



The Reliable One®

2003 Ten-Year Site Plan

Orlando Utilities Commission

April 2003

DOCUMENT NUMBER-DATE

03049 APR-18

FPSC-COMMISSION CLERK



ORIGINAL

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March 28, 2003

Mr. Michael Haff
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Michael,

Enclosed please find thirty (30) copies of the 2003 Orlando Utilities Commission (OUC) Ten-Year Site Plan (TYSP). Pursuant to your email dated March 11, 2003, all copies of the TYSP are being sent directly to you for distribution to the appropriate state agencies, cities and counties, water management districts, and regional planning councils.

Should you require additional copies of the OUC 2003 TYSP, or have any other questions regarding the Plan, please do not hesitate to contact me at (913) 458-7432.

Very truly yours,

Myron Rollins

Enclosure[s]

AUS	_____
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**2003 Ten-Year Site Plan
Orlando Utilities Commission**

**B&V File Number
133813.0040**

April 2003



11401 Lamar, Overland Park, Kansas 66211

(913) 458-2000

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1.0 Executive Summary

This report documents the 2003 Orlando Utilities Commission (OUC) Ten-Year Site Plan pursuant to Section 186.801 Florida Statutes and Section 25-17.0852 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule, and consists of nine main 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)
- Development of Supply-Side Alternatives (Section 7.0)
- Analysis, Results, and Conclusions (Section 8.0)
- Environmental and Land Use Information (Section 9.0)
- Ten-Year Site Plan Schedules (Section 10.0)

This Plan also integrates the power sales, purchases, and loads for the City of St. Cloud into the OUC Plan.

OUC is a member of the Florida Municipal Power Pool (FMPP) which consists of OUC, Lakeland Electric (Lakeland), Kissimmee Utility Authority (KUA), and the Florida Municipal Power Agency (FMPA) All-Requirements Project. Power for OUC is supplied by OUC jointly owned generation and power purchases. The total installed generating capacity based on OUC's ownership share (including the generating units owned by the City of St. Cloud) is 1,092 MW winter and 1,047 MW summer as of January 1, 2003. The existing supply system has a broad range of generation technology and fuel diversity, with coal providing the largest portion of OUC's energy requirements.

In 1999, OUC sold the Indian River Steam Units to Reliant. As part of the agreement with Reliant, OUC received a power purchase agreement (PPA) through September 30, 2003 with an extension option for up to four additional years.

Load forecasts for OUC and the City of St. Cloud have been integrated into one forecast and details are provided in Section 4.0. A banded forecast is provided with base case growth, high growth, and low growth scenarios. This analysis, considering the forecasted growth, existing units, retiring units, purchase power contracts, and reserve margin requirements, indicates an initial need for additional capacity beginning in the summer of 2008.

Final site certification for Stanton A was issued September 18, 2001. Construction began in November 2001 on Stanton A, a 633 MW combined cycle unit to

be built at Stanton Energy Center with an October 1, 2003 commercial operation date. Stanton A will be jointly owned by OUC, KUA, FMPA and Southern Company – Florida LLC (Southern-Florida), with OUC owning 28 percent, KUA and FMPA each owning 3.5 percent, and Southern-Florida owning the remaining 65 percent of Stanton A capacity.

OUC, KUA, and FMPA will purchase all of Southern-Florida's capacity in Stanton A pursuant to an executed PPA for ten years, although the utilities retain the right to reduce the capacity purchased from Southern-Florida by 50 MW each year, beginning in the sixth year of the PPA, as long as the total reduction in capacity purchased does not exceed 200 MW. Additionally, OUC, KUA, and FMPA have options to purchase all of Southern-Florida's capacity for an additional 20 years. Considerations of the Stanton A PPA as they impact the analysis of the Ten-Year Site Plan are presented in more detail in Section 2.2.

Three alternative power plant technologies including combustion turbines, combined cycles, and coal units were considered for capacity additions. The alternatives were modeled in Black & Veatch's POWROPT and POWRPRO optimal generation expansion and chronological production costing programs to rank the expansion plans according to total cumulative present worth costs over a ten-year planning period. Several sensitivity analyses were performed to determine their impact on the least-cost alternatives as well. Based on the detailed modeling of the OUC system, the forecast of electrical demand and energy, the forecast of fuel prices and availability, and environmental considerations, Table 1-1 presents the least-cost capacity expansion plan for the base case.

Table 1-1
OUC Least-Cost Base Case Expansion Plan¹

Year	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$166,490	\$166,490
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$203,711	\$355,111
2005	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$208,144	\$533,561
2006		\$193,337 ²	\$687,038
2007	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$207,896	\$839,848
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$218,098	\$988,282
2009		\$236,184	\$1,137,118
2010	40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$241,865	\$1,278,243
2011	156 MW GE 7FA Simple Cycle CT (06/01/2011)	\$259,056	\$1,418,203
2012		\$283,028	\$1,559,788

1. Capacity is stated at average annual temperature for OUC.

2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

2.0 Utility System Description

2.1 OUC Structure

At the turn of the twentieth century, John M. Cheney, an Orlando judge, organized the Orlando Water and Light Company and supplied electricity on a part-time basis with a 100 kilowatt generator. Twenty-four hour service began in 1903. The City's population 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 \$97,500 bond issue to enable the citizens of Orlando to purchase and municipally operate his privately owned utilities. The bond issue carried almost three to one, as did a subsequent issue for additional improvements. The citizens of Orlando took over Cheney's company and its 2,795 electricity customers and 5,000 water customers for a total initial investment of \$1.5 million.

In 1923, the Orlando Utilities Commission (OUC) was created by an act of the State Legislature and full authority was granted to OUC to operate the plant as a municipal utility. The business was a paying venture from the start, and by 1924, the number of customers had more than doubled and OUC contributed \$53,000 to the City. When Orlando citizens took over operations of their utility, the 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 in 1926 an additional \$111,000 was transferred. One outside private utility offered \$3 million to purchase the utility in 1928.

Between 1928 and 1931 there was a great deal of talk both for and against the sale of the utility. On August 18, 1931, an election was held and the people voted 1,033 to 140 not to sell the utility; 1,030 to 160 not to mortgage the utility, 744 to 436 not to issue tax notes; and 919 to 158 not to lease the utility. However, the question as to whether or not Orlando's utility should remain under municipal ownership did not end with the vote of the people in 1931. A year later a \$5 million offer was made for the plant, \$2 million more than the actual physical value at the time.

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 of Orlando. OUC has the full authority over the management and control of the electric and water works plants in the City of Orlando 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, and water production, transmission and distribution systems in order to meet the requirements of its customers.

In 1997, OUC entered an Interlocal Agreement with the City of St. Cloud in which OUC took over 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 took over management of St. Cloud's existing generating units and purchase power contracts.

OUC's electric system consisted of a year-end average of 148,556 active services for 2001. Of these, 128,314 are residential services, 15,648 are general service non-demand services, and the remaining 4,594 are general service demand services. St. Cloud's service area consisted of a year-end average of 19,261 active services for 2001.

2.2 Generation System

OUC presently has ownership interests in the following five electric generating plants, which are further described below. Table 2-1 summarizes OUC's generating facilities.

- Indian River Plant Combustion Turbine Units A, B, C, and D.
- Stanton Energy Center Units 1 and 2.
- Florida Power Corporation Crystal River Unit 3 Nuclear Generating Facility.
- Lakeland Electric McIntosh Unit 3.
- Florida Power and Light Company 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 Stanton 1 and 2 and the necessary supporting facilities. Stanton 1 was placed in commercial operation on July 1, 1987, followed by Stanton 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 requirement standards for SO₂, NO_x, and particulates. Stanton 1 is a 444 MW net coal-fired facility, of which OUC has a 68.6 percent ownership share providing 302 MW of capacity to the OUC system. Stanton 2 is a 446 MW net coal-fired generating facility, of which OUC maintains a 71.6 percent (319 MW) ownership share.

The Indian River Plant is located four 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 and as part of the sale, OUC has signed a power purchase agreement (PPA) with Reliant, the details of which are presented in Section 2.3. The combustion turbine units are primarily fueled by natural gas, with No. 2 fuel oil as an

Table 2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel		Fuel Transport		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability ¹	
				Pri	Alt	Pri	Alt				Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	FO2	PL	TK	06/89	Unknown	41.400	18	23.4
Indian River	B	Brevard	GT	NG	FO2	PL	TK	07/89	Unknown	41.400	18	23.4
Indian River	C	Brevard	GT	NG	FO2	PL	TK	08/92	Unknown	122.040	85.3	100.3
Indian River	D	Brevard	GT	NG	FO2	PL	TK	10/92	Unknown	122.040	85.3	100.3
Stanton Energy Center	1	Orange	ST	BIT	---	RR	---	07/87	Unknown	464.580	301.6	303.7
Stanton Energy Center	2	Orange	ST	BIT	---	RR	---	06/96	Unknown	464.580	319.3	319.3
McIntosh	3	Polk	ST	BIT	REF	RR	TK	09/82	Unknown	363.870	133	136
Crystal River	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	890.460	13	13
St. Lucie ²	2	St. Lucie	NP	UR	---	TK	---	06/83	Unknown	839.000	51	52
St. Cloud ³	1	Osceola	IC	NG	FO2	PL	TK	07/82	11/04	2.000	2	1.825
	2		IC	NG	FO2	PL	TK	12/74	11/04	5.850	5.85	5
	3		IC	NG	FO2	PL	TK	09/82	11/04	2.000	2	1.825
	4		IC	NG	FO2	PL	TK	08/61	11/04	3.750	3	3
	6		IC	NG	FO2	PL	TK	03/67	11/04	3.750	3	3
	7		IC	NG	FO2	PL	TK	09/82	11/04	6.300	6	6
	8		IC	NG	FO2	PL	TK	04/77	11/04	6.445	6	6

1. OUC ownership share.
2. OUC owns St. Lucie Unit No. 2. Reliability exchange divides 50 percent power from Unit No. 1 and 50 percent power from Unit No. 2.
3. St. Cloud No. 8 has never been connected to the grid and, therefore, OUC receives no capacity from this unit. St. Cloud owns the units, but OUC controls their operation.

alternative. OUC has a partial ownership share of 48.8 percent, or 36 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent (170 MW) in Indian River Units C and D.

Crystal River Unit 3 is an 835 MW net nuclear generating facility operated by the 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 fuel burning capability and also is capable of burning up to 20 percent petroleum coke. For purposes of the Ten-Year Site Plan analyses, it is assumed that McIntosh Unit 3 will burn coal priced identical to that used for Stanton 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 net 853 MW nuclear generating facility operated by the Florida Power and Light Company. OUC maintains 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 from St. Lucie Unit 1 and half provided by St. Lucie Unit 2.

As part of the Interlocal Agreement with St. Cloud, OUC has operating control of St. Cloud's seven internal combustion generating units, which have a total summer rating of 27.85 MW. One of the seven St. Cloud internal combustion generating units (Unit 8) has never been connected to the grid, so the resulting net summer generating capacity from St. Cloud's internal combustion units is 21.85 MW. All of the St. Cloud units are scheduled to retire in November 2004.

OUC has entered into an agreement with KUA, FMPA, and Southern-Florida for the construction and ownership of Stanton A, a 633 MW combined cycle unit currently under construction at the Stanton Energy Center with a planned commercial operation date of October 1, 2003. Final site certification for Stanton A was issued September 18, 2001, with construction commencing in November 2001. OUC, KUA, FMPA will be joint owners of Stanton A with OUC maintaining a 28 percent ownership share, KUA and FMPA each maintaining 3.5 percent ownership shares, and Southern-Florida maintaining the remaining 65 percent of Stanton A's capacity.

Stanton A will be a 2x1 combined cycle utilizing General Electric combustion turbines. Stanton A will be dual fueled with natural gas as the primary fuel and No. 2 oil as the backup fuel. Stanton A will use evaporative coolers, duct burning, and power augmentation for additional output during peak periods and will use treated sewage effluent for cooling water.

OUC, KUA and FMPA will purchase all of Southern-Florida's capacity under an executed PPA for 10 years with options to purchase all of Southern-Florida's capacity for

an additional 20 years. Under the initial contract, OUC is scheduled to purchase 80 percent of Southern-Florida's ownership of Stanton A, with KUA and FMPA each purchasing equal shares of the remaining capacity. However, beginning on the first day of the sixth year of the PPA, OUC, KUA, and FMPA may elect to reduce the amount of capacity purchased from Southern-Florida by a total of 50 MW per year. This reduction in capacity is available to the utilities in years six through ten of the PPA, although the total reduction in capacity between the three utilities may not exceed 200 MW. Given the fact that OUC will be purchasing 80 percent of the Stanton A capacity owned by Southern-Florida, it has been assumed that OUC can elect to reduce its capacity allocations as described above in 40 MW increments (i.e. 80 percent of 50 MW), with the total reduction not to exceed 160 MW.

2.3 Purchase Power Resources

As part of the sale of the Indian River steam units, OUC entered into a power purchase agreement with Reliant (Reliant Agreement) for capacity and energy from the Indian River steam units. The term of the Reliant Agreement extends through September 30, 2003 and the cost of the capacity and energy is based on a demand and energy charge. The energy charge is based on a fixed heat rate and a specified split of natural gas and oil for fuel.

OUC also has an option to extend the Reliant Agreement an additional four years beyond September 30, 2003. Through September 30, 2003, OUC will be purchasing the maximum amount available from the Reliant PPA (577.5 MW), and has elected to purchase various amounts during fiscal years 2004, 2005, 2006, and 2007. The maximum capacity available to OUC through the extension option with Reliant is 500 MW per year. The 500 MW can be reduced in 100 MW increments annually over the duration of the four-year option term through proper notice from OUC, but cannot increase from the previous year.

Additionally, St. Cloud has a Partial Requirements (PR) contract with Tampa Electric Company (TECO). As a result of the Interlocal Agreement with St. Cloud, OUC schedules the TECO PR purchase. The annual capacities associated with the Reliant Agreement and St. Cloud's TECO power purchase agreements are summarized in Table 2-2.

As shown in Table 2-3, OUC is also planning to purchase capacity from KUA's entitlement in Stanton A during the first three years of the unit's commercial operation.

Table 2-2 Power Purchase Agreements		
Company	Capacity	Duration
TECO PR	15 MW	Through 12/31/2012
Reliant	577.5 MW	10/01/2001 - 09/30/2003
Reliant	500 MW	10/01/2003 - 09/30/2004
Reliant	300 MW	10/01/2004 - 09/30/2005
Reliant	100 MW	10/01/2005 - 09/30/2007

Table 2-3 KUA Stanton A Capacity Purchased By OUC	
Duration	MW ¹
10/1/2003 - 9/30/2004	28
10/1/2004 - 9/30/2005	18
10/1/2005 - 9/30/2006	8
¹ Source: OUC Power Marketing.	

2.4 Power Sales Contracts

OUC is contractually obligated to supply power to a number of different purchasers for various durations of time. These power sales contracts are classified as either unit power sales or system power sales.

2.4.1 Unit Power Sales.

OUC has two separate unit power sales contracts in place with FMFA. The first of these contracts has been in place since May 1, 1986, and expires December 31, 2006. The capacity is available from the Indian River Plant and can be provided by OUC's other units if the capacity is available. The second such contract with FMFA has been in place since January 1, 1989, and is scheduled to expire December 31, 2003. This contract is based on providing power from the unit with the highest fuel cost operating on OUC's system at the time that energy is scheduled.

Additionally, OUC has had a unit power sales contract with Seminole Electric Cooperative (SEC) since January 1, 1996, which will expire May 31, 2004. The SEC unit power sale is from the Indian River Steam Units and the Indian River Combustion Turbines.

2.4.2 System Power Sales.

OUC has had a system power sales contract in place with KUA since January 1, 1989, which will expire December 31, 2003. Included in the power sale contract with

KUA is the understanding and agreement by and between OUC and KUA that OUC will provide power to KUA except when doing so would require OUC to curtail its native retail loads, other firm system sales agreements which were in place prior to the contract with KUA, and long-term unit power commitments to other utilities from units owned by OUC.

In addition to the system power sale contract with KUA, OUC has been involved in a partial requirements power sales contract with Reedy Creek Improvement District (RCID) since January 1, 1999. The RCID partial requirements contract expires December 31, 2005.

2.5 Transmission System

OUC's existing transmission system consists of 27 substations interconnected through approximately 310 miles of 230 kV and 115 kV lines and cables. OUC is fully integrated into the state transmission grid through its thirteen 230 kV interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 2-4. Additionally, OUC is now responsible for approximately 50 miles of St. Cloud's transmission system, including the 69 kV interconnection from St. Cloud's Central Substation to KUA's Carl Wall Substation, and a 230 kV interconnection from St. Cloud's East Substation to Florida Power Corporation's (FPC) Holopaw Substation. OUC's transmission system, including St. Cloud, is shown in Figure 2-1.

Table 2-4 OUC Transmission Interconnections		
Utility	kV	Number of Interconnections
FPL (2 circuits)	230	1
FPC	230	6
KUA	230	2
KUA/FMPA	230	1
Lakeland	230	1
TECO	230	1
TECO/RCID	230	1
FPL - Florida Power & Light FPC - Florida Power Corporation KUA - Kissimmee Utility Authority TECO - Tampa Electric Company RCID - Reedy Creek Improvement District FMPA - Florida Municipal Power Agency		

The 69 kV interconnection with FPC at the Magnolia Ranch substation was completed in June 2002, and in January 2003 the addition of the Grant to Robinson 115 kV transmission line was completed. To maintain reliable and economic service, OUC has developed the following schedule of upgrades:

- Addition of circuit breakers on the Stanton 230 kV bus effectively splitting the bus and providing available fault current and line loading relief. Completion will be prior to Stanton A coming on-line.
- 230 kV interconnection with FPC at OUC's Metrowest substation in summer of 2004.
- Addition of St. Cloud South substation and associated 69 kV transmission lines including an upgrade of the 69 kV line from KUA to the City of St. Cloud. Expected completion is summer 2005.

2.6 Service Area

OUC's service area encompasses approximately 394 square miles. This estimate includes the City of St. Cloud service area, which is served under a partnership formed in 1997. This 25-year agreement is precedent setting, as OUC has become the first municipal electric utility in the state to manage, operate, and maintain another municipal utility. The OUC service area, including St. Cloud, is shown in Figure 2-1.

3.0 Strategic Issues

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

3.1 Strategic Business Units

As the entire electric utility industry faces deregulation, OUC is aggressively developing strategies to be competitive in a deregulated environment. One strategy already implemented is to reorganize OUC into the following strategic business units, which are described below.

- Power Resource Business Unit
- Energy Delivery Business Unit

3.1.1 *Power Resources Business Unit.*

The Power Resources Business Unit (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 and the addition of new units and power purchase agreements.

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 more than 70 percent of the generating capacity either owned 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 on Schedule 1 of Section 10.

Plant Name	Winter Capacity				Summer Capacity			
	Coal	Nuclear	Gas/Oil	Total	Coal	Nuclear	Gas/Oil	Total
Stanton	623			623	621			621
Indian River			247	247			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	62	247	1,071	754	64	207	1,025
Total (percent)	70.87	6.07	23.06	100	73.56	6.24	20.20	100

Another example of OUC's commitment to fuel diversity is the use of alternative fuels, such as refuse derived fuel (RDF) at the McIntosh Unit 3 facility. The plant is designed to burn a mixture of RDF and coal. OUC's use of alternative or renewable fuels is further enhanced by burning a mixture of petroleum coke in McIntosh Unit 3, along with coal and RDF. Petroleum coke is a waste by-product of the refining industry and in addition to the benefits of using a waste product, petroleum coke's lower price results in significant savings over coal. Tests have been done that indicate the unit has the ability to use petroleum coke for approximately 20 percent of the fuel input. Permits have been modified and approved for this level of use and petroleum coke is being burned in the unit.

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

OUC's diversified mix of generating units provides protection against disruption of supply while simultaneously providing economic opportunities to reduce cost to customers. The ability to burn a variety of fuels is enhanced through the Indian River purchase power agreement, which utilizes a specified proportion of natural gas and oil which can be adjusted annually.

3.1.2 Energy Delivery Business Unit.

OUC's Energy Delivery Business Unit (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 is being phased out with the anticipated creation of a regional independent transmission organization.

OUC's leadership in providing reliable electric distribution service is demonstrated by its commitment to making initial investments in high quality material and equipment. Additionally, nearly 50 percent of OUC's distribution system is underground, protecting it from trees and high winds. OUC's dependability is also attributable to its proactive maintenance programs to identify and correct potential problems, proactive replacement of old equipment, and a tree trimming program that minimizes tree-related service disruptions. OUC's reliability is demonstrated by the fact that during 2002, the average annual customer interruption for the combined Orlando-St. Cloud service area was below 42 minutes. Through recent years, OUC's average customer interruption has decreased annually.

OUC's reputation for reliability has been enhanced by recognition outside of the State of Florida. PA Consulting Group, a leading management and technology consulting firm, named OUC the most reliable utility in the Southeast. The award was bestowed upon OUC based on an audit of OUC's power-restoration and reliability data.

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. Through a four-year PPA, Indian River steam generation units will continue to provide power to OUC while excess power generated by the plant will be sold by Reliant to other utilities. With the proceeds of the sale and by purchasing power, OUC is better able to diversify its generation portfolio and better take advantage of changing market conditions. The sale offers OUC the ability to replace the less competitive oil and gas steam units with more competitive combined cycle generation, as well as providing the alternative of purchasing power when it is more economical for OUC customers.

3.3 Florida Municipal Power Pool

In 1988, OUC joined with Lakeland Electric and the Florida Municipal Power Agency's (FMPA) All-Requirements Project members to form the Florida Municipal Power Pool (FMPP). Later, Kissimmee Utility Authority (KUA) joined FMPP. Through 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 one 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 thirteen 230 kV interconnections with other Florida utilities, including six interconnections with Florida Power Corporation (FPC), three with Kissimmee Utility Authority (KUA), and one each with Florida Power and Light (FPL), Tampa Electric Company (TECO), Reedy Creek Improvement District (RCID), and Lakeland Electric. In addition to enhancing reliability, these interconnections also facilitate the marketing of electric energy by OUC to and from other electric utilities in Florida. Through its agreement with St. Cloud, OUC is also now responsible for St. Cloud's 230 kV interconnection to FPC and 69 kV interconnection to KUA.

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.

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 low heat rate.

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 con-

sidered to be 20 times worse than carbon dioxide in terms of possible global warming effects. Both Stanton units have the capability of burning methane.

In addition to its commitment to clean air, OUC is also equally committed to minimizing the environmental and aesthetic impacts on land used for and adjacent to new construction projects. In planning the new transmission line to link Stanton and St. Cloud, OUC employed the best management practices in route selection and design. OUC used low-impact construction and clearing techniques to further minimize the environmental and aesthetic impacts of the project. As a result, the state required no additional mitigation measures.

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 Division 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.

OUC is also pursuing programs demonstrating alternate fuels for transportation. OUC has purchased two minivans which have been retrofitted with battery powered motors. They will be used in the normal daily activities of OUC's Conservation and Office Services Divisions. One of the vehicles is also equipped with solar photovoltaic panels on the roof to power cooling fans. The vehicles are powered by 10 large gel cell batteries and 27 horsepower, high torque drive motors. OUC purchased these vehicles to learn as much as possible about their operating and recharge characteristics and to demonstrate the new technology to customers. OUC has also donated two vehicles to the University of Central Florida's Alternate Fuels Research Program for purposes of conducting research on alternative fuel sources for transportation.

3.6 Community Relations

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

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

Each year, OUC lends a helping hand to charities and civic organizations across Central Florida. In its quest to make a difference, OUC provided financial support as well as in-kind donations and many volunteer hours to organizations such as the March of Dimes, American Cancer Society, Junior Achievement, Adult Literacy League, Daily Bread, UCF Shakespeare Festival, and the Heart of Florida United Way. Since September 2001, OUC has contributed \$200,000 to Project Care, an OUC program that provides emergency utility bill assistance. Additionally, OUC raised \$25,000 for the Women's Residential and Counseling Center, a program operated by the Coalition for the Homeless of Central Florida.

4.0 Forecast of Peak Demand and Energy Consumption

OUC has retained Regional Economic Research, Inc. (RER) to develop forecasts of peak demand and energy consumption. The forecast scope was to develop a sales forecast for OUC budgeting and financial planning process. The objective was thus to develop a forecast model that could be used successfully for forecasting both short and long-term energy and peak demand. The events of September 11, 2001 and the subsequent national economic slowdown have impacted the tourist-related aspects of this forecast.

4.1 Forecast Methodology

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

The difficulty of end-use modeling is that end-use 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. Further, given that there is little to no retail natural gas in the OUC service territory, end-use modeling would add little in terms of accounting for 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 a Statistically Adjusted Engineering (SAE) model, entails specifying end-use variables (heating, cooling, and base use) and utilizing these variables in sales regression models. While the SAE approach loses some end-use detail, it performs well forecasting short-term energy requirements, and it provides reasonable structure for forecasting energy requirements over the long-term.

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 are estimated over the period encompassing 1992 to 2000. This provides nine years of historical data, with more than enough observations to estimate strong regression models. Once models are estimated, the residential energy requirements in month T is calculated as the product of the customer and average use forecast:

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

4.1.1.1 Residential Customer Forecast. The number of customers is forecasted as a simple function of household projections for the Orlando Metropolitan Statistical Area (MSA). Models were estimated using MSA-level data, as 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 has an adjusted R² of 0.998 with an in-sample Mean Absolute Percent Error (MAPE) of 0.4 percent. For St. Cloud, the model performance is not as strong, given the “noise” in the historical monthly billing data. The adjusted R² is 0.57 with an in-sample MAPE of 4.7 percent. Given that St. Cloud is a relatively small part of OUC’s service territory, the 4.7 percent average customer forecast error represents a relatively small number of total system customers. Combined, the average model error (the Mean Absolute Deviation) is about 1,100 customers. The combined error is less than 1 percent.

4.1.1.2 Average Use Forecast. To incorporate end-use structure into the residential sales model, average use is disaggregated into its primary end-use components - heating, cooling, and base-use requirements:

$$\text{Average Use}_t = \text{Heat}_t + \text{Cooling}_t + \text{BaseUse}_t$$

Each end use is defined in terms of both an appliance index variable, which indicates relative saturation and efficiency of the existing stock, and a utilization variable, which reflects how the stock is utilized. The end-use variables are defined as:

$$\text{Cooling}_t = \text{CoolIndex}_t * \text{CoolUse}_t$$

$$\text{Heating}_t = \text{HeatIndex}_t * \text{HeatUse}_t$$

$$\text{BaseUse}_t = \text{BaseIndex}_t * \text{OtherUse}_t$$

4.1.1.3 End-Use Index Variables. The end-use index variables (*CoolIndex*, *HeatIndex*, and *BaseIndex*) are designed to capture both increases in appliance saturation and changes in the relative efficiency of the stock.

The indices are calculated as the ratio of the appliance saturation to average efficiency of the existing appliance stock. To generate a relative index, the ratio is divided by the estimated value for 1995. Thus, the index has a value of 1.0 in 1995. The indices are defined as:

$$CoolIndex_t = (CoolSat_t / CoolEff_t) / (CoolSat_{1995} / CoolEff_{1995})$$

$$HeatIndex_t = (HeatSat_t / HeatEff_t) / (HeatSat_{1995} / HeatEff_{1995})$$

$$BaseIndex_t = (BaseSat_t / BaseEff_t) / (HeatSat_{1995} / CoolEff_{1995})$$

OUC appliance saturation surveys from 1990 and 1994 were used to develop the indices. Appliance saturation and efficiency trends were projected using the EPRI REEPS (Residential End-Use Planning System) model. The projections are based on OUC saturation estimates and price projections, and on national default appliance stock age distribution, efficiency characteristics, and future efficiency standards.

Given that there is little residential gas availability in the OUC service territory, the saturation of electric space heat was over 80 percent in 1994. Similarly, given the heat and humidity in Orlando, there is nearly a 98 percent saturation of air conditioning. OUC is already starting out with an appliance stock that is highly sensitive to variation in weather conditions. For heating, while the saturation trend continues to increase, the overall index actually declines over the forecast period, as less efficient heating technologies (electric furnace and room heating) are replaced with more efficient heat pumps. Similarly, residential cooling load resulting from increases in central air conditioning saturation is largely mitigated by expected heat pump and central air conditioning efficiency gains. The overall cooling index is relatively flat throughout the forecast period. The implication of these index trends is that, despite a high saturation of electric heat and cooling, residential average use should be less sensitive to changes in temperature through the forecast period, with increasing end-use efficiency slowing residential average use growth. Improvements in efficiency of nonweather-sensitive appliances (including refrigerators, ranges, washers, and dryers) also help to mitigate residential electricity growth.

4.1.1.4 Utilization Variables. The utilization variables (*CoolUse_t*, *HeatUse_t*, and *BaseUse_t*) are designed to capture energy demand driven by use of the appliance stock (the end-use index variables). The utilization drivers include:

- Weather conditions (as captured by heating and cooling degree days).
- Electricity prices.
- Household income.
- Household size.

The typical modeling approach is simply to specify an average use model with the variables above on the “right-hand side” of the regression model. Due to multicollinearity, however, it is often impossible to isolate the impact of one variable on average use from the impact of another variable. This is because the variables are moving in the same direction – household income is increasing while price and household size are declining. While generally not a problem in a short-term forecast (the price impact will often be simply ignored), it is desirable to capture how changes in these variables impact the forecast over the longer term. To allow each of these drivers to impact usage, elasticities for the driver variables are imposed during the construction of the utilization variables. The utilization variables are defined as:

$$\begin{aligned}CoolUse_t &= (Price_t^{-.20}) * (Inc_per_HH_t^{.20}) * (HH_Size_t^{0.25}) * CDD \\HeatUse_t &= (Price_t^{-.20}) * (Inc_per_HH_t^{.20}) * (HH_Size_t^{0.25}) * HDD \\OtherUse_t &= (Price_t^{-.20}) * (Inc_per_HH_t^{.15}) * (HH_Size_t^{0.20})\end{aligned}$$

In this functional form, the values shown in the specifications are, in effect, elasticities. The elasticities give the percent change in utilization (*CoolUse*, *HeatUse*, and *BaseUse*) given a 1 percent change in the forecast drivers - price, household income, and household size. The elasticities imposed are relatively small, but reasonable. Changes in price, household income, and household size will have a small, but reasonable, impact on changes in the utilization variables. Over the historical period, heating and cooling use are dominated by month-to-month variation in cooling and heating degree days (CDD and HDD).

4.1.1.5 Estimate Models. To estimate the forecast models, monthly average residential usage is regressed on *Cooling*, *Heating*, and *BaseUse*. Lagged *Use* variables are also included in the specification because the *Use* 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 proved to work extremely well in the regression models. For OUC, the residential adjusted R^2 is 0.95 with an in-sample MAPE of less than 4 percent. The standard error of the regression model is 48.75 kWh compared with residential monthly average usage of 1,067 kWh. All the model coefficients are highly significant (exhibiting P-values less than 0.09). The St. Cloud model explains slightly less of the variation in average use, with an adjusted R^2 of 0.93 and an in-sample MAPE of 4.3 percent. 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.

4.1.2.1 GSND Models. The GSND models are developed along lines similar to the residential forecast with the GSND monthly energy demand calculated as:

$$GSND_T = GSND \text{ Average Use}_T * GSND \text{ Customers}_T$$

4.1.2.1.1 GSND Customers. GSND customers are forecasted using a simple regression model that relates GSND customers to Orlando MSA nonmanufacturing employment projections. An AR1 correction term was added to the specification to correct for serial correlation. The OUC customer model was estimated using monthly customer counts for the period October 1990 through 2001. For OUC, the overall model adjusted R^2 is 0.995 with an in-sample MAPE of 0.21 percent. Again, the customer model for St. Cloud did not perform as well due to significant “noise” in the month-to-month variation in customer counts. The adjusted R^2 is 0.67, with an in-sample MAPE of 4.63 percent. An AR1 correction was added to the St. Cloud model to help account for month-to-month swings in customer counts. The model coefficients in both the OUC and St. Cloud models are all highly significant.

A similar SAE modeling approach is used in specifying the GSND average use model. Where average GSND use is defined as:

$$\text{Average Use}_t = \text{Heating}_t + \text{Cooling}_t + \text{BaseUse}_t$$

Cooling, *Heating*, and *BaseUse* are defined as the product of an end-use stock index and utilization variable:

$$\text{Cooling}_t = \text{CoolIndex}_t * \text{CoolUse}_t$$

$$\text{Heating}_t = \text{HeatIndex}_t * \text{HeatUse}_t$$

$$\text{BaseUse}_t = \text{BaseIndex}_t * \text{OtherUse}_t$$

4.1.2.1.2 Nonresidential End-Use Index Variables. For the Nonresidential models, saturation and efficiency trends are accounted for by the change in annual energy intensities (kWh per square foot) over the forecast horizon. Energy intensity estimates are derived using the EPRI COMMEND model. The national default COMMEND model was modified to reflect OUC heating and cooling saturation estimates and long-term electric price forecasts. The commercial building type mix in the OUC/St. Cloud service territory is assumed to look like that of the national default model. In the OUC service territory, the base-year electric heating saturation is nearly 80 percent, and cooling saturation is 100 percent. The high electric saturation again reflects limited natural gas alternatives. The index is calculated using 1995 as the base year:

$$\text{Index}_t = \text{Energy Intensity}_t / \text{Energy Intensity}_{95}$$

With 100 percent saturation and constant real electricity prices over the long term, annual cooling intensities (i.e., use per square foot) are relatively flat and thus affect the Cooling Index very little over the forecast horizon. Similarly, the Other Use Index shows relatively slow growth through the forecast period. The heating index increases through 2010, as electric heat saturation continues to gain the remaining market share; however, as there are relatively few days of actual commercial heating (utilization of the heating stock) the heating index has relatively little impact on overall GSND average use.

4.1.2.1.3 GSND Usage Variables. The usage variables (*CoolUse*, *HeatUse*, and *OtherUse*) are designed to capture GSND end-use utilization. Where household size and income are the primary economic variables used in driving residential utilization, employment and output are used to drive nonresidential utilization. The Use variables are defined as:

$$\text{CoolUse} = (\text{Price}^{-.20}) * (\text{Output per Employee}^{.20}) * (\text{CDD})$$

$$\text{HeatUse} = (\text{Price}^{-.20}) * (\text{Output per Employee}^{.20}) * (\text{HDD})$$

$$\text{OtherUse} = (\text{Price}^{-.20}) * (\text{Output per Employee}^{.20})$$

The assumed utilization elasticities are relatively small, but reasonable. The price elasticity is set at -0.20; a 1 percent decrease in price causes a 0.2 percent increase in the use variables. Similarly the productivity elasticity is set at 0.2 percent; a 1 percent increase in productivity leads to a 0.2 percent increase in the end-use utilization.

The *Use* variables are multiplied by the *Index* variables to generate *Cooling*, *Heating*, and *BaseUse*. Since 1992, GSND average use for OUC has actually been declining. This is largely because GSND customers tend to be larger (when compared with St. Cloud), and they are typically migrated to the GSD classification as soon as customers exceed the GSND usage limit. To account for the downward trend, a trend variable interactive with the *BaseUse* is incorporated into the average use specification; the variable has a negative sign and is highly significant. All the GSND model variables are highly significant. The adjusted R² for the OUC GSND average use model is 0.99 with an in-sample MAPE of 3.1 percent. For St. Cloud the GSND average use model has an adjusted R² of 0.89, with an in-sample MAPE of 4.5 percent.

4.1.2.2 GSD Models. The general service demand class represents the largest nonresidential customer class. Over the last five years, OUC has seen the strongest sales gains in the GSD customer class, with GSD sales growth averaging 4.5 percent for the combined OUC and St. Cloud service territories. While overall sales growth will slow significantly over the forecast period, GSD sales are expected to continue to show relatively strong sales growth through the forecast horizon.

Because the GSD class represents such a diverse customer base, an aggregate sales model is used in place of an average use model. Again, end-use variable concepts are incorporated into the model specification where:

$$\text{GSD Sales}_t = f(\text{BaseUse}_t, \text{CoolUse}_t, \text{and HeatUse}_t)$$

Where

$$\text{Cooling}_t = \text{CoolIndex}_t * (\text{Price}_t^{-.20}) * (\text{GSP}_t^{.20}) * \text{CDD}_t$$

$$\text{Heating}_t = \text{HeatIndex}_t * (\text{Price}_t^{-.20}) * (\text{GSP}_t^{.20}) * \text{HDD}_t$$

$$\text{BaseUse}_t = \text{BaseIndex}_t * (\text{Price}_t^{-.20}) * (\text{GSP}_t^{.20}) * \text{HDD}_t$$

The index variables are the same as those used in estimating the GSND model. GSP, or Gross "State" Product, is the total economic output in the Orlando MSA. (GSP is the term used to describe total economic output at the state level. However, the nomenclature is kept the same at the MSA level for consistency.)

In the OUC model, the end-use variables are all highly significant (except for the lagged heating variable). The adjusted R^2 is 0.93 with an in-sample MAPE of 2.8 percent. In the St. Cloud model, all the variables except the heating end-use variables are highly significant. The adjusted R^2 is 0.84 with a MAPE of 4.7 percent. The low t-statistics on the heating variables indicate that there is relatively little electric space heating in the GSD class.

In 1999, GSD saw a significant jump in sales as a result of the opening of Universal Studios' *Islands of Adventure*, which is expected to continue contributing strong growth to the GSD rate class. While the large load increase in 1999 is partially captured by the regression model with a binary variable (*Aug99_Later*), it is impossible to capture future large incremental load additions that cannot be directly related to regional output data. Expected near-term sales growth from *Islands of Adventure* and other large development projects are added to the GSD statistical baseline forecast. Exogenous load adjustments include the airport expansion, the new convention center, and the continued expansion at Universal Studios.

4.1.2.2.1 Street Lighting Sales. Street lighting sales are forecasted using a simple trend model. It is assumed that street lighting sales will continue to increase at the rate experienced over the last 7 years. The forecast also includes sales from the *OUC Convenient Lighting Program*, which targets outdoor lighting use in the GSD sector. The lighting program absorbs sales that would otherwise be billed in the GSD tariffs; as such, the lighting program does not represent any new load growth. It is assumed that the *Convenient Lighting Program* will grow by about 3.0 GWh a year through the forecast period.

4.1.3 Hourly Load and Peak Forecast.

The system hourly load forecast is based on a set of hourly load models using load data covering the period January 1992 to December 2001. To forecast hourly loads, historical hourly loads are expressed as a percentage of the total daily energy:

$$Fraction_{hd} = Load_{hd}/Energy_d$$

Where

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

$Energy_d$ = the system energy in day d

Hourly percent models are then estimated for each hour using Ordinary Least Squares (OLS) regression. The hourly models are specified as a function of daily weather conditions, months, day of the week, and holidays.

The hourly load forecast is driven by the long-term retail energy forecast. Hourly loads are forecasted as the product of the daily energy forecast and forecasted hourly fraction. Thus the forecast for hour (h) equals:

$$Load_h = Fraction_h * DailyEnergyForecast_d$$

The daily energy forecast is generated from the long-term monthly retail sales forecast. Monthly retail energy forecasts are translated to daily system energy requirements through the conversion variable $DaykWh_d$, which is calculated by dividing actual system daily energy by a retail sales trend based on actual monthly retail sales:

$$DaykWh_d = System\ Energy_d / SalesTrend_m$$
$$SalesTrend_m = ResTrend_m + NonResTrend_m$$

Where:

$ResSalesTrend_m$ = 12-month moving average (Residential Sales)

$NonResTrend_m$ = 12-month moving average (Nonresidential Sales)

A regression model to forecast $DaykWh_d$ is then estimated that relates $DaykWh_d$ to daily weather conditions, day of the week, holidays, and season. Forecasted daily energy in period T is then calculated as:

$$DailyEnergyForecast_T = KWperKWh_T * SalesTrend_T$$

Where:

$SalesTrend_T$ is calculated from retail monthly sales forecast

Normal daily average temperatures are used to forecast hourly demand. Normal daily temperatures are calculated by ranking each historical year from the hottest to coldest average daily temperature. 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.

One surprising element is that 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 driven by back-up resistant heat built into residential heat pumps. With heat pumps continuing to gain market share, winter peaks are projected to grow slightly faster than summer peaks during the forecast horizon.

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 forecast is aggregated to yield a total system hourly load requirement. Forecasted seasonal peaks are derived by then finding the maximum hourly demand in January (for the winter peak) and July (for the summer peak).

4.2 Forecast Assumptions

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

4.2.1 Economics.

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

4.2.1.1 Employment and Regional Output. The nonresidential forecast models are driven by nonmanufacturing and regional output forecasts. Economy.com’s employment forecasts were used through 2005, with employment growth over this period consistent with the University of Florida’s outlook. After 2005, Economy.com projects regional employment and output growth that continues to exceed Economy.com’s Florida forecast and are somewhat more optimistic than the University of Florida. For the longer term (after 2005 to 2012), employment is assumed to continue to grow at the more conservative state growth rate forecasted by Economy.com. 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 through 2005. Between 2005 and 2012 the number of households and real income are assumed to grow

Table 4-1
Nonmanufacturing Employment (Thousands) and Gross Regional Product Projections (Billion Real \$)

Year	Retail	Wholesale	Services	Financial Services	Government	Gross Product (Billion Real \$)
1995	139.4	38.6	288.2	42.2	79.6	37.5
1996	146.7	41.3	304.4	44.5	81.6	39.6
1997	154.2	44.3	329.7	46.0	83.9	42.7
1998	159.6	45.9	352.4	49.7	86.7	46.4
1999	166.7	48.0	371.4	54.0	89.1	48.9
2000	169.4	49.4	395.0	50.8	92.3	50.9
2005	176.5	56.9	463.8	54.3	100.2	59.9
2012	193.3	66.0	599.2	63.1	113.5	78.8
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	5.2	7.0	5.6	5.5	2.5	5.6
1997	5.1	7.3	8.3	3.3	2.8	7.8
1998	3.5	3.6	6.9	8.0	3.3	8.6
1999	4.4	4.6	5.4	8.7	2.8	6.3
00-05	1.9	2.9	3.3	6.3	1.6	3.3
05-12	1.3	2.1	3.7	2.2	1.8	4.0

at the slower state rate. Household projections are then calculated by dividing population projections by household size (number of household members) projections. Table 4-2 shows annual the population, household, and real income forecasts.

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 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 was 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.

Since 1992, real prices have been trending downward. For the first 5 years of the forecast (2000 to 2005) no increases in nominal rates are assumed, thus real prices continue to

trend downward. After 2005, real prices are assumed constant. The average annual price series is provided in Table 4-3.

Table 4-2 Population, Household, and Income Projections			
Year	Real Income per HH	Households (Thousands)	Population (Thousands)
1992	55,383	499	1,324
1993	56,021	510	1,363
1994	56,515	523	1,399
1995	57,487	538	1,434
1996	58,555	557	1,476
1997	60,033	577	1,525
1998	62,455	597	1,571
1999	63,953	609	1,611
2000	65,864	627	1,649
2005	68,734	697	1,825
2012	72,402	827	2,148
Change	Percent	Percent	Percent
1993	1.2	2.2	2.9
1994	0.9	2.5	2.6
1995	1.7	2.9	2.5
1996	1.9	3.5	2.9
1997	2.5	3.6	3.3
1998	4.0	3.5	3.0
1999	2.4	2.0	2.5
00-05	0.9	2.1	2.0
05-12	0.7	2.5	2.4

Table 4-3 Historical and Forecasted Price Series Average Annual Price	
Year	Real Price (cents/kWh)
1992	6.7
1993	6.7
1994	6.7
1995	6.4
1996	6.2
1997	6.0
1998	5.8
1999	5.4
2000	5.3
2005	5.2
2012	5.2
Change	Percent
1993	0.0
1994	0.0
1995	-4.5
1996	-3.1
1997	-3.2
1998	-3.3
1999	-6.9
00-05	-0.4
05-12	0.0

4.2.3 Weather.

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

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

$$CDD_d = (AvgTemp_d - 65) * (AvgTemp_d >= 65)$$

CDD_d has a value equal to the average daily temperature minus 65 when temperatures are greater than or equal to 65 °F, and 0 °F if average daily temperature is less than 65 °F. The daily CDD values are then aggregated to yield a monthly CDD:

$$CDD_m = \Sigma CDD_{md}$$

For each month, a normal CDD estimate is calculated using a 10-year average of the monthly values calculated from 1990 through 1999:

$$CDD_{nm} = \Sigma CDD_m / 10$$

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

$$HDD_d = (65 - AvgTemp_d) * (AvgTemp_d <= 65)$$

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 0°F 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:

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

4.3 Base Case Load Forecast

A short-term monthly budget forecast was estimated through 2002, with a long-term annual forecast through 2012. As outlined in the methodology section, the sales forecast is developed from a set of structured regression models that can be used for both forecasting monthly sales and customers for the OUC budget period and over the longer term, 20-year forecast horizon. Forecast models are estimated for each of the major rate classifications including:

- Residential.
- General Service Non-Demand (Small Commercial Customers).
- General Service Demand (Large Commercial and Industrial Customers).
- Street Lighting.

Models are estimated using monthly sales data covering the period 1991 through 2001. A separate set of forecast models are estimated for the OUC and St. Cloud service territories.

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 period January 1992 to December 2001. 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 sales and peak forecast for the combined OUC and St. Cloud service territories.

4.3.1 Base Case Economic Outlook.

Between 1995 and 2000, population has grown at an average annual rate of 2.8 percent and real gross output has grown at 6.8 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and nation. Orlando is expected to exceed overall state economic growth throughout the next 10 years.

Much of this growth has been fueled by significant gains in the service sector, which has seen employment expand by nearly 100 percent since 1990. Moreover, employment in the service sector accounts for approximately 52 percent of total employment. Hotels and tourism-related activities, as well as call-centers, have continued to grow.

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	808	731	4,174
1995	861	876	4,377
1996	852	969	4,471
1997	917	849	4,566
1998	988	814	4,909
1999	1,055	965	5,011
2000	1,025	971	5,290
2005	1,216	1,200	6,056
2012	1,474	1,470	7,394
Change	Percent	Percent	Percent
95-00	3.5	2.1	3.9
00-05	3.5	4.3	2.7
05-12	2.8	2.8	2.9

Two of the largest regional employers are Walt Disney and Universal Studios. Universal Studios has doubled in size with the recent addition of *Islands of Adventure*, *CityWalk*, and the related hotel complex. The expanded Orange County convention center is expected to open during the forecast period, which will help increase regional convention and tourism activity.

To accommodate growing convention, tourism, and regional business activity, the Orlando International Airport (OIA) is anticipating a major expansion program that will ultimately double the capacity of the airport. In 2001, OIA served 28 million passengers. The airport has seen a decrease in number of passengers since September 11, 2001. Moving forward the OIA expects strong growth of over 3 percent a year over the next decade.

4.3.1.1 Economic Projections. While the economy is projected to slow from the torrid pace experienced over the last 5 years, relatively inexpensive labor and housing costs and strong in-migration from both other states and other nations will continue to fuel the regional economic expansion long into the future. The number of households in the Orlando MSA is projected to increase from 627,000 in 2000 to 827,000 by 2012, representing an average annual growth rate of 2.3 percent. Employment is projected to grow at 2.6 percent over the long-term.

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

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

4.3.2 Forecast Results.

Based upon the previously discussed economic assumptions, total retail sales for OUC are expected to increase from 4,696 GWh in 2000 to 6,552 GWh by 2012. St. Cloud sales are projected to increase from 369 GWh to 562 GWh. Sales and customer projections are summarized in Tables 4-5 through 4-8.

4.3.2.1 Residential Forecast. With high electric end-use saturation, coupled with projected appliance efficiency-gains, residential average use is projected to increase relatively slowly over the forecast period. For OUC, average use per customer is forecasted to grow at 0.6 percent. Residential sales growth will be driven largely by the addition of new customers. With relatively strong population projections for the region, residential customers are expected to increase at a 1.8 percent rate for OUC and 3.0 percent rate for St. Cloud between 2000 and 2012. 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 3.4 percent for OUC and St. Cloud, respectively, between 2000 and 2012. Projected GSND sales are driven by regional nonmanufacturing 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 cut-off, they are migrated to the appropriate GSD rate. For OUC, average GSND use has actually trended downward over the last five years. Small commercial customer growth accounts for most of the GSND sales gains. The GSND customer forecast is driven by regional nonmanufacturing employment projections. The number of GSND customers is projected to grow at an average annual

growth rate of 1.1 percent and 2.2 percent, respectively, for OUC and St. Cloud from 2000 to 2012. Tables 4-5 through 4-8 show annual GSND forecasts for OUC and St. Cloud.

4.3.2.3 Large Nonresidential Sales Forecast. General Service Demand (GSD) represents the largest commercial and industrial customers. Over the last couple of years, OUC has experienced phenomenal growth from this sector with GSD sales up 7.1 percent in 1999 and 4.8 percent in 2000. While sales are projected to slow significantly from this pace, sales are projected to continue to show relatively strong gains as a result of new major developments coming on line and overall strong regional output growth. Average use actually declines somewhat over the forecast period as smaller customers migrate from GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 4-5 through 4-8 summarize the GSD forecast.

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1,380	316	2,157	27	-	55	3,935
1996	1,419	318	2,211	28	-	53	4,030
1997	1,377	322	2,280	29	-	56	4,063
1998	1,583	311	2,410	27	-	93	4,423
1999	1,504	308	2,581	30	-	76	4,498
2000	1,583	293	2,705	31	-	84	4,696
2005	1,792	308	3,139	36	14	101	5,390
2012	2,138	325	3,892	41	32	129	6,557
Change	Percent	Percent	Percent	Percent	Percent	Percent	Percent
1996	2.8	0.5	2.5	3.1	-	-3.6	2.4
1997	-3.0	1.2	3.1	2.3	-	5.7	0.8
1998	15.0	-3.5	5.7	-5.4	-	66.1	8.9
1999	-5.0	-0.9	7.1	11.8	-	-18.3	1.7
00-05	2.5	0.4	3.0	3.0	-	3.8	2.8
05-12	2.6	0.4	3.1	1.9	12.5	3.6	2.8

Table 4-6 OUC Average Number of Customers Forecast				
Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108,702	14,572	2,965	126,239
1996	111,241	14,855	3,120	129,216
1997	113,669	15,065	3,438	132,172
1998	117,868	15,168	3,793	136,829
1999	121,173	15,659	3,865	140,697
2000	125,891	15,506	4,412	145,809
2005	136,808	16,314	5,219	158,341
2012	156,767	17,651	6,438	180,856
Change	Percent	Percent	Percent	Percent
1996	2.3	1.9	5.2	2.4
1997	2.2	1.4	10.2	2.3
1998	3.7	0.7	10.3	3.5
1999	2.8	3.2	1.8	2.8
00-05	1.7	1.0	3.4	1.7
05-12	2.0	1.1	3.0	1.9

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Total Retail
1995	180	19	56	-	254
1996	190	18	62	-	270
1997	192	19	67	1	278
1998	221	20	72	3	316
1999	221	22	73	3	318
2000	238	26	76	3	343
2005	287	29	96	3	416
2012	364	39	121	4	528
Change	Percent	Percent	Percent	Percent	Percent
1996	5.5	-1.5	11.0	-	6.2
1997	0.8	1.1	9.4	200.0	3.0
1998	15.2	9.4	7.1	-	13.7
1999	0.2	6.9	0.7	-	0.6
00-05	3.8	2.2	4.8	0.0	3.9
05-12	3.5	4.3	3.4	4.2	3.5

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	13,659	1,293	120	15,072
1996	14,158	1,311	138	15,607
1997	14,527	1,359	142	16,028
1998	15,010	1,427	150	16,586
1999	15,550	1,511	152	17,212
2000	16,470	1,610	163	18,242
2005	19,258	1,753	201	20,680
2012	23,449	2,096	254	25,799
Change	Percent	Percent	Percent	Percent
1996	3.7	1.4	15.1	3.6
1997	2.6	3.6	3.0	2.7
1998	3.3	5.0	5.3	3.5
1999	3.6	6.6	1.4	3.8
00-05	3.2	1.7	4.3	2.5
05-12	2.9	2.6	3.4	3.2

4.4 Net Peak Demand and Net Energy for Load

Hourly load models are used to forecast each of 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.

Table 4-9 OUC Net Peak Demand (Summer and Winter) and Net Energy for Load: History and Forecast			
Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	749	674	3,926
1995	798	800	4,103
1996	788	885	4,186
1997	846	773	4,271
1998	907	746	4,578
1999	969	873	4,674
2000	941	882	4,922
2005	1,105	1,083	5,614
2012	1,333	1,322	6,832
Change	Percent	Percent	Percent
95-00	3.3	2.0	3.7
00-05	3.3	4.2	2.7
05-12	2.7	2.9	2.8

Table 4-10 St. Cloud Net Peak Demand (Summer and Winter) and Net Energy for Load: History and Forecast			
Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1994	59	57	249
1995	63	76	274
1996	64	84	285
1997	71	76	295
1998	81	68	331
1999	86	92	337
2000	84	89	369
2005	111	117	442
2012	141	148	562
Change	Percent	Percent	Percent
95-00	6.0	3.2	6.1
00-05	5.7	5.6	3.7
05-12	3.5	3.4	3.5

4.5 High and Low Case Scenarios

In addition to the base case, two long-term forecast scenarios were developed in order to bound the potential demand outcome. Modifying the base case economic assumptions developed the high and low case scenarios. The primary drivers that were modified are regional population and employment. Table 4-11 show a comparison of the high, base, and low scenarios.

4.5.1 High Case Scenario.

The high scenario is based upon assumptions of continued strong economic growth. It has been assumed that through 2012, area population growth does not slow, but continues to expand at a rate experienced over the last few years. The University of Florida's high and low population projections were used to help bound the population growth assumptions. Stronger population growth allows for continued expansion of the labor force; this in turn translates into stronger employment and total output growth.

4.5.2 Low Case Scenario.

The low scenario assumes that there is a significant slowdown in regional population growth. The University of Florida's high and low population projections were used to help bound the population growth assumptions.

Table 4-11 Scenario Peak Forecast Orlando Utilities Commission and St. Cloud			
High Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,253	1,236	6,244
2012	1,604	1,599	8,055
95-00	3.6%	2.1%	3.9%
00-05	4.1%	4.9%	3.4%
05-12	3.6%	3.7%	3.7%
Base Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,216	1,200	6,056
2012	1,474	1,470	7,394
95-00	3.5%	2.1%	3.9%
00-05	3.5%	4.3%	2.7%
05-12	2.7%	2.9%	2.9%
Low Scenario			
Year	Summer (MW)	Winter (MW)	Net Energy (GWh)
1995	861	876	4,377
2000	1,025	971	5,290
2005	1,176	1,160	5,855
2012	1,340	1,337	6,726
95-00	3.5%	2.1%	3.9%
00-05	2.8%	3.6%	2.1%
05-12	1.8%	2.0%	2.0%

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 demand-side management (DSM) goals were approved by the FPSC on March 23, 2000, by Order No. PSC-00-0587-FOF-EG. The evaluations for this docket indicated that there were no cost-effective conservation measures available for OUC. As a result, the FPSC approved zero goals for OUC for the residential and commercial/industrial sectors as presented in Table 5-1. Nevertheless, OUC proposed to continue existing programs feeling that they were in the overall best interest of OUC's customers. The FPSC goals for OUC and the programs implemented to meet these goals are presented briefly in this section and in greater detail in OUC's 2000 Demand-Side Management Plan filed in Docket No. 990722-EG.

Year	Residential			Commercial / Industrial		
	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
2000	0	0	0	0	0	0
2001	0	0	0	0	0	0
2002	0	0	0	0	0	0
2003	0	0	0	0	0	0
2004	0	0	0	0	0	0
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

5.1 Existing Conservation Programs

The demand-side management programs voluntarily continued and offered by OUC to its customers during 2002 included programs which result in energy and/or demand reductions that are quantifiable, as well as programs that are not quantifiable but aid OUC's customers in reliability, energy conservation, and education. Table 5-2

presents a listing of the programs which were offered by OUC in 2002, and the remainder of this section provides a description of each of these programs.

Table 5-2. Conservation Programs Offered by OUC - 2002	
Quantifiable Conservation Programs	
Residential Energy Survey Program	
Residential Energy Efficiency Rebate Program	
Residential Home Energy Fix-Up Program	
Residential Financed Insulation Program	
Residential Efficient Electric Heat Pump Program	
Commercial Energy Survey Program	
Non-Quantifiable Conservation Programs	
Education Outreach Program	
Residential Gold Ring Program	
Residential Night Security Lighting Program	
Residential Energy Conservation Rate	
Commercial OUConsumption Online Program	
Commercial OUConvenient Lighting Program	
Commercial Power Quality Analysis Program	
Commercial Infrared Inspections Program	
Commercial Single- and Three-Phase Service Program	
OUCooling	
Commercial Indoor Lighting Program	
OUCash	

The decrease in cost-effectiveness of DSM programs is a result of numerous factors. As each program continues, participation tends to gradually decrease because the market for the program becomes saturated since most of the customers that are willing to participate will have done so early in the program; government mandates have forced manufacturers to increase their efficiency standards, thereby decreasing the incremental amount of energy savings achievable; the efficiency of new generation has increased and the cost of installing new generation has decreased; and with interest rates at all-time lows, the carrying costs of power plants have been greatly reduced. All of these factors have resulted in it becoming more difficult for DSM to be cost-effective and to achieve high levels of customer participation.

5.1.1 Residential Energy Survey Program.

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. This program consists of two measures, the Residential Energy Walk-through Survey and the Residential Energy Survey Video.

The Residential Energy Walk-through Survey includes a complete examination of the attic, air duct and air returns, window caulking, weather stripping, faucets, toilets, and lawn sprinkler systems. Literature on other OUC programs is also provided to the residential customers. The participant is given a choice to receive either a low-flow showerhead or a compact fluorescent bulb. OUC Energy Analysts 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 in November 2001 became available to OUC customers in an interactive CD-ROM format. The video (or CD-ROM) is free and is distributed to OUC customers by request. The measure was developed to further assist OUC customers in surveying their home for potential energy saving opportunities. The video walks the customer through a complete visual assessment of energy and water efficiency in the customer's 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 home energy audit complete with their previous billing information. The interactive home energy audit is available on OUC's website, OUC.com., and during 2002 approximately 400 individuals utilized this on-line energy audit each month.

One of the primary benefits of the Residential Energy Survey program is providing education to the customer on energy conservation measures and ways their lifestyle can directly impact their use of energy. Customers participating in the Energy Survey program are made aware of conservation measures which they can implement. Customers will benefit from the increased energy conservation in their homes, which will decrease their electric bills.

Participation has averaged over two thousand walk-through energy surveys per year for the past ten years and video distribution has averaged approximately 83 tapes per month. Feedback from customers that have taken advantage of the survey has been very positive.

5.1.2 Residential Energy Efficiency Rebate Program.

This program rewards customers who have invested in weather stripping, insulation, duct repairs, or other energy-saving measures for their single-family home. OUC will rebate customers up to \$75 for the purchase of caulking, weather stripping, window tinting, and solar screening. Additionally, OUC offers customers a rebate of up to \$75 for repairs made to leaking ducts.

5.1.3 Residential Home Energy Fix-Up Program.

This program targets residential customers with a total annual family income of less than \$25,000. Every customer must request a free Residential Energy Survey. Audit recommendations usually require the customer to spend money replacing or adding energy conservation measures. Low-income customers may not have the discretionary income to make these changes.

The program pays 85 percent of the total contract cost for home weatherization for the following measures:

- attic insulation
- exterior and interior caulking
- weather-stripping 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
- minor electrical repairs

Under this program, OUC will arrange for a licensed, approved contractor to perform the necessary repairs and will pay for 85 percent of the bill. The remaining 15 percent can be paid for on the participant's monthly electric bill. The purpose of the program is to reduce the energy cost for low-income households, particularly those households with elderly persons, disabled persons, and children, by improving the energy efficiency of their homes and ensuring a safe and healthy community.

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

5.1.4 Residential 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 a free Residential Energy Survey and have a satisfactory credit rating with OUC. The program provides a payment method to customers who insulate their attics to an R-19 level. Customers may pay for the insulation on their monthly utility bill for up to two years without being required to put any money down. Additionally, the customer will receive a \$100 rebate. OUC directly pays the total cost for installation when the customer makes payments to OUC as part of their monthly utility bill. 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 SEER of 11 (or greater). Customers will be able to obtain rebates ranging from \$100 to \$300, depending upon the SEER rating of the heat pump selected. Customers will benefit from the increased energy conservation in their home, which will decrease their electric bills. One of the main benefits of this program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

5.1.6 Commercial Energy Survey Program.

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

Participation has averaged around two hundred participants per year. Customers benefit from the energy conservation, which decreases their electric bills.

5.1.7 Education Outreach Program.

This program consists of hour-long classroom presentations focused on teaching students about energy and water conservation. Students are taught how electricity is generated and are encouraged to perform mini electric and water audits on their own

homes. After eighteen years of successful operation (including winning several awards for contributions to education), Education Outreach will not be offered by OUC beyond 2002.

5.1.8 Residential Gold Ring Program.

OUC has partnered with local contractors to construct new homes according to OUC's energy and water efficiency standards. Features include high efficiency heat pumps, heat recovery water heaters, R-30 attic insulation, interior air ducts, and window shading.

The contractor is required to install R-30 insulation and include four other conservation measures from a list of conservation measures developed by OUC. In return for each Gold Ring home built, the contractor receives \$225 toward advertising costs. The advertising must include a reference to the high efficiency Gold Ring homes available.

Gold Ring Homes use 20 to 30 percent less energy than other homes. Gold Ring homeowners benefit from lower energy bills and qualification for all FHA, VA, and Energy Efficient Mortgage Programs. This allows the homeowner to increase their income to debt ratio by two percent.

5.1.9 Residential Night Security Lighting Program.

OUC allows residential customers to pay for the cost of security lighting on their monthly utility bill. The customer is allowed to continue doing so for up to one year. The costs covered include the fixtures, bulb, materials, labor, and warranty. Lighting is to be installed by licensed contractors who will supply a warranty for the fixtures and the work.

5.1.10 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 will pay a higher rate for the additional energy usage. The purpose of this rate is to make OUC customers more energy aware and encourage conservation of energy resources.

5.1.11 Commercial OUC Consumption 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 the cost of additional infrastructure at the meter(s) and are responsible for a \$35.00 per month per channel fee for this service.

5.1.12 Commercial OUConvenient Lighting Program.

OUConvenient Lighting provides complete outdoor lighting services for commercial applications including industrial parks, sports complexes, and residential developments. Each lighting package is customized for each participant, allowing the participant to choose among light fixtures. OUC handles all of the up-front 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 in addition to providing preventive and corrective maintenance.

5.1.13 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 over voltage, under voltage, outages, electric noise, and harmonic distortion. Under the Power Quality Analysis program, trained and experienced service personnel will 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 on-going follow up services to monitor results.

5.1.14 Commercial Infrared Inspections Program.

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

5.1.15 Commercial Single- and Three-Phase Service Program.

The purpose of this program is to help customers protect their electrical equipment. While most homes and small businesses generally utilize single-phase service, other customers such as large industries, shopping centers, and even some homes have electrical equipment that requires three-phase service. Because this setup requires three energized lines in order to run properly, three-phase equipment needs added protection to prevent damage due to service interruptions resulting from lightning, falling tree limbs, wind, or electrical problems within the customer's home or facility. Although three-phase equipment typically relies on fuses, breakers, or overload devices, there may not be sufficient protection in the event such power outages occur. A licensed electrician can install monitoring relays to protect against phase loss, phase imbalance, reversal, under-voltage, and over-voltage conditions.

5.1.16 OUCooling.

OUCooling is a partnership between OUC and Trigen-Cinergy Solutions which helps to lower air conditioning-related electric charges and reduce capital and operating costs. OUCooling will fund, install, and maintain a central chiller plant for each business district participating in the program. The main benefits to the businesses are lower energy consumption, increased reliability, and no environmental risks associated with the handling of chemicals. Other benefits for the businesses include avoided initial capital cost, maintenance costs, a smaller mechanical room (therefore more rental space), no insurance requirements, federal income tax savings, improved property resale value, and relief of maintenance personnel for other duties.

OUC's first chiller plant was installed at Lockheed Martin Corp. The plant was built in 1999 and currently serves numerous buildings. OUC next began operation of a chilled water system serving downtown Orlando. In 1999, the downtown project won 3 awards. In 2000, the Downtown Orlando Partnership gave its Award of Excellence to OUC based on the chilled water plant. The system serves the OUC Administration Building, City Hall, CNL Center, Embassy Suites Hotel, Lincoln Tower, 201 E. Pine St., Westin Grand Bohemian Hotel, the First Presbyterian Church, 100 E. Pine St., Hughes Corporate Offices, 250 N. Orange Ave., City View at Hughes Square, and Orlando Terrance Condo Association. The system is under expansion to serve a number of other customers. Several companies have signed up for the service after realizing they would save time and money by outsourcing the production of chilled water for their air conditioning needs. OUCooling is evaluating options for a second downtown chilled water plant and loop in order to serve other downtown prospects.

In 2002, the International District Energy Association (IDEA) awarded OUCooling a first-place award for signing up more customer square footage for its chilled-water business than any other company in 2001. OUCooling brought on nine 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.

In January 2000, OUC signed a 20-year agreement to design, build, own, and operate a chiller plant for Vistana, a leading developer and operator of vacation ownership resorts. OUCooling currently serves the Sheraton Vistana Villages timeshare development in south Orange County. In addition, OUCooling provides service to the new Mall at Millenia and the Orange County Convention Center, which has expanded to incorporate a 160,000 ton per hour chilled water storage tank, the largest thermal energy storage tank in the world. The tank will be operational in April of 2003.

OUC envisions building other chiller plants serving commercial campuses, hotels, retail shopping centers, and tourist attractions. OUC recently received three awards from the Associated Builders and Contractors Inc. for one of the top construction projects in Orlando. The Awards were the Eagle Award for mechanical work, General Contractor Award of Merit, and the Subcontractor Award of Merit. OUCooling was most recently featured in the January-February 2003 issue of *Relay – Florida's Energy and Electric Utility Magazine*.

5.1.17 Commercial Indoor Lighting Retrofit.

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. Up-front 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 paid for in full, the participating customer's annual energy bill will decrease by the approximate amount of the projected energy cost savings.

5.1.18 OUCash.

The OUCash program is designed for commercial customers who sign a service agreement with OUC. The participant is provided with cash to spend on energy saving methods of the customer's choice. The program also enables the participant to qualify for financial incentives to save energy. Projects that may be eligible for OUCash

incentives include efficient lighting, air conditioning, solar window treatments, weatherization, insulation, heat recovery water heaters, waste heat recovery, energy management systems, building controls, motors and pumps, manufacturing, production, refrigeration, and compressed air. OUC restricted offering of the OUCash program to a limited basis in 2002.

6.0 Forecast of Facilities Requirements

6.1 Existing Capacity Resources and Requirements

6.1.1 Existing Generating Capacity.

As shown in Tables 6-1 and 6-2 which are presented at the end of this Section, OUC and St. Cloud together have an existing generating capability of 1,047 MW in the summer and, by October 2003, will have 1,273 MW of winter generating capability. The existing generating capability consists of OUC's joint ownership share of Stanton Energy Center and the Indian River combustion turbines operated by OUC, OUC's joint ownership share of Crystal River 3, McIntosh 3, and St. Lucie 2 operated by FPC, Lakeland Electric, and FPL, respectively, as well as St. Cloud's diesels (which are scheduled to retire in November 2004). Stanton Energy Center A, which received final site certification September 18, 2001, will add an additional 167 MW (summer) and 181 MW (winter) to OUC's generating capacity beginning October 1, 2003. Construction of Stanton A began in November 2001 in order to support its scheduled commercial operation date.

6.1.2 Power Purchase Agreements.

As described in detail in Section 2.3, OUC has a power purchase agreement in place with Reliant and schedules St. Cloud's purchase power from TECO. For purposes of the TYSP, it has been assumed that OUC will exercise its options from the Reliant PPA, purchasing 577.5 MW through September 2003. Beyond fiscal year 2003, OUC can elect to purchase from Reliant up to 500 MW, in 100 MW increments, through fiscal year 2007. OUC can reduce the amount of capacity purchased through the Reliant PPA each fiscal year, also in 100 MW increments, but cannot increase the amount of capacity it purchases from the amount taken the previous fiscal year. Tables 6-1 and 6-2 reflect OUC's commitment to purchasing 500 MW in fiscal year 2004, 300 MW in fiscal year 2005, and 100 MW from fiscal year 2006 through fiscal year 2007.

Additionally, OUC has entered into a 10-year agreement to purchase capacity from Southern-Florida's ownership share of Stanton A. The terms of this agreement specify that OUC will purchase 309 MW during the summer months and 336 MW during the winter months. However, beginning on the first day of the sixth year of the PPA and extending through the tenth year of the PPA, OUC, KUA, and FMFA collectively may elect to reduce the amount of capacity purchased by a total of 50 MW each year, with the total reduction in capacity not to exceed 200 MW. Because OUC will purchase 80 percent of Southern-Florida's ownership share of Stanton A, it has been assumed for

purposes of the TYSP that OUC may elect to reduce the amount of capacity purchased under the PPA by 40 MW each year, beginning with the sixth year of the PPA and extending through the tenth year of the PPA, with the total reduction not to exceed 160 MW. The SEC A PPA capacity presented in Tables 6-1 and 6-2 does not reflect OUC exercising the PPA capacity reduction option.

At the expiration of the 10-year agreement, OUC retains the option to extend the term of its purchase from Southern-Florida for 20 additional years, structured into four 5-year increments. OUC has also entered into an agreement to purchase power from KUA's share of Stanton A during the first three years of the unit's operation, which is reflected in Tables 6-1 and 6-2.

6.1.3 Power Sales Agreements.

As described in more detail in Section 2.4, OUC has entered into power sales contracts with FMPA, SEC, KUA, and RCID for various amounts of capacity and energy.

6.1.4 Modifications and Retirements of Generating Facilities.

OUC has not scheduled any unit modifications or retirements over the next ten years, but will continue to evaluate options on an ongoing basis. However, the diesel units owned by St. Cloud are scheduled to retire in November of 2004.

6.2 Reserve Margin Criteria

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

6.3 Future Resource Needs

6.3.1 Generator Capabilities and Requirements Forecast.

Since OUC has elected to use a 15 percent reserve margin criterion, OUC applies it to St. Cloud's load as well as partial requirements (PR) purchases and sales. Tables 6-1 and 6-2 (presented at the end of this Section) display the forecast reserve margins for OUC and St. Cloud for the winter and summer seasons, respectively.

Table 6-1 indicates that, considering the addition of Stanton A to OUC's generating assets and purchase power resources, additional capacity will not be needed until the winter of 2010/11. The addition of Stanton A (October 1, 2003 commercial operation) will provide enough capacity for OUC to meet forecast requirements through the summer of 2008 with the previously discussed Reliant PPA options, at which time OUC is forecast to require a minimal amount (1 MW) of additional capacity. Beyond the summer of 2008, the need for capacity additions increases annually.

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 their customers. OUC has adopted the North American Electric Reliability Council (NERC) Planning Standards as the basis for its and the City of St. Cloud's electric power transmission system planning. For the purposes of planning studies, OUC utilizes certain criteria that pertain to voltage and line and transformer loading. A criterion of 95 percent and 105 percent of nominal system voltage establishes 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 continually reviews the need and options for increasing the capability of the transmission system based on the following planning criteria. During the course of a planning study, the OUC and St. Cloud transmission systems are subjected to a single contingency analysis which involves outaging each 69 through 230 kV transmission line respectively. Bus tie transformers, tie lines with neighboring utilities, and off-system facilities known to cause internal problems are included as well. If a violation of the voltage or loading criteria occurs a permanent solution is determined in the form of an upgrade or new construction. The revised system containing the improvement is then subjected to the same analysis as the original to insure that no voltage or loading violations remain. Recently, OUC has had a change in planning philosophy when the voltage or loading criteria is exceeded. Instead of an operational procedure being the first step to correcting the problem, OUC in the future will investigate permanent solutions such as new construction. In the short term, operational remedies will continue to be used until new facilities can be put into service.

OUC has developed a schedule of transmission system upgrades based on the above criteria as well as economic and reliability factors. The schedule is presented in Section 2.5.

Table 6-1
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Base Case without Capacity Additions

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
	OUC	STC	RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed ¹	SEC A PPA ²	Reliant PPA	TECO P.R.	Total	Required ³	Available ⁴	
2003/04	1,058	113	76	65	0	75	0	1,387	1,273	364	500	15	2,153	187	768	581
2004/05	1,083	117	101	44	0	0	0	1,345	1,252	354	300	15	1,922	195	599	384
2005/06	1,114	121	0	34	0	0	0	1,269	1,252	344	100	15	1,712	201	445	244
2006/07	1,152	125	0	0	0	0	0	1,277	1,252	336	100	15	1,704	192	429	238
2007/08	1,182	129	0	0	0	0	0	1,311	1,252	336	0	15	1,704	197	295	99
2008/09	1,219	133	0	0	0	0	0	1,352	1,252	336	0	15	1,604	203	254	51
2009/10	1,253	138	0	0	0	0	0	1,391	1,252	336	0	15	1,604	209	215	7
2010/11	1,287	143	0	0	0	0	0	1,430	1,252	336	0	15	1,604	215	176	(38)
2011/12	1,322	148	0	0	0	0	0	1,470	1,252	336	0	15	1,604	221	136	(84)
2012/13	1,356	153	0	0	0	0	0	1,509	1,252	336	0	0	1,589	226	80	(146)

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.

Table 6-2
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Base Case without Capacity Additions

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
	OUC	STC	RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed ¹	SEC A PPA ²	Reliant PPA	TECO P.R.	Total	Required ³	Available ⁴	
2003	1,054	104	101	87	20	75	20 ⁶	1,461	1,047	0	577.5	15	1,640	169	181	12
2004	1,081	107	101	65	0	0	0	1,354	1,214	337	500	15	2,066	193	714	521
2005	1,105	111	113	43	0	0	0	1,372	1,193	327	300	15	1,834	199	464	265
2006	1,134	114	0	22	0	0	0	1,270	1,193	317	100	15	1,624	187	356	169
2007	1,169	118	0	0	0	0	0	1,287	1,193	309	100	15	1,516	193	331	138
2008	1,199	122	0	0	0	0	0	1,321	1,193	309	0	15	1,516	198	197	(1)
2009	1,235	127	0	0	0	0	0	1,362	1,193	309	0	15	1,516	204	156	(48)
2010	1,267	131	0	0	0	0	0	1,398	1,193	309	0	15	1,516	210	120	(90)
2011	1,300	136	0	0	0	0	0	1,436	1,193	309	0	15	1,516	215	82	(133)
2012	1,333	141	0	0	0	0	0	1,474	1,193	309	0	15	1,516	221	42	(177)

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.
6. The 20 MW sale to KUA is subordinate to native load and therefore is not included in the calculation to maintain the 15% reserve margin.

7.0 Development of Supply-Side Alternatives

This section provides the description of supply-side generating unit alternatives considered by OUC. Black & Veatch has estimated the capital cost, performance, and O&M costs for various technologies being considered as supply-side alternatives, including pulverized coal, combined cycle, and simple cycle.

Table 7-1 presents the supply-side alternatives considered by OUC for future capacity additions. The table includes the type of unit being considered, its probable location, its net capacity, and the earliest date it can achieve commercial operation (C.O.D.). As indicated in the table, specific manufacturers were used for the combustion turbine and combined cycle alternatives to provide output and performance data. The use of specific manufacturers is not intended to limit the alternatives to those manufacturers. Several manufacturers providing similar equipment could be utilized.

Technology	Description	Location	Net Capacity	C.O.D.
Simple Cycle	General Electric 7FA	Stanton	156 MW	06/05
Combined Cycle	Siemens-Westinghouse 2x1 501F	Stanton	514 MW	06/06
	Siemens-Westinghouse 2x1 501F	Stanton	610 MW	06/06
Solid Fuel	Pulverized Coal	Stanton	446 MW	06/09

Note: Capacity is stated at average annual temperature for OUC and includes degradation.

7.1 Performance Estimates

Performance estimates have been compiled for each of the alternatives listed in Table 7-1. The estimates provide representative values for each generation alternative and show expected trends in performance within a given technology as well as between technologies. Actual unit performance and availability will vary based on ambient temperature, regulatory requirements, and operation practices. The economic evaluation of an option involves consideration of a number of performance criteria, which are explained below.

7.1.1 Net Plant Output.

Net plant output (NPO) is equal to the gross plant output less the plant auxiliary power. In this analysis, net plant output estimates are provided at the annual average temperature for Orlando.

7.1.2 Equivalent Availability (EA).

Equivalent availability is a measure of the ability of a generating unit to produce power over a period of time, taking into account limitations such as equipment failures, unit deratings, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

7.1.3 Equivalent Forced Outage Rate (EFOR).

The equivalent forced outage rate is a reliability index which reflects the probability that a unit will not be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours plus equivalent forced outage hours by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

7.1.4 Planned Maintenance Outage.

This measure is an estimate of the time (number of days) required each year to perform scheduled maintenance.

7.1.5 Startup Fuel.

Estimates for startup fuel, where applicable, in millions of Btu (MBtu), are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operating conditions.

7.1.6 Net Plant Heat Rate.

The net plant heat rate is a measure of generating station thermal efficiency, generally expressed in Btu/kWh. It can be computed by dividing the total Btu content of the fuel burned for electric generation by the resulting net kWh generation. Estimates for net plant heat rates are based on the higher heating values of the fuel. In this analysis, heat rate estimates are provided for average annual temperature conditions for combustion turbines and combined cycle units. Heat rates may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, hours of operation, and local site conditions.

7.1.7 Degradation.

Power plant output and heat rate performance can degrade with hours of operation due to factors such as blade wear, erosion, corrosion, and increased leakage. Periodic maintenance and overhauls can recover much, but not all, of the degraded performance from the new and clean performance.

Approximations for output and performance degradation applied to the new and clean performance estimates of the combined cycle and simple cycle alternatives vary from unit to unit. Table 7-2 presents the degradation factors used for the General Electric simple cycle (GE 7FA) and the Siemens-Westinghouse combined cycle (WH 2x1 501F) units. Output and performance for the pulverized coal unit were developed incorporating degradation.

Table 7-2. Degradation Factors		
Unit	Net Output (%)	Heat Rate (%)
GE 7FA Simple Cycle	-4.04	2.87
WH 2x1 501F Combined Cycle	-3.72	1.84

7.2 Pulverized Coal

The pulverized coal unit is developed to be identical to Stanton 2 and considers the existing infrastructure included in the Stanton 1 project sufficient to incorporate future pulverized coal unit additions.

7.2.1 Pulverized Coal Capital Cost Estimates.

The capital cost estimate for the pulverized coal alternative is presented in Table 7-3. This cost is based on the current market for construction of a third pulverized coal unit at Stanton, identical to the existing Stanton 2.

7.2.2 Pulverized Coal O&M Costs and Performance Estimates.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Staffing estimates are based on Stanton 2 experience. Variable operating costs include an assumed reagent cost for flue gas desulfurization (FGD), waste disposal, and ammonia. Variable maintenance costs are the costs associated with the inspection and maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs and catalyst replacement.

Performance estimates for the pulverized coal alternative are based on the actual performance of Stanton 2. Table 7-3 presents these estimates, as well as the fixed and variable O&M estimates for the pulverized coal units.

Total Capital Cost ¹ , (\$1000)	\$571,800
O&M Cost - Baseload Duty	
Fixed O&M Cost (\$/kW-yr)	15.34
Variable O&M Cost (\$/MWh)	4.04
Equivalent Forced Outage Rate (percent)	3.00
Planned Maintenance (days/year)	30
Construction Period (months)	42
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	446,000/9,979
	329,710/10,125
	187,430/10,911
	117,060/12,463
1. Includes permitting and licensing. Note: Capital cost estimate does not include interest during construction.	

7.3 Combined Cycle Units

The two combined cycle units selected by OUC as generating unit alternatives include a standard size Siemens-Westinghouse 2x1 501F as well as a Siemens-Westinghouse 2x1 501F with an oversized steam turbine to accommodate maximum duct firing.

The standard size unit is based on a steam turbine sized to utilize all steam produced during normal cool weather conditions and includes duct burners sized to fully load the steam turbine during hot weather conditions. The oversized unit is based on a steam turbine sized to accommodate the maximum duct firing possible.

Typical combined cycle units consist of one or more combustion turbine generators (CTGs), an equal number of heat recovery steam generators (HRSGs), and normally a single steam turbine generator (STG). Fuel is supplied to the CTG(s) where it is mixed with compressed air and combusted. The combustion gases flow through a turbine that turns a generator to produce power. The CTG exhaust gas flows through the HRSG(s) where water is turned into steam. The steam created is run through the STG to

produce power. The total power output of the unit is the combination of the power from the CTG(s) and the STG.

The two Siemens-Westinghouse 2x1 501F combined cycle units each utilize conventional, heavy-duty, industrial type combustion turbines. This Ten-Year Site Plan limited the alternatives reviewed to "F" class CTGs based on size and because F class turbines are a proven technology. Several vendors provide combustion turbines with similar performance characteristics.

The combined cycle units would be dual fueled with natural gas as the primary fuel and No. 2 oil as the secondary fuel. Specifications for performance and operating costs are based on burning natural gas and baseload operation. The combined cycle alternatives assume that emission requirements will be met with dry low NO_x combustors on the CTGs and selective catalytic reduction (SCR) on the HRSGs. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate. The combined cycle alternatives include bypass stacks and dampers to allow simple cycle operation, and also include fuel oil and demineralized water storage tanks.

7.3.1 Siemens-Westinghouse 2x1 501F Combined Cycle Capital Costs.

The total capital cost of a plant is the summation of direct and indirect costs. Interest during construction (IDC) is not included in these estimates. Capital cost estimates were developed on the basis of the current costs observed in the competitive generation market, and are presented in Table 7-4. The competitive generation market currently indicates that combustion turbines can be procured for significantly less than as recently as two years ago. Because the capital cost estimates consider this low procurement cost, it is important to note that a sustained recovery in the competitive generation market will impact these capital costs, causing an overall increase as compared to what is shown in table 7-4.

7.3.1.1 General Assumptions.

- The plant will feature two (2) dual fuel combustion turbine generators, two (2) supplementary fired heat recovery steam generators, and one (1) condensing reheat steam turbine.
- The combustion turbines will be capable of firing either natural gas or number 2 fuel oil. The HRSG duct burners will be capable of burning natural gas only.
- Land and right of ways are not included.
- Raw and makeup water are assumed to be provided.
- Construction power is assumed to be provided.

- A continuous emissions monitoring system is included.
- Permitting and licensing are included.

7.3.1.2 Direct Cost Assumptions.

- Combustion turbine assumptions include:
 - Dry low NO_x combustion system.
 - Fire detection and protection system.
 - Turbine control panel.
 - Generator control panel.
 - Control and protection system.
 - Operator training.
- Condensing steam turbine generator assumptions include:
 - Generator control system.
 - Emergency trip system.
 - Operator training.
- Heat recovery steam generator assumptions include:
 - Duct burners.
 - Exhaust stack.
- Fuel gas scrubber/filter included for each combustion turbine.
- Selective catalytic reduction (SCR) system is included.
- Mechanical draft cooling tower is included.
- Full capacity steam turbine bypass system is included.
- Combustion turbines and steam turbines will have remote control stations.
- Start-up spare parts are included.
- The following buildings are included:
 - Steam turbine building (custom designed).
 - Circulating water chemical feed building (pre-engineered metal structure).
 - No costs have been included for interior furnishings.
- Shop fabricated tanks include:
 - Acid storage.
 - HRSG blowdown.
 - Fuel gas scrubber drains.
 - Air receiver.
 - Closed cycle cooling water head tank.
- Field erected tanks include:
 - Fuel oil storage tank.

- Demineralized water storage tank.

7.3.1.3 Indirect Cost Assumptions.

- General indirects are included.
- Insurance costs include:
 - General liability.
 - Builder's risk.
 - Liquidated damages.
- Engineering and related services are included.
- Field construction management services are included.

7.3.2 Siemens-Westinghouse 2x1 501F Combined Cycle O&M Costs and Performance.

O&M estimates were developed based on a recent bid to a Florida municipal utility for a similar sized combined cycle unit at an existing site. The O&M costs along with the performance estimates for the Siemens-Westinghouse 2x1 501F combined cycle units are presented in Table 7-4.

7.4 Simple Cycle Combustion Turbine Generator

Simple cycle combustion turbine generators are supplied with fuel, which is mixed with compressed air and combusted. The combustion gases flow through a turbine that turns a generator to produce power.

The GE 7FA combustion turbine is dual fueled with specifications for performance and operating costs based on natural gas operation. Part load performance information is also presented. The simple cycle combustion turbines assume that emission requirements will be met with dry low NO_x combustors on the CTGs. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate.

In December 2001, OUC developed detailed capital cost estimates for a pair of combustion turbines to be installed at either the Stanton site or a new site. Installation at the Stanton site resulted in lower capital costs and therefore those costs are used as a basis in the Ten-Year Site Plan. Final decisions regarding the location of new combustion turbines have not been made. The capital cost estimates developed in December 2001 assume that each site would include two identical combustion turbines. For purposes of the Ten-Year Site Plan, these estimates have been adjusted to appropriately consider the fact that only a single combustion turbine would be installed, and have been updated to account for the current competitive generation market.

Table 7-4. Generating Unit Characteristics Siemens-Westinghouse 2x1 501F Combined Cycle Units (Unless otherwise specified, all costs are in 2003 dollars)		
	Standard Turbine	Oversized Turbine
Total Capital Cost ¹ , (\$1000)	\$270,761	\$280,361
O&M Cost – Baseload Duty		
Fixed O&M Cost (\$/kW-yr)	6.36	5.35
Variable O&M Cost (\$/MWh)	3.70	3.70
Equivalent Forced Outage Rate (percent)	4.00	4.00
Planned Maintenance (days/year)	14	14
Construction Period (months)	24	24
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	513,830/7,074	609,730/7,542
	504,570/7,039	498,990/7,118
	316,110/7,512	311,450/7,625
	251,900/7,215	299,120/7,687
	247,160/7,186	243,740/7,287
	150,990/7,863	149,350/7,950
1. Includes permitting and licensing. Note: Capital cost does not include interest during construction.		

Since the detailed capital cost estimates were developed in December 2001, the overall slowdown in the competitive generation market has led to a substantial decrease in the procurement cost for a combustion turbine. This reduction has been considered in the updated capital cost estimate provided in Table 7-5. However, should the market experience a sustained recovery, the capital cost for the GE 7FA combustion turbine will likely increase significantly.

7.4.1 General Electric 7FA Combustion Turbine Generator Capital Costs.

The total capital cost of a plant is the summation of direct and indirect costs, and does not include interest during construction (IDC). The capital cost estimate for the addition of a single GE 7FA combustion turbine at the existing Stanton Energy Center is presented in Table 7-5.

7.4.1.1 General Assumptions.

- The plant will contain one dual fueled combustion turbine.
 - The combustion turbines will be capable of firing natural gas or No. 2 fuel oil.
 - All permitting, fuel supplies, and interconnections supplied by the utility and others shall be in place to support the schedule.
 - Land and rights-of-way are to be provided.
 - Costs of unloading and delivery to the project site are included.
 - Raw water is assumed to be provided.
 - Construction power is assumed to be provided.
 - Natural gas is assumed to be available at the site boundary at the required pressure.
 - Transmission hookup costs are included.
 - Permitting and licensing costs are included.

7.4.1.2 Direct Cost Assumptions.

- Direct costs include the costs associated with the purchase of equipment, erection, and contractors' service.
- Direct costs include sitework, concrete, architecture, metals, piping, insulation, mechanical equipment, electrical, and controls.
- Direct costs include dry low NO_x burners.
- Direct costs include a 3-day supply fuel oil storage tank for backup fuel.
- Direct costs include an allowance for startup spares.
- Fire protection is included.

7.4.1.3 Indirect Cost Assumptions.

- General indirects are included.
- Insurance costs include:
 - Worker's compensation.
 - Employer liability.
 - Comprehensive general liability.
 - Auto liability.
 - Excess liability.
- Engineering and related services are included.
- Field construction management services are included.

7.4.2 General Electric 7FA Combustion Turbine Generator O&M Costs.

For the GE 7FA combustion turbine, O&M estimates are based on a maintenance cycle of 25 years with an assumed capacity factor of 10 percent. Fixed O&M costs are those that do not directly vary according to plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. The fixed O&M analysis assumes that the fixed costs will remain constant over the life of the plant. Variable O&M costs change as a function of plant generation. Variable O&M costs include consumables, chemicals, lubricants, water, and maintenance repair parts.

O&M estimates for the GE 7FA combustion turbine, shown in Table 7-5, were based on the following assumptions:

- Assumed cycle life of 25 years.
- Primary fuel is natural gas.
- Unit will run at peak load operation with a capacity factor of 10 percent.
- Annual number of starts for the combustion turbine is 200.
- NO_x control method – dry low NO_x combustors for combustion turbine generator (CTG).
- CTG maintenance estimated costs provided by manufacturer.
- CTG specialized labor cost estimated at \$35/man-hour, provided by manufacturer.
- CTG initial operational spares, combustion spares, and hot gas path spares are not included.
- Balance-of-plant costs based on Black & Veatch experience.
- Five additional staff are estimated for the 7FA.
- Staff supplies and materials are estimated to be 10 percent of staff salary.
- Rental equipment and contract labor costs are estimated by Black & Veatch. Rental equipment includes costs for heavy mobile equipment required for specific maintenance activities.
- Routine maintenance costs are estimated based on Black & Veatch experience and include maintenance costs for services not included in balance-of-plant costs or maintenance that is not directly part of power production.
- Contract services include costs for services not directly related to power production.
- Insurance, training fees, and bonuses are not included.
- Fuel costs are not included.
- Employee training costs are not included.

- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and takes into account replacement and refurbishment costs.

Table 7-5. Generating Unit Characteristics 156 MW General Electric 7FA Combustion Turbine (Unless otherwise specified, all costs are in 2003 dollars)	
Total Capital Cost ¹ , (\$1000)	\$44,000
O&M Cost - Baseload Duty	
Fixed O&M Cost (\$/kW-yr)	5.55
Variable O&M Cost (\$/MWh)	2.52
Equivalent Forced Outage Rate (percent)	1.96
Planned Maintenance (days/year)	7
Construction Period (months)	12
Net kW Output/Net Plant Heat Rate (NPHR), HHV (Btu/kWh)	156,120 / 10,940
	117,090 / 11,878
	78,060 / 12,896
	39,030 / 14,002
1. Includes permitting and licensing. Note: Capital cost does not include interest during construction.	

8.0 Analysis, Results, and Conclusions

8.1 Analysis Methodology

8.1.1 Methodology.

The economic evaluation used to determine OUC's least-cost capacity expansion plan is based on the cumulative present worth of annual costs for capital costs, non-fuel O&M costs, fuel costs, and purchase power demand and energy costs. Capital costs are included for new unit additions only, as capital costs for existing units represent sunk costs and are the same for every plan. Annual capital costs for new unit additions are determined by applying an annual fixed charge rate to the capital costs for each unit beginning in the first year of commercial operation. Non-fuel O&M costs include fixed and variable O&M costs; however fixed O&M costs are not included for existing units since these costs are the same for every plan.

Evaluation of the generating unit alternatives was performed using POWROPT and POWRPRO, Black & Veatch's optimal generation expansion planning and production costing models. POWROPT evaluates all combinations of generating unit and power purchase alternatives and selects the alternatives that provide the lowest cumulative present worth revenue requirements. POWROPT uses an hourly chronological approach to determine the least-cost capacity expansion plan, and the results of POWROPT are input into POWRPRO to develop the associated production costs. The production costing results of several scenarios, as well as the methodology supporting the determination of such results, are contained later in this section.

8.1.2 Economic Parameters.

8.1.2.1 Escalation Rates. The general inflation rate applied is assumed to be 2.5 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is assumed to be 2.5 percent.

8.1.2.2 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, which is approximately 70/30, the embedded debt rate, which is approximately 6.6 percent, and the return on equity, which is approximately 10.3 percent. The weighted average cost of capital is thus approximately 7.7 percent. For economic evaluation purposes, the weighted average cost of capital is rounded to 8.0 percent.

8.1.2.3 Present Worth Discount Rate. OUC's present worth discount rate is assumed to be equal to the weighted average cost of capital of 8.0 percent.

8.1.2.4 Interest During Construction Interest Rate. The interest during construction rate is assumed to be 6.0 percent.

8.1.2.5 Levelized Fixed Charge Rate. The levelized fixed charge rate is assumed to be the sum of the capital recovery rate and the insurance rate. Based on the weighted average cost of capital of 8.0 percent, a 1.0 percent annual insurance cost, and a capital recovery period of 20 years, the levelized fixed charge rate is assumed to be 11.19 percent.

8.2 Fuel Price Projections

This section presents the fuel price projections for coal, natural gas, No. 6 fuel oil, and nuclear fuel. OUC provided fuel forecasts for natural gas, coal, and No. 6 fuel oil, while the forecast for nuclear fuel was developed by Black & Veatch.

Fuel prices are highly volatile and are dependent not only on supply and demand, but also political stability and interdependent markets. Even the best forecasters face a tough job of forecasting in such a volatile market. Figure 8-1 shows historical U.S. fuel prices and the wide range of fluctuations and responses to market conditions. Due to the difficulty of forecasting in this environment, a high fuel price scenario and a low fuel price scenario were also developed.

8.2.1 Base Case Fuel Price Projections.

OUC provided projections for the prices of natural gas, coal, and No. 6 fuel oil. These forecasts were developed on a nominal basis and are discussed in more detail below. Also discussed is the forecast for nuclear fuel, developed by Black & Veatch.

The past several years have provided a strong example of the volatility associated with the price of natural gas, particularly on the spot market. Recent seasonal spikes in the price of natural gas have further illustrated the difficulty associated with developing a forecast for natural gas (and fuel oil, for that matter) on even a short-term basis. OUC recognizes the fact that, given the current supply and demand issue and, in particular, the current worldwide political climate, this volatility is likely to continue. However, OUC feels confident that, to the best of its knowledge, the fuel price forecast presented in the Ten-Year Site Plan is adequate and appropriate for planning purposes.

8.2.1.1 Coal. The base case coal forecast is presented in Table 8-1. The forecast presented is for delivered coal and is based on a weighted average from various sources and suppliers, including spot market purchases.

8.2.1.2 Natural Gas. The base case forecast for delivered natural gas is presented in Table 8-1. OUC has natural gas transportation capability from Florida Gas Transmission Company (FGT) under FTS-1 and FTS-2 tariffs. The FTS-2 tariff is expected to change

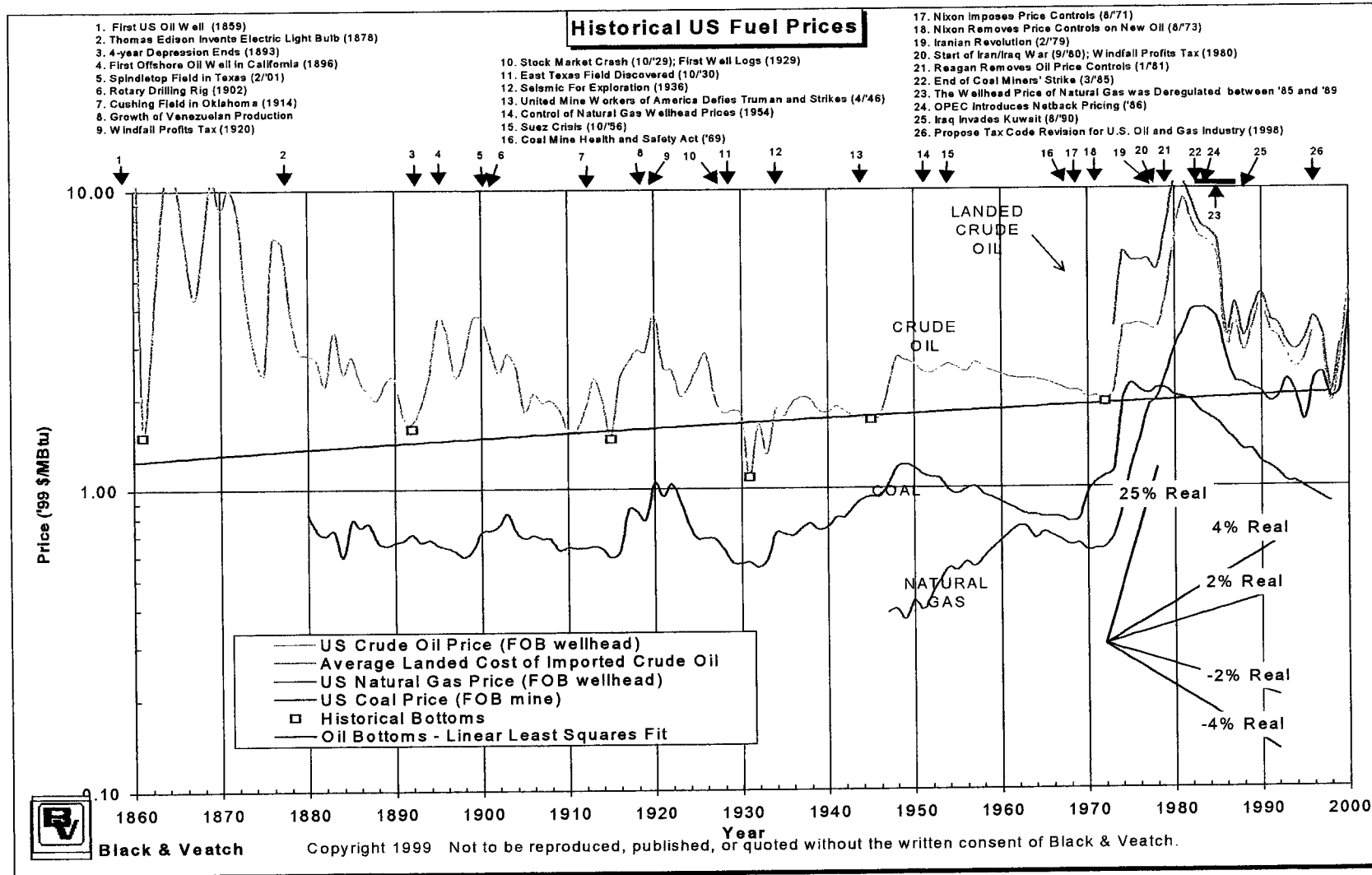


Figure 8-1. Historical U.S. Fuel Price Analysis

as additional expansions are conducted on the FGT system (described in Section 8.3.4). In general, it is expected that the FTS-2 tariff rates will decrease as additional system expansions are added. Also impacting the natural gas transportation situation is the Gulfstream pipeline project (described in Section 8.3.5). Increased competition would be expected to increase pressure to lower transportation costs. Finally, the impacts of transportation capacity being bought and sold on the secondary market will also influence the average natural gas transportation costs.

8.2.1.3 No. 6 Fuel Oil. The forecast for No. 6 fuel oil developed by OUC is presented in Table 8-1. Although OUC does not own any generating units that rely on No. 6 fuel oil as the primary fuel, the purchase power agreement with Reliant (described in Section 2.3) is based on utilizing a specified proportion of No. 6 fuel oil and natural gas.

8.2.1.4 Nuclear Fuel. The forecast for nuclear fuel remains unchanged from that used for the 2002 OUC Ten-Year Site Plan for the years 2003 through 2011. The forecast for 2012 was developed by applying the general inflation rate of 2.5 percent to the 2011 forecast. The nuclear fuel price forecast is presented in Table 8-1.

Year	Coal	Natural Gas	No. 6 Oil	Nuclear
2003	\$1.84	\$4.37	\$3.54	\$0.40
2004	\$1.92	\$4.42	\$3.59	\$0.41
2005	\$2.00	\$4.46	\$3.65	\$0.42
2006	\$2.04	\$4.50	\$3.63	\$0.43
2007	\$2.11	\$4.55	\$3.67	\$0.44
2008	\$2.21	\$4.59	\$3.74	\$0.45
2009	\$2.27	\$4.64	\$3.82	\$0.46
2010	\$2.32	\$4.69	\$3.90	\$0.47
2011	\$2.43	\$4.73	\$3.97	\$0.49
2012	\$2.80	\$4.78	\$4.05	\$0.50

8.2.2 High and Low Fuel Price Projections.

In order to address the uncertainty surrounding forecasting fuel prices ten years into the future, OUC developed high and low fuel price forecasts for coal natural gas, and No. 6 fuel oil. For nuclear fuel, the base case average annual escalation rate was increased by 2 percentage points (high case) and decreased by 2 percentage points (low case). The resulting high fuel price forecast is presented in Table 8-2, and the resulting low fuel price forecast is presented in Table 8-3.

Table 8-2. High Fuel Price Forecast Summary (Delivered nominal \$/MBtu)				
Year	Coal	Natural Gas	No. 6 Oil	Nuclear
2003	\$1.88	\$4.59	\$4.95	\$0.40
2004	\$1.98	\$4.73	\$5.03	\$0.42
2005	\$2.09	\$4.87	\$5.11	\$0.44
2006	\$2.15	\$5.02	\$5.08	\$0.46
2007	\$2.27	\$5.17	\$5.13	\$0.48
2008	\$2.39	\$5.32	\$5.24	\$0.50
2009	\$2.45	\$5.48	\$5.34	\$0.52
2010	\$2.51	\$5.65	\$5.45	\$0.54
2011	\$2.65	\$5.82	\$5.56	\$0.57
2012	\$3.00	\$5.99	\$5.67	\$0.59

Table 8-3. Low Fuel Price Forecast Summary (Delivered nominal \$/MBtu)				
Year	Coal	Natural Gas	No. 6 Oil	Nuclear
2003	\$1.83	\$3.13	\$2.12	\$0.40
2004	\$1.89	\$3.13	\$2.16	\$0.40
2005	\$1.96	\$3.13	\$2.19	\$0.40
2006	\$1.98	\$3.13	\$2.18	\$0.41
2007	\$2.04	\$3.13	\$2.20	\$0.41
2008	\$2.13	\$3.13	\$2.24	\$0.41
2009	\$2.17	\$3.13	\$2.29	\$0.41
2010	\$2.21	\$3.13	\$2.34	\$0.41
2011	\$2.29	\$3.13	\$2.38	\$0.42
2012	\$2.46	\$3.13	\$2.43	\$0.42

8.3 Fuel Availability

Plentiful coal and natural gas reserves exist both in the United States and North American mainland and coastal regions. Large coal reserves within the east, central, and western United States are adequate to supply power generation needs for the foreseeable future. Oil reserves are dependent upon both domestic and offshore production and imports. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home heating and power production is contributing to the volatility of its price, which in turn has provided incentives for

increased production. A somewhat cyclic effect is expected, where short-term demand and volatility will drive increased production and future price stability.

8.3.1 Service to Proposed Plant Site.

FGT's 26-inch pipeline is located approximately 2.5 miles south of the Stanton Energy Center site which, as discussed in Section 7.0, is the assumed location of the natural gas generating alternatives considered in the Ten-Year Site Plan.

8.3.2 Florida Gas Transmission Company.

FGT is an open access interstate pipeline company transporting natural gas for third parties through its 4,900 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation, which is the leading supplier and transporter of natural gas in the Southeast from Texas into Florida. Citrus Corporation is owned jointly by Enron Corp. and El Paso Energy, with each maintaining a 50 percent ownership interest.

The FGT pipeline system accesses a diversity of natural gas supply regions, including:

- Anadarko Basin (Texas, Oklahoma, and Kansas).
- Arkona Basin (Oklahoma and Arkansas).
- Texas and Louisiana Gulf Areas (Gulf of Mexico).
- Black Warrior Basin (Mississippi and Alabama).
- Louisiana – Mississippi – Alabama Salt Basin.
- Mobile Bay.

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.95 billion cubic feet per day.

8.3.3 Florida Gas Transmission Market Area Pipeline System.

The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County where it turns south, generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa-St. Petersburg-Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the

St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

8.3.4 Florida Gas Transmission Expansions.

The Phase IV Expansion project, completed May 1, 2001, added 134 miles of underground pipeline and more than 38,000 horsepower of compression to FGT's existing underground natural gas transmission system. The expansion allows FGT to transport approximately 200 million cubic feet per day (MMcf/d) of additional natural gas for use in electric power generation and to supply natural gas to homes and businesses through local distribution companies.

FGT's Phase V expansion faced many changes that caused it to file an amended project application with FERC. After the Florida Supreme Court ruling that limited the ability of nonutility merchant plants to use the Florida Electrical Power Plant Siting Act, two major Phase V customers, Enron and Dynergy, withdrew from Phase V. However, FGT subsequently gained back some of the lost market by signing a long-term contract with Tampa Electric Company as a Phase V customer. FERC granted preliminary approval to the expansion in November of 2000. The Phase V expansion received final environmental approval in the summer of 2001.

As of April 2002, FGT had completed and placed into service the second stage of its four-stage Phase V expansion project. Scheduled for completion in mid 2003, the Phase V project will add approximately 167 miles of new pipeline and 132,615 horsepower of compression to the existing system. The result of this expansion will be the addition of more than 428 MMcf/d of incremental mainland capacity to Florida.

On November 15, 2001, FGT filed an application with FERC to expand its existing transmission system (the Phase VI Expansion). The new pipeline will add approximately 33 miles of new pipeline and 18,600 horsepower of additional compression to the existing FGT system. The purpose of the Phase VI Expansion is to deliver additional natural gas to four existing customers, including OUC. With a projected cost of \$105 million, the Phase VI Expansion will provide approximately 121 MMcf/d of incremental firm transportation capacity. Phase VI is scheduled to be completed by November 1, 2003.

8.3.5 Gulfstream Pipeline.

In April 2000, FERC granted preliminary approval for the construction of two natural gas pipelines capable of servicing Peninsular Florida. The Buccaneer gas pipeline (to be jointly developed by Williams Energy and Duke Energy) and the Gulfstream

pipeline (to be developed by Coastal Corporation) each received one of the two required approvals from FERC in September 2000. Shortly thereafter, in November 2000, Williams Energy and Duke Energy announced their intent to purchase the Gulfstream project from Coastal Corporation, subject to federal regulatory approvals and conditioned upon completion of the Coastal Corporation/El Paso Energy Corporation merger. Federal regulatory approval was subsequently granted and the Coastal/El Paso merger was finalized as well.

Plans for the Buccaneer pipeline were dropped by Williams and Duke, who instead focused on the Gulfstream pipeline. The \$1.6 billion pipeline project won FERC approval, subject to environmental review, on April 24, 2000. FERC issued its final Environmental Impact Statement in January 2001, with its final order issued in February 2001. The first major acquisition of right-of-way occurred July 20, 2000 with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained permanent right-of-way easement to cross through Port Manatee. Construction of the pipeline began May 31, 2001, and the Gulfstream pipeline was placed into service May 28, 2002.

The Gulfstream pipeline represents the first new natural gas pipeline in the State of Florida in over 40 years, and has a capacity of approximately 1.1 billion cubic feet per day. Gulfstream spans a total of 581 miles, originating near Pascagoula, Mississippi and Mobile, Alabama, crossing the Gulf of Mexico with more than 30 miles of 36-inch diameter pipeline to Manatee County, Florida. Once onshore, 130 miles of pipe ranging in diameter from 36 inches to 16 inches cross Manatee, Hardee, Polk, and Osceola counties. FERC has certified an additional 173 miles of 24-inch, 30-inch, and 36-inch diameter onshore mainland pipe. Gulfstream is supplied with its natural gas in Mobile Bay, East Louisiana, and Mississippi, which have total supply area reserves of 22.7 billion cubic feet of natural gas.

8.4 Results for Capacity Expansion Plans

8.4.1 Methodology.

The supply-side evaluation of generating unit alternatives was performed using POWROPT, an optimal generation expansion model developed by Black & Veatch. Developed as an alternative to and benchmarked against other optimization programs, POWROPT has proven to be an effective modeling program. POWROPT has been used in several Need for Power proceedings before the Florida Public Service Commission.

POWROPT operates on an hourly chronological basis and is used to determine a set of capacity expansion plans based on capacity requirements, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth

revenue requirements. POWROPT evaluates all combinations of available generating unit alternatives and purchase power options to maintain user-defined reliability criteria. The reserve requirement utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a 10-year period from 2003 through 2012.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's detailed chronological production costing program, POWRPRO, was used to obtain the annual production cost for the expansion plan. For purposes of expansion planning, POWROPT and POWRPRO consider the combined systems of OUC and St. Cloud.

8.4.2 Expansion Candidates.

The expansion candidates for the POWROPT evaluation are presented in Section 7.0. OUC's elected amounts of capacity through extension of the Reliant PPAs from fiscal year 2004 through fiscal year 2007 (described in Section 2.3) have been included among the existing generation resources and are not considered as capacity addition alternatives.

8.4.3 Results of the Economic Analysis.

The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and planned reserve margins. The evaluations were based upon the cost and performance characteristics of the generating unit alternatives described in detail in Section 7.0. Production costs were modeled at temperatures which closely approximate (within two degrees) the average annual temperature for OUC. Winter and summer unit ratings were used to determine capacity requirements. Table 8-4 represents the least-cost capacity addition plan for the combined OUC and St. Cloud system under the base case scenario, while Tables 8-5 and 8-6 present the forecast reserve margins for the combined OUC and St. Cloud system after implementation of the expansion plan presented in Table 8-4 for the winter and summer seasons, respectively. Examination of the annual costs shows a decrease between 2005 and 2006, which is attributable to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

Table 8-4 OUC Least-Cost Base Case Expansion Plan ¹			
Year	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$166,490	\$166,490
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$203,711	\$355,111
2005	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$208,144	\$533,561
2006		\$193,337 ²	\$687,038
2007	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$207,896	\$839,848
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$218,098	\$988,282
2009		\$236,184	\$1,137,118
2010	40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$241,865	\$1,278,243
2011	156 MW GE 7FA Simple Cycle CT (06/01/2011)	\$259,056	\$1,418,203
2012		\$283,028	\$1,559,788

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

Table 8-5
OUC and St. Cloud (STC) Forecast Winter Reserve Requirements – Base Case After Expansion Plan

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
	OUC	STC	RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed ¹	SEC A PPA ²	Reliant PPA	TECO P.R.	Total	Required ³	Available ⁴	
2003/04	1,058	113	76	65	0	75	0	1,387	1,273	364	500	15	2,153	187	768	581
2004/05	1,083	117	101	44	0	0	0	1,345	1,253	354	300	15	1,922	195	579	384
2005/06	1,114	121	0	34	0	0	00	1,269	1,253	344	100	15	1,712	201	445	244
2006/07	1,152	125	0	0	0	0	0	1,277	1,253	336	100	15	1,704	192	429	238
2007/08	1,182	129	0	0	0	0	0	1,311	1,253	336	0	15	1,604	197	295	99
2008/09	1,219	133	0	0	0	0	0	1,352	1,428	296	0	15	1,739	203	389	186
2009/10	1,253	138	0	0	0	0	0	1,391	1,428	296	0	15	1,739	209	350	142
2010/11	1,287	143	0	0	0	0	0	1,430	1,428	256	0	15	1,699	215	271	57
2011/12	1,322	148	0	0	0	0	0	1,470	1,603	256	0	15	1,874	221	406	186
2012/13	1,356	153	0	0	0	0	0	1,509	1,603	256	0	0	1,859	226	350	124

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.

Table 8-6
OUC and St. Cloud (STC) Forecast Summer Reserve Requirements – Base Case After Expansion Plan

Year	Retail Peak Demand (MW)		Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
	OUC	STC	RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed ¹	SEC A PPA ²	Reliant PPA	TECO P.R.	Total	Required ³	Available ⁴	
2003	1,054	104	101	87	20	75	20 ⁶	1,461	1,047	0	577.5	15	1,640	169	181	12
2004	1,081	107	101	65	0	0	0	1,354	1,214	337	500	15	2,066	193	714	521
2005	1,105	111	113	43	0	0	0	1,372	1,192	327	300	15	1,834	199	464	265
2006	1,134	114	0	22	0	0	0	1,270	1,192	317	100	15	1,624	187	356	169
2007	1,169	118	0	0	0	0	0	1,287	1,192	309	100	15	1,616	193	331	138
2008	1,199	122	0	0	0	0	0	1,321	1,332	309	0	15	1,656	198	337	139
2009	1,235	127	0	0	0	0	0	1,362	1,332	269	0	15	1,616	204	256	52
2010	1,267	131	0	0	0	0	0	1,398	1,332	269	0	15	1,616	210	220	10
2011	1,300	136	0	0	0	0	0	1,436	1,472	229	0	15	1,716	215	282	67
2012	1,333	141	0	0	0	0	0	1,474	1,472	229	0	15	1,716	221	244	23

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.
6. The 20 MW sale to KUA is subordinate to native load and therefore is not included in the calculation to maintain the 15% reserve margin.

8.5 Sensitivity Analysis

Several sensitivity analyses were performed to measure the impact of key assumptions. The sensitivity analyses include high and low fuel price scenarios as well as high load and energy growth and low load and energy growth scenarios. The sensitivity analyses were performed over a 10-year planning horizon, similar to the base case economic evaluation, with a projection of both annual and cumulative present worth costs.

8.5.1 High Fuel Price Scenario.

The high fuel price forecast is provided in Table 8-2. Table 8-7 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price sensitivity case.

8.5.2 Low Fuel Price Scenario.

The low fuel price forecast is provided in Table 8-3. Table 8-8 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price sensitivity case.

8.5.3 High Load and Energy Growth.

The high load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the base case forecast. When compared to the base case, the high load and energy growth scenario requires the addition of more generation and therefore an increase in cumulative present worth for the least-cost capacity addition plan. The high load and energy growth scenario is based upon the high load and energy growth forecast presented in Section 4.0. Tables 8-9 and 8-10 indicate the summer and winter need for capacity based upon the high load and energy growth forecast.

Analysis of Tables 8-9 and 8-10 show that under the high load and energy growth scenario, OUC would not require additional generating capacity to satisfy winter requirements until winter 2008/09. Additionally, OUC will have sufficient summer generating capacity through the summer of 2007, with the need for additional summer capacity initiating during the summer of 2008 and increasing annually thereafter. Table 8-11 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity.

8.5.4 Low Load and Energy Growth.

The low load and energy growth scenario provides insight into the effect of resource decisions made in an environment where load and energy growth is less than the

base case forecast. The low load and energy growth scenario requires less generation resources than the base case forecast. The low load and energy growth scenario is based upon the low load and energy growth forecast presented in Section 4.0. Tables 8-12 and 8-13 indicate the summer and winter need for capacity based upon the low load and energy forecast, and show that under the low load and energy growth scenario OUC would not need additional capacity until the summer of 2012, assuming no reduction to the amount of capacity purchased under the Stanton A Southern-Florida power purchase agreement. Table 8-14 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity.

8.5.5 No. 2 Fuel Oil Scenario.

The No. 2 fuel oil sensitivity examines a scenario in which the simple cycle combustion turbines candidates available to OUC would be run only on No. 2 fuel oil instead of natural gas. In order to consider such a situation, a forecast had to be developed for No. 2 fuel oil. To do so, the annual difference in price between No. 2 and No. 6 fuel oils used in the Stanton Energy Center A Need for Power Application was applied to the forecast for No. 6 fuel oil presented in Table 8-1 herein. The resulting No. 2 fuel oil forecast is presented in Table 8-15, along with the results of the least-cost expansion plan under this scenario.

Table 8-7 OUC High Fuel Price Sensitivity Least-Cost Expansion Plan ¹			
Year	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$177,087	\$177,087
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$211,186	\$372,630
2005	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$218,143	\$559,652
2006		\$204,450 ²	\$721,951
2007	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$222,194	\$885,270
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$235,034	\$1,045,230
2009		\$256,669	\$1,206,975
2010	40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$264,990	\$1,361,595
2011	156 MW GE 7FA Simple Cycle CT (06/01/2011)	\$285,591	\$1,515,890
2012		\$318,077	\$1,675,008
<p>1. Capacity is stated at average annual temperature for OUC. 2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.</p>			

Table 8-8
OUC Low Fuel Price Sensitivity Least-Cost Expansion Plan¹

Year	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$150,905	\$150,905
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$181,929	\$319,357
2005	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$187,654	\$480,241
2006		\$176,790 ³	\$620,582
2007	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$189,599	\$759,943
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$197,399	\$894,290
2009		\$209,002	\$1,025,997
2010	40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$212,779	\$1,150,151
2011	156 MW GE 7FA Simple Cycle CT (06/01/2011)	\$227,468	\$1,273,045
2012		\$243,675	\$1,394,943

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

Table 8-9

OUC and St. Cloud (STC) Winter Reserve Requirements – High Load and Energy Growth Sensitivity without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
	OUC & STC	RCID	FMPA	FMPA	SEC	KUA		Installed ¹	SEC A	Reliant	TECO	Total	Required	Available	
		P.R.	I.R.	D-2	I.R.	D			PPA ²	PPA	P.R.				
2003/04	1,178	76	65	0	75	0	1,394	1,273	364	500	15	2,153	188	761	573
2004/05	1,236	101	44	0	0	0	1,381	1,252	354	300	15	1,922	201	543	343
2005/06	1,282	0	34	0	0	0	1,316	1,252	344	100	15	1,712	208	398	189
2006/07	1,330	0	0	0	0	0	1,330	1,252	336	100	15	1,704	200	376	176
2007/08	1,380	0	0	0	0	0	1,380	1,252	336	0	15	1,704	207	226	19
2008/09	1,432	0	0	0	0	0	1,432	1,252	336	0	15	1,604	215	134	(81)
2009/10	1,486	0	0	0	0	0	1,486	1,252	336	0	15	1,604	223	41	(182)
2010/11	1,541	0	0	0	0	0	1,541	1,252	336	0	15	1,604	231	(55)	(286)
2011/12	1,599	0	0	0	0	0	1,599	1,252	336	0	15	1,604	240	(153)	(393)
2012/13	1,659	0	0	0	0	0	1,659	1,252	336	0	0	1,589	249	(110)	(359)

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.

Table 8-10

OUC and St. Cloud (STC) Summer Reserve Requirements – High Load and Energy Growth Sensitivity without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
	OUC & STC	RCID	FMPA	FMPA	SEC	KUA		Installed ¹	SEC A	Reliant	TECO	Total	Required	Available	
		P.R.	I.R.	D-2	I.R.	D			PPA ²	PPA	P.R.				
2003	1,156	101	87	20	75	20 ⁶	1,459	1,047	0	577.5	15	1,640	168	182	14
2004	1,204	101	65	0	0	0	1,370	1,214	337	500	15	2,066	196	698	503
2005	1,253	113	43	0	0	0	1,409	1,193	327	300	15	1,834	205	427	222
2006	1,298	0	22	0	0	0	1,320	1,193	317	100	15	1,624	195	306	111
2007	1,345	0	0	0	0	0	1,345	1,193	309	100	15	1,516	202	273	72
2008	1,393	0	0	0	0	0	1,393	1,193	309	0	15	1,516	209	125	(84)
2009	1,443	0	0	0	0	0	1,443	1,193	309	0	15	1,516	216	35	(181)
2010	1,495	0	0	0	0	0	1,495	1,193	309	0	15	1,516	224	(57)	(281)
2011	1,548	0	0	0	0	0	1,548	1,193	309	0	15	1,516	232	(150)	(383)
2012	1,604	0	0	0	0	0	1,604	1,193	309	0	15	1,516	241	(246)	(487)

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.
6. The 20 MW sale to KUA is subordinate to native load and therefore is not included in the calculation to maintain the 15% reserve margin.

Table 8-11
 OUC High Load Growth Sensitivity Least-Cost Expansion Plan¹

Year	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$158,282	\$158,282
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$203,804	\$346,989
2005	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$212,273	\$528,979
2006		\$200,330 ²	\$688,008
2007	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$217,555	\$847,917
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$230,793	\$1,004,991
2009	156 MW GE 7FA Simple Cycle CT (06/01/2009)	\$253,060	\$1,164,462
2010	40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$265,745	\$1,319,521
2011	156 MW GE 7FA Simple Cycle CT (06/01/2011)	\$287,545	\$1,474,873
2012		\$317,444	\$1,633,674

1. Capacity is stated at average annual temperature for OUC.
 2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

Table 8-12
OUC and St. Cloud (STC) Winter Reserve Requirements – Low Load and Energy Growth Sensitivity without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed ¹	SEC A PPA ²	Reliant PPA	TECO P.R.	Total	Required	Available	
2003/04	1,119	76	65	0	75	0	1,335	1,273	364	500	15	2,153	179	819	640
2004/05	1,160	101	44	0	0	0	1,305	1,252	354	300	15	1,922	189	619	430
2005/06	1,184	0	34	0	0	0	1,218	1,252	344	100	15	1,712	194	496	303
2006/07	1,208	0	0	0	0	0	1,208	1,252	336	100	15	1,704	181	498	317
2007/08	1,233	0	0	0	0	0	1,233	1,252	336	0	15	1,704	185	373	188
2008/09	1,258	0	0	0	0	0	1,258	1,252	336	0	15	1,604	189	308	119
2009/10	1,284	0	0	0	0	0	1,284	1,252	336	0	15	1,604	193	242	50
2010/11	1,310	0	0	0	0	0	1,310	1,252	336	0	15	1,604	197	176	(20)
2011/12	1,337	0	0	0	0	0	1,337	1,252	336	0	15	1,604	201	109	(91)
2012/13	1,364	0	0	0	0	0	1,364	1,252	336	0	0	1,589	205	64	(141)

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.

Table 8-13
OUC and St. Cloud (STC) Summer Reserve Requirements – Low Load and Energy Growth Sensitivity without Capacity Additions

Year	Retail Peak Demand (MW)	Contracted Firm Wholesale Delivery (MW)					Total Peak Demand (MW)	Available Capacity (MW)					Reserves (MW)		Excess/(Deficit) Capacity to Maintain 15% Reserve Margin ⁵ (MW)
		RCID P.R.	FMPA I.R.	FMPA D-2	SEC I.R.	KUA D		Installed ¹	SEC A PPA ²	Reliant PPA	TECO P.R.	Total	Required	Available	
2003	1,113	101	87	20	75	20 ⁶	1,416	1,047	0	577.5	15	1,640	162	226	64
2004	1,144	101	65	0	0	0	1,310	1,214	337	500	15	2,066	187	758	571
2005	1,176	113	43	0	0	0	1,332	1,193	327	300	15	1,834	193	504	311
2006	1,198	0	22	0	0	0	1,220	1,193	317	100	15	1,624	180	406	226
2007	1,221	0	0	0	0	0	1,221	1,193	309	100	15	1,516	183	397	214
2008	1,244	0	0	0	0	0	1,244	1,193	309	0	15	1,516	187	274	88
2009	1,267	0	0	0	0	0	1,267	1,193	309	0	15	1,516	190	211	21
2010	1,291	0	0	0	0	0	1,291	1,193	309	0	15	1,516	194	287	94
2011	1,315	0	0	0	0	0	1,315	1,193	309	0	15	1,516	197	223	26
2012	1,340	0	0	0	0	0	1,340	1,193	309	0	15	1,516	201	158	(43)

1. Includes OUC's equity portion of SEC A, as well as St. Cloud's diesel units (which are scheduled to retire in November 2004).
2. Includes OUC's purchase of SEC A capacity from Southern-Florida and KUA.
3. Required reserves include 15% reserve margin on OUC retail peak demand, STC retail peak demand, and RCID partial requirements contract.
4. Available reserves equals the difference between total available capacity and total peak demand, plus 15 % of the TECO P.R. purchase.
5. Calculated as the difference between available reserves and required reserves.
6. The 20 MW sale to KUA is subordinate to native load and therefore is not included in the calculation to maintain the 15% reserve margin.

Table 8-14
OUC Low Load Growth Sensitivity Least-Cost Expansion Plan¹

Year	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$150,774	\$150,774
2004	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$194,137	\$330,531
2005	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$199,275	\$501,377
2006		\$183,483 ²	\$647,032
2007	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$193,804	\$789,484
2008	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$200,874	\$926,195
2009	40 MW Reduction in Southern-Florida Power Purchase (10/01/2009)	\$209,386	\$1,058,143
2010	156 MW GE 7FA Simple Cycle CT (06/01/2010) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$214,353	\$1,183,216
2011	40 MW Reduction in Southern-Florida Power Purchase (10/01/2011)	\$223,128	\$1,303,766
2012	156 MW GE 7FA Simple Cycle CT (06/01/2012)	\$239,181	\$1,423,415

1. Capacity is stated at average annual temperature for OUC.
2. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

Table 8-15. OUC No. 2 Fuel Oil Sensitivity - Least-Cost Expansion Plan ¹				
Year	No. 2 Fuel Oil (\$/MBtu) ²	Generation Addition (month/year)	Annual Costs (\$1000)	Cumulative Present Worth (\$1000)
2003	4.63	Terminate 577.5 MW Reliant Power Purchase Start 500 MW Reliant Power Purchase (10/01/2003) 171 MW Stanton A (10/01/2003) Start 317 MW Southern - Florida Power Purchase (10/01/2003)	\$166,490	\$166,490
2004	4.65	Terminate 500 MW Reliant Power Purchase (09/30/2004) Start 300 MW Reliant Power Purchase (10/01/2003)	\$203,711	\$355,111
2005	4.71	Terminate 300 MW Reliant Power Purchase (09/30/2004) Start 100 MW Reliant Power Purchase (10/01/2003)	\$208,144	\$533,561
2006	4.67		\$193,337 ³	\$687,038
2007	4.73	Terminate 100 MW Reliant Power Purchase (09/30/2007)	\$207,896	\$839,848
2008	4.81	156 MW GE 7FA Simple Cycle CT (06/01/2008) 40 MW Reduction in Southern-Florida Power Purchase (10/01/2008)	\$218,162	\$988,325
2009	4.91		\$236,236	\$1,137,194
2010	5.04	40 MW Reduction in Southern-Florida Power Purchase (10/01/2010)	\$241,885	\$1,278,331
2011	5.13	156 MW GE 7FA Simple Cycle CT (06/01/2011)	\$259,251	\$1,418,397
2012	5.26		\$283,249	\$1,560,092

1. Capacity is stated at average annual temperature for OUC.
2. No. 2 fuel oil forecast represents delivered, nominal price.
3. Reduction in annual cost in 2006 as compared to 2005 is due to the expiration of OUC's partial requirements contract with Reedy Creek Improvement District, under which OUC supplies a significant amount of capacity and energy.

9.0 Environmental and Land Use Information

The Stanton Energy Center, originally certified for 2,000 MW, currently consists of two pulverized coal units, which went into service in 1987 and 1996. 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. 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. The identification of the GE 7FA combustion turbines in Section 8 herein as part of the least-cost expansion plan is considered indicative at this point, and no formal plans have been developed for their construction at this time. However, should future studies continue to indicate construction of these units is cost-effective for OUC, they will likely be constructed at the Stanton Energy Center site or a new site. Specific site layouts have been developed and existing infrastructure is available to support the 7FA combustion turbines at the Stanton Site. The following information focuses on Stanton A to be installed for commercial operation on October 1, 2003 and also applies to future combustion turbines installed at Stanton.

9.1 Status of Site Certification

Ultimate certification for 2,000 MW was obtained with the Site Certification for Stanton 1. Stanton 2 was certified under the Supplemental Site Certification provisions of the Florida Electrical Power Plant Siting Act (Act). Stanton A received final site certification on September 18, 2001 and construction began in November 2001 to support the scheduled October 1, 2003 commercial operation date.

9.2 Land and Environmental Features

The Stanton Energy Center is located in Orange County, Florida, with approximately 3,280 acres. The Econlockhatchee River is about three-fourths of one 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.

Currently, a natural gas pipeline is planned to be installed to connect Stanton A to the Florida Gas Transmission (FGT) system. The pipeline will be approximately 2.5 miles in total length, connecting with FGT's system south of the Stanton site. The pipeline is planned to be routed in the existing transmission and railroad spur right-of-way. Other pipelines may be considered as competing pipelines are successful in getting approved for construction in the State.

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 and Stanton A.

9.3 Air Emissions

Stanton A, a GE 7FA 2x1 combined cycle unit, will utilize lox NO_x combustors as well as selective catalytic reduction (SCR) to reduce NO_x emissions. The resulting expected NO_x emissions are 3.5 parts per million (ppm). The HRSG will be designed to include a spool piece for a CO catalyst, but installation of the CO catalyst is not required at this time. No. 2 fuel oil will be used as an alternate fuel and SO₂ emissions will be controlled by limiting the sulfur content of the oil.

9.4 Water and Wastewater

The use of combined cycle technology reduces the amount of water required by Stanton A as compared to conventional steam generation. Stanton A will obtain water in the same manner as the existing Stanton units with ground water being used for steam cycle makeup and water injection. Treated sewage effluent from the Orange County Easterly Subregional Wastewater Treatment Plant will be used for Stanton A, as it is currently used for Stanton 1 and Stanton 2 and for other Stanton A service water requirements.

The Stanton site is designed to reuse wastewater to the extent possible. When wastewater cannot be reused, it is evaporated with a brine concentrator/crystalizer; thus, the Stanton site is truly a zero discharge site. Stanton A will utilize the same wastewater treatment process as the existing Stanton units.

10.0 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 2003 OUC Ten-Year Site Plan.

Table 10-1 (Schedule 1)
OUC and St. Cloud Existing Generating Facilities as of December 31, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)
Plant Name	Unit No.	Location	Unit Type	Primary Fuel		Alternate Fuel		Alt Fuel Storage (Days Burn)	Commercial In-Service MM/YYYY	Expected Retirement MM/YYYY	Gross Capability ¹		Net Capability ¹	
				Fuel Type	Transport Method	Fuel Type	Transport Method				Summer MW	Winter MW	Summer MW	Winter MW
Indian River	A	Brevard	GT	NG	PL	DFO	TK	0.2	06/1989	Unknown	18.30	23.50	18.00	23.30
Indian River	B	Brevard	GT	NG	PL	DFO	TK	0.2	07/1989	Unknown	18.30	23.50	18.00	23.30
Indian River	C	Brevard	GT	NG	PL	DFO	TK	0.2	08/1992	Unknown	86.10	101.10	85.30	100.30
Indian River	D	Brevard	GT	NG	PL	DFO	TK	0.2	10/1992	Unknown	86.10	101.10	85.30	100.30
Stanton Energy Center	1	Orange	ST	BIT	RR	NA	UN	UN	07/1987	Unknown	320.13	322.19	301.62	303.68
Stanton Energy Center	2	Orange	ST	BIT	RR	NA	UN	UN	06/1996	Unknown	335.76	335.76	319.29	319.29
McIntosh	3	Polk	ST	BIT	REF	NA	UN	UN	09/1982	Unknown	146.00	146.00	136.80	136.80
Crystal River	3	Citrus	ST	NUC	TK	NA	UN	UN	03/1977	Unknown	14.03	14.27	13.36	13.64
St. Lucie ²	2	St. Lucie	ST	NUC	TK	NA	UN	UN	08/1983	Unknown	54.20	54.20	51.09	51.94
St. Cloud	1	Osceola	IC	NG	PL	DFO	TK	5	07/1982	11/2004	1.825	1.825	1.825	1.825
St. Cloud	2	Osceola	IC	NG	PL	DFO	TK	5	12/1974	11/2004	5.000	5.000	5.000	5.000
St. Cloud	3	Osceola	IC	NG	PL	DFO	TK	5	09/1982	11/2004	1.825	1.825	1.825	1.825
St. Cloud	4	Osceola	IC	NG	PL	DFO	TK	5	08/1961	11/2004	3.000	3.000	3.000	3.000
St. Cloud	6	Osceola	IC	NG	PL	DFO	TK	5	03/1967	11/2004	3.000	3.000	3.000	3.000
St. Cloud	7	Osceola	IC	NG	PL	DFO	TK	5	09/1982	11/2004	6.000	6.000	6.000	6.000
St. Cloud ³	8	Osceola	IC	NG	PL	DFO	TK	5	04/1977	11/2004	6.000	6.000	6.000	6.000

1. OUC ownership share

2. Reliability exchange divides 50% power from Unit 1 and 50% power from Unit 2.

3. St. Cloud Unit 8 has never been connected to the grid and therefore is not included in the summation of existing generating capacity.

(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
1993	306,300	2.59	1,406	118,452	11,870	327	15,408	21,223
1994	312,400	2.59	1,454	120,813	12,035	335	15,678	21,368
1995	315,900	2.56	1,560	123,351	12,647	335	15,953	20,999
1996	321,600	2.56	1,609	125,617	12,809	336	16,221	20,714
1997	330,000	2.55	1,568	129,433	12,114	341	16,416	20,772
1998	341,000	2.55	1,804	133,732	13,490	331	16,597	19,943
1999	351,400	2.55	1,725	137,815	12,517	330	17,066	19,337
2000	362,000	2.56	1,821	141,546	12,865	318	17,172	18,519
2001	372,200	2.55	1,893	145,762	12,987	316	17,281	18,286
2002	380,700	2.55	1,967	150,365	13,082	314	17,681	17,759
Forecast								
2003	384,000	2.55	1,976	150,372	13,141	330	17,635	18,713
2004	391,300	2.55	2,028	153,287	13,230	333	17,862	18,643
2005	398,500	2.55	2,079	156,066	13,321	337	18,067	18,653
2006	405,700	2.55	2,129	158,910	13,398	341	18,273	18,661
2007	413,400	2.55	2,182	161,948	13,473	344	18,485	18,610
2008	421,700	2.55	2,238	165,261	13,542	348	18,718	18,592
2009	431,400	2.55	2,303	169,026	13,625	353	18,971	18,607
2010	440,900	2.55	2,369	172,828	13,707	356	19,229	18,514
2011	450,300	2.55	2,435	176,476	13,798	361	19,485	18,527
2012	459,800	2.55	2,502	180,216	13,883	364	19,747	18,433

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
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
1993	2,075	2,752	753,997	0	25	4	3,837
1994	2,185	2,872	760,794	0	24	5	4,003
1995	2,263	3,072	736,654	0	24	5	4,187
1996	2,321	3,245	715,254	0	26	5	4,297
1997	2,399	3,597	666,945	0	26	5	4,339
1998	2,569	3,956	649,393	0	25	5	4,734
1999	2,725	4,078	668,220	0	28	5	4,813
2000	2,859	4,418	647,199	0	28	6	5,032
2001	2,967	4,774	621,557	0	31	6	5,213
2002	3,031	4,981	608,512	0	40	6	5,358
Forecast							
2003	3,162	5,060	624,802	0	40	6	5,513
2004	3,253	5,243	620,465	0	44	6	5,664
2005	3,331	5,420	614,520	0	48	6	5,800
2006	3,437	5,597	613,990	0	51	6	5,963
2007	3,575	5,775	618,996	0	54	6	6,161
2008	3,678	5,955	617,666	0	58	6	6,328
2009	3,806	6,139	620,003	0	61	6	6,529
2010	3,913	6,323	618,868	0	65	6	6,709
2011	4,022	6,507	618,042	0	68	6	6,892
2012	4,137	6,692	618,171	0	72	6	7,080

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

(1) Year	(2) Sales for Resale ² GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
1993	0	175	4,012	0	121,204
1994	0	141	4,144	0	123,685
1995	0	188	4,375	0	126,423
1996	0	174	4,471	0	128,862
1997	0	226	4,565	0	133,030
1998	0	175	4,909	0	137,688
1999	0	198	5,011	0	141,893
2000	0	259	5,291	0	145,963
2001	971	191	6,375	0	150,536
2002	820	217	6,395	0	155,346
Forecast					
2003	789	246	6,548	0	155,432
2004	726	251	6,641	0	158,530
2005	719	256	6,775	0	161,486
2006	24	264	6,251	0	164,507
2007	0	271	6,432	0	167,723
2008	0	279	6,607	0	171,216
2009	0	287	6,816	0	175,165
2010	0	296	7,005	0	179,151
2011	0	303	7,195	0	182,983
2012	0	314	7,394	0	186,908

1. Historical and forecast data includes both OUC and the City of St. Cloud.
2. To maintain consistency with the FRCC Forms, the "Sales for Resale" forecast includes OUC's forecast GWh sales to FMPA, KUA, SEC, and RCID. Historical "Sales for Resale" includes GWh sales to FMPA, KUA, SEC, and RCID for 2001 and 2002, as in the FERC forms.

Table 10-5 (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	Commercial/Industrial	Conservation	Net Firm Demand
					Load Management	Load Management		
1993	760	0	760	0	0	0	-	760
1994	808	0	808	0	0	0	-	808
1995	862	0	862	0	0	0	-	862
1996	852	0	852	0	0	0	-	852
1997	917	0	917	0	0	0	-	917
1998	988	0	988	1	0	0	-	987
1999	1,055	0	1,055	0	0	0	-	1,055
2000	1,026	0	1,026	1	0	0	-	1,025
2001	1,382	341	1,041	1	0	0	-	1,381
2002	1,408	319	1,089	1	0	0	-	1,407
Forecast								
2003	1,462	303	1,159	1	0	0	-	1,461
2004	1,355	166	1,189	1	0	0	-	1,354
2005	1,373	156	1,217	1	0	0	-	1,372
2006	1,271	22	1,249	1	0	0	-	1,270
2007	1,288	0	1,288	1	0	0	-	1,287
2008	1,322	0	1,322	1	0	0	-	1,321
2009	1,363	0	1,363	1	0	0	-	1,362
2010	1,399	0	1,399	1	0	0	-	1,398
2011	1,437	0	1,437	1	0	0	-	1,436
2012	1,475	0	1,475	1	0	0	-	1,474

1. Historical data includes both OUC and the City of St. Cloud for 1994 and beyond. Forecast data includes both OUC and the City of St. Cloud.
 2. Includes conservation.
 3. To maintain consistency with the FRCC Forms, the "Wholesale" forecast includes OUC's forecast MW sales to FMPA, KUA, SEC, and RCID. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001 and 2002, as in the FERC forms.

Table 10-6 (Schedule 3.2) OUC and St. Cloud History and Forecast of Winter Peak Demand (Base Case) ¹								
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total ²	Wholesale ³	Retail	Interruptible	Residential	Commercial/Industrial	Conservation	Net Firm Demand
					Load Management	Load Management		
1992/93	721	0	721	0	0	0	-	721
1993/94	731	0	731	0	0	0	-	731
1994/95	876	0	876	0	0	0	-	876
1995/96	969	0	969	0	0	0	-	969
1996/97	851	0	851	0	0	0	-	851
1997/98	814	0	814	1	0	0	-	813
1998/99	1,030	0	1,030	1	0	0	-	1,029
1999/00	1,060	0	1,060	1	0	0	-	1,059
2000/01	1,066	0	1,066	1	0	0	-	1,065
2001/02	1,345	302	1,044	1	0	0	-	1,345
2002/03	1,414	277	1,137	1	0	0	-	1,413
Forecast								
2003/04	1,388	216	1,172	1	0	0	-	1,387
2004/05	1,346	145	1,201	1	0	0	-	1,345
2005/06	1,270	34	1,236	1	0	0	-	1,269
2006/07	1,278	0	1,278	1	0	0	-	1,277
2007/08	1,312	0	1,312	1	0	0	-	1,311
2008/09	1,353	0	1,353	1	0	0	-	1,352
2009/10	1,392	0	1,392	1	0	0	-	1,391
2010/11	1,431	0	1,431	1	0	0	-	1,430
2011/12	1,471	0	1,471	1	0	0	-	1,470
2012/13	1,509	0	1,509	1	0	0	-	1,509

1. Historical data includes both OUC and the City of St. Cloud for 1993/94 and beyond. Forecast data includes both OUC and the City of St. Cloud.
2. Includes conservation.
3. To maintain consistency with the FRCC Forms, the "Wholesale" forecast includes OUC's forecast MW sales to FMPA, KUA, SEC, and RCID. Historical "Wholesale" includes MW sales to FMPA, KUA, SEC, and RCID for 2001/02 and 2002/03, as in the FERC forms. The 2001/02 data includes the forecasts of each of these sales.

Table 10-7 (Schedule 3.3)
OUC and St. Cloud History and Forecast of Annual Net Energy for Load – GWH (Base Case)¹

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total ²	Conservation	Retail	Wholesale ³	Utility Use & Losses	Net Energy for Load	Load Factor ⁴ (%)
1993	3,837	-	3,837	0	175	4,012	60.3
1994	4,003	-	4,003	0	141	4,144	58.5
1995	4,187	-	4,187	0	188	4,375	57.9
1996	4,297	-	4,297	0	174	4,471	59.9
1997	4,339	-	4,339	0	226	4,565	56.8
1998	4,734	-	4,734	0	175	4,909	56.8
1999	4,813	-	4,813	0	198	5,011	54.2
2000	5,032	-	5,032	0	259	5,291	58.9
2001	5,213	-	5,213	971	191	6,375	52.7
2002	5,358	-	5,358	820	217	6,395	51.9
Forecast							
2003	5,513	-	5,513	789	246	6,548	51.2
2004	5,664	-	5,664	726	251	6,641	56.0
2005	5,800	-	5,800	719	256	6,775	56.4
2006	5,963	-	5,963	24	264	6,251	56.2
2007	6,161	-	6,161	0	271	6,432	57.1
2008	6,328	-	6,328	0	279	6,607	57.1
2009	6,529	-	6,529	0	287	6,816	57.1
2010	6,709	-	6,709	0	296	7,005	57.2
2011	6,892	-	6,892	0	303	7,195	57.2
2012	7,080	-	7,080	0	314	7,394	57.3

1. Historical data includes both OUC and the City of St. Cloud for 1994 and beyond. Forecast data includes both OUC and the City of St. Cloud.
2. Includes conservation.
3. To maintain consistency with the FRCC Forms, the “Wholesale” forecast includes OUC’s forecast GWh sales to FMPA, KUA, SEC, and RCID. Historical “Wholesale” includes MW sales to FMPA, KUA, SEC, and RCID for 2001 and 2002, as in the FERC forms.
4. Forecast load factor calculation considers all retail and wholesale peak demand and energy.

Table 10-8 (Schedule 4)						
OUC and St. Cloud Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month¹						
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Month	Actual – 2002		2003 Forecast		2004 Forecast	
	Peak Demand ² MW	NEL GWh	Peak Demand ² MW	NEL GWh	Peak Demand ² MW	NEL GWh
January	1,345	470	1,413	509	1,387	517
February	1,147	370	1,153	435	1,099	441
March	1,127	477	1,063	479	1,022	493
April	1,235	524	1,199	499	1,182	527
May	1,304	589	1,365	583	1,320	595
June	1,329	552	1,293	597	1,195	606
July	1,403	614	1,461	707	1,353	690
August	1,317	620	1,343	669	1,250	667
September	1,334	621	1,310	596	1,222	598
October	1,277	612	1,159	517	1,058	531
November	1,175	461	1,058	454	934	464
December	1,124	483	1,110	501	1,038	510

1. Includes OUC and City of St. Cloud peak demand and NEL as well as wholesale sales to FMPA, KUA, SEC, and RCID (MW and NEL) for historical 2002 and forecast 2003 and 2004. Forecast 2003 and 2004 also includes OUC wholesale sales to FMPA, KUA, SEC, and RCID.
2. Includes Load Management, Conservation and Interruptible Load.

**Table 10-9 (Schedule 5)
Fuel Requirements¹**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	2002 Actual	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Nuclear		Trillion BTU	6	5	5	5	5	5	5	5	5	5	5
(2)	Coal		1000 Ton	2,022	2,092	1,853	1,987	1,962	2,010	2,006	1,920	1,977	2,095	2,091
(3)	Residual ²	Total	1000 BBL	7	0	0	0	0	4	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	7	0	0	0	0	0	0	0	0	0	0
(7)	Distillate ³	Total	1000 BBL	11	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	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	1000 BBL	11	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Total	1000 MCF	971	3,229	13,104	11,758	8,503	9,016	10,607	13,789	14,019	13,580	15,082
(12)		Steam	1000 MCF	108	0	0	0	0	0	0	0	0	0	0
(13)		CC	1000 MCF	0	3,159	13,104	11,736	8,307	8,398	9,900	11,934	13,229	11,797	13,169
(14)		CT	1000 MCF	863	70	0	22	196	618	707	1,855	790	1,783	1,913
(15)	Other ⁴		Trillion BTU	0	1	0	0	0	0	0	0	0	0	0

1. Includes fuel required for OUC and the City of St. Cloud.

2. Residual includes #4, #5 and #6 oil.

3. Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

4. For 2002, Other does not include the OUC purchase from RES or the STC purchase from TEC. For 2003 and beyond, Other includes the RES purchase, the STC TEC purchase, and any necessary emergency purchases.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	2002 Actual	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Annual Firm Inter-region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	536	489	469	501	489	471	501	489	470	463	489
(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	5	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	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	5	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWH	63	427	1,756	1,569	1,119	1,169	1,379	1,764	1,847	1,747	1,951
(12)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)		CC	GWH	0	421	1,756	1,567	1,103	1,117	1,320	1,608	1,783	1,600	1,791
(14)		CT	GWH	63	6	0	2	16	52	59	156	64	147	160
(15)	Coal	Steam	GWH	5,197	4,926	4,333	4,646	4,588	4,712	4,698	4,513	4,643	4,932	4,925
(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	Purchases	GWH	594	707	83	60	56	80	29	50	45	33	28
		Sales	GWH	0	0	0	0	0	0	0	0	0	0	0
		Total	GWH	594	707	83	60	56	80	29	50	45	33	28
(19)	Net Energy for Load ²		GWH	6,395	6,549	6,641	6,776	6,252	6,432	6,607	6,816	7,005	7,195	7,393

1. For 2002, Other represents purchase necessary to supply retail and firm obligations. For 2003 and beyond, Other includes the OUC purchase from RES and the STC purchase from TEC, as well as any emergency purchases.

2. Variation in Net Energy for Load between Schedule 3.3 and Schedule 6.1 can be attributed to rounding error.

Table 10-11 (Schedule 6.2)															
Energy Sources (%)															
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	
	Energy Sources		Units	2002 Actual	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	
(1)	Annual Firm Inter-region Interchange		GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
(2)	Nuclear	Total	GWH	8.38%	7.47%	7.06%	7.39%	7.82%	7.32%	7.58%	7.17%	6.71%	6.71%	6.61%	
(3)	Residual		GWH	0.00%	9.04%	3.38%	0.12%	0.27%	0.34%	0.00%	0.00%	0.00%	0.00%	0.00%	
(4)			Steam	GWH	0.00%	9.04%	3.38%	0.12%	0.27%	0.34%	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%	
(6)			CT	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
(7)	Distillate		Total	GWH	0.08%	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%	
(9)			CC	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
(10)			CT	GWH	0.08%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
(12)	Natural Gas		Total	GWH	0.99%	6.52%	26.44%	23.16%	17.90%	18.17%	20.87%	25.88%	26.37%	24.28%	26.39%
(12)			Steam	GWH	0.00%	3.89%	7.93%	0.04%	0.11%	0.14%	0.00%	0.00%	0.00%	0.00%	0.00%
(13)			CC	GWH	0.00%	6.43%	26.44%	23.13%	17.64%	17.37%	19.98%	23.59%	25.45%	22.24%	24.23%
(14)			CT	GWH	0.99%	0.09%	0.00%	0.03%	0.26%	0.81%	0.89%	2.29%	0.91%	2.04%	2.16%
(15)	Coal		Steam	GWH	81.27%	75.22%	65.25%	68.57%	73.38%	73.26%	71.11%	66.2%	66.28%	68.55%	66.62%
(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		Purchases	GWH	9.29%	10.80%	1.25%	0.89%	0.90%	1.24%	0.44%	0.73%	0.64%	0.46%	0.38%
			Sales	GWH	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
			Total	GWH	9.29%	10.80%	1.25%	0.89%	0.90%	1.24%	0.44%	0.73%	0.64%	0.46%	0.38%
(19)	Net Energy for Load		GWH	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

1. For 2002, Other represents purchase necessary to supply retail and firm obligations. For 2003 and beyond, Other includes the OUC purchase from RES and the STC purchase from TEC, as well as any emergency purchases.

(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	%
2003	1,047	593	287	0	1,345	1,158	12	15.95%	0	12	15.95%
2004	1,214	852	166	0	1,900	1,188	521	55.39%	0	521	55.39%
2005	1,192	642	156	0	1,678	1,216	265	34.92%	0	265	34.92%
2006	1,192	432	22	0	1,602	1,248	169	28.53%	0	169	28.53%
2007	1,192	424	0	0	1,616	1,287	138	25.73%	0	138	25.73%
2008	1,332	324	0	0	1,656	1,321	139	25.52%	0	139	25.52%
2009	1,332	284	0	0	1,616	1,362	52	18.80%	0	52	18.80%
2010	1,332	284	0	0	1,616	1,398	10	15.74%	0	10	15.74%
2011	1,472	244	0	0	1,716	1,436	67	19.64%	0	67	19.64%
2012	1,472	244	0	0	1,716	1,474	23	16.56%	0	23	16.56%

1. Installed capacity includes the City of St. Cloud's generating units, which are scheduled to retire in November 2004.

2. Firm capacity imports include capacity purchased from Reliant (Indian River units), capacity purchased from KUA (from Stanton A), capacity purchased from TECO, and capacity purchased from Southern-Florida (from Stanton A).

3. Firm capacity export includes all forecast sales to FMPA, SEC, and RCID. The 20 MW sale to KUA is subordinate to native load and therefore is not included in the calculation to maintain the 15% reserve margin..

4. Includes OUC peak demand and City of St. Cloud peak demand.

5. Assumes TECO purchase (15 MW) includes reserves and that OUC must include reserves to meet its retail peak demand and the City of St. Cloud's retail peak demand. Additionally, OUC must supply reserves along with the capacity sold to RCID.

6. Reserve margin percentages are calculated as the sum of installed capacity and firm capacity import (plus an additional 15% of the TECO purchase) minus the sum of OUC peak demand, St. Cloud peak demand, and firm capacity export, all divided by the sum of the forecast OUC peak demand, St. Cloud peak demand, and RCID peak demand.

Table 10-13 (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	%
2003/04	1,273	879	216	0	1,937	1,171	581	61.58%	0	581	61.58%
2004/05	1,253	669	145	0	1,777	1,200	384	44.52%	0	384	44.52%
2005/06	1,253	459	34	0	1,678	1,235	260	36.05%	0	260	36.05%
2006/07	1,253	451	0	0	1,704	1,277	238	33.61%	0	238	33.61%
2007/08	1,253	351	0	0	1,604	1,311	99	22.52%	0	99	22.52%
2008/09	1,428	311	0	0	1,739	1,352	186	28.79%	0	186	28.79%
2009/10	1,428	311	0	0	1,739	1,391	142	25.18%	0	142	25.18%
2010/11	1,428	271	0	0	1,699	1,430	57	18.97%	0	57	18.97%
2011/12	1,603	271	0	0	1,874	1,470	186	27.63%	0	186	27.63%
2012/13	1,603	256	0	0	1,859	1,509	124	23.19%	0	124	23.19%

1. Installed capacity includes the City of St. Cloud's generating units, which are scheduled to retire in November 2004.
 2. Firm capacity imports include capacity purchased from Reliant (Indian River units), capacity purchased from KUA (from Stanton A), capacity purchased from TECO, and capacity purchased from Southern-Florida (from Stanton A).
 3. Firm capacity export includes all forecast sales to FMPA, KUA, SEC, and RCID.
 4. Includes OUC peak demand and City of St. Cloud peak demand.
 5. Assumes TECO purchase (15 MW) includes reserves and that OUC must include reserves to meet its retail peak demand and the City of St. Cloud's retail peak demand. Additionally, OUC must supply reserves along with the capacity sold to RCID.
 6. Reserve margin percentages are calculated as the sum of installed capacity and firm capacity import (plus an additional 15% of the TECO purchase) minus the sum of OUC peak demand, St. Cloud peak demand, and firm capacity export, all divided by the sum of the forecast OUC peak demand, St. Cloud peak demand, and RCID peak demand.

Table 10-14 (Schedule 8)															
Planned and Prospective Generating Facility Additions and Changes															
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)		(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Construction Start	Commercial In-Service	Expected Retirement	Gross Capability ¹		Net Capability ¹		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	Sum MW	Win MW	Sum MW	Win MW	
Stanton	A	Stanton Energy Center	CT	NG	DFO	PL	TK	10/2001	10/2003	UNK	173	188	167	181.	U
Stanton	UNK	Stanton Energy Center	GT	NG	DFO	PL	TK	06/2007	06/2008	UNK	148	184	140	175	P
Stanton	UNK	Stanton Energy Center	GT	NG	DFO	PL	TK	06/2010	06/2011	UNK	148	184	140	175	P

1. Capability ratings reflect OUC's ownership share of Stanton A.

**Table 10-15 (Schedule 9)
Status Report and Specifications of Proposed Generation Facilities**

	Stanton A	Combustion Turbine 1	Combustion Turbine 2
(1) Plant Name and Unit Number:	Stanton A	Combustion Turbine 1	Combustion Turbine 2
(2) Capacity ¹			
a. Summer:	167	140 MW	140 MW
b. Winter:	181	175 MW	175 MW
(3) Technology Type:	CT	GT	GT
(4) Anticipated Construction Timing			
a. Field construction start-date:	11/2001	10//2006	06//2207
b. Commercial in-service date:	10/2003	10//2007	06//2008
(5) Fuel			
a. Primary fuel:	NG	NG	NG
b. Alternate fuel:	DFO	DFO	DFO
(6) Air Pollution Control Strategy	Low NO _x burners with SCR	Low NO _x burners	Low NO _x burners
(7) Cooling Method	Cooling Tower	NA	NA
(8) Total Site Area	3,280 ² acres	NA ³	NA ³
(9) Construction Status	U	P	P
(10) Certification Status	Certified	NA	NA
(11) Status with Federal Agencies	Complete	Not begun	Not begun
(12) Projected Unit Performance Data			
Planned Outage Factor (POF):	CONFIDENTIAL	1.92	1.92
Forced Outage Factor (FOF):	CONFIDENTIAL	1.96	1.96
Equivalent Availability Factor (EAF):	CONFIDENTIAL	96.2	96.2
Resulting Capacity Factor (%):	CONFIDENTIAL	3.6	4.3
Average Net Operating Heat Rate (ANOHR):		11,500	11,393
(13) Projected Unit Financial Data			
Book Life (Years):	CONFIDENTIAL	20	20
Total Installed Cost (In-Service Year \$/kW):	CONFIDENTIAL	328	353
Direct Construction Cost (\$/kW):	CONFIDENTIAL	282	282
AFUDC Amount (\$/kW):	CONFIDENTIAL	6	6
Escalation (\$/kW):	CONFIDENTIAL	40	65
Fixed O&M (\$/kW-Yr) ⁴ :	CONFIDENTIAL	5.52	5.52
Variable O&M (\$/MWH) ⁴ :	CONFIDENTIAL	2.51	2.51
K Factor:	CONFIDENTIAL	1.1865	1.1865

1. Capacity ratings for Stanton A represent OUC's 28 percent ownership share of the unit.
2. Represents total area of the Stanton Energy Center site.
3. Because no site has been finalized for Combustion Turbine 1 or 2, the site area is unknown. However, should the units be constructed at the Stanton Energy Center, the total site area would be 3,280 acres.
4. O&M projections are indicated in 2003 dollars.