast Energy Center Unit 1 Need for Power Application (approved in July 2005) and OUC's Stanton Energy Center Unit B Need for Power Application (approved in May 2006).

POWRPRO summarizes each unit's operating characteristics for every year of the planning horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours the unit was on line, the capacity factor, variable O&M costs, and the number of starts and associated costs. Fixed O&M costs are generally considered sunk costs that will not vary from one expansion plan to another and were therefore not included for existing units. The annual capacity charges for the Stanton A and the TECO Partial Requirements purchase power agreements likewise were not included, as they also represent sunk costs. Similarly, fixed costs for firm natural gas transportation capacity from FGT for existing firm natural gas transportation capacity are considered sunk costs and are not included. The operating costs of each unit are aggregated to determine annual operating costs for each year of the expansion plan.

The cumulative present worth cost (CPWC) calculations presented in this section account for annual system costs (i.e. fuel and energy, non-fuel variable O&M, and startup costs) for each year of the expansion planning period and discounts each back to 2009 at the present worth discount rate of 7.2 percent. These annual present worth costs are then summed over the 2009 through 2018 period to calculate the total CPWC of the expansion plan being considered. Such analysis allows for a comparison of CPWC between various capacity expansion plans across the sensitivities considered

9.1 CPWC Analyses

9.1.1 Base Case Analysis

The base case considers the base load forecast presented in Section 4 and the base fuel price forecasts presented in Section 8 of this Ten-Year Site Plan. The CPWC for OUC's base case expansion plan is approximately $2.26 billion.

9.1.2 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 sensitivities that OUC may consider in its planning processes are high and low fuel prices, high and low load and energy growth projections, a case in which the differential between natural gas and coal price projections is held constant over time, and ahigh present worth discount rate case. 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, the constant differential fuel price, and the high present worth discount rate sensitivities.

9.1.2.1 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 2016. The capacity expansion plan under the high load forecast sensitivity scenario includes the addition of a 7FA simple cycle combustion turbine for operation in May 2016, followed by the addition of a second 7FA simple cycle combustion turbine for operation in May 2018. The CPWC for OUC's high load forecast sensitivity is approximately $2.45 billion.

9.1.2.2 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. The CPWC for OUC's low load forecast sensitivity is approximately $2.14 billion.

9.1.2.3 High Natural Gas and Coal Price Forecast Sensitivity. OUC developed high natural gas price forecasts, and high coal price forecasts were developed by increasing the delivered coal price forecasts presented in Section 8.0 by 15 percent. The 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 fuel oil and nuclear fuel price forecasts presented in Section 8 have not been changed for this sensitivity.

As in the base case analysis, the capacity expansion plan under the high natural gas and coal price forecast sensitivity does not include any capacity additions beyond Stanton B. The CPWC for OUC's high natural gas and coal price forecast sensitivity is approximately $2.83 billion.

9.1.2.4 Low Natural Gas and Coal Price Forecast Sensitivity. OUC developed low natural gas price forecasts, and low coal price forecasts were developed by decreasing the 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 fuel oil and nuclear fuel price forecasts presented in Section 8.0 have not been changed for this sensitivity.

As in the base case analysis, the capacity expansion plan under the high natural gas and coal price forecast sensitivity does not include any capacity additions beyond Stanton B. The CPWC for OUC's high natural gas and coal price forecast sensitivity is approximately $1.80 billion.

9.1.2.5 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 2009 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 2009 natural gas and coal price forecasts to convert from real to nominal dollars. The fuel oil and nuclear fuel price forecasts presented in Section 8.0 have not been changed for this sensitivity.

As in the base case analysis, the capacity expansion plan under the constant differential natural gas and coal price forecast sensitivity does not include any capacity additions beyond Stanton B. The CPWC for OUC's high natural gas and coal price forecast sensitivity is approximately $2.00 billion.

9.1.2.6 High Present Worth Discount Rate Sensitivity. The high present worth discount rate sensitivity assumes a 10 percent present worth discount rate instead of the 7.2 percent present worth discount rate used in the other economic analyses discussed in this section. As in the base case analysis, the capacity expansion plan under the high present worth discount sensitivity does not include any capacity additions beyond Stanton B. The CPWC for OUC's high natural gas and coal price forecast sensitivity is approximately $2.01 billion.

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

Calendar Year	Stanton Energy Center Coal - Delivered	Delivered Natural Gas	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2009	$3.73	$8.43	$10.47	$0.56
2010	$3.87	$9.04	$12.66	$0.59
2011	$4.29	$11.38	$15.07	$0.62
2012	$4.53	$12.23	$15.81	$0.65
2013	$4.63	$12.77	$16.36	$0.68
2014	$4.73	$13.31	$16.93	$0.71
2015	$4.87	$14.20	$17.54	$0.75
2016	$5.00	$15.30	$18.91	$0.78
2017	$5.19	$16.61	$21.80	$0.82
2018	$5.34	$17.77	$22.58	$0.86

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

Calendar Year	Stanton Energy Center Coal - Delivered	Delivered Natural Gas	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2009	$2.59	$4.01	$10.47	$0.56
2010	$2.70	$4.35	$12.66	$0.59
2011	$2.98	$4.88	$15.07	$0.62
2012	$3.15	$5.00	$15.81	$0.65
2013	$3.22	$5.34	$16.36	$0.68
2014	$3.29	$5.78	$16.93	$0.71
2015	$3.39	$6.27	$17.54	$0.75
2016	$3.48	$6.63	$18.91	$0.78
2017	$3.61	$7.05	$21.80	$0.82
2018	$3.71	$7.31	$22.58	$0.86

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

Calendar Year	Stanton Energy Center Coal - Delivered	Delivered Natural Gas	Ultra-Low Sulfur Diesel (0.0015% sulfur)	Nuclear
2009	$3.24	$5.59	$10.47	$0.56
2010	$3.32	$5.73	$12.66	$0.59
2011	$3.41	$5.87	$15.07	$0.62
2012	$3.49	$6.02	$15.81	$0.65
2013	$3.58	$6.17	$16.36	$0.68
2014	$3.67	$6.33	$16.93	$0.71
2015	$3.76	$6.48	$17.54	$0.75
2016	$3.85	$6.65	$18.91	$0.78
2017	$3.95	$6.81	$21.80	$0.82
2018	$4.05	$6.98	$22.58	$0.86

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 February 2010. The addition of Stanton B satisfies forecast capacity requirements through the ten year planning horizon considered in this Ten-Year Site Plan under the base case load forecast. Under the high load forecast sensitivity, for purposes of this Ten-Year Site Plan it has been assumed that simple cycle combustion turbines would be installed as needed to maintain the 15 percent reserve margin.

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 beyond Stanton B, 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 2009 OUC Ten-Year Site Plan.

Table 12-1 (Schedule 1)
OUC and St. Cloud Existing Generating Facilities as of December 31, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
				Primary Fuel		Alternate Fuel					Gross Capability[1]		Net Capability[1]	
Plant Name	Unit No.	Location	Unit Type	Fuel Type	Transport Method	Fuel Type	Transport Method	Alt Fuel Storage (Days Burn)	Commercial. In-Service MM/YYYY	Expected 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	23.4
Indian River	B	Brevard	GT	NG	PL	DFO	TK	0.2	07/1989	Unknown	18.30	23.50	18	23.4
Indian River	C	Brevard	GT	NG	PL	DFO	TK	0.2	08/1992	Unknown	86.10	101.10	85.3	100.3
Indian River	D	Brevard	GT	NG	PL	DFO	TK	0.2	10/1992	Unknown	86.10	101.10	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	RR	NA	UN	UN	07/1987	Unknown	320.13	322.19	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	RR	NA	UN	UN	06/1996	Unknown	351.70	351.70	319.3	319.3
Stanton Energy Center	A	Orange	CC	NG	PL	DFO	TK	3	10/2001	Unknown	180.60	198.00	173.6	184.8
McIntosh	3	Polk	ST	BIT	REF	NA	UN	UN	09/1982	Unknown	146.00	146.00	133	136
Crystal River	3	Citrus	ST	NUC	TK	NA	UN	UN	03/1977	Unknown	14.03	14.27	13	13
St. Lucie[2]	2	St. Lucie	ST	NUC	TK	NA	UN	UN	08/1983	Unknown	54.20	54.20	51	52

(1)Reflects capability to serve OUC and St. Cloud.
(2)Reliability exchange divides 50% power from Unit 1 and 50% power from Unit 2.

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
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
2008	457,897	2.55	2,269	179,785	12,622	395	20,463	19,283
Forecast								
2009	454,121	2.55	2,303	178,282	12,917	388	20,973	18,523
2010	459,752	2.55	2,320	180,524	12,854	399	21,242	18,776
2011	467,012	2.55	2,352	183,384	12,826	403	21,790	18,481
2012	480,387	2.55	2,433	188,610	12,898	409	22,624	18,089
2013	494,938	2.55	2,508	194,340	12,905	417	23,381	17,843
2014	509,828	2.55	2,584	200,178	12,910	425	24,036	17,695
2015	524,984	2.55	2,662	206,138	12,914	434	24,657	17,589
2016	541,507	2.55	2,746	212,638	12,914	440	25,336	17,347
2017	558,259	2.55	2,833	219,225	12,924	446	26,052	17,107
2018	575,341	2.55	2,925	225,912	12,949	452	26,793	16,862

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

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	General Service Demand						
Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
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
2008	3,390	5,961	568,659	0	45	17	6,115
Forecast							
2009	3,374	6,070	555,897	2	46	17	6,128
2010	3,401	5,958	570,783	3	48	19	6,187
2011	3,457	5,982	577,865	4	49	21	6,282
2012	3,543	6,111	579,715	5	51	23	6,459
2013	3,625	6,240	580,930	6	52	25	6,628
2014	3,710	6,356	583,780	7	54	27	6,801
2015	3,805	6,464	588,645	8	55	29	6,986
2016	3,883	6,588	589,437	9	57	31	7,157
2017	3,962	6,721	589,498	10	58	33	7,333
2018	4,037	6,857	588,712	11	60	36	7,510

[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)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale[2] GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers[3]
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
2008	0	150	6,265	0	206,209
Forecast					
2009	0	147	6,275	0	205,325
2010	357	148	6,692	0	207,724
2011	368	150	6,801	0	211,157
2012	378	156	6,993	0	217,345
2013	395	157	7,180	0	223,961
2014	411	162	7,374	0	230,570
2015	421	165	7,572	0	237,259
2016	432	172	7,762	0	244,562
2017	443	175	7,950	0	251,998
2018	454	194	8,158	0	259,562

(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
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
2008	1,221	0	1,221	0	0	0	0	1,221
Forecast								
2009	1,232	0	1,232	0	0	0	0	1,232
2010	1,304	63	1,241	0	0	0	0	1,304
2011	1,324	64	1,260	0	0	0	0	1,324
2012	1,358	66	1,292	0	0	0	0	1,358
2013	1,397	70	1,327	0	0	0	0	1,397
2014	1,436	73	1,363	0	0	0	0	1,436
2015	1,475	75	1,400	0	0	0	0	1,475
2016	1,513	77	1,436	0	0	0	0	1,513
2017	1,551	79	1,472	0	0	0	0	1,551
2018	1,590	82	1,508	0	0	0	0	1,590

(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)
					Residential	Commercial/Industrial		
Year	Total[2]	Wholesale[3]	Retail	Interruptible	Load Management	Load Management	Conservation	Net Firm Demand
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	1,297	0	1,297	0	0	0	0	1,297
2008/09[4]	1,141	0	1,141	0	0	0	0	1,141
Forecast								
2009/10	1,238	83	1,155	0	0	0	0	1,238
2010/11	1,254	85	1,169	0	0	0	0	1,254
2011/12	1,285	87	1,198	0	0	0	0	1,285
2012/13	1,321	91	1,230	0	0	0	0	1,321
2013/14	1,360	95	1,265	0	0	0	0	1,360
2014/15	1,399	97	1,302	0	0	0	0	1,399
2015/16	1,438	99	1,339	0	0	0	0	1,438
2016/17	1,476	102	1,374	0	0	0	0	1,476
2017/18	1,514	105	1,409	0	0	0	0	1,514

[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]2008/09 is a forecast as actual information was not available at time of publication.

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

(1) Year	(2) Total[2]	(3) Conservation	(4) Retail	(5) Wholesale[3]	(6) Utility Use & Losses	(7) Net Energy for Load	(8) Load Factor[4] (%)
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%
2008	6,265	0	6,115	0	150	6,265	58.6%
Forecast							
2009	6,275	0	6,128	0	147	6,275	58.1%
2010	6,692	0	6,187	357	148	6,692	58.6%
2011	6,801	0	6,282	368	150	6,801	58.6%
2012	6,993	0	6,459	378	156	6,993	58.8%
2013	7,180	0	6,628	395	157	7,180	58.7%
2014	7,374	0	6,801	411	162	7,374	58.6%
2015	7,572	0	6,986	421	165	7,572	58.6%
2016	7,762	0	7,157	432	172	7,762	58.6%
2017	7,950	0	7,333	443	175	7,950	58.5%
2018	8,158	0	7,510	454	194	8,158	58.6%

(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 – 2008[2]		2009 Forecast		2010 Forecast	
Month	Peak Demand[3] MW	NEL GWh	Peak Demand[3] MW	NEL GWh	Peak Demand[3, 4] MW	NEL GWh[4]
January	1,104	474	1,141	469	1,155	473
February	890	435	964	425	971	428
March	882	459	914	453	918	458
April	948	478	974	470	979	476
May	1,083	570	1,051	534	1,052	540
June	1,182	593	1,144	584	1,149	589
July	1,195	607	1,209	631	1,216	636
August	1,221	623	1,232	649	1,241	655
September	1,153	593	1,180	595	1,188	599
October	1,052	529	1,110	544	1,121	543
November	922	450	997	454	1,008	462
December	895	456	939	469	949	476

(1)Includes OUC and City of St. Cloud peak demand and NEL.
(2) NEL may not correspond to Schedule 3.3 due to rounding.
(3)Includes Load Management, Conservation and Interruptible Load.
(4)Does not include MW and NEL to be supplied to Vero Beach in 2010.

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 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Nuclear		Trillion BTU	6	6	6	5	6	6	6	6	6	6	6
(2)	Coal		1000 Ton	2,060	2,068	2,114	2,144	2,177	2,193	2,204	2,218	2,249	2,263	2,279
(3)	Residual[2]	Total	1000 BBL	0	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	0	0	0	0	0	0	0	0	0	0	0
(7)	Distillate[3]	Total	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
(8)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	1000 BBL	1	0	0	0	0	0	0	0	0	0	0
(10)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	4,496	3,644	5,331	5,679	5,974	7,155	8,680	9,720	10,475	11,811	12,717
(12)		Steam	1000 MCF	9	0	0	0	0	0	0	0	0	0	0
(13)		CC	1000 MCF	4,239	3,231	5,134	5,482	5,661	6,795	8,271	9,159	9,928	11,183	12,049
(14)		CT	1000 MCF	247	412	197	198	313	360	410	560	547	629	668
(15)	Other		Trillion BTU	0	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 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	Annual Firm Inter-Region Interchange		GWH	0	78	78	77	18	0	0	0	0	0	0
(2)	Nuclear		GWH	475	518	522	494	561	557	508	538	538	508	538
(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	620	453	696	748	781	933	1,142	1,275	1,376	1,555	1,676
(12)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	GWH	603	421	683	734	759	908	1,112	1,233	1,336	1,508	1,626
(14)		CT	GWH	17	31	14	13	23	25	30	42	40	47	51
(15)	Coal	Steam	GWH	5,109	5,230	5,395	5,481	5,571	5,630	5,660	5,693	5,778	5,819	5,859
(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	Landfill Gas and Purchases	GWH	61	74	80	78	82	61	63	64	62	63	62
(19)	Net Energy for Load(1)		GWH	6,266	6,276	6,693	6,801	6,995	7,181	7,373	7,570	7,755	7,945	8,136

(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 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(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	7.58%	8.26%	7.79%	7.26%	8.02%	7.76%	6.89%	7.11%	6.94%	6.39%	6.61%
(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	0.01%	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	9.90%	7.21%	10.40%	11.00%	11.17%	12.99%	15.49%	16.84%	17.75%	19.57%	20.60%
(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	9.62%	6.71%	10.20%	10.80%	10.85%	12.64%	15.08%	16.29%	17.23%	18.98%	19.98%
(14)		CT	GWH	0.28%	0.50%	0.20%	0.20%	0.32%	0.35%	0.40%	0.55%	0.52%	0.59%	0.62%
(15)	Coal	Steam	GWH	81.54%	83.34%	80.61%	80.59%	79.64%	78.40%	76.77%	75.21%	74.51%	73.24%	72.02%
(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	Landfill Gas and Purchases	GWH	0.98%	1.19%	1.19%	1.15%	1.17%	0.85%	0.86%	0.84%	0.80%	0.80%	0.76%
(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	%
2009	1,217	337	0	0	1,554	1,232	324	26.3%	0	324	26.3%
2010	1,504	337	0	0	1,841	1,304	540	41.4%	0	540	41.4%
2011	1,504	337	0	0	1,841	1,324	519	39.2%	0	519	39.2%
2012	1,512	337	0	0	1,849	1,358	493	36.3%	0	493	36.3%
2013	1,512	322	0	0	1,834	1,397	438	31.3%	0	438	31.3%
2014	1,512	322	0	0	1,834	1,436	398	27.7%	0	398	27.7%
2015	1,512	322	0	0	1,834	1,475	359	24.4%	0	359	24.4%
2016	1,512	322	0	0	1,834	1,513	321	21.2%	0	321	21.2%
2017	1,512	322	0	0	1,834	1,551	283	18.2%	0	283	18.2%
2018	1,512	322	0	0	1,834	1,590	245	15.4%	0	245	15.4%

(1) Installed capacity reflects commercial operation of Stanton B (February 2010) and OUC's share of the incremental capacity associated with the upgrades of the existing Crystal River and St. Lucie nuclear generating units.
(2) Firm capacity imports include capacity purchased from TECO and capacity purchased from Southern Company-Florida, LLC (from Stanton A).
(3) OUC has no Firm Capacity Export, as supplemental power sale to Vero Beach is included in System Firm Peak Demand. (4) Includes OUC peak demand and City of St. Cloud peak demand.
(4) Includes OUC peak demand, City of St. Cloud peak demand, and capacity to be provided to Vero Beach.
(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. Also includes reserves associated with supplemental power sale to Vero Beach.
(6) Reserve margin percentages are calculated as the sum of Total Installed Capacity and Firm Capacity Import (plus an additional 15% of the TECO purchase) minus the sum of System Firm Peak Demand and Firm Capacity Export, all divided by the sum of System Firm Peak Demand and Firm Capacity Export.

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	1,141	494	43.3%	0	494	43.3%
2009/10	1,275	358	0	0	1,633	1,238	398	32.1%	0	398	32.1%
2010/11	1,588	358	0	0	1,946	1,254	694	55.3%	0	694	55.3%
2011/12	1,590	358	0	0	1,948	1,285	665	51.7%	0	665	51.7%
2012/13	1,596	343	0	0	1,939	1,321	618	46.8%	0	618	46.8%
2013/14	1,596	343	0	0	1,939	1,360	579	42.6%	0	579	42.6%
2014/15	1,596	343	0	0	1,939	1,399	540	38.6%	0	540	38.6%
2015/16	1,596	343	0	0	1,939	1,438	501	34.8%	0	501	34.8%
2016/17	1,596	343	0	0	1,939	1,476	463	31.4%	0	463	31.4%
2017/18	1,596	343	0	0	1,939	1,514	426	28.1%	0	426	28.1%

(1) Installed capacity reflects commercial operation of Stanton B (February 2010) and OUC's share of the incremental capacity associated with the upgrades of the existing Crystal River and St. Lucie nuclear generating units.
(2) Firm capacity imports include capacity purchased from TECO and capacity purchased from Southern Company-Florida, LLC (from Stanton A).
(3) OUC has no Firm Capacity Export, as supplemental power sale to Vero Beach is included in System Firm Peak Demand. (4) Includes OUC peak demand and City of St. Cloud peak demand.
(4) Includes OUC peak demand, City of St. Cloud peak demand, and capacity to be provided to Vero Beach.
(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. Also includes reserves associated with supplemental power sale to Vero Beach.
(6) Reserve margin percentages are calculated as the sum of Total Installed Capacity and Firm Capacity Import (plus an additional 15% of the TECO purchase) minus the sum of System Firm Peak Demand and Firm Capacity Export, all divided by the sum of System Firm Peak Demand and Firm Capacity Export.

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	10/2007	2/2010	N/A	304	329	287	312	V

[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.

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]
(2)	**Capacity**	
	a. Summer:	287
	b. Winter:	321
(3)	**Technology Type:**	Combined Cycle
(4)	**Anticipated Construction Timing**	
	a. Field construction start-date:	Oct-07
	b. Commercial in-service date:	Feb-10
(5)	**Fuel**	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	Distillate Fuel Oil
(6)	**Air Pollution Control Strategy**	BACT Compliant
(7)	**Cooling Method**	Mechanical Draft
(8)	**Total Site Area**	Approximately 3,200 acres
(9)	**Construction Status**	V
(10)	**Certification Status**	Complete
(11)	**Status with Federal Agencies**	Complete
(12)	**Projected Unit Performance Data**	
	Planned Outage Factor (POF):	3.8
	Forced Outage Factor (FOF):	3.0
	Equivalent Availability Factor (EAF):	93
	Resulting Capacity Factor (%):	39
	Average Net Operating Heat Rate (ANOHR):	7,067
(13)	**Projected Unit Financial Data**	
	Book Life (Years):	30
	Total Installed Cost (In-Service Year $/kW):	1,148
	Direct Construction Cost ($/kW):	1,063
	AFUDC Amount ($/kW):	43
	Escalation ($/kW):	42
	Fixed O&M ($/kW-Yr) [2]:	5.1
	Variable O&M ($/MWH)[2]:	5.2
	K Factor:	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. All data for Stanton B is consistent with data presented in 2008 Ten-Year Site Plan, with the exception of construction start date and commercial in-service date, which have both been updated.
[2] Fixed and variable O&M stated in 2008 dollars.