Stanton Energy Center Combined Cycle Unit A

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Need for Power Application

Orlando Utility Commission - Volume 1B

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1B.1.0 Overview and Summary

1B.1.1 Overview

Stanton A is planned as a new combined cycle addition to the existing Stanton Energy Center site, located 12 miles southeast of Orlando, Florida. The Stanton Energy Center site was originally certified for an ultimate capacity of approximately 2,000 MW. The existing Stanton 1 is a 444 MW net coal fired facility and Stanton 2 is a 446 MW net coal fired generating facility. 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. Stanton A will provide very economical power for the Orlando Utilities Commission (OUC) with a minimal environmental impact. Stanton A will be a 2 x 1 GE 7FA combined cycle unit. The net output of the unit is estimated to be 633 MW at 70° F under new and clean conditions and will be jointly owned by OUC, Kissimmee Utility Authority (KUA), Florida Municipal Power Agency (FMPA), and Southern Company-Florida LLC (Southern-Florida). OUC will be an 80 percent joint owner of the 35 percent (222 MW) capacity to be owned by the utility applicants. OUC's portion will be approximately 177 MW. OUC will also be entitled to 80 percent of the 65 percent capacity supplied under the power purchase agreement (PPA). Details specific to the project are presented in Volume 1A. This volume, Volume 1B, contains information specific to OUC's need for the project.

OUC strives to meet its responsibility to supply its customer's loads in a reliable manner at the lowest achievable cost while maintaining a concern for the environment. OUC's rates are among the lowest in the state due to strategic planning and ability to provide economies of scale to its customers.

OUC is committed to meet its customer's needs and identify projects that will provide economical power through the combination of demand-side and supply-side resources. OUC has been a strong supporter of conservation and demand-side programs where cost-effective. With OUC's ability to pursue very economical supply-side resources, it is difficult for demand-side programs to be cost-effective.

OUC achieves savings through economy interchange and central dispatch obtained through participation in the Florida Municipal Power Pool (FMPP), which consists of OUC, Lakeland, KUA, and the FMPA All-Requirements Project.

OUC's mission to provide low cost power while striving to meet or exceed environmental regulations will continue with the Stanton A project. Stanton A will burn natural gas as the primary fuel with Selective Catalytic Reduction (SCR) providing a very clean highly efficient unit.

As discussed in the remainder of this Volume, OUC has evaluated appropriate alternatives to Stanton A to determine if any are more cost-effective.

OUC believes that Stanton A represents the minimal cost and performance risk to its customers due to the proven performance of the F class combined cycle technology. As demonstrated in this application, Stanton A has proven to be OUC's most cost-effective alternative through exhaustive evaluations as well as a thorough test of the marketplace.

1B.1.2 Summary

OUC historically has been one of the fastest growing utilities in the United States with a 4.8 percent annual growth rate in peak demand over the last 10 years. With the addition of St. Cloud, rapid growth is projected to continue with a 2.5 percent annual growth rate in peak demand projected through the end of the 20 year planning period.

OUC is currently using a 15 percent reserve margin for planning purposes. OUC has evaluated numerous demand-side and supply-side alternatives to meet capacity requirements. The low cost of Stanton A precludes demand-side alternatives from being cost-effective. Stanton A was found to be the most cost-effective alternative under both base and nearly all of the sensitivity analyses.

1B.2.0 Description of System

1B.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 145,410 active services for 2000. Of these, 125,523 are residential services, 15,262 are general service non-demand services, and the remaining, 4,262 are general service demand services. St. Cloud's service area consisted of a year-end average of 17,995 active services for 2000.

1B.2.2 Generation System

OUC presently has ownership interests in the following five electric generating plants, which are further described below. Table 1B.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.
- City of Lakeland 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 SO_2, 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 4 miles south of Titusville on US Highway 1. The 160-acre Indian River Plant site contains three steam electric generating units, Nos. 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. As part of the sale, OUC has signed a power purchase agreement (PPA) with Reliant, the details of which are presented in Section 1B.2.3. The combustion turbine units are primarily fueled by natural gas, with

Table 1B.2-1
Summary of OUC Generation Facilities

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max Nameplate MW	Net Capability[1] Summer MW	Net Capability[1] Winter MW
	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
Indian River	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
Stanton Energy Center	3	Polk	ST	BIT	REF	RR	TK	09/82	Unknown	363.870	133	136
McIntosh	3	Citrus	NP	UR	---	TK	---	03/77	Unknown	890.460	13	13
Crystal River	2	St. Lucie	NP	UR	---	TKPL	TK	08/83	Unknown	839.000	51	52
St. Lucie[2]	1	Osceola	IC	NG	FO2	PL	TK	07/82	11/04	2.000	2	1.825
St. Cloud[3]	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

OUC ownership share.

OUC owns St. Lucie Unit No. 2. Reliability exchange divides 50% power from Unit No. 1 and 50% power from Unit No. 2.

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.

No. 2 fuel oil as an alternative. OUC has a partial ownership share of 48.8 percent, or 36 MW, in Indian River Units A and B as well as a partial ownership share of 79 percent (170 MW) in Indian River Units C and D.

Crystal River Unit 3 is an 835 MW net nuclear generating facility operated by 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 the City of Lakeland. McIntosh Unit 3 has supplementary oil and refuse fuel burning capability and also is capable of burning up to 20 percent petroleum coke. OUC has a 40 percent ownership share in this unit, 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, with a total summer rating of 27.85 MW. 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.

1B.2.3 Purchase Power Resources

As part of the sale of 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 from October 1, 1999, through September 30, 2003. OUC also has an option to extend the Reliant Agreement an additional 4 years. 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. The capacities from the Power Purchase Agreements are summarized in Table 1B.2-2. The capacity from the Reliant Agreement shown in Table 1B.2-2 from October 1, 2001, through September 30, 2003, is 525 MW, but has an option for an additional 10 percent capacity. Thus, the capacity shown in Table 1B.2-2 is the maximum available.

The maximum capacity available should OUC exercise its additional 4 year option with Reliant is 500 MW per year. The 500 MW can be reduced in 100 MW increments annually over the duration of the 4 year option term through proper notice from OUC, but cannot increase from the previous year. The cost of the capacity and energy is based on a demand and energy charge. The energy charge is based on fixed heat rate and a specified split of gas and oil for fuel.

Table 1B.2-2 Power Purchase Agreements		
Company	Capacity	Duration
TECO PR	15 MW	Through 12/31/2012
Reliant	593 MW	10/01/1999 – 09/30/2001
Reliant	577.5 MW	10/01/2001 09/30/2003

OUC is also planning to purchase KUA's excess capacity from KUA's entitlement in Stanton A during the first 3 years of the Southern-Florida PPA. The excess capacity assumed in the evaluations is presented in Table 1B.2-3. The purchase price is assumed to be equal to the price paid to Southern-Florida under the PPA and, in essence, just increases OUC's entitlement during the first 3 years that KUA has excess.

Table 1B.2-3 Excess KUA Entitlement Purchased By OUC	
Period	MW[1]
10/1/2003 – 9/30/2004	40
10/1/2004 – 9/30/2005	24
10/1/2005 – 9/30/2006	10
[1]Based on 633 MW rating of 70° F.	

1B.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.

1B.2.4.1 Unit Power Sales

OUC has two separate unit power sales contracts in place with FMPA. 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 FMPA 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 highest fuel cost unit 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 and can be supplied by other OUC units if the capacity is available. Table 1B.2-4 displays OUC's unit power sales obligations.

Table 1B.2-4
OUC Unit Power Sales (MW)

Unit Sales	2001	2002	2003	2004	2005	2006
FMPA I.R.	130	108	87	65	43	22
FMPA D-2	20	20	20	0	0	0
SEC I.R.	75	75	75	75	0	0
Total	225	203	182	140	43	22

1B.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. In addition, OUC has been involved in a partial requirements power sales contract with Reedy Creek Improvement District (RCID) since January 1, 1999. The contract is scheduled to expire December 31, 2005, but has an option for extension through 2010. For evaluation purposes, the contract is assumed to extend through 2010. Table 1B.2-5 summarizes OUC's system power sales contracts.

Table 1B.2-5
OUC Projected System Power Sales (MW)

Unit Sales	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
KUA D.	20	20	20	0	0	0	0	0	0	0
RCID PR	96	100	110	123	129	117	139	142	144	146
Total	116	120	130	123	129	117	139	142	144	146

1B.2.4.3 Power Sales Forecast Load Requirements

Table 1B.2-6 summarizes the forecast energy requirements associated with each of the power sales described in Sections 1B.2.4.1 and 1B.2.4.2. For evaluation purposes, unit power sales and system power sales are treated identically.

Table 1B.2-6
OUC Projected Energy Sales (GWh)

Unit Sales	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
FMPA I.R.	167	133	97	62	39	20	0	0	0	0
FMPA D2	10	10	10	0	0	0	0	0	0	0
SEC I.R.	70	65	65	24	0	0	0	0	0	0
KUA D.	17	17	17	0	0	0	0	0	0	0
RCID PR	602	613	641	689	664	713	703	714	724	728
Total	866	838	830	775	703	733	703	714	724	728

1B.2.5 Transmission System

OUC's existing transmission system consists of 26 substations interconnected through approximately 302 miles of 230 kV and 115 kV lines and cables. OUC is fully integrated into the state transmission grid through its twelve 230 kV interconnections with other generating utilities that are members of the Florida Reliability Coordinating Council (FRCC) as summarized in Table 1B.2-7. OUC's service area and transmission system are also shown in Figure 1B.2-1.

Table 1B.2-7
OUC Transmission Interconnections

Utility	kV	Number of Interconnections
FPL (2 circuits)	230	1
FPC	230	5
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

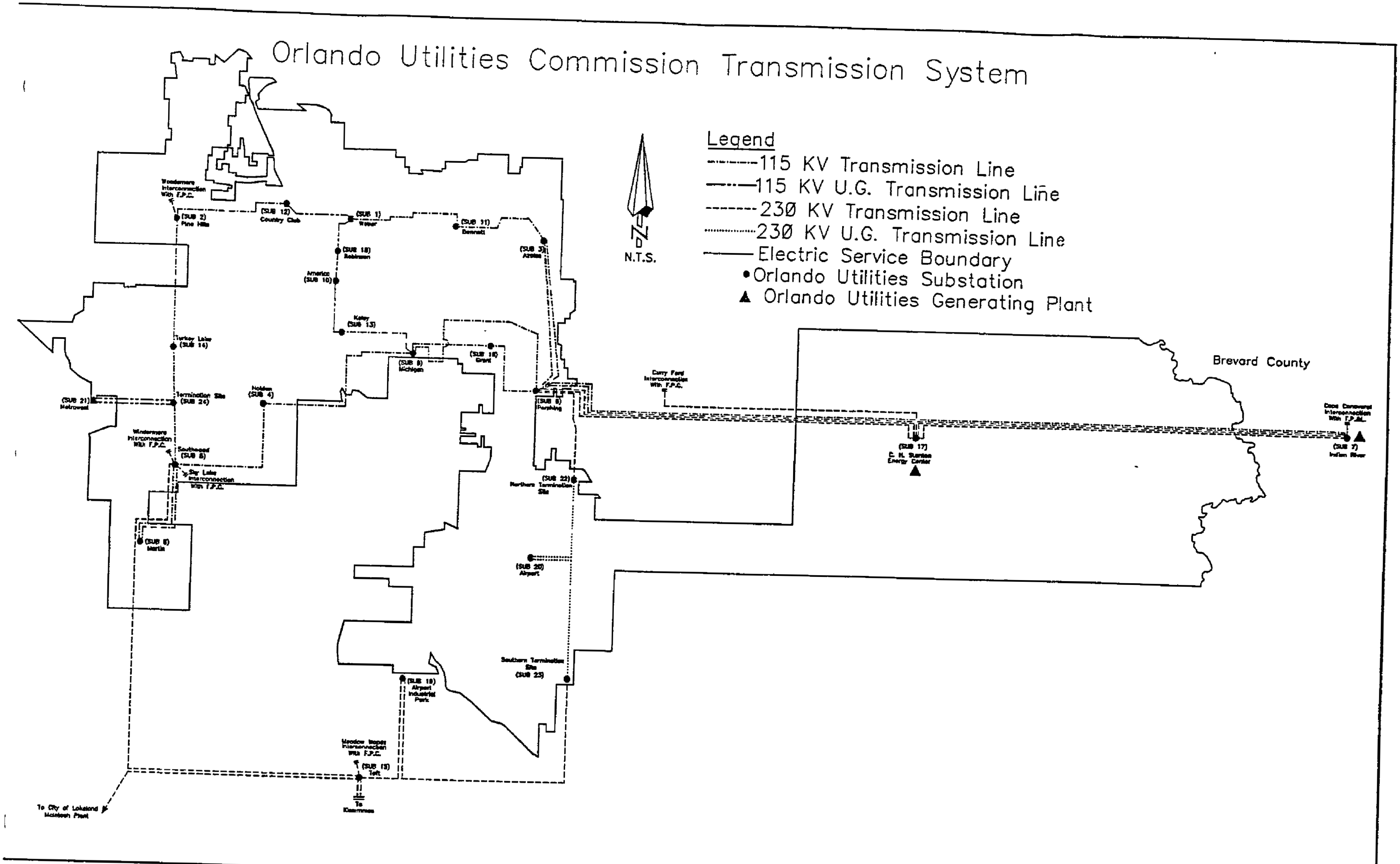

Orlando Utilities Commission Transmission System
Legend
115 KV Transmission Line
115 KV U.G. Transmission Line
230 KV Transmission Line
230 KV U.G. Transmission Line
Electric Service Boundary
Orlando Utilities Substation
Orlando Utilities Generating Plant
N
N.T.S.
Brevard County
Woodsmere Interconnection With F.P.C.
(SUB 2) Pine Hills
(SUB 12) Country Club
(SUB 1) Wever
(SUB 11) Bennett
(SUB 3) Azalea
(SUB 18) Robinson
America (SUB 10)
Kaley (SUB 13)
(SUB 9) Michigan
(SUB 16) Grant
(SUB 6) Pershing
Curry Ford Interconnection With F.P.C.
Turkey Lake (SUB 14)
Termination Site (SUB 24)
(SUB 21) Metrowest
Holden (SUB 4)
Southwood (SUB 5)
Sky Lake Interconnection With F.P.C.
(SUB 8) Martin
(SUB 22) Northern Termination Site
(SUB 20) Airport
Southern Termination Site (SUB 23)
(SUB 19) Airport Industrial Park
(SUB 15) Taft
To Kissimmee
To City of Lakeland McIntosh Plant
(SUB 17) C. H. Stanton Energy Center
Cape Canaveral Interconnection With F.P.&L.
(SUB 7) Indian River

Figure 2-1

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 has developed the following schedule of upgrades to maintain reliable and economic service:

- A second 230 kV tie line between Stanton and FPC. Expected completion date is January, 2001.
- Upgrade the 69 kV line from KUA to the City of St. Cloud. Expected completion date is in 2003.
- Addition of the Grant to Robinson 115 kV transmission line. Expected completion date is in 2002.
- Addition of second bus tie transformer at the Southwood Substation. Expected completion date is in 2004.

1B.2.6 Service Area

OUC's service area encompasses approximately 394 square miles. This estimate includes the service OUC provides to the City of St. Cloud 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.

1B.3.0 Evaluation Criteria

The evaluation criteria used by OUC is described in Section 1A.3.0.

1B.4.0 Forecast of Power Demand and Energy Consumption

OUC has retained Regional Economic Research, Inc. (RER) to develop forecasts of power demand and energy consumption. The initial forecast scope was to develop a sales forecast for the OUC budgeting process and short-term financial planning. The scope was then extended to develop a long-term energy and demand forecast through 2020. 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.

1B.4.1 Forecast Methodology

There are two primary forecasting approaches used in forecasting electricity requirements - econometric-based modeling (such as linear regression) or 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.

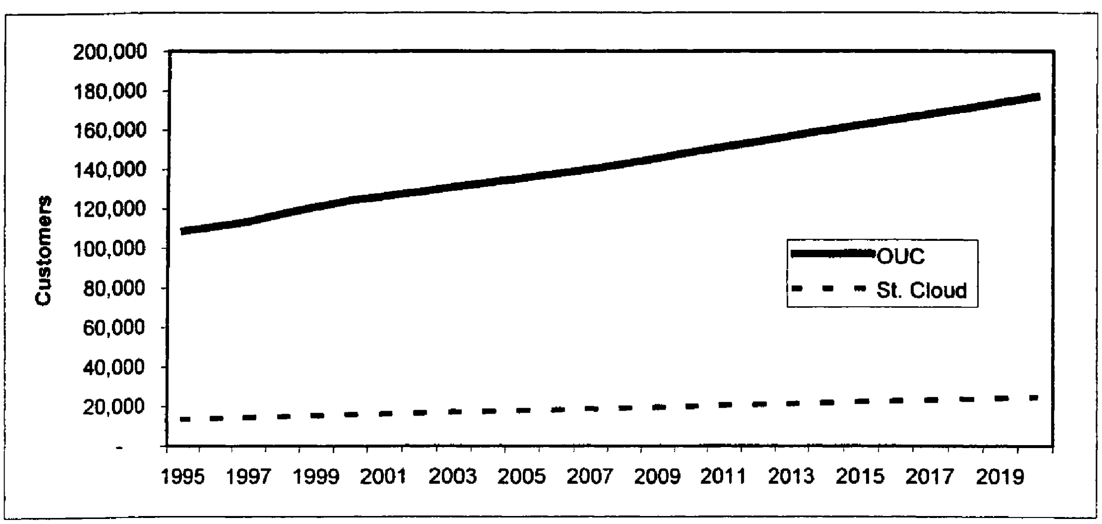
1B.4.1.1 Residential Sector Model

The residential model consists of two equations – an average use per household model, and a customer forecast model. Monthly average use models are estimated over the period 1992 to 1999. This provides 8 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:

$$Residential\ Sales_T = Average\ User\ Per\ Household_T * Number\ of\ Customers_T$$

Residential Customer Forecast. The number of customers is forecasted as a simple function of household projections for the Orlando 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 R^2 of 0.997 with an in-sample Mean Absolute percent Error (MAPE) of 0.2 percent. For St. Cloud, the model performance is not as strong, given the "noise" in the historical monthly billing data. The adjusted R^2 is 0.71 with an in-sample MAPE of 4.2 percent. Given that St. Cloud is a relatively small part of OUC's service territory, the 4.2 percent average customer forecast error represents a relatively small number of total system customers. Combined, the average model error (the Mean Absolute Deviation) is 744 customers; this compares with an average number of customers over the estimation period of 123,100. The combined error is less than 1 percent. The model statistics are included in Appendix 1B.A. Figure 1B.4-1 shows the residential customer forecast.

Figure 1B.4-1
Residential Customer Forecast



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:

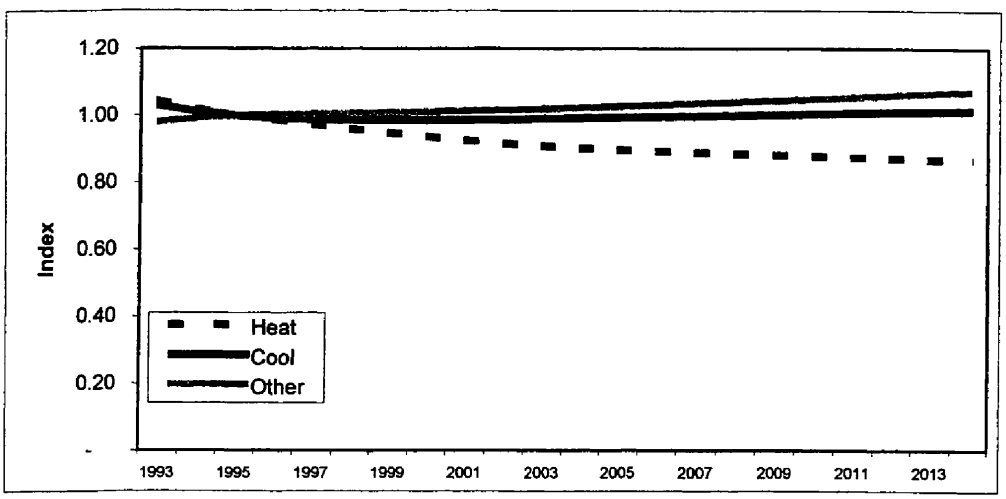
$$\text{Average Use}_t = \text{Heat}_t + \text{Cooling}_t + \text{BaseUse}_t$$

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:

$$Cooling_t = CoolIndex_t * CoolUse_t$$
$$Heating_t = HeatIndex_t * HeatUse_t$$
$$BaseUse_t = BaseIndex_t * OtherUse_t$$

End-Use Index Variables. The end-use index variables (*CoolIndex*, *HeatIndex*, and *BaseIndex*) are illustrated in Figure 1B.4-2. These variables are designed to capture both increases in appliance saturation and changes in the relative efficiency of the stock.

Figure 1B.4-2
End-Use Trend Variables



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 is 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.

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:

$$CoolUse_t = (Price_t \wedge (-.20)) * (Inc\_per\_HH_t \wedge .20) * (HH\_Size_t \wedge 0.25) * CDD$$
$$HeatUse_t = (Price_t \wedge (-.20)) * (Inc\_per\_HH_t \wedge .20) * (HH\_Size_t \wedge 0.25) * HDD$$
$$OtherUse_t = (Price_t \wedge (-.20)) * (Inc\_per\_HH_t \wedge .15) * (HH\_Size_t \wedge 0.20)$$

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).

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 0.94 with an in-sample MAPE of less than 4 percent. The standard error of the regression model is 52.43 kWh compared with residential monthly average usage of 1,033 kWh. All the model coefficients are highly significant (exhibiting P-values less than 0.05). The St. Cloud model explains slightly less of the variation in average use, with an adjusted R^2 of 0.91 and an in-sample MAPE of 5.6 percent. The model coefficients are highly significant.

Figure 1B.4-3 shows projected average residential use on an annual basis and Figure 1B.4-4 depicts projected residential sales.

1B.4.1.2 Non-residential 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.

Figure 1B.4-3
Residential Average Use Forecast (kWh)

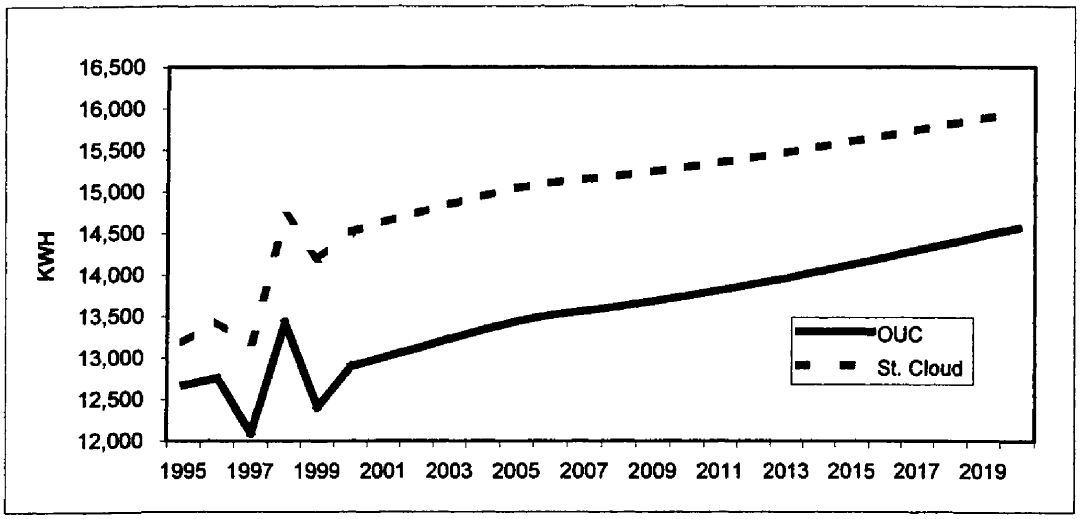
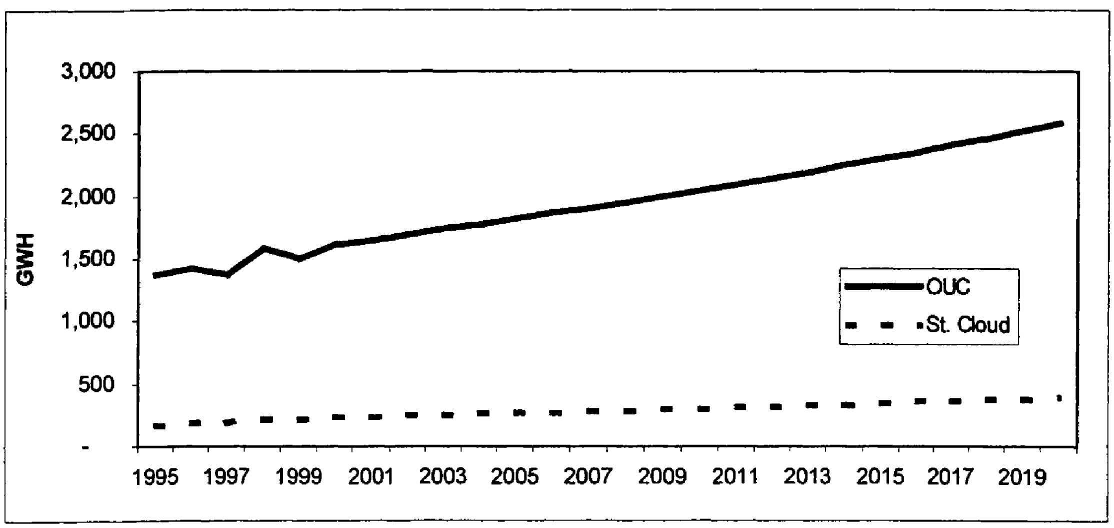


Figure 1B.4-4
Residential Sales Forecast (GWh)

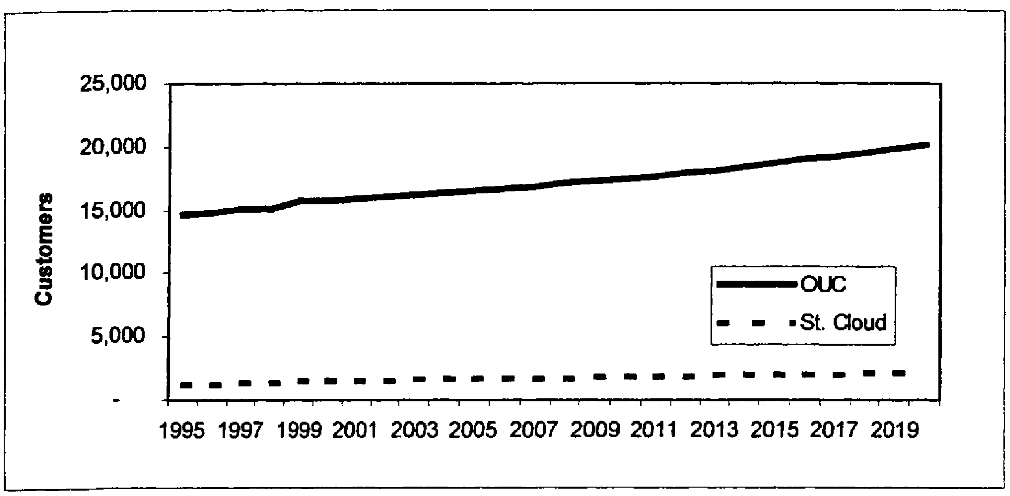


GSND Model. The GSND models are developed along lines similar to the residential forecast with the GSND monthly energy demand calculated as:

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

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 1999. For OUC, the overall model adjusted R^2 is 0.996 with an in-sample MAPE of 0.20 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 0.73, with an in-sample MAPE of 3.45 percent. An AR1 and AR2 correction were 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. Figure 1B.4-5 shows the GSND customer forecasts.

Figure 1B.4-5
GSND Customer Forecast



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

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

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

$Cooling_t = CoolIndex_t * CoolUse_t$

$Heating_t = HeatIndex_t * HeatUse_t$

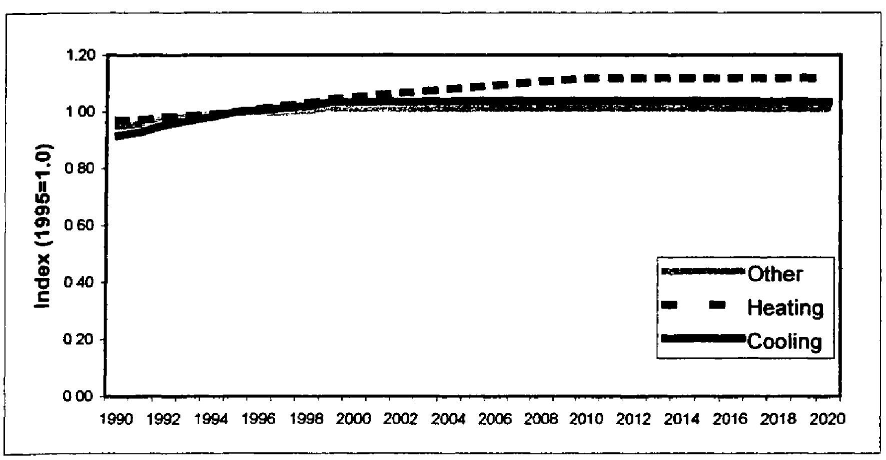
$BaseUse_t = BaseIndex_t * OtherUse_t$

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:

$Index_t = Energy\ Intensity_t / Energy\ Intensity_{95}$

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 days of actual commercial heating (utilization of the heating stock) the heating index has relatively little impact on overall GSND average use. Figure 1B.4-6 depicts the end-use trend variables.

Figure 1B.4-6
Commercial End-Use Index Projections (1995 = 1.0)



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:

CoolUse = (Price^-.20)(Output per Employee^.20)*(CDD)*

HeatUse = (Price^-.20)(Output per Employee^.20)*(HDD)*

OtherUse = (Price^-.20)(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 R^2 for the OUC GSND average use model is 0.99 with an in-sample MAPE of 2.8 percent. For St. Cloud the GSND average use model has an adjusted R^2 of 0.86, with an in-sample MAPE of 4.1 percent. Figure 1B.4-7 shows forecasted GSND average use on an annual basis. Total GSND sales are depicted in Figure 1B.4-8. Model results are included in Appendix 1B.A.

Figure 1B.4-7
GSND Average Use Forecast (kWh)

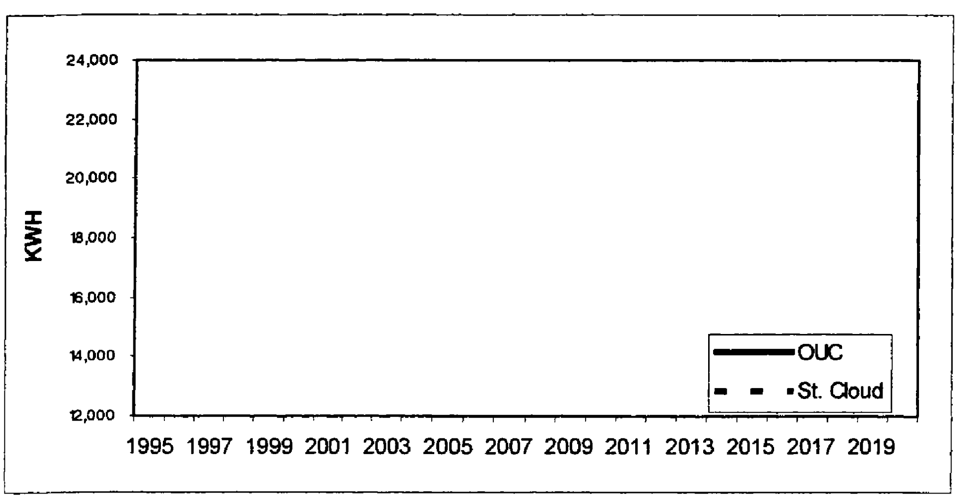
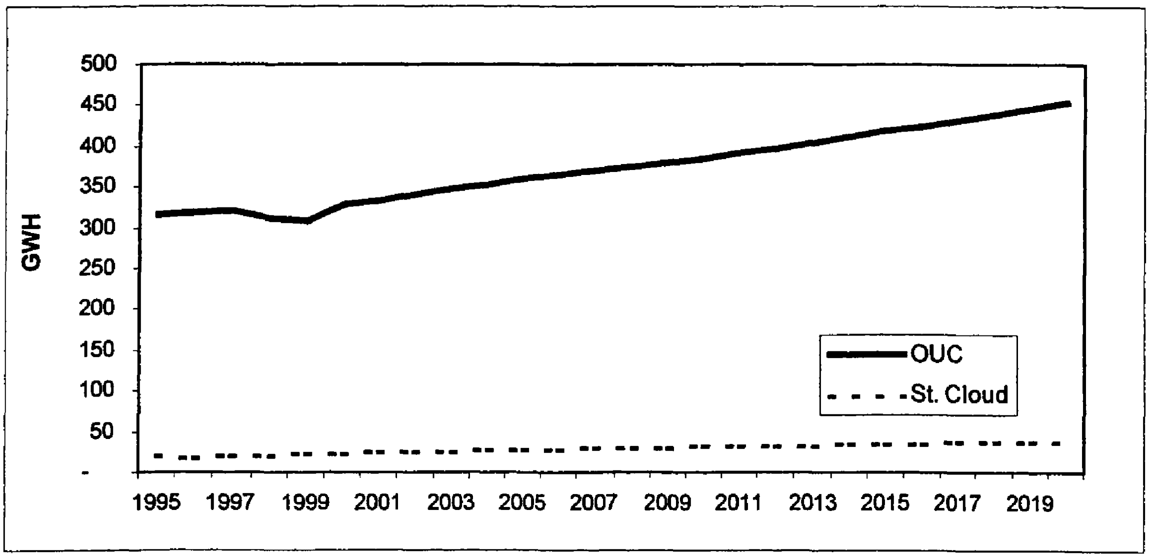


Figure 1B.4-8
GSND Sales Forecast (GWh)



1B.4.1.3 GSD Models

The general service demand class represents the largest Nonresidential customers. Over the last 5 years, OUC has seen the strongest sales gains in the GSD customer class, with GSD sales growth averaging 4.6 percent for the combined OUC and St. Cloud service territories. While 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:

$$GSD\ Sales_t = f(BaseUse_t,\ CoolUse_t,\ and\ HeatUse_t)$$

Where

$$Cooling_t = CoolIndex_t * (Price_t\text{^-}.20) * (GSP_t\text{^}.20) * CDD_t$$

$$Heating_t = HeatIndex_t * (Price_t\text{^-}.20) * (GSP_t\text{^}.20) * HDD_t$$

$$BaseUse_t = BaseIndex_t * (Price_t\text{^-}.20) * (GSP_t\text{^}.20)$$

The index variables are the same as those used in estimating the GSND model. Aggregate regional output for the Orlando MSA (GSP_t) is used to capture utilization resulting from historical and projected economic activity. In the OUC model, the end-use variables are all highly significant (except for the lagged heating variable). The adjusted R^2 is 0.94, with an in-sample MAPE of 2.7 percent. In the St. Cloud model, the adjusted

R^2 is 0.92, with a MAPE of 3.7 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, an internet switching center, and the continued expansion at Universal Studios. Aggregate new-project load is shown in Figure 1B.4-9.

Figure 1B.4-9
New GSD Load (GWh)

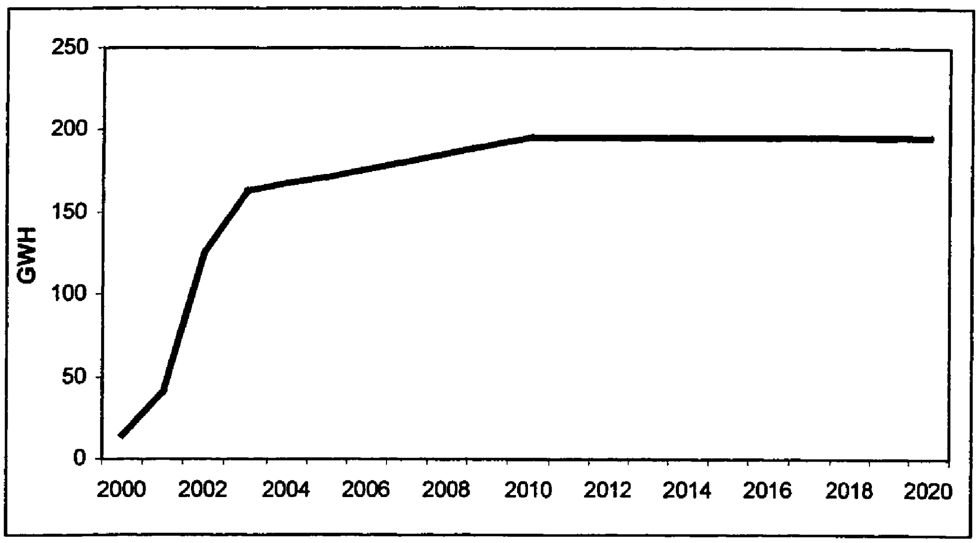


Figure 1B.4-10 shows total forecasted GSD loads for OUC and St. Cloud.

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 a new OUC program called 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 3.4 GWh a year through the forecast period. Figures 1B.4-11 and 1B.4-12 show forecasted street lighting sales.

Figure 1B.4-10
GSD Sales Forecast (GWh)

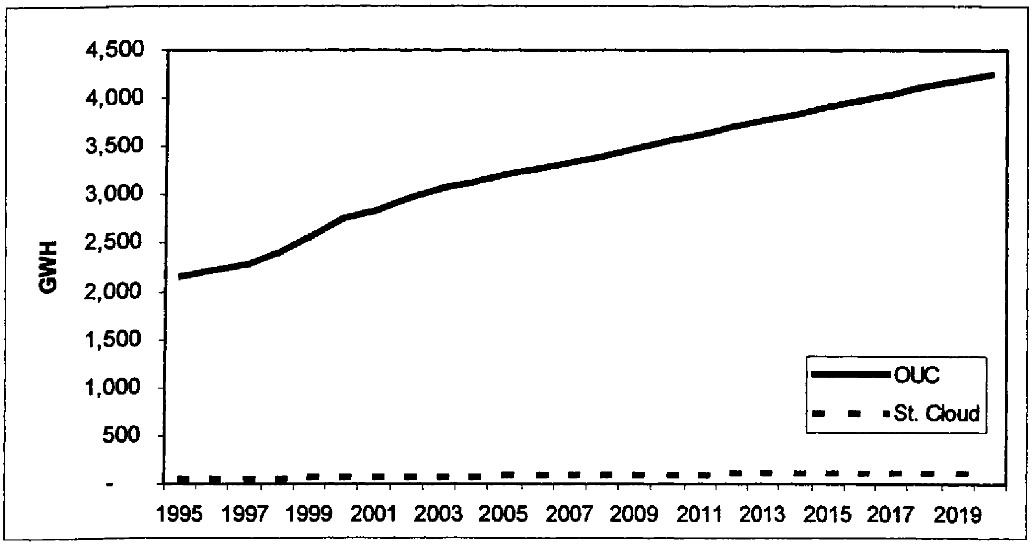


Figure 1B.4-11
OUC Street Light Sales Forecast (GWh)

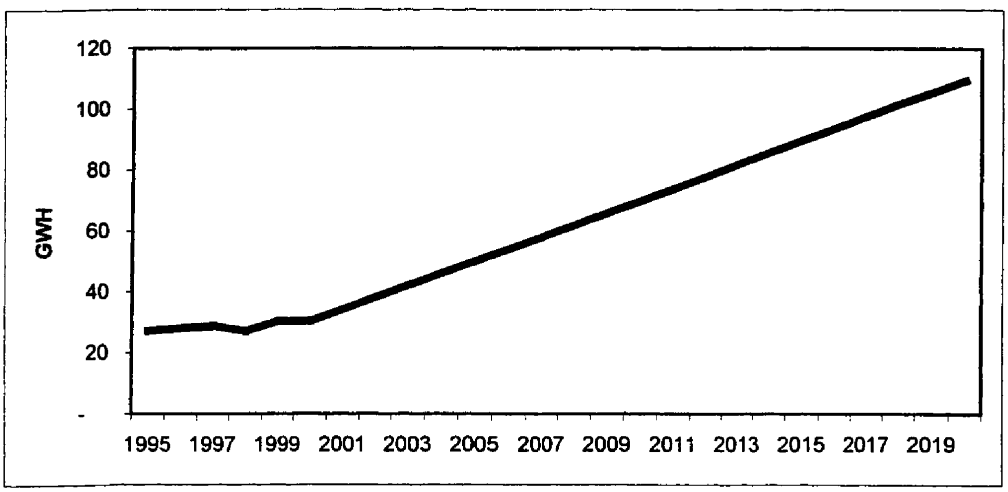
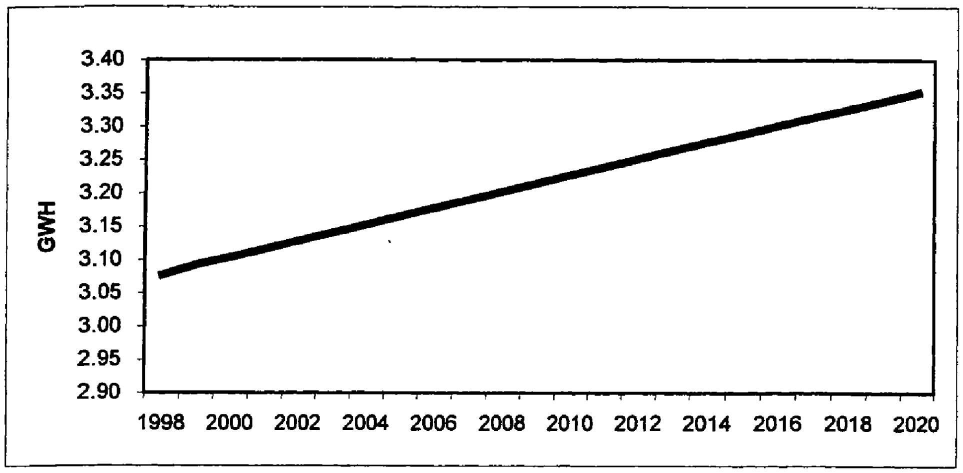


Figure 1B.4-12
St. Cloud Street Light Sales Forecast (GWh)



1B.4.1.4 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 1999. 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. In the on-peak hours (6:00 a.m. to 8:00 p.m.) adjusted R^2 varies from 0.65 to 0.81, with MAPEs that vary from 4.0 percent to 2.4 percent. The off-peak fractional models have adjusted R^2 values that vary from 0.65 to as low as 0.35. The low R^2 in the off-peak model is attributable to significant "noise" in the off-peak load data that can't be explained by weather or day-type variables. Still, even the models with low R^2 values have MAPEs of less than 4 percent.

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 $DaykWh_t$, 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:

$$ResSaleTrend_m = \text{12-month moving average (Residential Sales)}$$
$$NonResTrend_m = \text{12-month moving average (Nonresidential Sales)}$$

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. The model adjusted R^2 is 0.95, with a MAPE of 2.6 percent. 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.

The resulting hourly load forecast for January and July of 2001 are depicted in Figures 1B.4-13 and 1B.4-14.

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.

Figure 1B.4-13
January OUC Hourly Load for 2001 (MW)

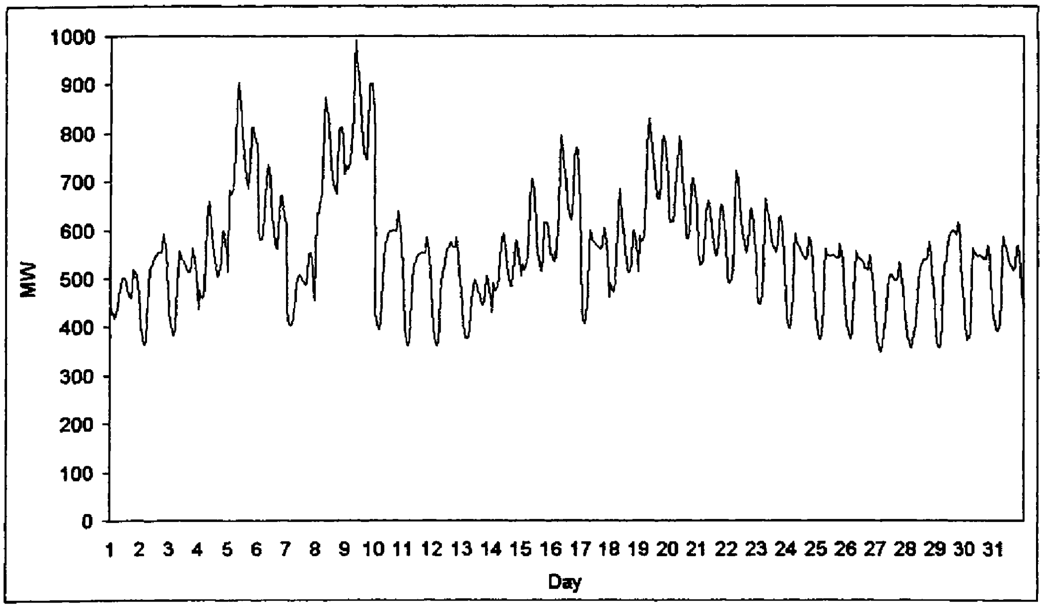
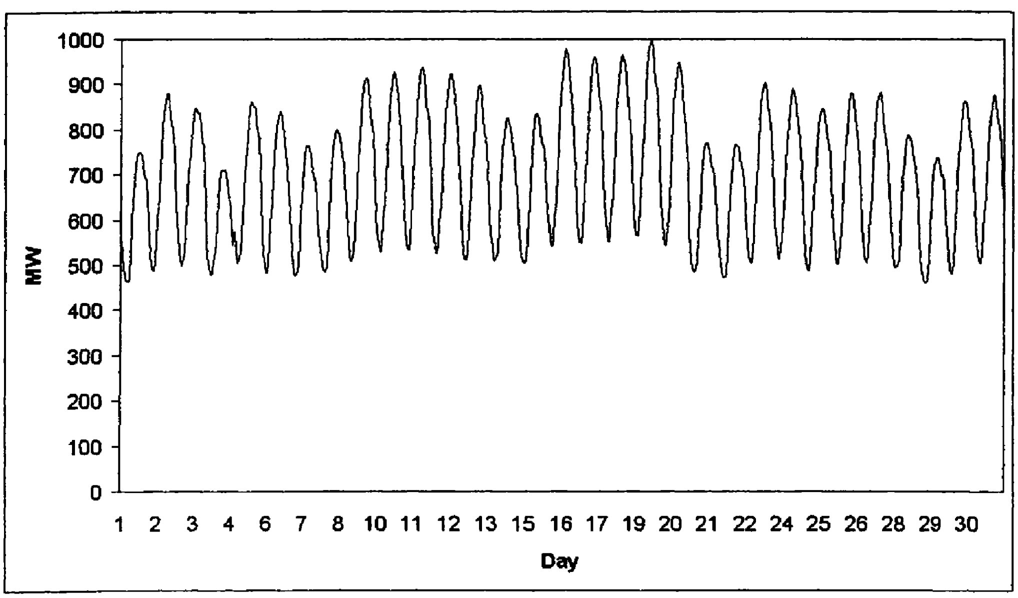


Figure 1B.4-14
July OUC Hourly Load for 2001 (MW)



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. Figure 1B.4-15 shows forecasted summer and winter system peak for the combined OUC and St. Cloud load requirements.

1B.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.

1B.4.2.1 Economics

The economic assumptions are derived from forecasts from Regional Financial Associates (RFA), which is now doing business under the name Economy.com, and the University of Florida. RFA's monthly economic forecast for the Orlando MSA is used to drive the forecast through 2005. Thereafter, adjustments were made to create a more conservative economic outlook.

1B.4.2.1.1 Employment and Regional Output. The nonresidential forecast models are driven by nonmanufacturing and regional output forecasts. RFA employment forecasts were used through 2005. Employment growth over this period is consistent with the University of Florida's outlook. After 2005, RFA projects regional employment and output growth that continues to exceed RFA's Florida forecast and are somewhat more optimistic than the University of Florida. For the longer term (after 2005 to 2010), employment is assumed to continue to grow at the more conservative state growth rate forecasted by RFA. The slower growth is extrapolated beyond 2010 using an exponential smoothing model. The same process is used to develop a more conservative regional forecast of gross output. The resulting long-term employment and output growth (after 2010) is lower than RFA's outlook for Orlando and the state, and consistent with the University of Florida's long-term population forecast for the region. Table 1B.4-1 shows the annual employment and gross state product projections.

1B.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. RFA's projections for the Orlando MSA were used through 2005. Between 2005 and 2010 the number of households and real income are assumed to grow at the slower state rate. After 2010, population is assumed to grow at the rate projected by the University of Florida. Household projections are then calculated by dividing population projections by household size (number of household members) projections. An exponential smoothing model is used to extrapolate household size beyond 2010. Table 1B.4-2 shows annual population, household, and real income forecast.

Figure 1B.4-15
Summer and Winter System Peak Forecasts (OUC and St. Cloud Combined) (MW)

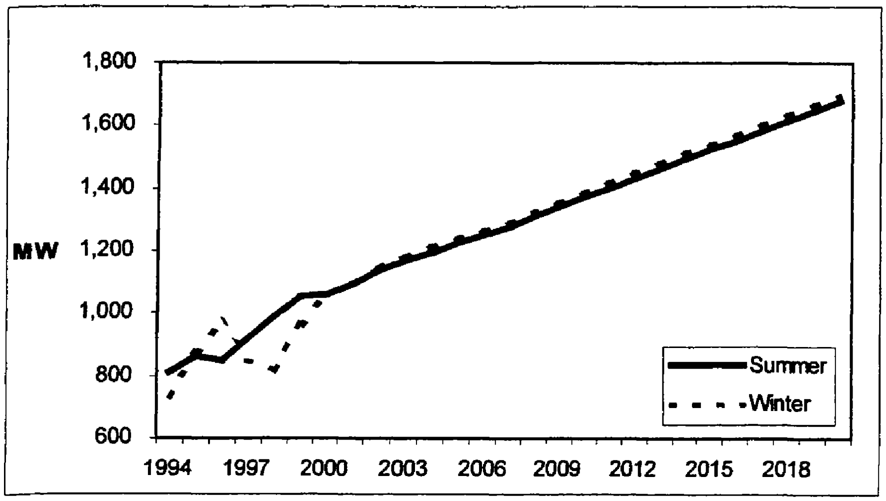


Table 1B.4-1
Nonmanufacturing Employment (Thousands) and
Gross Regional Product Projections (Billion Real $)

Year	Retail	Wholesale	Services	Financial Services	Government	Gross Product (Billion Real $)
1995	139.4	38.6	288.2	42.2	79.6	35.8
1996	146.7	41.3	304.4	44.5	81.6	37.8
1997	154.2	44.3	329.7	46.0	83.9	40.3
1998	158.7	46.2	354.7	49.3	86.9	43.1
1999	166.1	47.7	373.6	52.2	89.5	44.9
2000	171.2	49.4	391.1	54.4	91.9	46.8
2005	183.5	56.2	456.4	59.9	98.3	54.7
2010	197.7	63.5	540.9	66.5	105.2	64.9
2015	209.3	70.5	631.6	72.9	112.8	76.2
2020	220.6	77.5	722.1	79.1	120.3	87.4
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	5.3	7.0	5.6	5.5	2.5	5.6
1997	5.1	7.4	8.3	3.3	2.9	6.4
1998	3.0	4.3	7.6	7.2	3.5	7.0
1999	4.7	3.2	5.3	5.9	3.1	4.2
00-05	1.4	2.6	3.1	2.0	1.3	3.2
05-10	1.5	2.5	3.5	2.1	1.4	3.5
10-15	1.1	2.1	3.1	1.8	1.4	3.2
15-20	1.1	1.9	2.7	1.7	1.3	2.8

Table 1B.4-2
Population, Household, and Income Projections

Year	Real Income per HH	Households (Thousands)	Population (Thousands)
1992	54,673	491	1,306
1993	56,031	499	1,337
1994	56,957	508	1,366
1995	57,724	520	1,393
1996	59,487	534	1,427
1997	61,079	551	1,468
1998	63,582	567	1,509
1999	64,343	582	1,545
2000	65,684	596	1,577
2005	70,545	655	1,723
2010	74,207	721	1,894
2015	78,478	791	2,079
2020	83,331	863	2,273
Change	Percent	Percent	Percent
1993	2.5	1.6	2.3
1994	1.7	1.8	2.1
1995	1.3	2.3	2.0
1996	3.1	2.8	2.4
1997	2.7	3.1	2.9
1998	4.1	3.0	2.8
1999	1.2	2.7	2.3
00-05	1.4	1.9	1.8
05-10	1.0	2.0	1.9
10-15	1.1	1.9	1.9
15-20	1.2	1.8	1.8

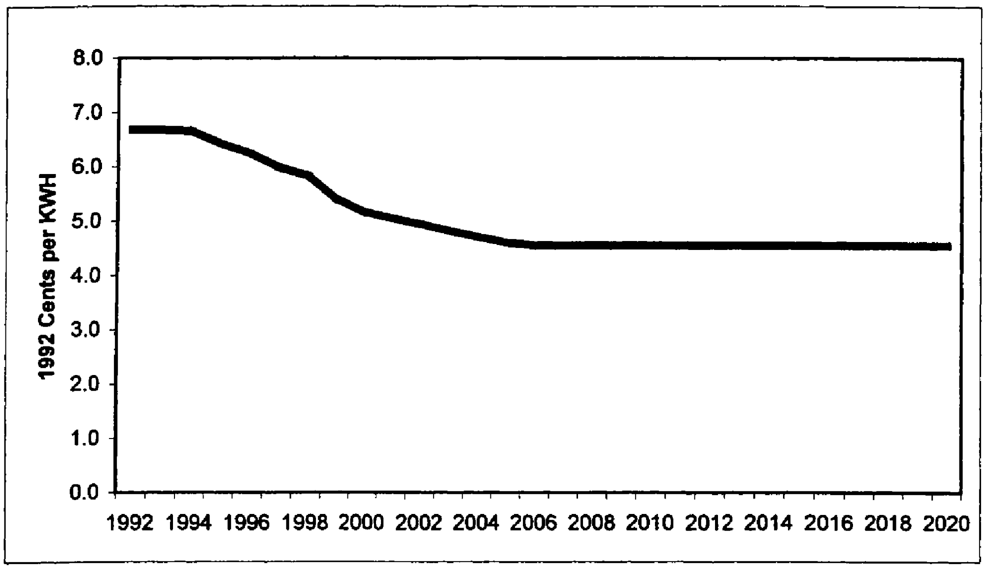
1B.4.2.2 Price Assumption

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. Historical and projected prices are depicted on Figure 1B.4-16. The average annual price series is provided in Table 1B.4-3.

Figure 1B.4-16
Historical and Forecasted Average Electricity Prices
(1992 Cents per kWh)



1B.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 degree Fahrenheit base. First a daily CDD is calculated as:

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

Table 1B.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	6.3
1997	6.0
1998	5.8
1999	5.4
2000	5.2
2005	4.6
2010	4.6
2015	4.6
2020	4.6
Change	Percent
1993	-0.1
1994	-0.4
1995	-3.4
1996	-2.7
1997	-4.1
1998	-2.7
1999	-7.3
00-05	-2.3
05-10	-0.2
10-15	0.0
15-20	0.0

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° if average daily temperature is less than 65°. The daily CDD values are then aggregated to yield a monthly CDD:

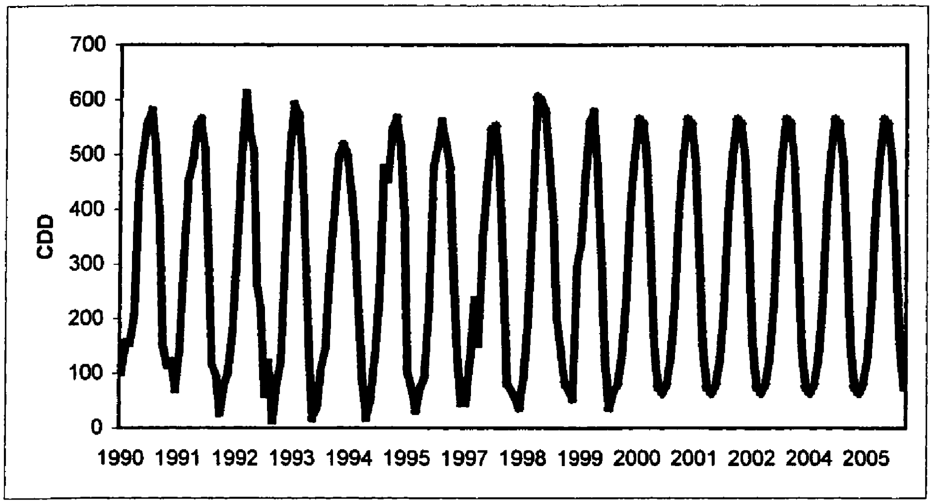
$CDD_m = \Sigma CDD_{md}$

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

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

Figure 1B.4-17 shows historical and forecasted monthly CDD. The forecast begins in 2000.

Figure 1B.4-17
Monthly Cooling Degree Days



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

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

HDD_d equals 65° minus the average daily temperature, if the average daily temperature is less than or equal to 65, and equals 0° if the daily temperature is greater than 65°. Aggregate monthly HDD (HDD_m) is then calculated by summing daily HDD over each month:

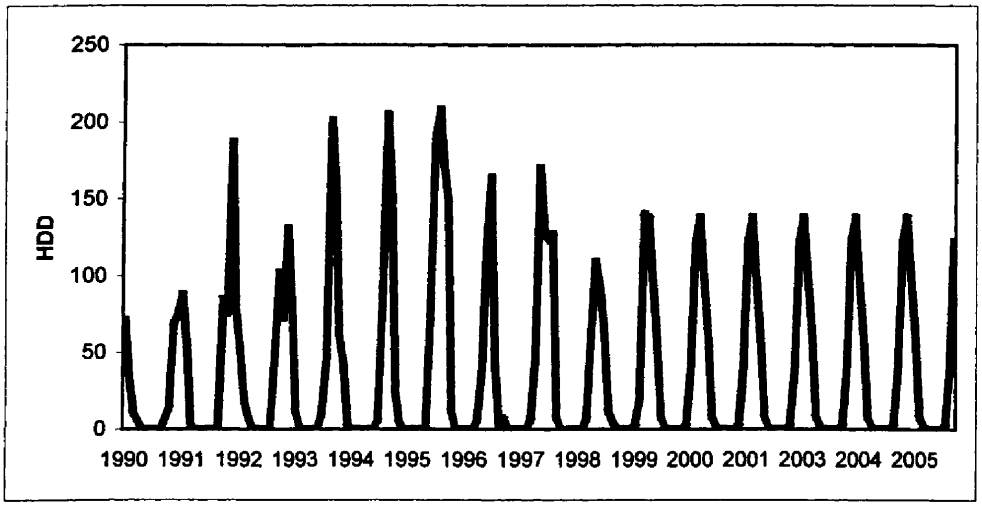
$HDD_m = \Sigma HDD_{md}$

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

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

Figure 1B.4-18 depicts the resulting HDD series. The forecast begins in 2000.

Figure 1B.4-18
Heating Degree Days



1B.4.3 Base Case Load Forecast

A short-term monthly budget forecast was estimated through 2002, with a long-term annual forecast through 2020. 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.*

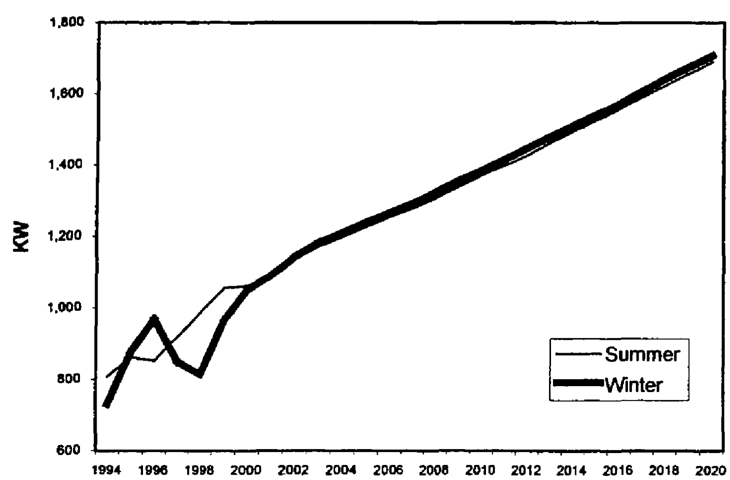
Models are estimated using monthly sales data covering the period 1991 through 1999. A separate set of forecast models are estimated for the OUC and St. Cloud service territories.

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 1999. 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 1B.4-4 and Figure 1B.4-19 summarize annual sales and peak forecast for the combined OUC and St. Cloud service territories.

Table 1B.4-4
System Peak (Summer and Winter) and
Net Energy Forecast (Total of OUC and St. Cloud)

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	1,062	1,051	5,363
2005	1,227	1,239	6,192
2010	1,372	1,386	6,925
2015	1,522	1,539	7,692
2020	1,679	1,697	8,492
Change	percent	percent	percent
95-99	4.1	2.0	2.7
00-05	2.9	3.3	2.9
05-10	2.3	2.3	2.3
10-15	2.1	2.1	2.1
15-20	2.0	2.0	2.0

Figure 1B.4-19
Summer and Winter System Peak Forecasts
(OUC and St. Cloud Combined) (MW)

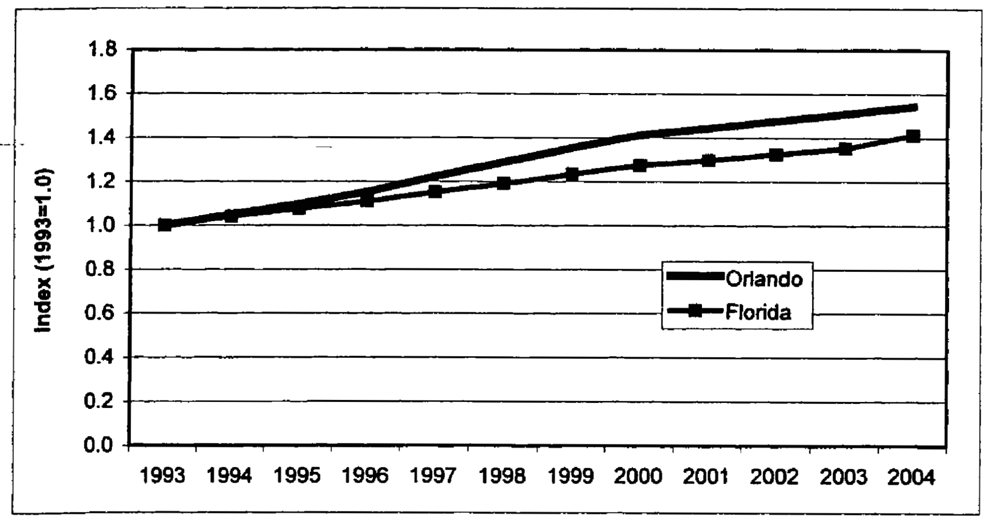


1B.4.3.1 Base Case Economic Outlook

The Orlando area has seen some of the strongest economic growth in the nation. RFA ranked Orlando as number 16 (out of 321 MSAs) in terms of current and expected employment growth. RFA projects continued strong growth for the region well into the next decade.

Between 1995 and 1999, population has grown at an average annual rate of 2.6 percent and real gross output has grown at 5.8 percent. Orlando's economic growth has consistently exceeded economic growth in both the state and nation. Florida, over the same period, experienced population and gross output growth of 1.6 percent and 3.9 percent, respectively. Orlando is expected to exceed overall state economic growth throughout the next 10 years. Figure 1B.4-20 compares relative employment projections of Orlando and Florida. By indexing total employment to 1.0 in 1993, it is easier to compare the growth projected for Orlando and Florida.

Figure 1B.4-20
Relative Employment Performance (RFA) (1993=1.0)



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 42 percent of total employment. Hotels and tourism-related activities, as well as call-centers, have continued to grow. OUC is also seeing increasing interest in establishing internet-support and switching centers.

In recent years, the area has reaped the benefits of a booming national economy and the associated upturn in tourism. 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. Several new hotels are currently under construction, with the largest being the new Hard Rock Hotel and complex that will open this year. The new Orlando convention center is expected to open in 2002, further fueling regional convention and tourism activity. In addition, Lockheed Martin is planning to open a commercial flight-training and simulation center, which is expected to draw thousands of pilots seeking training and recertification. Top employers in the Orlando MSA are shown in Table 1B.4-5.

Table 1B.4-5
Largest Regional Employers

Employer	Number of Employees
Walt Disney World Company	55,000
Florida Hospital	11,210
Publix Super Markets, Inc.	<9,000
Winn-Dixie Stores, Inc.	8,978
Orlando Regional Healthcare System	8,200
Universal Studios Escape	7,000
Central Florida Investments, Inc.	5,000
Central Florida Healthcare System	4,500
Sun Trust Bank Central Florida	4,244
Darden Restaurants, Inc.	4,200
Lockheed Martin Electronics & Missiles	3,800
Sprint Communications Company	3,747

Source: RFA

To accommodate growing convention, tourism, and regional business activity, the Orlando International Airport (OIA) is in the process of a major expansion program that will ultimately double the capacity of the airport. In 1999, OIA served 29 million passengers -- nearly 10 percent over the prior year. OIA projects continued strong passenger volume growth for the region well into the next decade.

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 582,000 in 1999 to 863,000 by 2020, representing an average annual growth rate of 1.9 percent. Employment is projected to grow at 2.1 percent over the long term.

RFA ranks Orlando at 99 percent (with respect to the US average of 100 percent) in terms of the cost of doing business. Similarly, Orlando is ranked at 97 percent for cost of living, implying a slightly lower-than-average cost of living in the area. 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.

Table 1B.4-6 summarizes economic projections for the Orlando MSA. Economic projections are based on RFA's economic outlook for Orlando and the state of Florida. Projections are in line with economic projections by the University of Florida. University of Florida's long-term population projections for the region are used to drive household growth after 2010.

1B.4.3.2 Forecast Results

Based upon the previously discussed economic assumptions, total retail sales for OUC are expect to increase from 4,488 GWh in 1999 to 7,569 GWh by 2020. St. Cloud sales are projected to increase from 320.5 GWh to 573.6 GWh. Sales and customer projections are summarized in Tables 1B.4-7 through 1B.4-10.

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 0.8 percent and slow to 0.6 percent by the end of the forecast period. 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 2.2 percent rate for St. Cloud between 2000 and 2020. The OUC and St. Cloud residential sales forecasts are shown in Tables 1B.4-11 and 1B.4-12, respectively.

Small Commercial Sales Forecast. GSND sales are projected to grow at an average annual rate of 1.9 percent and 2.6 percent for OUC and St. Cloud respectively between 1999 and 2020. 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

Table 1B.4-6
Orlando MSA Economic Projections

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57724	723	757	4.5	36
1996	534	59487	750	780	3.8	38
1997	551	61079	788	815	3.4	40
1998	567	63582	816	842	3.0	43
1999	582	64343	854	879	2.9	45
2000	596	65684	882	908	2.8	47
2005	655	70545	977	1013	3.5	55
2010	721	74207	1084	1122	3.4	65
2015	791	78478	1205	1248	3.4	76
2020	863	83331	1340	1387	3.4	87
Change	Percent	Percent	Percent	Percent	Percent	Percent
1996	2.8	3.1	3.8	3.0	-	5.6
1997	3.1	2.7	4.9	4.5	-	6.4
1998	3.0	4.1	3.7	3.2	-	7.0
1999	2.7	1.2	4.6	4.5	-	4.2
00-05	1.9	1.4	2.1	2.2	-	3.2
05-10	2.0	1.0	2.1	2.1	-	3.5
10-15	1.9	1.1	2.1	2.1	-	3.2
15-20	1.8	1.2	2.1	2.1	-	2.8

Table 1B.4-7
OUC Long-Term Sales Forecast (GWH)

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St. Lts.	OUC Use	Total Retail
1995	1380	316	2154	27	-	55	3932
1996	1419	318	2211	28	-	61	4037
1997	1377	322	2274	29	-	56	4057
1998	1583	310	2405	27	-	78	4404
1999	1504	308	2570	30	-	76	4488
2000	1606	329	2756	31	-	78	4800
2005	1822	360	3207	33	17	100	5539
2010	2046	386	3561	36	34	122	6185
2015	2298	418	3913	39	51	145	6863
2020	2579	454	4259	42	67	167	7569
Change	percent	percent	percent	percent	percent	percent	percent
1996	2.8	0.5	2.7	3.1	-	11.7	2.7
1997	-3.0	1.2	2.8	2.3	-	-8.4	0.5
1998	15.0	-3.5	5.8	-5.4	-	39.9	8.5
1999	-5.0	-0.8	6.9	11.8	-	-3.1	1.9
00-05	2.5	1.8	3.1	1.8	-	5.2	2.9
05-10	2.3	1.4	2.1	1.7	14.9	4.1	2.2
10-15	2.3	1.6	1.9	1.6	8.4	3.4	2.1
15-20	2.3	1.7	1.7	1.5	5.9	2.9	2.0

Table 1B.4-8
OUC Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	108845	14572	2970	126387
1996	111241	14855	3120	129216
1997	113808	15065	3445	132319
1998	117868	15168	3799	136836
1999	121173	15659	3871	140703
2000	124484	15779	4074	144337
2005	135530	16524	4560	156615
2010	148822	17474	5151	171448
2015	162621	18682	5753	187056
2020	177054	20107	6351	203512
Change	percent	percent	percent	percent
1996	2.2	1.9	5.0	2.2
1997	2.3	1.4	10.4	2.4
1998	3.6	0.7	10.3	3.4
1999	2.8	3.2	1.9	2.8
00-05	1.7	0.9	2.3	1.6
05-10	1.9	1.1	2.5	1.8
10-15	1.8	1.3	2.2	1.8
15-20	1.7	1.5	2.0	1.7

Table 1B.4-9
St. Cloud Sales Forecast (GWH)

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	74	3	320
2000	234	23	80	3	340
2005	271	27	94	3	396
2010	309	31	108	3	451
2015	351	34	123	3	511
2020	396	38	136	3	574
Change	percent	percent	percent	percent	percent
1996	5.5	-1.5	11.0	-	6.2
1997	0.8	1.1	9.4	-	3.0
1998	15.2	9.4	7.1	-	13.7
1999	0.2	8.5	2.4	0.5	1.3
00-05	3.0	3.1	3.4	0.4	3.1
05-10	2.7	2.6	2.8	0.4	2.7
10-15	2.6	2.2	2.5	0.4	2.5
15-20	2.5	1.9	2.1	0.4	2.3

Table 1B.4-10
St. Cloud Average Number of Customers Forecast

Year	Residential	GS Nondemand	GS Demand	Total Retail
1995	13659	1293	116	15068
1996	14158	1311	132	15602
1997	14527	1359	140	16026
1998	15010	1427	150	16586
1999	15594	1522	152	17268
2000	16092	1553	163	17807
2005	18026	1714	182	19923
2010	20208	1886	203	22296
2015	22472	2037	219	24728
2020	24841	2188	236	27264
Change	percent	percent	percent	percent
1996	3.7	1.4	13.9	3.5
1997	2.6	3.6	6.1	2.7
1998	3.3	5.0	6.9	3.5
1999	3.9	6.6	1.6	4.1
00-05	2.3	2.0	2.3	2.3
05-10	2.3	1.9	2.1	2.3
10-15	2.1	1.6	1.6	2.1
15-20	2.0	1.4	1.5	2.0

Table 1B.4-11
OUC Residential Sales Forecast Summary

Year	Retail Sales	Customers	Average Use (Kwh)
1995	1380	108845	12679
1996	1419	111241	12765
1997	1377	113808	12096
1998	1583	117868	13430
1999	1504	121173	12411
2000	1606	124484	12905
2005	1822	135530	13443
2010	2046	148822	13749
2015	2298	162621	14128
2020	2579	177054	14565
Change	percent	percent	percent
1996	2.8	2.2	0.6
1997	-3.0	2.3	-5.2
1998	15.0	3.6	11.0
1999	-5.0	2.8	-7.6
00-05	2.5	1.7	0.8
05-10	2.3	1.9	0.5
10-15	2.3	1.8	0.5
15-20	2.3	1.7	0.6

Table 1B.4-12
St. Cloud Residential Sales Forecast Summary

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	180	13659	13194
1996	190	14158	13431
1997	192	14527	13191
1998	221	15010	14713
1999	221	15594	14197
2000	234	16092	14522
2005	271	18026	15045
2010	309	20208	15298
2015	351	22472	15606
2020	396	24841	15956
Change	percent	percent	percent
1996	5.5	3.7	1.8
1997	0.8	2.6	-1.8
1998	15.2	3.3	11.5
1999	0.2	3.9	-3.5
00-05	3.0	2.3	0.7
05-10	2.7	2.3	0.3
10-15	2.6	2.1	0.4
15-20	2.5	2.0	0.4

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 the 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 1.2 percent and 1.7 percent respectively for OUC and St. Cloud from 1999 to 2020. Tables 1B.4-13 and 1B.4-14 show annual GSND forecasts for OUC and St. Cloud.

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 5.8 percent in 1998 and 6.9 percent in 1999. 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 the GSND to GSD. The GSD customer forecast is driven by total employment projections and total sales by projected regional gross output. Tables 1B.4-15 and 1B.4-16 summarize the GSD forecast.

1B.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 1B.4-17 and 1B.4-18 show seasonal peak demands and net energy for load forecasts for OUC and St. Cloud.

1B.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. The High and Low Case Scenarios were developed by modifying the Base Case economic assumptions. The primary drivers that were modified are regional population, labor force, employment, output, and income. Table 1B.4-19 shows a comparison of the economic assumptions.

Table 1B.4-13
OUC General Service Nondemand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	316	14572	21713
1996	318	14855	21400
1997	322	15065	21353
1998	310	15168	20465
1999	308	15659	19657
2000	329	15779	20853
2005	360	16524	21764
2010	386	17474	22074
2015	418	18682	22382
2020	454	20107	22577
Change	Percent	Percent	Percent
1996	0.5	1.9	-1.4
1997	1.2	1.4	-0.2
1998	-3.5	0.7	-4.2
1999	-0.8	3.2	-3.9
00-05	1.8	0.9	0.9
05-10	1.4	1.1	0.3
10-15	1.6	1.3	0.3
15-20	1.7	1.5	0.2

Table 1B.4-14
St. Cloud General Service Nondemand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	19	1293	14426
1996	18	1311	14004
1997	19	1359	13660
1998	20	1427	14229
1999	22	1522	14484
2000	23	1553	14967
2005	27	1714	15769
2010	31	1886	16316
2015	34	2037	16813
2020	38	2188	17197
Change	percent	percent	percent
1996	-1.5	1.4	-2.9
1997	1.1	3.6	-2.5
1998	9.4	5.0	4.2
1999	8.5	6.6	1.8
00-05	3.1	2.0	1.0
05-10	2.6	1.9	0.7
10-15	2.2	1.6	0.6
15-20	1.9	1.4	0.5

Table 1B.4-15
OUC Large General Service Demand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	2154	2970	725046
1996	2211	3120	708721
1997	2274	3445	660036
1998	2405	3799	632959
1999	2570	3871	663841
2000	2756	4074	676550
2005	3207	4560	703253
2010	3561	5151	691198
2015	3913	5753	680176
2020	4259	6351	670635
Change	percent	percent	percent
1996	2.7	5.0	-2.3
1997	2.8	10.4	-6.9
1998	5.8	10.3	-4.1
1999	6.9	1.9	4.9
00-05	3.1	2.3	0.8
05-10	2.1	2.5	-0.3
10-15	1.9	2.2	-0.3
15-20	1.7	2.0	-0.3

Table 1B.4-16
St. Cloud Large General Service Demand Sales Forecast

Year	Retail Sales (GWH)	Customers	Average Use (kWH)
1995	56	116	479495
1996	62	132	467126
1997	67	140	481841
1998	72	150	482554
1999	74	152	486316
2000	80	163	488021
2005	94	182	516042
2010	108	203	534083
2015	123	219	559371
2020	136	236	578504
Change	percent	percent	percent
1996	11.0	13.9	-2.6
1997	9.4	6.1	3.2
1998	7.1	6.9	0.1
1999	2.4	1.6	0.8
00-05	3.4	2.3	1.1
05-10	2.8	2.1	0.7
10-15	2.5	1.6	0.9
15-20	2.1	1.5	0.7

Table 1B.4-17
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	3926
1995	798	800	4103
1996	788	885	4186
1997	846	773	4271
1998	907	746	4578
1999	969	873	4674
2000	973	956	5006
2005	1123	1127	5777
2010	1253	1258	6451
2015	1389	1394	7156
2020	1529	1535	7890
Change	Percent	Percent	Percent
95-00	4.0	3.6	4.1
00-05	2.9	3.3	2.9
05-10	2.2	2.2	2.2
10-15	2.1	2.1	2.1
15-20	1.9	2.0	2.0

Table 1B.4-18
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	89	95	357
2005	104	113	415
2010	118	128	474
2015	134	145	536
2020	150	162	602
Change	Percent	Percent	Percent
95-00	7.2	4.7	5.4
00-05	3.1	3.3	3.1
05-10	2.7	2.6	2.7
10-15	2.5	2.5	2.5
15-20	2.3	2.2	2.3

Table 1B.4-19
Economic Assumptions

Economic Projections: Orlando MSA

High Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2.8	47
2005	687	68,479	1,038	1,075	3.5	56
2010	779	70,938	1,188	1,229	3.3	67
2015	875	74,998	1,358	1,404	3.3	81
2020	978	80 575	1 554	1 606	3.3	96
95-00	2.8%	2.6%	4.1%	3.7%	-	5.5%
00-05	2.9%	0.8%	3.3%	3.4%	-	3.6%
05-10	2.5%	0.7%	2.7%	2.7%	-	3.7%
10-15	2.3%	1.1%	2.7%	2.7%	-	3.7%
15-20	2.3%	1.4%	2.7%	2.7%	-	3.5%

Base Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2.8	47
2005	655	70,545	977	1,013	3.5	55
2010	721	74,207	1,084	1,122	3.4	65
2015	791	78,478	1,205	1,248	3.4	76
2020	863	83,331	1,340	1,387	3.4	87
95-00	2.8%	2.6%	4.1%	3.7%	-	5.5%
00-05	1.9%	1.4%	2.1%	2.2%	-	3.2%
05-10	2.0%	1.0%	2.1%	2.1%	-	3.5%
10-15	1.9%	1.1%	2.1%	2.1%	-	3.2%
15-20	1.8%	1.2%	2.1%	2.1%	-	2.8%

Low Scenario

Year	Households (thousands)	Per HH Income (real $)	Employment (thousands)	Labor Force (thousands)	Unemployment Rate (Average)	Gross Output (billions real $)
1995	520	57,724	723	757	4.5	36
2000	596	65,684	882	908	2.8	47
2005	641	65,666	929	988	5.9	50
2010	679	66,812	974	1,047	7.0	55
2015	712	69,916	1,030	1,107	7.0	61
2020	743	74,118	1,085	1,166	7.0	66
95-00	2.8°/	2.6%	4.1%	3.7%	-	5.5%
00-05	1.5%	0.0%	1.0%	1.7%	-	1.3%
05-10	1.1%	0.3%	1.0%	1.2%	-	1.9%
10-15	0.9%	0.9%	1.1%	1.1%	-	2.0%
15-20	0.9%	1.2%	1.1%	1.1%	-	1.8%

1B.4.5.1 High Case Scenarios

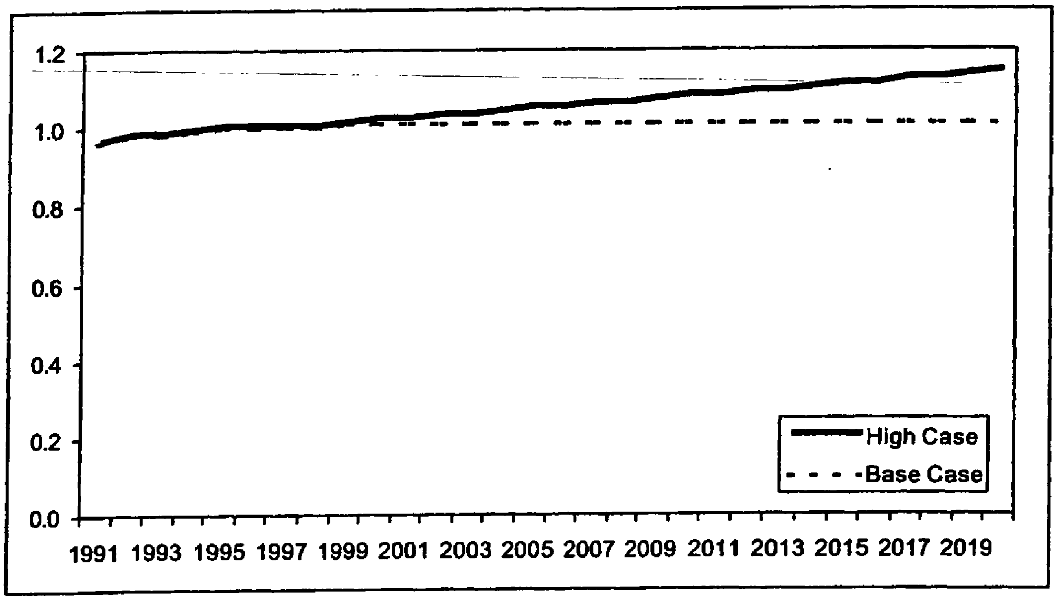
The high scenario is based upon assumptions of continued strong economic growth. We assume that through 2005, area population growth does not slow, but continues to expand at a rate experienced over the last few years. After 2005, the number of households increases 0.5 percent to 0.4 percent faster than the base case. 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. Employment and regional output in the high case scenario are somewhat constrained by the relatively low unemployment rate already assumed in the base case. We assume that there is only a slight improvement in the unemployment rate, as a relatively high labor force participation rate is already incorporated in RFA's base case forecast. Given that the number of households increases at a faster rate than the population during the first 10 years of the forecast (since household size declines during this period), income per household increases at a slightly lower rate than it does in the base case over the first 10 years. After 2010, household income grows at roughly the same rate as in the base case.

One other assumption was made for the high case: the Orlando area experiences stronger electricity demand due to an increase in computer-related loads. Implicit in the base case "other use" index is that computer loads increase at roughly 3 percent per year over the forecast horizon. This is based on Energy Information Administration (EIA) assumptions that have been incorporated into the EPRI COMMEND forecast model. Recently, there has been some debate as to the contribution of increased "computerization" to electric loads. In the high case scenario, we assume that computer loads increase at 6 percent annually. This results in the "other use" index (which is basically flat in the base case) increasing at a faster rate in the high case. Figure 1B.4-21 shows a comparison of the resulting change in the commercial "other use" index.

1B.4.5.2 Low Case Scenario

In the low case scenario, we assume that there is a significant slowdown in regional population growth. We assume that the growth in the number of households slows to 1.5 percent during the first 5 years, and declines further to a long-term growth rate of 0.9 percent. Moreover, we assume the unemployment rate averages 6.0 percent over the 20 year forecast horizon; this is not beyond the realm of possibility, given that Orlando's unemployment rate approached 8 percent during the summer of 1992. The higher unemployment rate translates into lower employment and economic output growth. Orlando's economic output is projected to increase less than 2 percent through

Figure 1B.4-21
Comparison of Commercial "Other Use" Index



forecast horizon. By way of comparison, growth in Orlando's gross product never dipped below 2.7 percent during the 1990s. Similarly, household income growth slows, with average household income growth remaining unchanged (in real terms) through the first 5 years, and not reaching the base case growth rate until after 2015.

1B.4.5.3 High and Low Forecast Scenario Results

Table 1B.4-20 summarizes the forecast scenario results, Table 1B.4-21 summarizes the total system peak forecast, and both provide a comparison with the base case. Through 2005, high case assumptions result in an overall sales growth rate of 3.6 percent, compared with the base case growth of 2.9 percent. The growth rates narrow somewhat over the longer term, with energy requirements increasing at a 2.8 percent pace in the high case, compared with a 2.1 percent average in the base case.

In the low case, sales slow to a 2.5 percent pace through 2005. Energy requirements further decline as a result of weak population and employment growth to a 1.6 percent growth between 2005 and 2010 and to a 1.3 percent pace after 2010.

Over the 20 year forecast horizon, the average growth rates in total electricity retail sales for the OUC and St. Cloud service territories are: 1.7 percent in the low case, 2.3 percent in the base case, and 3.0 percent in the high case.

Table 1B.4-20
Scenario Energy Forecast

Orlando Utilities Commission & St. Cloud

High Scenario - GWH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts.	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,186	399	3,400	36	17	100	6,139
2010	2,523	444	3,878	39	34	122	7,040
2015	2,905	497	4,429	42	51	145	8,070
2020	3,348	559	5,070	45	67	167	9,258
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	3.5%	2.5%	3.7%	1.6%	-	5.2%	3.6%
05-10	2.9%	2.2%	2.7%	1.6%	14.9%	4.1%	2.8%
10-15	2.9%	2.3%	2.7%	1.5%	8.4%	3.4%	2.8%
15-20	2.9%	2.4%	2.7%	1.4%	5.9%	2.9%	2.8%

Base Scenario - GWH

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,093	387	3,301	36	17	100	5,934
2010	2,355	417	3,669	39	34	122	6,636
2015	2,648	452	4,035	42	51	145	7,374
2020	2.975	492	4,396	45	67	167	8,143
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	2.5%	1.8%	3.1%	1.8%	-	5.2%	2.9%
05-10	2.3%	1.4%	2.1%	1.7%	14.9%	4.1%	2.2%
10-15	2.3%	1.6%	1.9%	1.6%	8.4%	3.4%	2.1%
15-20	2.3%	1.7%	1.7%	1.5%	5.9%	2.9%	2.0%

Low Scenario - G*WH*

Year	Residential	GS Nondemand	GS Demand	St. Lighting	Conv. St Lts	OUC Use	Total Retail
1995	1,560	335	2,209	27	-	55	4,186
2000	1,840	352	2,836	34	-	78	5,139
2005	2,026	361	3,262	36	17	100	5,802
2010	2,177	360	3,535	39	34	122	6,268
2015	2,338	359	3,771	42	51	145	6,705
2020	2,510	360	4,004	45	67	167	7,153
95-00	3.4%	1.0%	5.1%	4.3%	-	7.2%	4.2%
00-05	1.9%	0.5%	2.9%	1.8%	-	5.2%	2.5%
05-10	1.4%	0.0%	1.6%	1.7%	14.9%	4.1%	1.6%
10-15	1.4%	-0.1%	1.3%	1.6%	8.4%	3.4%	1.3%
15-20	1.4%	0.0%	1.2%	1.5%	5.9%	2.9%	1.3%

Table 1B.4-21
Scenario Peak Forecast

Total System Peak Forecast

High Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,265	1,273	6,384
2010	1,453	1,465	7,333
2015	1,662	1,673	8,392
2020	1,903	1,915	9,623
Average chg	Percent	Percent	Percent
95-00	4.3%	3.7%	4.1 %
00-05	3.6%	3.9%	3.5%
05-10	2.8%	2.8%	2.8%
10-15	2.7%	2.7%	2.7%
15-20	2.8%	2.7%	2.8%

Base Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,227	1,239	6,192
2010	1,372	1,386	6,925
2015	1,522	1,539	7,692
2020	1,679	1,697	8,492
chg			
95-00	4.3%	3.7%	4.1%
00-05	2.9%	3.3%	2.9%
05-10	2.3%	2.3%	2.3%
10-15	2.1%	2.1%	2.1%
15-20	2.0%	2.0%	2.0%

Low Case Scenario

Year	Summer (MW)	Winter (MW)	Net Energy (GWH)
1995	861	876	4,377
2000	1,062	1,051	5,363
2005	1,177	1,193	5,940
2010	1,259	1,279	6,359
2015	1,338	1,358	6,763
2020	1,419	1,440	7,178
chg			
95-00	4.3%	3.7%	4.1%
00-05	2.1%	2.6%	2.1%
05-10	1.4%	1.4%	1.4%
10-15	1.2%	1.2%	1.2%
15-20	1.2%	1.2%	1.2%

1B.5.0 Demand-Side Analysis

According to Section 403.519, Florida Statutes, in its determination of need, the Florida Public Service Commission (FPSC) must take into consideration conservation measures that could mitigate or delay the need of the proposed plant. Based on this requirement, OUC has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the PSC-approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of conservation measures by determining the relative cost-effectiveness of the measures versus an avoided supply-side resource. The FIRE model was designed by Florida Power Corporation and is used by several utilities in Florida.

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. The demand-side management goals for OUC 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 1B.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.

1B.5.1 Existing Conservation Programs

There have been significant changes in the market place in the last 5 years. Today there is much more emphasis on competition as the electric industry prepares for deregulation. Economic conditions have also changed significantly; for example, the cost of power plants and interest rates have decreased drastically. As a result, conservation programs are significantly less cost-effective. OUC's existing programs include the following:

- Residential Energy Survey Program.
- Residential Heat Pump Program.
- Residential Weatherization Program.
- Low Income Home Energy Fixup Program.
- Educational Outreach Program.
- Commercial Energy Survey Program.

Table 1B.5-1
Total Conservation Goals Approved by the FPSC

	Residential			Commercial / Industrial		
Year	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction	Winter kW Reduction	Summer kW Reduction	MWh Energy Reduction
1999						
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

1B.5.1.1 Residential Energy Survey

This program is designed to provide residential homeowners with recommended energy efficiency measures and practices. The Residential Energy Survey includes complete attic, air duct, and air return inspections. The customer is given a choice to receive either a low-flow showerhead or compact fluorescent bulb. OUC energy analysts are presently using this walk-through type audit as a means to get OUC customers to participate in other conservation programs and to qualify for appropriate rebates. Customers may also choose to perform their own energy audit by requesting a copy of OUC's home energy audit video. This video will soon be available in an interactive CD format. Beginning in the first quarter of 2001, an Internet interactive home energy audit complete with previous billing information on the customer will be available.

1B.5.1.2 Residential Heat Pump Program

Heat pumps are marketed to the owners of existing residential strip heating systems and older, inefficient central air conditioners and heat pumps. The program requires heat pumps with a SEER of 11 (or greater) and a HSPF of 7.0 (or greater) in order to qualify for rebates. Rebates vary by equipment SEER levels. One of the main benefits of the program is the duct work and insulation level improvements made by contractors when installing the energy efficient heat pumps.

1B.5.1.3 Residential Weatherization Program

This program is designed for existing single family homes and promotes R-19 ceiling insulation (or higher), caulking, weather-stripping, window treatment, water heater insulation, and air condition/heating supply and return air duct repair. The customer can receive a $140 rebate for installing R-19 ceiling insulation (or higher), $100 rebate for duct repairs, and up to $110 for other conservation measures specified above. In addition, the customer is allowed to carry payments for ceiling insulation on their electric bill for 12 or 24 months. OUC directly pays the total cost for installation when OUC provides the financing.

The program is promoted through Residential Energy Surveys, trade shows, exhibits, and neighborhood meetings.

1B.5.1.4 Low Income Home Energy Fixup Program

This program targets residential customers with an annual income of less than $20,000. Every customer is eligible for an energy audit. 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 will pay 85 percent of the total contract cost for home weatherization for the following measures:

- Upgrading ceiling insulation to R-19.
- Exterior and interior caulking.
- Weather-stripping doors and windows.
- Air conditioning/heating supply and return air duct repairs.
- Water heater insulation.

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.

1B.5.1.5 Education Outreach Program

This program is now entering its 15th year of operation. The program is very successful and has won several awards for contributions to education. The 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.

1B.5.1.6 Commercial Energy Survey Program

This survey is a physical walk-through inspection of the commercial facility. The commercial customer having a Commercial Energy Survey receives a report at the time of the survey. Within 30 days of a detailed audit, the customer receives a written report. Conservation literature is provided to all customers. The program is focused on commercial customers to increase the energy efficiency and energy conservation. OUC has also developed an alliance with a large performance contractor in order to provide large commercial customers with a more complete solution to their needs.

1B.5.2 Analysis of Demand-Side Management Alternatives

OUC used the FIRE model to evaluate the most cost-effective DSM measures from FPL's 2000 Demand-Side Management Plan as discussed in Section 1A.8. The results of that analysis are as follows.

1B.5.2.1 FIRE Model Output Analysis

OUC requires all measures to pass the Rate Impact Test to be considered cost-effective. Of the potential DSM measures tested, none passed the Rate Impact Test. Thus, OUC has concluded that there are no cost-effective DSM measures reasonably available that would avoid or defer the need for Stanton A. Table 1B.5-2 presents the FIRE model results of the DSM analysis.

Table 1B.5-2
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
Direct Load Control	0.49	1.00	2.33
Commercial			
Off-Peak Battery Charging	0.98	0.04	0.48

The results of the DSM analysis are not surprising due to the previously performed analysis for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for Kissimmee Utility Authority (KUA) and Florida Municipal Power Agency (FMPA) for Cane Island Unit 3 (Docket

No. 980802) and Lakeland Electric's conversion of McIntosh Unit 5 (Docket No. 990023), and in recent Demand Side Management Ten Year Plans for Orlando Utilities Commission (Docket No. 990722-EG) and JEA (Docket No. 990720-EG).

The decrease in the cost-effectiveness of the DSM measures can be attributed to the decreased price of installing new generation, the higher efficiency of new generation, relatively low interest rates, and the general increase in the efficiency of appliances and dwellings.

1B.6.0 Reliability Criteria

Prudent utility practices require a utility to plan for sufficient capacity resources to meet its peak demand plus maintain an additional margin of capacity should unforeseen events result in higher system demand or lower than anticipated availability of capacity. This section presents the development of the reliability criteria used by OUC.

1B.6.1 Development of Reliability Criteria

A number of methods are used in the electric utility industry to calculate a utility's system reliability. Two basic methods, known as the Traditional Reserve Margin and the Loss of Load Probability, apply deterministic and probabilistic methods, respectively, to calculate the reliability of a system. The methods are discussed below.

1B.6.1.1 Traditional Reserve Margin

The most commonly used deterministic method is the Traditional Reserve Margin method, which is calculated as follows:

$$\frac{\text{System Net Capacity} - \text{System Net Peak Demand}}{\text{System Net Peak Demand}}$$

From the equation, it is seen that should the net capacity or net peak demand deviate from the predicted levels, the actual reserve margin will vary. For a relatively small or isolated utility system, an unanticipated plant outage or higher than expected growth in system demand can quickly reduce or eliminate the planned reserve margin. A weakness with the formula is that it does not indicate what the appropriate reserve margin is for a given system; the appropriate reserve level must be determined elsewhere. 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 through out much of the industry. OUC has adopted the 15 percent minimum reserve margin requirement as its planning methodology.

1B.6.1.2 Loss of Load Probability

The second commonly-used method of calculating the reliability of a utility system is the Loss of Load Probability (LOLP) method. This method has the advantage that it can result in a measure of how much capacity (and reserves) are needed to meet a target level of reliability (most utilities adopt a LOLP of 1 day in 10 years). Given the nature of OUC's relatively small, high interconnected system, LOLP for OUC's system is driven almost entirely by the interconnections. Since the reliability of the interconnections is driven by the capacity from other systems available to the interconnection, the reliability of interconnections is difficult to predict and is generally out of the control of OUC. For these reasons, OUC does not use LOLP as the reliability criterion and instead uses the reserve margin criterion. LOLP is much better suited for measuring reliability of large systems such as FRCC.

1B.6.2 Reliability Need

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 1B.6-1 and 1B.6-2 display the forecast reserve margins for OUC and St. Cloud for the winter and summer seasons, respectively.

Table 1B.6-1 indicates that additional capacity will not be needed by the winter of 2002. Furthermore, Table 1B.6-2 shows that additional capacity will be necessary to satisfy forecast demand requirements for the summer of 2002. The majority of the capacity required in 2002 and 2003 can be satisfied by exercising the additional 10 percent option on the Reliant contract, which represents 52.5 MW. Regardless, OUC will need a substantial amount of capacity beginning with the expiration of the Reliant agreement on October 1, 2003.

Table 1B.6-1
OUC Winter Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1,051	440	1,491	1,092	608	1,700	208	168	40
2001	1,090	341	1,431	1,092	608	1,700	268	176	93
2002	1,144	323	1,467	1,092	540	1,632	165	184	(19)
2003	1,182	312	1,494	1,092	540	1,632	138	192	(54)
2004	1,210	263	1,473	1,092	15	1,107	-366	198	(564)
2005	1,239	172	1,411	1,071	15	1,086	-325	203	(528)
2006	1,267	139	1,406	1,071	15	1,086	-320	205	(525)
2007	1,292	139	1,431	1,071	15	1,086	-345	212	(558)
2008	1,323	142	1,465	1,071	15	1,086	-379	218	(597)
2009	1,356	144	1,500	1,071	15	1,086	-414	223	(637)
2010	1,386	146	1,532	1,071	15	1,086	-446	228	(673)
2011	1,416	0	1,416	1,071	15	1,086	-330	210	(540)
2012	1,449	0	1,449	1,071	15	1,086	-363	215	(578)
2013	1,480	0	1,480	1,071	0	1,071	-409	222	(631)
2014	1,512	0	1,512	1,071	0	1,071	-441	227	(667)
2015	1,542	0	1,542	1,071	0	1,071	-471	231	(702)
2016	1,572	0	1,572	1,071	0	1,071	-501	236	(737)
2017	1,608	0	1,608	1,071	0	1,071	-537	241	(779)
2018	1,643	0	1,643	1,071	0	1,071	-572	246	(818)
2019	1,675	0	1,675	1,071	0	1,071	-604	251	(855)

1. Includes St. Cloud.

Table 1B.6-2
OUC Summer Reserve Requirements

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1,062	440	1,502	1,047	608	1,653	153	170	(17)
2001	1,092	341	1,433	1,047	608	1,653	222	176	46
2002	1,136	323	1,459	1,047	540	1,585	128	183	(55)
2003	1,170	312	1,482	1,047	540	1,585	105	190	(85)
2004	1,197	263	1,460	1,047	15	1,060	-398	196	(593)
2005	1,227	172	1,399	1,025	15	1,039	-359	201	(560)
2006	1,254	139	1,393	1,025	15	1,039	-353	203	(557)
2007	1,278	139	1,417	1,025	15	1,039	-377	210	(587)
2008	1,306	142	1,448	1,025	15	1,039	-408	215	(623)
2009	1,339	144	1,483	1,025	15	1,039	-443	220	(663)
2010	1,372	146	1,518	1,025	15	1,039	-478	225	(703)
2011	1,399	0	1,399	1,025	15	1,039	-359	208	(567)
2012	1,428	0	1,428	1,025	15	1,039	-388	212	(600)
2013	1,463	0	1,463	1,025	15	1,039	-438	219	(658)
2014	1,495	0	1,495	1,025	0	1,024	-470	224	(695)
2015	1,526	0	1,526	1,025	0	1,024	-501	229	(730)
2016	1,557	0	1,557	1,025	0	1,024	-532	234	(766)
2017	1,591	0	1,591	1,025	0	1,024	-566	239	(805)
2018	1,625	0	1,625	1,025	0	1,024	-600	244	(844)
2019	1,656	0	1,656	1,025	0	1,024	-631	248	(879)

1. Includes St. Cloud.

1B.7.0 Economic Analysis

The economic analysis for the cost-effectiveness of the project consists of several evaluations to arrive at the least-cost supply plan to meet the growing needs of OUC's customers. The methodology of the analyses, the expansion candidates evaluated, and the results of the base case evaluations are discussed in detail in this section.

A four phase economic analysis was conducted to determine OUC's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side analyses are included in this section and discussed in detail. The results of the demand-side evaluation analyses are presented in Section 1B.5.0. The proposal evaluations are presented in Section 1A.6. The sensitivity analyses are discussed in Section 1B.8.0.

1B.7.1 Methodology

The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program and has been used in several other Need for Power proceedings before the FPSC. The program 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 20 year period from 2000 to 2019.

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. OUC's and St. Cloud's systems were combined for purposes of expansion planning.

1B.7.2 Expansion Candidates

The expansion candidates for the POWROPT evaluation represent the conventional alternatives presented in Section 1A.7. Table 1B.7-1 summarizes the expansion alternatives considered for OUC in the optimization study for supply-side alternatives.

Table 1B.7-1
Summary of OUC Generation Alternatives (2000 $, unless otherwise noted)

Description	Capital Costs	Capacity[1]	O&M Costs		Fuel Type	Full Load Heat Rate (HHV)[1]	Forced Outage Rate	Scheduled Maintenance	First Year Available
			Variable	Fixed					
	$1,000	MW	$/MWh	$/kW-yr		Btu/kWh	percent	days/year	
Pulverized Coal	513,163	446	3.73	14.17	Coal	9,979	3.0	30	2006
Fluidized Bed	366,076	267	5.53	23.55	Pet. Coke	10,543	3.0	28	2005
501F 2x1 CC (standard)	275,756[4]	514	[redacted]	[redacted]	Nat. Gas	7,074	4.0	[redacted]	2005
501F 2x1 CC (oversized)	288,211[4]	610	[redacted]	[redacted]	Nat. Gas	7,542	4.0	[redacted]	2005
7FA SC	68,615	156	2.33	5.13	Nat. Gas	10,940	1.96	7	2005
7FA 2x1 CC (self-build)[3]	232,169[4]	488	[redacted]	[redacted]	Nat. Gas	[redacted]	4.0	[redacted]	2003[5]
7FA 2x1 CC (joint development)[3]	[redacted]	171	[redacted]	[redacted]	Nat. Gas	[redacted]	[redacted]	[redacted]	2003[5]

1. At 70 – 72° F, depending on the generation alternative (after degradation).
2. (2003 $)
3. Reflects OUC's portion of total generation alternative capacity.
4. Mixed year dollars to reflect commercial operation date of October 1, 2003.
5. October 1, 2003.

1B.7.3 Results of 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 described in detail in Section 1A.7 and summarized in Table 1B.7-1. Production costs were modeled at temperatures which closely approximate (within 2 degrees) the average annual temperature for OUC. Winter and summer unit ratings were used to determine capacity requirements.

The expansion plan outlined in Table 1B.7-2 shows that the joint development project with Southern-Florida is the least-cost capacity addition plan for OUC under the base case scenario. For comparison purposes, Table 1B7-3 displays the least-cost expansion capacity addition plan for OUC that does not include the joint-development project with Southern-Florida. The units and power purchases comprising the expansion plans are listed in the tables according to their year of commercial operation. Tables 1B.7-4 through 1B.7-7 present the summer and winter capacity balances for the expansion plans presented in Tables 1B.7-2 and 1B.7-3, respectively. Appendix 1B.B presents tables showing the fuel, O&M, and capital costs for expansion plans on an annual basis.

The addition of the Southern-Florida joint development project and the self-build General Electric 7FA 2x1 combined cycle represent the only two available alternatives that allow OUC to meet OUC's reserve requirements in 2004. In fact, even the self-build General Electric 7FA 2x1 combined cycle is no longer an option because it was based on obtaining the General Electric 7FA combustion turbines that KUA had under option with General Electric. The option for the two General Electric 7FA combustion turbines expired on September 30, 2000. However, the option was available during the time that OUC was evaluating the joint development and purchase power proposals and is presented to demonstrate the prudence of the selection of the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement does not provide sufficient capacity for OUC to meet its capacity requirements in 2004 without the Southern-Florida joint development project. The extension of the full 500 MW of the Reliant Agreement would still result in a 93 MW shortfall for OUC in the summer of 2004 as demonstrated by Table 1B.6-2. OUC is precluded from installing other options until at least 2005 as shown in Table 1B.7-1 due to the delivery schedule for combustion turbines.

It is clear from a comparison of Tables 1B.7-2 and 1B.7-3 that the joint development project with Southern-Florida provides the most cost-effective solution to satisfy OUC's forecast capacity requirements. The joint development project with Southern-Florida results in a projected $6.925 million in cumulative present worth savings over the self-build alternative while providing the flexibility and strategic advantages discussed in Section 1A.6.4.

Table 1B.7-2
OUC Least-Cost Base Case Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,238	294,507
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,346	441,409
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	182,414	586,216
2004	171 MW Joint Development with Southern – Florida (10/03)	220,125	748,014
	317 MW Southern – Florida Power Purchase (10/03)		
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	221,724	898,915
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	216,619	1,035,422
2007	156 MW GE 7FA Simple Cycle (06/07)	230,334	1,169,819
2008	156 MW GE 7FA Simple Cycle (06/08)	245,040	1,302,207
2009		264,023	1,434,284
2010		271,624	1,560,098
2011		280,395	1,680,355
2012		294,709	1,797,388
2013	Terminate 317 MW Southern – Florida Power Purchase (11/13)	306,249	1,909,995
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		333,329	2,023,481
2015		348,185	2,133,243
2016		360,765	2,238,547
2017		374,692	2,339,814
2018		393,339	2,438,247
2019		413,511	2,534,062

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

Table 1B.7-3
OUC Base Case Expansion Plan – Runner Up #1

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	162,238	294,507
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	171,346	441,409
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	183,514	587,088
2004	488 MW Self-Build GE 7FA 2x1 (10/03)	219,155	748,174
	100 MW Indian River Power Purchase (10/03 - 09/04)		
2005	100 MW Indian River Power Purchase (10/04 - 09/05)	220,767	898,424
2006	100 MW Indian River Power Purchase (10/05 – 09/06)	218,188	1,035,919
2007	156 MW GE 7FA Simple Cycle (06/07)	233,111	1,171,938
2008	156 MW GE 7FA Simple Cycle (06/08)	243,714	1,303,609
2009		263,213	1,435,281
2010		271,205	1,560,901
2011		278,923	1,680,526
2012		294,851	1,797,616
2013		307,495	1,910,681
2014		339,450	2,026,250
2015		339,155	2,133,166
2016	156 MW GE 7FA Simple Cycle (06/16)	364,773	2,239,640
2017		378,698	2,341,990
2018		406,327	2,443,673
2019		419,978	2,540,987

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

Table 1B.7-4
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1213	465	1679	219	196	23
2005	1227	172	1399	1192	449	1641	242	201	41
2006	1254	139	1393	1192	434	1626	233	203	29
2007	1278	139	1417	1332	324	1656	239	210	28
2008	1306	142	1448	1472	324	1796	348	215	133
2009	1339	144	1483	1472	324	1796	313	220	92
2010	1372	146	1518	1472	324	1796	278	225	53
2011	1399	0	1399	1472	324	1796	396	208	189
2012	1428	0	1428	1472	324	1796	368	212	156
2013	1463	0	1463	1472	309	1781	318	219	98
2014	1495	0	1495	1953	0	1953	457	224	233
2015	1526	0	1526	1953	0	1953	427	229	198
2016	1557	0	1557	1953	0	1953	395	234	162
2017	1591	0	1591	1953	0	1953	361	239	123
2018	1625	0	1625	1953	0	1953	328	244	84
2019	1656	0	1656	1953	0	1953	297	248	48

[1]Includes St. Cloud.

Table 1B.7-5
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-2)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1273	492	1765	293	198	95
2005	1239	172	1411	1252	476	1729	317	203	114
2006	1267	139	1406	1252	461	1714	308	205	103
2007	1292	139	1431	1427	351	1779	348	212	135
2008	1323	142	1465	1602	351	1954	489	218	271
2009	1356	144	1500	1602	351	1954	454	223	231
2010	1386	146	1532	1602	351	1954	422	228	194
2011	1416	0	1416	1602	351	1954	537	210	327
2012	1449	0	1449	1602	351	1954	505	215	290
2013	1480	0	1480	1602	336	1939	458	222	236
2014	1512	0	1512	2166	0	2166	655	227	428
2015	1542	0	1542	2166	0	2166	624	231	393
2016	1572	0	1572	2166	0	2166	594	236	358
2017	1608	0	1608	2166	0	2166	558	241	316
2018	1643	0	1643	2166	0	2166	523	246	277
2019	1675	0	1675	2166	0	2166	491	251	240

[1]Includes St. Cloud.

Table 1B.7-6
OUC Summer Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1092	341	1433	1047	608	1655	222	176	46
2002	1136	323	1459	1047	593	1639	180	183	(3)
2003	1170	312	1482	1047	593	1639	157	190	(33)
2004	1197	263	1460	1523	156	1679	219	196	23
2005	1227	172	1399	1501	140	1641	242	201	41
2006	1254	139	1393	1501	125	1626	233	203	29
2007	1278	139	1417	1641	15	1656	239	210	28
2008	1306	142	1448	1781	15	1796	348	215	133
2009	1339	144	1483	1781	15	1796	313	220	92
2010	1372	146	1518	1781	15	1796	278	225	53
2011	1399	0	1399	1781	15	1796	396	208	189
2012	1428	0	1428	1781	15	1796	368	212	156
2013	1463	0	1463	1781	0	1781	318	219	98
2014	1495	0	1495	1781	0	1781	285	224	61
2015	1526	0	1526	1781	0	1781	255	229	26
2016	1557	0	1557	1921	0	1921	363	234	130
2017	1591	0	1591	1921	0	1921	330	239	91
2018	1625	0	1625	1921	0	1921	296	244	52
2019	1656	0	1656	1921	0	1921	265	248	17

[1] Includes St. Cloud.

Table 1B.7-7
OUC Winter Capacity Balance (After Expansion Plan Outlined in Table 1B.7-3)

Year	Retail Peak Demand[1] (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	208	168	40
2001	1090	341	1431	1092	608	1700	268	176	93
2002	1144	323	1467	1092	593	1684	218	184	33
2003	1182	312	1494	1092	593	1684	190	192	(1)
2004	1210	263	1473	1609	156	1765	293	198	95
2005	1239	172	1411	1589	140	1729	317	203	114
2006	1267	139	1406	1589	125	1714	308	205	103
2007	1292	139	1431	1764	15	1779	348	212	135
2008	1323	142	1465	1939	15	1954	489	218	271
2009	1356	144	1500	1939	15	1954	454	223	231
2010	1386	146	1532	1939	15	1954	422	228	194
2011	1416	0	1416	1939	15	1954	537	210	327
2012	1449	0	1449	1939	15	1954	505	215	290
2013	1480	0	1480	1939	0	1939	458	222	236
2014	1512	0	1512	1939	0	1939	427	227	200
2015	1542	0	1542	1939	0	1939	397	231	166
2016	1572	0	1572	1939	0	1939	366	236	130
2017	1608	0	1608	2114	0	2114	505	241	264
2018	1643	0	1643	2114	0	2114	471	246	224
2019	1675	0	1675	2114	0	2114	439	251	187

[1]Includes St. Cloud.

1B.8.0 Sensitivity Analysis

OUC performed several sensitivity analyses to measure the impact of key assumptions on the least-cost plan. The sensitivity analyses are presented in Sections 1B.8.1 through 1B.8.7 and include low and high fuel escalation as well as three additional fuel price scenarios. Two were based on the AEO fuel price projections. One uses the actual AEO projections and the other applies the AEO escalation rates to the actual 2000 OUC prices. Finally, a fuel price that assumes the actual OUC 2000 fuel prices remain constant in real terms is analyzed. High load and energy growth and low load and energy growth scenarios were also evaluated. For each sensitivity analysis, the two least-cost plans over the planning horizon are identified. The sensitivity analyses were performed over a 20 year planning horizon, similar to the base case economic evaluation, with a projection of annual costs and cumulative present worth costs.

1B.8.1 High Fuel Price Escalation

The high fuel price scenario applies an annual escalation rate that is 2.0 percentage points higher than that used for the base case forecast. The high fuel price forecast is provided in Table 1A.5-6. Table 1B.8-1 displays the results of the economic evaluation for the least-cost expansion plan for the high fuel price escalation sensitivity and Table 1B.8-2 presents the runner-up expansion plan. The planning including the joint development alternative is $18.9 million lower than the plan with the self-build alternative indicating the benefit of flexibility with the joint development project.

1B.8.2 Low Fuel Price Escalation

The low fuel price scenario applies an annual growth rate that is 2.0 percentage points lower than that used for the base case forecast. The low fuel price forecast is provided in Table 1A.8-7. Table 1B.8-3 displays the results of the economic evaluation for the least-cost expansion plan for the low fuel price escalation sensitivity and Table 1B.8-4 presents the runner-up expansion plan. Comparing the two plans indicates the plan with the joint development project continues to be the lowest cost with a $4.4 million cumulative present worth savings over the self-build plan.

1B.8.3 AEO Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast provided by AEO as presented in Table 1A.5-10. The results of the economic evaluation for the least-cost expansion plan using the AEO fuel price forecast are shown in Tables 1B.8-5. Table 1B.8-6 presents the

the runner-up expansion plan. Under this screen, the expansion plan with the joint development project is $27 million lower in cumulative present worth cost.

1B.8.4 OUC 2000 Fuel Costs with 2001 AEO Escalation

This sensitivity analysis is based on the 2001 AEO fuel price escalation rates being applied to OUC's actual 2000 fuel costs as presented in Table 1A.5-11. Table 1B.8-7 presents the results of the economic evaluation for the least cost expansion plan and Table 1B.8-8 presents the runner-up expansion plan. With these higher fuel prices, the plan with the joint development project shows its increasing value with a $28 million savings over the plan with the self-build project.

1B.8.5 Constant 2000 Fuel Price Projections

This sensitivity analysis utilizes the fuel forecast resulting from escalating OUC's average 2000 fuel prices at the general inflation rate as presented in Table 1A.5-8. The results of the economic evaluation for the least-cost expansion plan using the constant 2000 fuel price forecast are shown in Table 1B.8-9 and Table 1B.8-10 presents the runner-up expansion plan. Again, the plan with the joint development project represents the lowest cost by $9 million.

1B.8.6 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. 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 1B.4. Tables 1B.8-11 and 1B.8-12 indicate the summer and winter need for capacity based upon the high load and energy forecast.

As indicated in Table 1B.8-11, the high load and energy growth scenario results in a 59 MW capacity shortfall in the summer of 2002. Since the only option available to OUC for the summer of 2002 and 2003 is the additional 52.5 MW purchase from the Reliant Agreement, it has been assumed that OUC will purchase power on the spot market to make up the resultant deficit.

As indicated in Table 1B.8-12, the high load and energy growth scenario results in a capacity shortfall in the winter of 2002. The additional 52.5 MW purchase from the Reliant Agreement will satisfy OUC's needs for the winter of 2002 as well as for the winter of 2003.

Table 1B.8-13 displays the results of the economic evaluation for the least-cost expansion plan for the high load and energy growth sensitivity and Table 1B.8-14 presents the runner-up expansion plan. Comparing the two plans indicates that the plan including the self-build alternative is $24.4 million lower in cost than the plan including joint development project. It is not surprising that continued assured high growth would favor the self-build plan. The joint development project has been structured to provide relatively greater protection to OUC in scenarios that would have negative consequences such as loss of retail load or increases in the cost of fuel than it would be scenarios that would have positive consequences such as higher load growth or lower fuel prices.

1B.8.7 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 1B.4.0. Tables 1B.8-15 and 1B.8-16 indicate the summer and winter need for capacity based upon the low load and energy forecast.

Capacity is required beginning in the summer of 2002 and the winter of 2004 for the low load and energy forecast. The extension of the 52.5 MW Reliant Agreement option will satisfy OUC's capacity requirements in the summer of 2002 and 2003 for the low load and energy growth scenario.

Table 1B.8-17 displays the results of the economic evaluation for the least-cost expansion plan for the low load and energy growth sensitivity and Table 1B.8-18 presents the runner-up expansion plan. Over the entire 20 year planning horizon, the cumulative present worth cost of the joint development alternative is only $68,000 over the cost of the self-build alternative. Notably, closer examination of Tables 1B.8-17 and 1B.8-18 indicate that the joint development alternative was lower in cumulative present worth cost every year until 2019. As discussed in Section 1A.4.1, the PPA has provisions for reducing the contract demand beginning in the sixth year. While this provision has not been explicitly evaluated, it would have significant economic benefit to OUC in a scenario such as this with low load and energy growth.

Table 1B.8-1
OUC High Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,289	296,406
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,171	448,301
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	191,164	600,054
2004	171 MW Joint Development with Southern–Florida (10/03)	231,516	770,225
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	235,960	930,815
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	233,733	1,078,107
2007	156 MW GE 7FA SC (06/07)	251,687	1,224,964
2008	156 MW GE 7FA SC (06/08)	270,915	1,371,331
2009		295,247	1,519,028
2010		307,799	1,661,598
2011		323,212	1,800,218
2012		344,259	1,936,929
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	363,258	2,070,498
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		396,384	2,205,451
2015		419,684	2,337,753
2016		441,382	2,466,588
2017		465,221	2,592,323
2018		496,565	2,716,588
2019		529,979	2,839,391

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

Table 1B.8-2
OUC High Fuel Price Escalation Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	164,289	296,406
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	177,171	448,301
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	192,307	600,961
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	230,839	770,634
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	235,521	930,926
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	235,852	1,079,552
2007	156 MW GE 7FA Simple Cycle (06/07)	254,957	1,228,317
2008	156 MW GE 7FA Simple Cycle (06/08)	270,225	1,374,311
2009		294,810	1,521,790
2010		307,904	1,664,409
2011		322,025	1,802,520
2012		344,937	1,939,499
2013		365,063	2,073,732
2014		405,479	2,211,782
2015		414,694	2,342,511
2016	156 MW GE 7FA Simple Cycle (06/16)	451,016	2,474,158
2017		475,406	2,602,645
2018		518,102	2,732,300
2019		544,055	2,858,364

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

Table 1B.8-3
OUC Low Fuel Price Escalation Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,185	292,606
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,925	434,002
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,546	571,769
2004	171 MW Joint Development with Southern–Florida (10/03)	209,053	725,429
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	207,624	866,734
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	200,591	993,140
2007	156 MW GE 7FA SC (06/07)	210,874	1,116,183
2008	156 MW GE 7FA SC (06/08)	221,690	1,235,955
2009		236,622	1,354,325
2010		240,421	1,465,687
2011		245,689	1,571,058
2012		254,781	1,672,235
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	261,501	1,768,389
	514 MW WH 501F 2x1 Combined Cycle (11/13)		
2014		283,548	1,864,926
2015		292,001	1,956,977
2016		298,822	2,044,200
2017		306,041	2,126,913
2018		317,550	2,206,380
2019		328,694	2,282,542

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

Table 1B.8-4
OUC Low Fuel Price Escalation Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,185	292,606
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	164,925	434,002
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	174,598	572,604
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	208,324	725,728
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	206,980	866,596
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	202,613	994,276
2007	156 MW GE 7FA Simple Cycle (06/07)	213,997	1,119,141
2008	156 MW GE 7FA Simple Cycle (06/08)	220,775	1,238,419
2009		235,859	1,356,407
2010		240,138	1,467,638
2011		244,155	1,572,351
2012		254,857	1,673,558
2013		262,395	1,770,041
2014		288,183	1,868,156
2015		281,862	1,957,010
2016	156 MW GE 7FA Simple Cycle (06/16)	300,532	2,044,733
2017		308,417	2,128,088
2018		326,864	2,209,886
2019		332,718	2,286,980

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

Table 1B.8-5
AEO Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,908	118,908
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,708	232,527
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	132,497	346,122
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	151,522	466,405
2004	171 MW Joint Development with Southern–Florida (10/03)	197,457	611,541
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	199,966	747,635
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	193,452	869,543
2007	156 MW GE 7FA Simple Cycle (06/07)	206,116	989,809
2008	156 MW GE 7FA Simple Cycle (06/08)	219,525	1,108,411
2009		240,175	1,228,559
2010		247,005	1,342,970
2011		253,273	1,451,594
2012		265,287	1,556,943
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	276,371	1,658,564
	446 MW Pulverized Coal (11/13)		
2014		304,969	1,762,394
2015		313,858	1,861,336
2016		322,682	1,955,523
2017		330,997	2,044,982
2018		345,025	2,131,324
2019		362,463	2,215,311

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

Table 1B.8-6
OUC AEO Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	118,908	118,908
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	122,708	232,527
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	132,497	346,122
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	152,409	467,109
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	196,586	611,605
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	198,849	746,938
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	195,519	870,148
2007	156 MW GE 7FA Simple Cycle (06/07)	209,159	992,191
2008	156 MW GE 7FA Simple Cycle (06/08)	218,328	1,110,147
2009		239,495	1,229,954
2010		246,794	1,344,267
2011		251,727	1,452,229
2012		265,525	1,557,672
2013		279,765	1,660,541
2014		312,218	1,766,839
2015		311,659	1,865,087
2016	156 MW GE 7FA Simple Cycle (06/16)	335,802	1,963,104
2017		349,077	2,057,449
2018		376,073	2,151,561
2019		391,644	2,242,309

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

Table 1B.8-7
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,459	282,961
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,025	437,303
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	203,037	598,480
2004	171 MW Joint Development with Southern–Florida (10/03)	253,491	784,804
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 – 09/05)	257,005	959,717
2006	100 MW Reliant Power Purchase (10/05 – 09/06)	249,138	1,116,716
2007	446 MW Pulverized Coal (06/07)	268,688	1,273,494
2008		287,446	1,428,792
2009		301,604	1,579,669
2010		309,986	1,723,252
2011		315,982	1,858,772
2012		327,314	1,988,753
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	340,116	2,113,813
	156 MW GE 7FA Simple Cycle (11/13)		
2014		338,576	2,229,085
2015		349,387	2,339,226
2016	156 MW GE 7FA Simple Cycle (06/08)	367,064	2,446,368
2017		382,871	2,549,847
2018		402,612	2,650,600
2019		428,000	2,749,773

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

Table 1B.8-8
OUC 2000 + 2001 AEO Escalation Fuel Price Projection Runner Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,459	282,961
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	180,025	437,303
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	201,973	597,636
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	251,771	782,695
	100 MW Reliant Power Purchase (10/03 - 09/04)	256,974	957,587
2005	100 MW Reliant Power Purchase (10/04 - 09/05)		
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	251,494	1,116,071
2007	446 MW Pulverized Coal (06/07)	266,697	1,271,686
2008		285,234	1,425,789
2009		301,513	1,576,620
2010		310,517	1,720,450
2011		313,384	1,854,855
2012		327,308	1,984,834
2013		344,237	2,111,409
2014		362,922	2,234,970
2015		369,969	2,351,599
2016		390,049	2,465,451
2017		395,341	2,572,299
2018		412,722	2,675,583
2019		440,339	2,777,614

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

Table 1B.8-9
OUC Constant 2000 Fuel Price Projection Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	197,052	589,686
2004	171 MW Joint Development with Southern–Florida (10/03)	247,056	771,280
	317 MW Southern–Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	251,529	942,466
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	244,615	1,096,615
2007	156 MW GE 7FS Simple Cycle (06/07)	260,608	1,248,677
2008	156 MW GE 7FS Simple Cycle (06/08)	276,878	1,398,266
2009		303,257	1,549,970
2010		311,701	1,694,348
2011		319,979	1,831,581
2012		335,338	1,964,749
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	349,905	2,093,408
	446 MW Pulverized Coal (11/13)		
2014		380,309	2,222,888
2015		392,229	2,346,535
2016		407,450	2,465,466
2017		416,981	2,578,163
2018		431,843	2,686,231
2019		452,146	2,790,999

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

Table 1B.8-10
OUC Constant 2000 Fuel Price Projection Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	142,721	142,721
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	151,191	282,712
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	175,598	433,259
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	196,022	588,868
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	245,124	769,042
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant Power Purchase (10/04 - 09/05)	250,986	939,859
2006	100 MW Reliant Power Purchase (10/05 - 09/06)	246,819	1,095,397
2007	267 MW Circulating Fluidized Bed (06/07)	270,023	1,252,952
2008		283,728	1,406,242
2009		303,691	1,558,163
2010		311,841	1,702,606
2011		317,723	1,838,872
2012		333,218	1,971,197
2013		350,713	2,100,154
2014		383,039	2,230,564
2015		385,175	2,351,987
2016	156 MW GE 7FA Simple Cycle (06/16)	407,963	2,471,067
2017		418,305	2,584,122
2018		439,226	2,694,038
2019		457,245	2,799,987

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

Table 1B.8-11
OUC Summer Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1100	341	1441	1047	608	1655	214	177	37
2002	1139	323	1462	1047	540	1587	125	184	(59)
2003	1180	312	1492	1047	540	1587	95	191	(96)
2004	1222	263	1485	1047	15	1062	-423	199	(622)
2005	1265	172	1437	1025	15	1040	-397	207	(604)
2006	1301	139	1440	1025	15	1040	-400	210	(610)
2007	1337	139	1476	1025	15	1040	-436	219	(655)
2008	1375	142	1517	1025	15	1040	-477	225	(702)
2009	1413	144	1557	1025	15	1040	-517	231	(749)
2010	1453	146	1599	1025	15	1040	-559	238	(797)
2011	1493	0	1493	1025	0	1025	-468	224	(691)
2012	1533	0	1533	1025	0	1025	-508	230	(738)
2013	1575	0	1575	1025	0	1025	-550	236	(786)
2014	1618	0	1618	1025	0	1025	-593	243	(836)
2015	1662	0	1662	1025	0	1025	-637	249	(886)
2016	1708	0	1708	1025	0	1025	-683	256	(939)
2017	1755	0	1755	1025	0	1025	-730	263	(993)
2018	1803	0	1803	1025	0	1025	-778	270	(1048)
2019	1852	0	1852	1025	0	1025	-827	278	(1105)

Table 1B.8-12
OUC Winter Reserve Requirements - High Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1092	341	1433	1092	608	1700	267	176	91
2002	1135	323	1458	1092	540	1632	174	183	(9)
2003	1179	312	1491	1092	540	1632	141	191	(51)
2004	1225	263	1488	1092	15	1107	-381	200	(581)
2005	1273	172	1445	1071	15	1086	-359	208	(567)
2006	1309	139	1448	1071	15	1086	-362	212	(574)
2007	1347	139	1486	1071	15	1086	-400	221	(621)
2008	1386	142	1528	1071	15	1086	-442	227	(668)
2009	1425	144	1569	1071	15	1086	-483	233	(716)
2010	1466	146	1612	1071	15	1086	-526	240	(766)
2011	1505	0	1505	1071	0	1071	-434	226	(660)
2012	1546	0	1546	1071	0	1071	-475	232	(707)
2013	1587	0	1587	1071	0	1071	-516	238	(755)
2014	1630	0	1630	1071	0	1071	-559	245	(804)
2015	1674	0	1674	1071	0	1071	-603	251	(854)
2016	1720	0	1720	1071	0	1071	-649	258	(907)
2017	1767	0	1767	1071	0	1071	-696	265	(961)
2018	1815	0	1815	1071	0	1071	-744	272	(1017)
2019	1865	0	1865	1071	0	1071	-794	280	(1074)

Table 1B.8-13
OUC High Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,315	295,504
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,583	444,324
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,934	593,718
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	224,984	758,088
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	230,989	915,295
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	226,773	1,058,201
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	244,413	1,200,813
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	258,724	1,340,594
2009		286,270	1,483,800
2010		296,837	1,621,293
2011		306,477	1,752,736
2012		322,542	1,880,822
2013		337,271	2,004,836
2014		359,225	2,127,138
2015		370,994	2,244,090
2016		391,488	2,358,362
2017		412,787	2,469,926
2018		433,819	2,578,488
2019	156 MW GE 7FA Simple Cycle (06/19)	459,965	2,685,068

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

Table 1B.8-14
OUC High Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	163,315	295,504
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	173,583	444,324
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	186,878	592,674
2004	171 MW Joint Development with Southern-Florida (10/03)	229,335	761,242
	317 MW Southern-Florida Power Purchase (10/03)		
	200 MW Reliant Power Purchase (10/03 - 09/04)		
2005	200 MW Reliant Power Purchase (10/04 - 09/05)	232,478	919,462
2006	200 MW Reliant Power Purchase (10/05 - 09/06)	229,257	1,063,933
2007	200 MW Reliant Power Purchase (10/06 - 09/07)	246,606	1,207,825
2008	610 MW WH 501F 2x1 Combined Cycle (06/08)	259,828	1,348,202
2009		288,881	1,492,714
2010		299,302	1,631,349
2011		308,461	1,763,642
2012		324,990	1,892,700
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	336,629	2,016,478
	156 MW GE 7FA Simple Cycle (11/13)		
2014		346,693	2,134,514
2015	156 MW GE 7FA Simple Cycle (06/15)	369,997	2,251,152
2016		391,959	2,365,561
2017		415,571	2,477,877
2018	267 MW Circulating Fluidized Bed (06/18)	459,699	2,592,916
2019		502,907	2,709,446

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

Table 1B.8-15
OUC Summer Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1062	440	1502	1047	608	1655	153	170	(17)
2001	1084	341	1425	1047	608	1655	230	175	55
2002	1106	323	1429	1047	540	1587	158	179	(21)
2003	1129	312	1441	1047	540	1587	146	184	(38)
2004	1152	263	1415	1047	15	1062	-353	189	(542)
2005	1176	172	1348	1025	15	1040	-308	194	(502)
2006	1192	139	1331	1025	15	1040	-291	194	(485)
2007	1209	139	1348	1025	15	1040	-308	200	(508)
2008	1226	142	1368	1025	15	1040	-328	203	(531)
2009	1243	144	1387	1025	15	1040	-347	206	(552)
2010	1260	146	1406	1025	15	1040	-366	209	(575)
2011	1275	0	1275	1025	0	1025	-250	191	(442)
2012	1291	0	1291	1025	0	1025	-266	194	(460)
2013	1307	0	1307	1025	0	1025	-282	196	(478)
2014	1323	0	1323	1025	0	1025	-298	198	(496)
2015	1339	0	1339	1025	0	1025	-314	201	(515)
2016	1355	0	1355	1025	0	1025	-330	203	(533)
2017	1371	0	1371	1025	0	1025	-346	206	(551)
2018	1387	0	1387	1025	0	1025	-362	208	(570)
2019	1403	0	1403	1025	0	1025	-378	211	(589)

Table 1B.8-16
OUC Winter Reserve Requirements - Low Load and Energy Growth Scenario

Year	Retail Peak Demand (MW)	Firm Sales (MW)	Total Sales (MW)	Installed Capacity (MW)	Purchases (MW)	Available Capacity (MW)	Available Reserves (MW)	Required Reserves (MW)	Excess/ (Deficit) to Maintain 15% Reserve Margin (MW)
2000	1051	440	1491	1092	608	1700	209	168	40
2001	1078	341	1419	1092	608	1700	281	174	107
2002	1106	323	1429	1092	540	1632	203	179	24
2003	1134	312	1446	1092	540	1632	186	184	1
2004	1163	263	1426	1092	15	1107	-319	191	(510)
2005	1193	172	1365	1071	15	1086	-279	196	(475)
2006	1210	139	1349	1071	15	1086	-263	197	(459)
2007	1227	139	1366	1071	15	1086	-280	203	(482)
2008	1244	142	1386	1071	15	1086	-300	206	(506)
2009	1261	144	1405	1071	15	1086	-319	209	(528)
2010	1279	146	1425	1071	15	1086	-339	212	(551)
2011	1294	0	1294	1071	0	1071	-223	194	(418)
2012	1310	0	1310	1071	0	1071	-239	197	(436)
2013	1326	0	1326	1071	0	1071	-255	199	(454)
2014	1342	0	1342	1071	0	1071	-271	201	(472)
2015	1358	0	1358	1071	0	1071	-287	204	(491)
2016	1374	0	1374	1071	0	1071	-303	206	(509)
2017	1390	0	1390	1071	0	1071	-319	209	(528)
2018	1407	0	1407	1071	0	1071	-336	211	(547)
2019	1423	0	1423	1071	0	1071	-352	213	(566)

Table 1B.8-17
OUC Low Load and Energy Growth Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,757	437,020
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	176,683	577,276
2004	488 MW Self-build GE 7FA 2x1 Combined Cycle (10/03)	211,624	732,826
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,824	878,352
2006		207,424	1,009,064
2007	156 MW GE 7FA SC (06/07)	211,585	1,132,522
2008		220,912	1,251,874
2009		239,899	1,371,883
2010		241,165	1,483,589
2011		246,476	1,589,298
2012		259,106	1,692,193
2013		268,149	1,790,791
2014		299,017	1,892,594
2015		292,159	1,984,695
2016		313,582	2,076,226
2017		307,061	2,159,215
2018		333,532	2,242,682
2019		339,328	2,321,308

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

Table 1B.8-18
OUC Low Load and Energy Growth Runner-Up Expansion Plan

Year	Generation Addition (month/year)	Annual Costs ($1000)	Cumulative Present Worth ($1000)
2000	525 MW Reliant Power Purchase (10/99 - 09/00)	144,287	144,287
2001	525 MW Reliant Power Purchase (10/00 - 09/01)	160,822	293,196
2002	577.5 MW Reliant Power Purchase (10/01 - 09/02)	167,757	437,020
2003	577.5 MW Reliant Power Purchase (10/02 - 09/03)	173,098	574,430
2004	171 MW Joint Development with Southern–Florida (10/03)	214,185	731,863
	317 MW Southern-Florida Power Purchase (10/03)		
	100 MW Reliant Power Purchase (10/03 - 09/04)		
2005	100 MW Reliant River Power Purchase (10/04 - 09/05)	213,374	877,082
2006		203,692	1,005,442
2007	156 MW GE 7FA SC (06/07)	216,845	1,131,969
2008		225,042	1,253,552
2009		237,138	1,372,180
2010		241,196	1,483,901
2011		247,667	1,590,121
2012		259,560	1,693,195
2013	Terminate 317 MW Southern–Florida Power Purchase (11/13)	264,093	1,790,302
	Extension of 317 MW Southern-Florida Power Purchase (11/13)		
2014		297,971	1,891,750
2015		291,445	1,983,625
2016		313,141	2,075,028
2017		308,630	2,158,441
2018	Terminate 317 MW Southern–Florida Power Purchase (11/18)	331,107	2,241,300
	514 MW WH 501F 2x1 Combined Cycle (11/18)	345,582	2,321,376
2019			

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

1B.9.0 Financial Analysis

OUC has not made a final decision regarding financing OUC's 28 percent equity share of Stanton A. In order to be conservative for evaluation purposes, OUC's weighted average cost of capital of approximately 8 percent was assumed. Actual financing alternatives for Stanton A include either using available cash from the Indian River Steam Unit sale or some form of taxable or tax exempt financing.

OUC's strong financial position will support either mode of financing. OUC's current senior lien bond ratings are AA^+, Aal, and AA from Fitch Investors Services, Moody's Investors Service, and Standard & Poor's, respectively. In 2000, OUC's operating revenues were $501.1 million, with a net income of $51.3 million and a combined debt service coverage rate of 2.23.

Appendix 1B.A
Load Forecast Model Statistics

Appendix 1B.A
Load Forecast Model Statistics

Project:	**D:\2000 Projects\OUC\Ouc Res.NDM**
Model:	**ResCust**
Dependent Variable:	**ResCust**
Date:	**October 03, 2000**
Time:	**09:19 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	5348.693	5290.065	1.011	31%
HH_OR	198.901	9.832	20.231	0%
Nov98	-1199.404	235.434	-5.094	0%
AR(1)	0.874	0.070	12.434	0%

Regression Statistics	
Iterations	5
Adjusted Observations	95
Deg. of Freedom for Error	91
R-Squared	0.997
Adjusted R-Squared	0.997
Durbin-Watson Statistic	2.056
Durbin-H Statistic	0.000
AIC	11.532
BIC	11.639
F-Statistic	11158.748
Prob (F-Statistic)	0.000
Log-Likelihood	-671.41
Model Sum of Squares	3273019663
Sum of Squared Errors	8897198
Mean Squared Error	97771.41
Std. Error of Regression	312.68
Mean Abs. Dev. (MAD)	205.10
Mean Abs. % Err. (MAPE)	0.18%
Ljung-Box Statistic	13.56
Prob (Ljung-Box)	0.956

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
HH_OR	198.901	531.488	0.952
Nov98	-1199.404	0.010	-0.000

Project:	**D:\2000 Projects\OUC\Ouc Res.NDM**
Model:	**ResAveUse**
Dependent Variable:	**ResAveUse**
Date:	**October 03, 2000**
Time:	**09:19 AM**
Estimation Begin Date:	**1990:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
Heating	0.217	0.033	6.660	0%
Cooling	0.126	0.014	9.117	0%
BaseUse	112.798	6.219	18.139	0%
Summer98	108.213	28.371	3.814	0%
January	72.406	24.339	2.975	0%
November	-59.667	23.704	-2.517	1%
Lag_Heating	0.384	0.030	12.604	0%
Lag_Cooling	0.187	0.012	15.768	0%

Regression Statistics	
Iterations	1
Adjusted Observations	95
Deg. of Freedom for Error	87
R-Squared	0.941
Adjusted R-Squared	0.936
Durbin-Watson Statistic	1.778
Durbin-H Statistic	0.000
AIC	7.999
BIC	8.214
F-Statistic	172.911
Prob (F-Statistic)	0.000
Log-Likelihood	-501.43
Model Sum of Squares	3802221
Sum of Squared Errors	239135
Mean Squared Error	2748.68
Std. Error of Regression	52.43
Mean Abs. Dev. (MAD)	38.09
Mean Abs. % Err. (MAPE)	3.62%
Ljung-Box Statistic	27.02
Prob (Ljung-Box)	0.304

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Heating	0.217	206.322	0.043
Cooling	0.126	1477.390	0.180
BaseUse	112.798	3.911	0.427
Summer98	108.213	0.042	0.004
January	72.406	0.074	0.005
November	-59.667	0.084	-0.005
Lag_Heating	0.384	208.644	0.078
Lag_Cooling	0.187	1476.739	0.268

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**GSNDAveUse**
Dependent Variable:	**GSNDAveUse**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1991:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
BaseUse	0.056	0.008	7.284	0%
Heating	0.030	0.014	2.147	3%
LagHeating	0.071	0.014	5.174	0%
Cooling	0.040	0.005	7.335	0%
LagCooling	0.070	0.005	13.094	0%
July94	400.066	74.395	5.378	0%
Aug94	-304.943	74.423	-4.097	0%
Sept97	739.825	75.805	9.760	0%
Jul98	-384.214	76.732	-5.007	0%
GSND_Reclass	-114.014	24.728	-4.611	0%
Mar96	-226.423	76.431	-2.962	0%
July99	3863.365	76.160	50.727	0%
Aug99	-4680.072	76.443	-61.223	0%
BaseUseTrend	-0.056	0.010	-5.370	0%

Regression Statistics	
Iterations	1
Adjusted Observations	95
Deg. of Freedom for Error	81
R-Squared	0.990
Adjusted R-Squared	0.988
Durbin-Watson Statistic	1.933
Durbin-H Statistic	0.777
AIC	8.721
BIC	9.097
F-Statistic	567.021
Prob (F-Statistic)	0.000
Log-Likelihood	-529.39
Model Sum of Squares	42486573
Sum of Squared Errors	433520
Mean Squared Error	5352.10
Std. Error of Regression	73.16
Mean Abs. Dev. (MAD)	50.34
Mean Abs. % Err. (MAPE)	2.82%
Ljung-Box Statistic	43.02
Prob (Ljung-Box)	0.010

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
BaseUse	0.056	88389.056	2.784
Heating	0.030	632.629	0.011
LagHeating	0.071	637.159	0.025
Cooling	0.040	4465.614	0.100
LagCooling	0.070	4463.285	0.176
July94	400.066	0.011	0.002
Aug94	-304.943	0.011	-0.002
Sept97	739.825	0.011	0.004

Variable	Coefficient	Mean	Elast
Jul98	-384.214	0.011	-0.002
GSND_Reclass	-114.014	0.305	-0.020
Mar96	-226.423	0.011	-0.001
July99	3863.365	0.011	0.023
~~Aug99~~	~~-4680.072~~	0.011	-0.028
BaseUseTrend	-0.056	66291.101	-2.073

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**GSND_Custs**
Dependent Variable:	**GSNDCust**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	9790.486	148.966	65.723	0%
EmpNonMfg	7.669	0.242	31.748	0%
GSND_Reclass	-200.192	36.368	-5.505	0%
Jan99	828.602	30.537	27.134	0%
AR(1)	0.777	0.063	12.345	0%

Regression Statistics	
Iterations	6
Adjusted Observations	110
Deg. of Freedom for Error	105
R-Squared	0.996
Adjusted R-Squared	0.996
Durbin-Watson Statistic	1.994
Durbin-H Statistic	0.000
AIC	7.353
BIC	7.475
F-Statistic	6871.524
Prob (F-Statistic)	0.000
Log-Likelihood	-555.48
Model Sum of Squares	41023002
Sum of Squared Errors	156713
Mean Squared Error	1492.50
Std. Error of Regression	38.63
Mean Abs. Dev. (MAD)	29.71
Mean Abs. % Err. (MAPE)	0.20%
Ljung-Box Statistic	20.03
Prob (Ljung-Box)	0.695

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
EmpNonMfg	7.669	630.827	0.332
GSND_Reclass	-200.192	0.261	-0.004
Jan99	828.602	0.009	0.001

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**GSD_Sales**
Dependent Variable:	**GSD_Sales**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	56947682.454	6698858.495	8.501	0%
Jun98	-45109277.510	7755986.845	-5.816	0%
Jul98	-26399324.042	7718486.933	-3.420	0%
Sept98	41393749.634	7666165.406	5.400	0%
July99	-55153601.306	7738781.619	-7.127	0%
Aug99	79706289.043	8476499.245	9.403	0%
GSD_Base	1399757.574	96781.109	14.463	0%
GSD_Cooling	15108.300	2425.338	6.229	0%
Lag_GSDCooling	16141.098	2331.346	6.924	0%
GSD_Heating	10249.511	5847.980	1.753	8%
Lag_GSDHeating	4604.901	5788.629	0.796	43%
Aug99_Later	5434470.575	4316377.243	1.259	21%

Regression Statistics	
Iterations	1
Adjusted Observations	95
Deg. of Freedom for Error	83
R-Squared	0.944
Adjusted R-Squared	0.937
Durbin-Watson Statistic	2.282
Durbin-H Statistic	0.000
AIC	31.737
BIC	32.060
F-Statistic	127.203
Prob (F-Statistic)	0.000
Log-Likelihood	-1613.16
Model Sum of Squares	75540701850192880
Sum of Squared Errors	4480945093362323
Mean Squared Error	53987290281473.77
Std. Error of Regression	7347604.39
Mean Abs. Dev. (MAD)	4925826.77
Mean Abs. % Err. (MAPE)	2.67%
Ljung-Box Statistic	53.11
Prob (Ljung-Box)	0.001

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
Jun98	-45109277.510	0.011	-0.003
Jul98	-26399324.042	0.011	-0.002
Sept98	41393749.634	0.011	0.002
July99	-55153601.306	0.011	-0.003
Aug99	79706289.043	0.011	0.005
GSD_Base	1399757.574	65.779	0.499
GSD_Cooling	15108.300	1056.946	0.087
Lag_GSDCooling	16141.098	1056.297	0.092
GSD_Heating	10249.511	149.572	0.008
Lag_GSDHeating	4604.901	150.156	0.004

Variable	Coefficient	Mean	Elast
Aug99_Later	5434470.575	0.053	0.002

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**StLight_Sales**
Dependent Variable:	**StLts**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	2012876.659	42744.453	47.091	0%
TrendVar	49023.586	5960.946	8.224	0%
Apr96	-1918758.866	75238.299	-25.502	0%
may96	1923975.858	75232.163	25.574	0%
Nov96	4320205.696	75215.113	57.438	0%
Dec96	-4179920.384	75261.754	-55.538	0%
Sept98	-451587.739	75419.185	-5.988	0%
Dec98	1329406.097	75465.734	17.616	0%
oct98	-1806874.006	75424.021	-23.956	0%
Aug93	-488624.427	75800.292	-6.446	0%
SAR(1)	0.255	0.059	4.363	0%

Regression Statistics	
Iterations	5
Adjusted Observations	84
Deg. of Freedom for Error	73
R-Squared	0.991
Adjusted R-Squared	0.990
Durbin-Watson Statistic	0.910
Durbin-H Statistic	0.000
AIC	22.634
BIC	22.952
F-Statistic	831.655
Prob (F-Statistic)	0.000
Log-Likelihood	-1058.82
Model Sum of Squares	49770614244176
Sum of Squared Errors	436870549241
Mean Squared Error	5984528071.80
Std. Error of Regression	77359.73
Mean Abs. Dev. (MAD)	48373.95
Mean Abs. % Err. (MAPE)	2.11%
Ljung-Box Statistic	164.30
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
TrendVar	49023.586	6.042	0.128
Apr96	-1918758.866	0.010	-0.009
may96	1923975.858	0.010	0.009
Nov96	4320205.696	0.010	0.019
Dec96	-4179920.384	0.010	-0.019
Sept98	-451587.739	0.010	-0.002
Dec98	1329406.097	0.010	0.006
oct98	-1806874.006	0.010	-0.008
Aug93	-488624.427	0.010	-0.002

Project:	**D:\2000 Projects\OUC\Ouc NonRes.NDM**
Model:	**OUC_Use**
Dependent Variable:	**OUCUse**
Date:	**October 03, 2000**
Time:	**09:23 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	2735548.121	316080.643	8.655	0%
TrendVar	373651.537	51068.268	7.317	0%
Apr96	8454584.818	562206.729	15.038	0%
Jun98	-2445484.012	697965.815	-3.504	0%
Jul98	-1389289.650	701443.210	-1.981	5%
Sept98	3157306.679	548872.300	5.752	0%
January	-589874.272	245612.725	-2.402	2%
February	-909196.065	327059.646	-2.780	1%
March	-627157.412	327291.895	-1.916	6%
April	-354918.286	253821.606	-1.398	17%
MA(1)	0.798	0.097	8.216	0%
MA(2)	0.323	0.098	3.307	0%

Regression Statistics	
Iterations	22
Adjusted Observations	111
Deg. of Freedom for Error	99
R-Squared	0.849
Adjusted R-Squared	0.832
Durbin-Watson Statistic	1.874
Durbin-H Statistic	0.000
AIC	27.021
BIC	27.313
F-Statistic	50.572
Prob (F-Statistic)	0.000
Log-Likelihood	-1630.32
Model Sum of Squares	272880896985166
Sum of Squared Errors	48562894184925
Mean Squared Error	490534284696.21
Std. Error of Regression	700381.53
Mean Abs. Dev. (MAD)	430723.90
Mean Abs. % Err. (MAPE)	8.93%
Ljung-Box Statistic	13.14
Prob (Ljung-Box)	0.964

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
TrendVar	373651.537	5.417	0.439
Apr96	8454584.818	0.009	0.017
Jun98	-2445484.012	0.009	-0.005
Jul98	-1389289.650	0.009	-0.003
Sept98	3157306.679	0.009	0.006
January	-589874.272	0.081	-0.010
February	-909196.065	0.081	-0.016
March	-627157.412	0.081	-0.011
April	-354918.286	0.081	-0.006

Project:	**D:\2000 Projects\OUC\StCloud Res.NDM**
Model:	**ResAveUse**
Dependent Variable:	**ResAveUse**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:11**
Forecast Period End Date:	**2020:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
Heating	0.185	0.051	3.616	0%
Cooling	0.088	0.020	4.352	0%
Lag_Cooling	0.235	0.018	12.985	0%
Lag_Heating	0.354	0.045	7.928	0%
BaseUse	117.809	11.470	10.271	0%
January	75.456	29.020	2.600	1%
November	-52.951	28.639	-1.849	7%
Jun93	-134.633	69.134	-1.947	5%
Summer98	55.184	54.656	1.010	32%
Feb94	186.019	69.851	2.663	1%
After98	105.120	27.483	3.825	0%
MA(1)	0.432	0.104	4.140	0%

Regression Statistics	
Iterations	11
Adjusted Observations	94
Deg. of Freedom for Error	82
R-Squared	0.918
Adjusted R-Squared	0.906
Durbin-Watson Statistic	1.802
Durbin-H Statistic	0.000
AIC	8.754
BIC	9.078
F-Statistic	76.040
Prob (F-Statistic)	0.000
Log-Likelihood	-532.80
Model Sum of Squares	5132552
Sum of Squared Errors	461237
Mean Squared Error	5624.84
Std. Error of Regression	75.00
Mean Abs. Dev. (MAD)	57.91
Mean Abs. % Err. (MAPE)	5.55%
Ljung-Box Statistic	45.10
Prob (Ljung-Box)	0.006

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
Heating	0.185	208.644	0.036
Cooling	0.088	1476.866	0.120
Lag_Cooling	0.235	1485.248	0.324
Lag_Heating	0.354	209.801	0.069
BaseUse	117.809	3.907	0.427
January	75.456	0.084	0.006
November	-52.951	0.084	-0.004
Jun93	-134.633	0.011	-0.001
Summer98	55.184	0.042	0.002
Feb94	186.019	0.011	0.002

Variable	Coefficient	Mean	Elast
After98	105.120	0.242	0.024

Project:	**D:\2000 Projects\OUC\StCloud Res.NDM**
Model:	**ResCust**
Dependent Variable:	**ResCust**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:11**
Forecast Period End Date:	**2020:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	-2811.148	1188.330	-2.366	2%
January	-563.063	510.524	-1.103	27%
February	-466.123	473.617	-0.984	33%
March	567.573	473.630	1.198	23%
April	-636.382	473.761	-1.343	18%
May	-731.206	473.772	-1.543	13%
June	-476.667	473.830	-1.006	32%
July	-900.618	473.979	-1.900	6%
August	-433.281	474.029	-0.914	36%
September	-1319.827	473.699	-2.786	1%
October	12.129	461.947	0.026	98%
November	-1364.388	496.991	-2.745	1%
HH_OR	32.641	2.206	14.799	0%
MA(1)	-0.166	0.101	-1.644	10%
SMA(1)	0.380	0.099	3.846	0%

Regression Statistics	
Iterations	40
Adjusted Observations	110
Deg. of Freedom for Error	95
R-Squared	0.747
Adjusted R-Squared	0.709
Durbin-Watson Statistic	2.079
Durbin-H Statistic	0.000
AIC	13.358
BIC	13.726
F-Statistic	19.988
Prob (F-Statistic)	0.000
Log-Likelihood	-875.76
Model Sum of Squares	156059399
Sum of Squared Errors	52981729
Mean Squared Error	557702.41
Std. Error of Regression	746.79
Mean Abs. Dev. (MAD)	567.66
Mean Abs. % Err. (MAPE)	4.20%
Ljung-Box Statistic	52.57
Prob (Ljung-Box)	0.001

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
January	-563.063	0.082	-0.003
February	-466.123	0.082	-0.003
March	567.573	0.082	0.003
April	-636.382	0.082	-0.004
May	-731.206	0.082	-0.004
June	-476.667	0.082	-0.003
July	-900.618	0.082	-0.005

Variable	Coefficient	Mean	Elast
August	-433.281	0.082	-0.003
September	-1319.827	0.082	-0.008
October	12.129	0.091	0.000
November	-1364.388	0.091	-0.009
HH_OR	32.641	523.698	1.239

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSNDAveUse**
Dependent Variable:	**GSNDAveUse**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1992:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
BaseUse	0.153	0.006	24.178	0%
Heating	0.025	0.014	1.772	8%
Cooling	0.008	0.006	1.299	20%
LagHeating	0.009	0.020	0.449	65%
LagCooling	0.048	0.007	7.177	0%
March98	-172.982	66.198	-2.613	1%
Nov97	-222.707	67.501	-3.299	0%
Apr99	88.140	62.128	1.419	16%
Feb98	-140.253	65.995	-2.125	4%
Nov99	-193.779	68.049	-2.848	1%
Dec99	31.395	75.927	0.413	68%
Dec97	-421.379	69.926	-6.026	0%
AR(1)	0.431	0.102	4.249	0%

Regression Statistics	
Iterations	9
Adjusted Observations	95
Deg. of Freedom for Error	82
R-Squared	0.877
Adjusted R-Squared	0.858
Durbin-Watson Statistic	2.234
Durbin-H Statistic	0.777
AIC	8.484
BIC	8.834
F-Statistic	44.781
Prob (F-Statistic)	0.000
Log-Likelihood	-519.29
Model Sum of Squares	2482238
Sum of Squared Errors	349642
Mean Squared Error	4263.93
Std. Error of Regression	65.30
Mean Abs. Dev. (MAD)	46.83
Mean Abs. % Err. (MAPE)	4.05%
Ljung-Box Statistic	17.21
Prob (Ljung-Box)	0.840

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
BaseUse	0.153	5882.272	0.774
Heating	0.025	654.657	0.014
Cooling	0.008	4423.257	0.031
LagHeating	0.009	584.847	0.005
LagCooling	0.048	4543.486	0.187
March98	-172.982	0.010	-0.002
Nov97	-222.707	0.010	-0.002
Apr99	88.140	0.010	0.001
Feb98	-140.253	0.010	-0.001

Variable	Coefficient	Mean	Elast
Nov99	-193.779	0.010	-0.002
Dec99	31.395	0.010	0.000
Dec97	-421.379	0.010	-0.004

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSND_Custs**
Dependent Variable:	**GSNDCust**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1994:1**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	1079.666	122.945	8.782	0%
EmpNonMfg	0.459	0.186	2.473	2%
GSND_Reclass	-1352.179	301.967	-4.478	0%
Employ_GSNDReclass	14.294	3.059	4.673	0%
January	-116.386	52.670	-2.210	3%
February	-94.701	48.369	-1.958	6%
March	69.442	40.761	1.704	9%
April	-140.275	44.830	-3.129	0%
May	-88.172	44.542	-1.980	5%
July	-72.206	44.440	-1.625	11%
August	1.536	44.734	0.034	97%
June	-26.673	42.768	-0.624	54%
September	-149.412	40.117	-3.724	0%
October	18.607	46.354	0.401	69%
November	-196.990	50.930	-3.868	0%
AR(1)	-0.457	0.134	-3.418	0%
AR(2)	-0.285	0.136	-2.103	4%

Regression Statistics		Forecast Statistics	
Iterations	4	Forecast Observations	0
Adjusted Observations	70	Mean Abs. Dev. (MAD)	0.00
Deg. of Freedom for Error	53	Mean Abs. % Err. (MAPE)	0.00%
R-Squared	0.793	Avg. Forecast Error	0.00
Adjusted R-Squared	0.730	Mean % Error	0.00%
Durbin-Watson Statistic	1.846	Root Mean-Square Error	0.000
Durbin-H Statistic	0.000	Theil's Inequality Coefficient	0.000
AIC	8.642	-- Bias Proportion	0.00%
BIC	9.188	-- Variance Proportion	0.00%
F-Statistic	12.671	-- Covariance Proportion	0.00%
Prob (F-Statistic)	0.000		
Log-Likelihood	-384.79		
Model Sum of Squares	933103		
Sum of Squared Errors	243942		
Mean Squared Error	4602.67		
Std. Error of Regression	67.84		
Mean Abs. Dev. (MAD)	47.65		
Mean Abs. % Err. (MAPE)	3.45%		
Ljung-Box Statistic	57.81		
Prob (Ljung-Box)	0.000		

Variable	Coefficient	Mean	Elast
EmpNonMfg	0.459	681.899	0.229
GSND_Reclass	-1352.179	0.403	-0.398
Employ_GSNDReclass	14.294	40.955	0.428
January	-116.386	0.083	-0.007
February	-94.701	0.083	-0.006

Variable	Coefficient	Mean	Elast
March	69.442	0.083	0.004
April	-140.275	0.083	-0.009
May	-88.172	0.083	-0.005
July	-72.206	0.083	-0.004
August	1.536	0.083	0.000
June	-26.673	0.083	-0.002
September	-149.412	0.083	-0.009
October	18.607	0.083	0.001
November	-196.990	0.083	-0.012

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSD_Sales**
Dependent Variable:	**GSD_TotalSales**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-1863568.838	454565.035	-4.100	0%
GSD_Cooling	359.590	216.204	1.663	10%
Lag_GSD_Cooling	2847.770	802.301	3.550	0%
GSD_Heating	-217.588	371.986	-0.585	56%
Lag_GSD_Heating	1533.459	1545.172	0.992	32%
GSD_Base	190928.776	31408.131	6.079	0%
Apr93	2991202.924	306343.234	9.764	0%
January	-195063.859	367604.241	-0.531	60%
February	-179833.970	416359.445	-0.432	67%
March	-43121.803	279737.317	-0.154	88%
April	-251605.485	237471.426	-1.060	29%
May	-1082473.886	269605.011	-4.015	0%
June	-2616646.564	608454.222	-4.300	0%
July	-3486524.701	859129.892	-4.058	0%
August	-4302445.726	1038405.320	-4.143	0%
September	-3848607.963	1012754.108	-3.800	0%
October	-3116822.110	831525.435	-3.748	0%
November	-2137594.704	436466.133	-4.898	0%
Dec99	825183.583	331124.764	2.492	2%
~~Nov99~~	-362433.846	~~323225.161~~	~~-1.121~~	27%
June93	-1028714.314	292503.875	-3.517	0%
AR(1)	0.163	0.119	1.374	17%
AR(2)	0.087	0.122	0.714	48%
AR(3)	0.221	0.122	1.809	7%

Regression Statistics	
Iterations	11
Adjusted Observations	95
Deg. of Freedom for Error	71
R-Squared	0.940
Adjusted R-Squared	0.921
Durbin-Watson Statistic	2.069
Durbin-H Statistic	0.000
AIC	25.294
BIC	25.939
F-Statistic	48.483
Prob (F-Statistic)	0.000
Log-Likelihood	-1298.46
Model Sum of Squares	86986136116639
Sum of Squared Errors	5538475140717
Mean Squared Error	78006692122.78
Std. Error of Regression	279296.78
Mean Abs. Dev. (MAD)	181254.04
Mean Abs. % Err. (MAPE)	3.69%
Ljung-Box Statistic	25.45
Prob (Ljung-Box)	0.382

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
– Bias Proportion	0.00%
– Variance Proportion	0.00%
– Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
GSD_Cooling	359.590	1046.882	0.077
Lag_GSD_Cooling	2847.770	1074.910	0.630
GSD_Heating	-217.588	154.523	-0.007
Lag_GSD_Heating	1533.459	137.978	0.044
GSD_Base	190928.776	26.434	1.038
Apr93	2991202.924	0.009	0.006
January	-195063.859	0.081	-0.003
February	-179833.970	0.081	-0.003
March	-43121.803	0.081	-0.001
April	-251605.485	0.081	-0.004
May	-1082473.886	0.081	-0.018
June	-2616646.564	0.081	-0.044
July	-3486524.701	0.081	-0.058
August	-4302445.726	0.081	-0.072
September	-3848607.963	0.081	-0.064
October	-3116822.110	0.090	-0.058
November	-2137594.704	0.090	-0.040
Dec99	825183.583	0.009	0.002
Nov99	-362433.846	0.009	-0.001
June93	-1028714.314	0.009	-0.002

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**GSD_Custs**
Dependent Variable:	**GSDCust**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1990:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-106.857	21.729	-4.918	0%
EmpMfg	2.525	0.237	10.643	0%
AR(1)	0.414	0.081	5.088	0%

Regression Statistics	
Iterations	3
Adjusted Observations	110
Deg. of Freedom for Error	107
R-Squared	0.762
Adjusted R-Squared	0.757
Durbin-Watson Statistic	2.534
Durbin-H Statistic	0.000
AIC	4.734
BIC	4.807
F-Statistic	171.146
Prob (F-Statistic)	0.000
Log-Likelihood	-413.43
Model Sum of Squares	37885
Sum of Squared Errors	11843
Mean Squared Error	110.68
Std. Error of Regression	10.52
Mean Abs. Dev. (MAD)	8.23
Mean Abs. % Err. (MAPE)	6.85%
Ljung-Box Statistic	72.37
Prob (Ljung-Box)	0.000

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	Coefficient	Mean	Elast
EmpMfg	2.525	91.246	1.876

Project:	**D:\2000 Projects\OUC\StCloud NonRes.NDM**
Model:	**StLight_Sales**
Dependent Variable:	**StLts**
Date:	**October 03, 2000**
Time:	**09:24 AM**
Estimation Begin Date:	**1997:10**
Estimation End Date:	**1999:12**
Forecast Period End Date:	**2020:12**

Variable	**Coefficient**	**StdErr**	**T-Stat**	**P-Value**
CONST	249726.016	7437.356	33.577	0%
TrendVar	1029.968	809.078	1.273	23%
January	-5090.577	2416.910	-2.106	6%
February	-1694.408	2408.431	-0.704	50%
March	6927.762	2401.816	2.884	1%
April	-2863.069	2397.080	-1.194	26%
May	-6513.900	2394.233	-2.721	2%
June	5136.769	2393.284	2.146	5%
July	-1758.061	2394.233	-0.734	48%
August	-965.392	2397.080	-0.403	69%
September	-4012.223	2401.816	-1.670	12%
October	-797.499	2144.861	-0.372	72%
November	-11108.978	2141.680	-5.187	0%

Regression Statistics	
Iterations	1
Adjusted Observations	27
Deg. of Freedom for Error	14
R-Squared	0.864
Adjusted R-Squared	0.747
Durbin-Watson Statistic	2.299
Durbin-H Statistic	0.000
AIC	16.049
BIC	16.673
F-Statistic	7.389
Prob (F-Statistic)	0.000
Log-Likelihood	-233.02
Model Sum of Squares	609489100
Sum of Squared Errors	96227177
Mean Squared Error	6873369.80
Std. Error of Regression	2621.71
Mean Abs. Dev. (MAD)	1514.39
Mean Abs. % Err. (MAPE)	0.59%
Ljung-Box Statistic	22.25
Prob (Ljung-Box)	0.564

Forecast Statistics	
Forecast Observations	0
Mean Abs. Dev. (MAD)	0.00
Mean Abs. % Err. (MAPE)	0.00%
Avg. Forecast Error	0.00
Mean % Error	0.00%
Root Mean-Square Error	0.000
Theil's Inequality Coefficient	0.000
-- Bias Proportion	0.00%
-- Variance Proportion	0.00%
-- Covariance Proportion	0.00%

Variable	**Coefficient**	**Mean**	**Elast**
TrendVar	1029.968	8.917	0.036
January	-5090.577	0.074	-0.001
February	-1694.408	0.074	-0.000
March	6927.762	0.074	0.002
April	-2863.069	0.074	-0.001
May	-6513.900	0.074	-0.002
June	5136.769	0.074	0.001
July	-1758.061	0.074	-0.001
August	-965.392	0.074	-0.000

Variable	Coefficient	Mean	Elast
September	-4012.223	0.074	-0.001
October	-797.499	0.111	-0.000
November	-11108.978	0.111	-0.005

Appendix 1B.B
Economic Evaluation Spreadsheets

Orlando Utilities Commission Economic Evaluation

Case	
Scenario	Base Case
Joint Development	

Economic	
CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003 833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance	
Fixed Charge Rate.	11.19%
Interest During Const.	6%
Finance Term (yrs).	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,238	0	162,238	294,507
2002	147,488	20,870	2,989	0	171,346	0	171,346	441,409
2003	147,655	22,448	10,227	(219)	180,121	2,303	182,414	586,216
2004	150,406	26,681	34,710	(882)	210,950	9,210	220,125	748,014
2005	151,675	28,059	33,674	(895)	212,550	9,210	221,724	898,915
2006	149,444	27,781	31,091	(908)	207,446	9,210	216,619	1,035,422
2007	160,655	29,669	26,251	(921)	215,692	14,681	230,334	1,169,819
2008	164,045	30,469	27,266	(935)	220,885	24,195	245,040	1,302,207
2009	176,711	32,318	27,744	(949)	235,864	28,199	264,023	1,434,284
2010	183,009	33,559	27,820	(964)	243,466	28,199	271,624	1,560,098
2011	190,023	35,252	27,898	(978)	252,238	28,199	280,395	1,680,355
2012	202,945	36,580	27,979	(993)	266,553	28,199	294,709	1,797,388
2013	211,868	39,047	24,629	(1,009)	274,580	31,714	306,249	1,909,995
2014	215,826	40,439	7,717	(1,025)	263,002	70,372	333,329	2,023,481
2015	228,606	42,338	7,910	(1,041)	277,860	70,372	348,185	2,133,243
2016	238,852	44,491	8,107	(1,058)	290,441	70,372	360,765	2,238,547
2017	250,954	46,130	8,310	(1,075)	304,369	70,372	374,692	2,339,814
2018	266,997	48,545	8,518	(1,093)	323,017	70,372	393,339	2,438,247
2019	284,860	50,659	8,731	(1,111)	343,191	70,372	413,511	2,534,062

Notes
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Base Case
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003 833	251,663	28,161
GE 7FA SC	156	68,615	12	2007 417	83,801	9,377
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const ·	6%
Finance Term (yrs)	20
Plant Life.	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	141,221	20,267	751	0	162,238	0	162,238	294,507
2002	147,488	20,870	2,989	0	171,346	0	171,346	441,409
2003	149,581	22,462	4,430	0	176,473	7,040	183,514	587,088
2004	154,145	26,843	10,006	0	190,994	28,161	219,155	748,174
2005	154,206	28,254	10,146	0	192,606	28,161	220,767	898,424
2006	153,519	27,836	8,671	0	190,026	28,161	218,188	1,035,919
2007	166,024	30,032	3,424	0	199,480	33,631	233,111	1,171,938
2008	165,379	30,704	4,486	0	200,569	43,145	243,714	1,303,609
2009	178,683	32,368	5,012	0	216,063	47,150	263,213	1,435,281
2010	185,254	33,664	5,137	0	224,055	47,150	271,205	1,560,901
2011	191,052	35,455	5,265	0	231,773	47,150	278,923	1,680,526
2012	205,553	36,751	5,397	0	247,700	47,150	294,851	1,797,616
2013	215,617	39,196	5,532	0	260,345	47,150	307,495	1,910,681
2014	245,428	41,202	5,670	0	292,300	47,150	339,450	2,026,250
2015	243,011	43,182	5,812	0	292,005	47,150	339,155	2,133,166
2016	258,930	45,207	6,654	0	310,792	53,982	364,773	2,239,640
2017	265,300	47,212	7,325	0	319,836	58,861	378,698	2,341,990
2018	290,162	49,797	7,508	0	347,466	58,861	406,327	2,443,673
2019	301,583	51,839	7,696	0	361,117	58,861	419,978	2,540,987

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario. High Fuel Price Projections
Joint Development

Economic

CPW Discount Rate.	8 0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007 417	83,801	9,377
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013.912	376,879	42,173

Finance

Fixed Charge Rate.	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	143,272	20,266	751	0	164,289	0	164,289	296,406
2002	153,314	20,868	2,989	0	177,171	0	177,171	448,301
2003	156,402	22,451	10,227	(219)	188,871	2,303	191,164	600,054
2004	161,788	26,689	34,710	(882)	222,341	9,210	231,516	770,225
2005	165,907	28,063	33,674	(895)	226,786	9,210	235,960	930,815
2006	166,476	27,864	31,091	(908)	224,561	9,210	233,733	1,078,107
2007	181,924	29,753	26,251	(921)	237,046	14,681	251,687	1,224,964
2008	189,810	30,579	27,266	(935)	246,760	24,195	270,915	1,371,331
2009	207,820	32,433	27,744	(949)	267,088	28,199	295,247	1,519,028
2010	219,038	33,705	27,820	(964)	279,641	28,199	307,799	1,661,598
2011	232,814	35,278	27,898	(978)	295,055	28,199	323,212	1,800,218
2012	252,380	36,695	27,979	(993)	316,104	28,199	344,259	1,936,929
2013	268,829	39,095	24,629	(1,009)	331,589	31,714	363,258	2,070,498
2014	278,866	40,454	7,717	(1,025)	326,058	70,372	396,384	2,205,451
2015	300,032	42,411	7,910	(1,041)	349,359	70,372	419,684	2,337,753
2016	319,497	44,464	8,107	(1,058)	371,058	70,372	441,382	2,466,588
2017	341,508	46,106	8,310	(1,075)	394,898	70,372	465,221	2,592,323
2018	370,212	48,556	8,518	(1,093)	426,244	70,372	496,565	2,716,588
2019	401,252	50,735	8,731	(1,111)	459,659	70,372	529,979	2,839,391

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario. High Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003 833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
GE 7FA SC	156	68,615	12	2016 417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	143,272	20,266	751	0	164,289	0	164,289	296,406
2002	153,314	20,868	2,989	0	177,171	0	177,171	448,301
2003	158,374	22,462	4,430	0	185,267	7,040	192,307	600,961
2004	165,819	26,853	10,006	0	202,678	28,161	230,839	770,634
2005	168,955	28,258	10.146	0	207,360	28,161	235,521	930,926
2006	171,107	27,913	8,671	0	207,691	28,161	235,852	1,079,552
2007	187,781	30,120	3,424	0	221,325	33,631	254,957	1,228,317
2008	191,774	30,819	4,486	0	227,079	43,145	270,225	1,374,311
2009	210,166	32,483	5,012	0	247,660	47,150	294,810	1,521,790
2010	221,824	33,793	5,137	0	260,754	47,150	307,904	1,664,409
2011	234,154	35,455	5,265	0	274,875	47,150	322,025	1,802,520
2012	255,516	36,873	5,397	0	297,787	47,150	344,937	1,939,499
2013	273,162	39,218	5,532	0	317,913	47,150	365,063	2,073,732
2014	311,401	41,258	5,670	0	358,329	47,150	405,479	2,211,782
2015	318,413	43,319	5,812	0	367,544	47,150	414,694	2,342,511
2016	345,089	45,291	6,654	0	397,034	53,982	451,016	2,474,158
2017	361,891	47,329	7,325	0	416,544	58,861	475,406	2,602,645
2018	401,865	49,867	7,508	0	459,241	58,861	518,102	2,732,300
2019	425,450	52,048	7,696	0	485,194	58,861	544,055	2,858,364

Notes:
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Low Fuel Price Projections
Joint Development

Economic

CPW Discount Rate.	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612
WH 501F 2x1 (small)	514	258,481	24	2013 912	376,879	42,173

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,168	20,267	751	0	160,185	0	160,185	292,606
2002	141,069	20,867	2,989	0	164,925	0	164,925	434,002
2003	138,789	22,446	10,227	(219)	171,252	2,303	173,546	571,769
2004	139,339	26,676	34,710	(882)	199,878	9,210	209,053	725,429
2005	137,671	27,963	33,674	(895)	198,450	9,210	207,624	866,734
2006	133,419	27,778	31,091	(908)	191,418	9,210	200,591	993,140
2007	141,198	29,666	26,251	(921)	196,232	14,681	210,874	1,116,183
2008	140,694	30,471	27,266	(935)	197,535	24,195	221,690	1,235,955
2009	149,337	32,291	27,744	(949)	208,463	28,199	236,622	1,354,325
2010	151,791	33,574	27,820	(964)	212,263	28,199	240,421	1,465,687
2011	155,350	35,220	27,898	(978)	217,532	28,199	245,689	1,571,058
2012	163,034	36,563	27,979	(993)	226,625	28,199	254,781	1,672,235
2013	167,163	39,003	24,629	(1,009)	229,832	31,714	261,501	1,768,389
2014	166,066	40,417	7,717	(1,025)	213,222	70,372	283,548	1,864,926
2015	172,350	42,410	7,910	(1,041)	221,676	70,372	292,001	1,956,977
2016	176,910	44,491	8,107	(1,058)	228,498	70,372	298,822	2,044,200
2017	182,329	46,105	8,310	(1,075)	235,718	70,372	306,041	2,126,913
2018	191,214	48,539	8,518	(1,093)	247,229	70,372	317,550	2,206,380
2019	200,034	50,668	8,731	(1,111)	258,374	70,372	328,694	2,282,542

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario Low Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,696	9,612
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,168	20,267	751	0	160,185	0	160,185	292,606
2002	141,069	20,867	2,989	0	164,925	0	164,925	434,002
2003	140,672	22,455	4,430	0	167,558	7,040	174,598	572,604
2004	143,317	26,840	10,006	0	180,163	28,161	208,324	725,728
2005	140,511	28,162	10,146	0	178,819	28,161	206,980	866,596
2006	137,954	27,827	8,671	0	174,452	28,161	202,613	994,276
2007	146,915	30,027	3,424	0	180,365	33,631	213,997	1,119,141
2008	142,432	30,712	4,486	0	177,630	43,145	220,775	1,238,419
2009	151,354	32,344	5,012	0	188,709	47,150	235,859	1,356,407
2010	154,170	33,681	5,137	0	192,988	47,150	240,138	1,467,638
2011	156,318	35,421	5,265	0	197,004	47,150	244,155	1,572,351
2012	165,583	36,727	5,397	0	207,707	47,150	254,857	1,673,558
2013	170,557	39,155	5,532	0	215,245	47,150	262,395	1,770,041
2014	194,192	41,171	5,670	0	241,033	47,150	288,183	1,868,156
2015	185,792	43,107	5,812	0	234,711	47,150	281,862	1,957,010
2016	194,753	45,143	6,654	0	246,550	53,982	300,532	2,044,733
2017	195,120	47,112	7,325	0	249,556	58,861	308,417	2,128,088
2018	210,689	49,807	7,508	0	268,003	58,861	326,864	2,209,886
2019	214,445	51,716	7,696	0	273,856	58,861	332,718	2,286,980

Notes:
(1) Includes start-up costs
(2) Fixed costs are included only for new units Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario AEO Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
Pulverized Coal	446	513,163	42	2013.912	767,298	85,861

Finance

Fixed Charge Rate.	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,365	19,543	0	0	118,908	0	118,908	118,908
2001	101,697	20,260	751	0	122,708	0	122,708	232,527
2002	108,643	20,864	2,989	0	132,497	0	132,497	346,122
2003	116,744	22,467	10,227	(219)	149,228	2,303	151,522	466,405
2004	127,717	26,702	34,710	(882)	188,283	9,210	197,457	611,541
2005	129,997	27,979	33,674	(895)	190,792	9,210	199,966	747,635
2006	126,268	27,791	31,091	(908)	184,280	9,210	193,452	869,543
2007	136,428	29,678	26,251	(921)	191,474	14,681	206,116	989,809
2008	138,521	30,478	27,266	(935)	195,370	24,195	219,525	1,108,411
2009	152,862	32,319	27,744	(949)	212,016	28,199	240,175	1,228,559
2010	158,387	33,562	27,820	(964)	218,847	28,199	247,005	1,342,970
2011	162,910	35,243	27,898	(978)	225,116	28,199	253,273	1,451,594
2012	173,535	36,568	27,979	(993)	237,131	28,199	265,287	1,556,943
2013	177,491	39,144	25,391	(1,009)	241,061	35,355	276,371	1,658,564
2014	138,190	41,359	12,386	(1,025)	190,955	114,060	304,969	1,762,394
2015	144,603	43,541	12,695	(1,041)	199,845	114,060	313,858	1,861,336
2016	150,981	45,686	13,013	(1,058)	208,670	114,060	322,682	1,955,523
2017	157,295	47,379	13,338	(1,075)	216,986	114,060	330,997	2,044,982
2018	168,370	50,016	13,671	(1,093)	231,016	114,060	345,025	2,131,324
2019	183,030	52,471	14,013	(1,111)	248,455	114,060	362,463	2,215,311

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water

Orlando Utilities Commission Economic Evaluation

Case

Scenario: AEO Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488	198,985	24	2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612
GE 7FA SC	156	68,615	12	2016 417	104,656	11,711

Finance

Fixed Charge Rate.	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	99,365	19,543	0	0	118,908	0	118,908	118,908
2001	101,697	20,260	751	0	122,708	0	122,708	232,527
2002	108,643	20,864	2,989	0	132,497	0	132,497	346,122
2003	118,473	22,466	4,430	0	145,369	7,040	152,409	467,109
2004	131,551	26,868	10,006	0	168,425	28,161	196,586	611,605
2005	132,369	28,172	10,146	0	170,688	28,161	198,849	746,938
2006	130,834	27,852	8,671	0	167,357	28,161	195,519	870,148
2007	142,062	30,042	3,424	0	175,528	33,631	209,159	992,191
2008	139,981	30,717	4,486	0	175,183	43,145	218,328	1,110,147
2009	154,961	32,372	5,012	0	192,345	47,150	239,495	1,229,954
2010	160,855	33,652	5,137	0	199,644	47,150	246,794	1,344,267
2011	163,870	35,441	5,265	0	204,576	47,150	251,727	1,452,229
2012	176,243	36,734	5,397	0	218,375	47,150	265,525	1,557,672
2013	187,884	39,199	5,532	0	232,615	47,150	279,765	1,660,541
2014	218,196	41,202	5,670	0	265,068	47,150	312,218	1,766,839
2015	215,452	43,245	5,812	0	264,508	47,150	311,659	1,865,087
2016	230,003	45,163	6,654	0	281,820	53,982	335,802	1,963,104
2017	235,624	47,267	7,325	0	290,215	58,861	349,077	2,057,449
2018	259,873	49,830	7,508	0	317,212	58,861	376,073	2,151,561
2019	273,179	51,908	7,696	0	332,783	58,861	391,644	2,242,309

Notes
(1) Includes start-up costs.
(2) Fixed costs are included only for new units.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario OUC 2000 + 2001 AEO Escalators
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate:	11.19%
Interest During Const:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,391	20,317	751	0	151,459	0	151,459	282,961
2002	156,083	20,953	2,989	0	180,025	0	180,025	437,303
2003	168,230	22,497	10,227	(219)	200,743	2,303	203,037	598,480
2004	183,675	26,778	34,710	(882)	244,317	9,210	253,491	784,804
2005	186,996	28,020	33,674	(895)	247,832	9,210	257,005	959,717
2006	181,910	27,834	31,091	(908)	239,965	9,210	249,138	1,116,716
2007	157,918	29,721	30,097	(921)	216,853	51,874	268,688	1,273,494
2008	141,517	31,098	33,418	(935)	205,138	82,348	287,446	1,428,792
2009	153,835	32,734	33,636	(949)	219,296	82,348	301,604	1,579,669
2010	160,417	34,325	33,860	(964)	227,679	82,348	309,986	1,723,252
2011	164,593	35,931	34,089	(978)	233,677	82,348	315,982	1,858,772
2012	174,226	37,409	34,324	(993)	245,009	82,348	327,314	1,988,753
2013	187,758	39,479	30,623	(1,009)	256,896	83,266	340,116	2,113,813
2014	193,362	41,627	11,254	(1,025)	245,265	93,357	338,576	2,229,085
2015	201,679	43,858	11,535	(1,041)	256,077	93,357	349,387	2,339,226
2016	209,568	45,845	12,521	(1,058)	266,924	100,188	367,064	2,446,368
2017	218,041	47,500	13,338	(1,075)	277,852	105,068	382,871	2,549,847
2018	234,933	50,033	13,671	(1,093)	297,595	105,068	402,612	2,650,600
2019	257,444	52,586	14,013	(1,111)	322,984	105,068	428,000	2,749,773

Notes.
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: OUC 2000 + 2001 AEO Escalators
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
Pulverized Coal PC	446	513,163	42	2007.417	653,601	73,138

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,391	20,317	751	0	151,459	0	151,459	282,961
2002	156,083	20,953	2,989	0	180,025	0	180,025	437,303
2003	167,983	22,521	4,430	0	194,933	7,040	201,973	597,636
2004	186,676	26,928	10,006	0	223,610	28,161	251,771	782,695
2005	190,467	28,199	10,146	0	228,812	28,161	256,974	957,587
2006	186,644	28,018	8,671	0	223,333	28,161	251,494	1,116,071
2007	158,725	29,876	7,271	0	195,872	70,825	266,697	1,271,686
2008	142,054	31,243	10,638	0	183,935	101,299	285,234	1,425,789
2009	156,366	32,944	10,904	0	200,214	101,299	301,513	1,576,620
2010	163,536	34,505	11,176	0	209,218	101,299	310,517	1,720,450
2011	164,511	36,119	11,456	0	212,085	101,299	313,384	1,854,855
2012	176,766	37,500	11,742	0	226,009	101,299	327,308	1,984,834
2013	191,171	39,732	12,036	0	242,938	101,299	344,237	2,111,409
2014	207,669	41,618	12,337	0	261,623	101,299	362,922	2,234,970
2015	212,633	43,393	12,645	0	268,670	101,299	369,969	2,351,599
2016	229,716	46,073	12,961	0	288,750	101,299	390,049	2,465,451
2017	233,641	47,115	13,285	0	294,042	101,299	395,341	2,572,299
2018	247,845	49,961	13,617	0	311,423	101,299	412,722	2,675,583
2019	273,059	52,023	13,958	0	339,040	101,299	440,339	2,777,614

Notes
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario Constant 2000 Fuel Price Projections
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007 417	83,801	9,377
GE 7FA SC	156	68,615	12	2008.417	85,896	9,612
Pulverized Coal PC	446	513,163	42	2013.912	767,298	85,861

Finance

Fixed Charge Rate.	11.19%
Interest During Const..	6%
Finance Term (yrs):	20
Plant Life.	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,175	20,265	751	0	151,191	0	151,191	282,712
2002	151,738	20,871	2,989	0	175,598	0	175,598	433,259
2003	162,264	22,477	10,227	(219)	194,759	2,303	197,052	589,686
2004	177,298	26,721	34,710	(882)	237,882	9,210	247,056	771,280
2005	181,557	27,983	33,674	(895)	242,355	9,210	251,529	942,466
2006	177,417	27,804	31,091	(908)	235,442	9,210	244,615	1,096,615
2007	190,899	29,700	26,251	(921)	245,966	14,681	260,608	1,248,677
2008	195,838	30,515	27,266	(935)	252,723	24,195	276,878	1,398,266
2009	215,859	32,404	27,744	(949)	275,098	28,199	303,257	1,549,970
2010	223,039	33,606	27,820	(964)	283,543	28,199	311,701	1,694,348
2011	229,550	35,310	27,898	(978)	291,823	28,199	319,979	1,831,581
2012	243,547	36,607	27,979	(993)	307,182	28,199	335,338	1,964,749
2013	250,922	39,247	25,391	(1,009)	314,595	35,355	349,905	2,093,408
2014	214,003	40,885	12,386	(1,025)	266,295	114,060	380,309	2,222,888
2015	223,640	42,875	12,695	(1,041)	278,216	114,060	392,229	2,346,535
2016	236,313	45,122	13,013	(1,058)	293,438	114,060	407,450	2,465,466
2017	243,872	46,786	13,338	(1,075)	302,971	114,060	416,981	2,578,163
2018	256,042	49,162	13,671	(1,093)	317,833	114,060	431,843	2,686,231
2019	272,696	52,488	14,013	(1,111)	338,138	114,060	452,146	2,790,999

Notes:
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: Constant 2000 Fuel Price Projections
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28.161
CFB PC	267	366,076	36	2007 417	462,363	51,738
GE 7FA SC	156	68,615	12	2016.417	104,656	11,711

Finance

Fixed Charge Rate	11.19%
Interest During Const..	6%
Finance Term (yrs).	20
Plant Life.	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	123,174	19,547	0	0	142,721	0	142,721	142,721
2001	130,175	20,265	751	0	151,191	0	151,191	282,712
2002	151,738	20,871	2,989	0	175,598	0	175,598	433,259
2003	162,067	22,485	4,430	0	188,981	7,040	196,022	588,868
2004	180,103	26,854	10,006	0	216,963	28,161	245,124	769,042
2005	184,543	28,135	10,146	0	222,825	28,161	250,986	939,859
2006	182,010	27,977	8,671	0	218,658	28,161	246,819	1,095,397
2007	171,674	32,759	7,248	0	211,681	58,342	270,023	1,252,952
2008	157,562	35,667	10,599	0	203,829	79,900	283,728	1,406,242
2009	175,310	37,617	10,864	0	223,791	79,900	303,691	1,558,163
2010	181,791	39,015	11,136	0	231,941	79,900	311,841	1,702,606
2011	185,652	40,758	11,414	0	237,824	79,900	317,723	1,838,872
2012	199,169	42,450	11,699	0	253,319	79,900	333,218	1,971,197
2013	214,018	44,803	11,992	0	270,814	79,900	350,713	2,100,154
2014	243,947	46,901	12,292	0	303,139	79,900	383,039	2,230,564
2015	244,038	48,638	12,599	0	305,275	79,900	385,175	2,351,987
2016	256,624	50,997	13,611	0	321,232	86,731	407,963	2,471,067
2017	259,753	52,486	14,455	0	326,695	91,611	418,305	2,584,122
2018	277,279	55,520	14,817	0	347,616	91,611	439,226	2,694,038
2019	293,052	57,395	15,187	0	365,634	91,611	457,245	2,799,987

Notes.
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario: High Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate.	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003 833	251,663	28,161
WH 501 F 2x1 (large)	630	267,633	24	2008 417	340,709	38,125
GE 7FA SC	156	68,615	12	2019.417	112,703	12,611

Finance

Fixed Charge Rate.	11 19%
Interest During Const ·	6%
Finance Term (yrs)	20
Plant Life·	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,243	20,321	751	0	163,315	0	163,315	295,504
2002	149,588	21,007	2,989	0	173,583	0	173,583	444,324
2003	151,331	22,627	5,930	0	178,997	7,040	186,934	592,718
2004	153,868	26,959	15,981	0	196,303	28,161	224,984	758,088
2005	157,842	28,631	16,277	0	200,634	28,161	230,989	915,295
2006	153,696	28,342	16,575	0	198,534	28,161	226,773	1,058,201
2007	173,306	30,452	12,435	0	215,490	28,161	244,413	1,200,813
2008	171,395	31,740	5,090	0	206,533	50,401	258,724	1,340,594
2009	179,920	33,280	6,774	0	219,762	66,286	286,270	1,483,800
2010	188,485	35,120	6,944	0	230,247	66,286	296,837	1,621,293
2011	196,135	36,907	7,117	0	239,471	66,286	306,477	1,752,736
2012	210,110	38,797	7,295	0	256,066	66,286	322,542	1,880,822
2013	222,094	41,346	7,478	0	270,580	66,286	337,271	2,004,836
2014	241,706	43,531	7,665	0	289,970	66,286	359,225	2,127,138
2015	250,970	45,823	7,856	0	303,320	66,286	370,994	2,244,090
2016	268,465	48,617	8,053	0	323,131	66,286	391,488	2,358,362
2017	287,674	50,504	8,254	0	342,018	66,286	412,787	2,469,926
2018	305,215	53,710	8,460	0	366,871	66,286	433,819	2,578,488
2019	320,697	56,119	9,423	0	385,697	73,643	459,965	2,685,068

Notes
(1) Includes start-up costs.
(2) Fixed costs are included only for new units. Also includes purhase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario High Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate.	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171			2003.833	[redacted]	
WH 501F 2x1 (large)	630	267,633	24	2008 417	340,709	38,125
GE 7FA SC	156	68,615	12	2013.912	98,379	11,009
GE 7FA SC	156	68,615	12	2015.417	102,103	11,425
CFB PC	267	366,076	36	2018.417	606,660	67,885

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	142,243	20,321	751	0	163,315	0	163,315	295,504
2002	149,588	21,007	2,989	0	173,583	0	173,583	444,324
2003	150,440	22,627	11,728	(219)	184,576	2,303	186,878	592,674
2004	153,363	26,959	40,685	(882)	220,124	9,210	229,335	761,242
2005	155,726	28,631	39,805	(895)	223,267	9,210	232,478	919,462
2006	153,617	28,342	38,996	(908)	220,046	9,210	229,257	1,063,933
2007	172,604	30,452	35,261	(921)	237,395	9,210	246,606	1,207,825
2008	169,703	31,740	27,870	(935)	228,378	31,450	259,828	1,348,202
2009	179,708	33,280	29,507	(949)	241,545	47,336	288,881	1,492,714
2010	188,183	35,120	29,627	(964)	251,966	47,336	299,302	1,631,349
2011	195,446	36,907	29,750	(978)	261,125	47,336	308,461	1,763,642
2012	209,974	38,797	29,877	(993)	277,654	47,336	324,990	1,892,700
2013	221,903	41,417	26,065	(1,009)	288,376	48,253	336,629	2,016,478
2014	239,218	43,574	6,582	(1,025)	288,349	58,344	346,693	2,134,514
2015	252,507	46,095	7,426	(1,041)	304,988	65,009	369,997	2,251,152
2016	266,418	48,726	8,104	(1,058)	322,189	69,770	391,959	2,365,561
2017	287,726	50,844	8,307	(1,075)	345,801	69,770	415,571	2,477,877
2018	279,329	57,829	14,264	(1,093)	350,330	109,369	459,699	2,592,916
2019	284,771	62,813	18,779	(1,111)	365,252	137,655	502,907	2,709,446

Notes
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges.
(3) Includes fees for site lease and services and cooling water.

Orlando Utilities Commission Economic Evaluation

Case

Scenario Low Load and Energy Growth
Self Build

Economic

CPW Discount Rate:	8 0%
Capital Escalation Rate:	2 5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Self-Build	488			2003.833	251,663	28,161
GE 7FA SC	156	68,615	12	2008 417	85,896	9,612

Finance

Fixed Charge Rate:	11.19%
Interest During Const..	6%
Finance Term (yrs):	20
Plant Life	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	144,031	20,736	2,989	0	167,757	0	167,757	437,020
2003	143,006	22,207	4,430	0	169,643	7,040	176,683	577,276
2004	147,386	26,071	10,006	0	183,463	28,161	211,624	732,826
2005	149,786	27,309	8,568	0	185,663	28,161	213,824	878,352
2006	148,127	27,133	4,003	0	179,263	28,161	207,424	1,009,064
2007	151,825	28,174	3,424	0	183,423	28,161	211,585	1,132,522
2008	154,361	28,870	3,914	0	187,144	33,768	220,912	1,251,874
2009	167,869	30,246	4,011	0	202,127	37,773	239,899	1,371,883
2010	168,194	31,086	4,112	0	203,392	37,773	241,165	1,483,589
2011	172,166	32,323	4,215	0	208,703	37,773	246,476	1,589,298
2012	183,519	33,494	4,320	0	221,333	37,773	259,106	1,692,193
2013	190,701	35,247	4,428	0	230,376	37,773	268,149	1,790,791
2014	219,961	36,745	4,539	0	261,244	37,773	299,017	1,892,594
2015	211,723	38,011	4,652	0	254,386	37,773	292,159	1,984,695
2016	231,234	39,807	4,768	0	275,809	37,773	313,582	2,076,226
2017	223,657	40,744	4,888	0	269,288	37,773	307,061	2,159,215
2018	247,470	43,280	5,010	0	295,760	37,773	333,532	2,242,682
2019	252,503	43,917	5,135	0	301,555	37,773	339,328	2,321,308

Notes:
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water

Orlando Utilities Commission Economic Evaluation

Case

Scenario Low Load and Energy Growth
Joint Development

Economic

CPW Discount Rate:	8.0%
Capital Escalation Rate:	2.5%
Base Year for $	2000

Generation Additions

Unit	Size (MW)	2000 Capital Cost ($1,000)	Construction Period (months)	Year Installed (year)	Installed Cost ($1,000)	Levelized Cost ($1,000)
Southern	171	68,792	24	2003.833	[redacted]	
GE 7FA SC	156	68,615	12	2007.417	83,801	9,377
WH 501F 2x1 (small)	514	258,481	24	2018.912	426,403	47,715

Finance

Fixed Charge Rate:	11.19%
Interest During Const.:	6%
Finance Term (yrs):	20
Plant Life:	30

Year	Fuel and Energy Cost[1] ($1,000)	O&M Variable ($1,000)	O&M Fixed (2) ($1,000)	Rent Paid to OUC by So-Fl, etc[3] ($1000)	*Total Production Cost ($1,000)*	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2000	124,739	19,547	0	0	144,287	0	144,287	144,287
2001	139,882	20,189	751	0	160,822	0	160,822	293,196
2002	144,031	20,736	2,989	0	167,757	0	167,757	437,020
2003	142,874	22,191	5,949	(219)	170,804	2,303	173,098	574,430
2004	145,212	25,935	34,710	(882)	205,010	9,210	214,185	731,863
2005	145,815	27,148	32,095	(895)	204,201	9,210	213,374	877,082
2006	142,133	26,833	26,423	(908)	194,519	9,210	203,692	1,005,442
2007	148,815	28,020	26,251	(921)	202,203	14,681	216,845	1,131,969
2008	152,046	28,650	26,693	(935)	206,494	18,588	225,042	1,253,552
2009	162,720	30,036	26,744	(949)	218,591	18,588	237,138	1,372,180
2010	165,872	30,905	26,795	(964)	222,650	18,588	241,196	1,483,901
2011	171,033	32,177	26,848	(978)	229,122	18,588	247,667	1,590,121
2012	181,861	33,203	26,901	(993)	241,016	18,588	259,560	1,693,195
2013	184,072	34,329	28,114	(1,009)	245,550	18,588	264,093	1,790,302
2014	210,726	35,743	33,940	(1,025)	279,429	18,588	297,971	1,891,750
2015	202,964	36,936	33,998	(1,041)	272,904	18,588	291,445	1,983,625
2016	222,714	38,840	34,057	(1,058)	294,602	18,588	313,141	2,075,028
2017	217,363	39,635	34,119	(1,075)	290,091	18,588	308,630	2,158,441
2018	237,723	42,228	29,683	(1,093)	308,593	22,564	331,107	2,241,300
2019	230,264	42,676	7,450	(1,111)	279,331	66,302	345,582	2,321,376

Notes:
(1) Includes start-up costs
(2) Fixed costs are included only for new units. Also includes purchase power capacity charges
(3) Includes fees for site lease and services and cooling water.