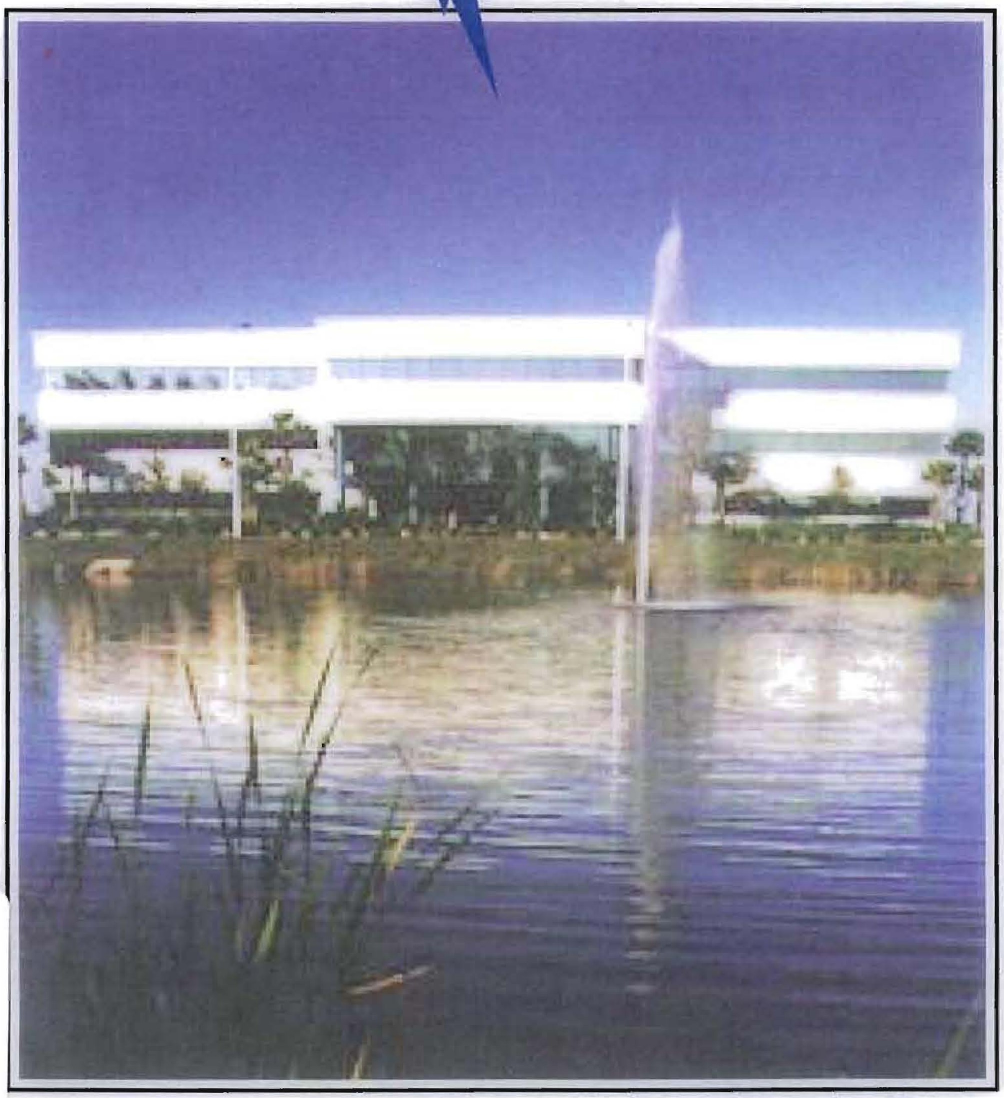
ORIGINAL

2001 10-Year Site Plan

KUA
KISSIMMEE UTILITY AUTHORITY



April 2001

APP
CAF
CMP
COM
CTR
ECR
LEG
OPC
PAI
RGO
SEC 1
SER
OTH Hbry-1

Contents

Contents (Continued)

Contents (Continued)

Tables

Contents (Continued)

Tables (Continued0

Figures

1.0 Executive Summary

This report documents the 2000 Kissimmee Utility Authority (KUA) Ten-Year Site Plan (TYSP) pursuant to Florida Administrative Codes (FAC) 25-22.070 through 25-22.072. The TYSP provides the information required by this rule. The TYSP is divided into five main sections: Description of Existing Facilities, Forecast of Electric Power Demand and Energy Consumption, Conservation and Demand-Side Management, Forecast of Facilities Requirements and Appendix. Schedules required by the FPSC have been included in Appendix A following Section 5.0.

1.1 Description of Existing Facilities

Section 2.0 of the TYSP details KUA's existing generating and transmission facilities. The section includes a historical overview of KUA's electric system, description and table of existing power generating facilities, existing power purchase information, and maps showing service area and transmission lines. KUA's existing generating facilities and purchases provide KUA approximately 294 MW (net) during winter and 274 MW (net) during summer.

1.2 Forecast of Demand and Energy Consumption

Section 3.0 of the TYSP presents the load forecast summary for KUA's system. KUA is projected to remain a summer peaking system. A 4.0 percent annual summer peak demand growth rate is projected for 2001 through 2010. This growth rate is slightly lower than KUA's historical annual growth rate of 5.3 percent during the last 10 years.

Net energy for load is projected to grow at an average annual rate of 3.6 percent over the next 10 years compared to 5.0 percent over the last 10 years. In addition to the base case load forecast, projections were developed for high and low load growth scenarios based on high and low population estimates published by the Bureau of Economic and Business Research (BEBR).

1.3 Demand-Side Programs

Section 4.0 provides descriptions of KUA's existing conservation and demand-side management (DSM) programs and additional programs that have been evaluated. With the exception of direct load control, none of the evaluated alternatives were determined to be cost-effective.

1.4 Forecast of Facilities Requirements

Section 5.0 integrates the electrical demand and energy forecast with the conservation and DSM forecast to determine the facilities requirements for a 20-year planning horizon (2001-2020).

Fuel price projections are provided with a description of the applied forecast methodology. Fuel price forecasts are provided for coal, natural gas, No. 2 oil, No. 6 oil, and nuclear.

PROSYM production costing software was used to develop annual fuel usage and total system production cost forecasts. The forecast of fuel usage is presented in the Appendix A and schedules.

2.0 Description of Existing Facilities

2.1 Historical Background

The first recorded mention of electric lights--in what was then called Kissimmee City--was made during a City Council meeting on December 17, 1891. An Electric Light Committee was formed and notified the Council that a plan had been prepared showing the location of proposed lights for the town. However, to implement the plan, requests for 300 lights would be required to secure the first electric light plant in the area.

During the ensuing years, electric light discussions persisted. On April 9, 1892, a proposal was made that a bond issue for $23,000 be implemented to provide for a public works department and electric lights. On April 18, 1893, a ballot was taken and this bonding request was approved by a vote of 41 to 5.

On December 4, 1900, Kissimmee City entered into a contract with W. C. Maynard, a citizen of the town, doing business as Kissimmee Light Co. The contract with Mr. Maynard gave him the exclusive right and franchise to erect and maintain an electric light plant in Kissimmee City for a period of 20 years.

Initially, Kissimmee Light Co. agreed to supply consumers with electricity at a cost of 3 cents per night for each sixteen candle power incandescent light and $7.50 per month for arc lights of standard power.

During a Council meeting on June 28, 1901, a resolution was passed and Kissimmee City purchased Kissimmee Light Co. from Maynard for $4,293.59. A Committee was then appointed by the City Council to manage the company.

2.1.1 History In The Making

The decades that span the 1900s to the 1980s were spent laying the operational groundwork and infrastructure that KUA heavily relies on today. The utility's initial purchase was a 15 kilowatt generator in 1901. In the twenties, three diesel engines were added to the system, providing electricity to approximately 200 customers. The thirties marked the pioneer connection between St. Cloud and Kissimmee, while during the forties and fifties, the utility worked diligently to increase the distribution capacity. The seventies were monumental in KUA's importance when Kissimmee and St. Cloud inter-tied with the rest of the continental United States through Florida Power Corporation at Lake Cecile.

From 1972 to 1982, the utility experienced multiple management changes, including five Utility Directors. In 1982, James C. Welsh, current President and General Manager, replaced Don Hornak as Utility Director. As KUA settled in with a new Director, many accomplishments were realized: KUA became an owner in the St. Lucie Nuclear Power Plant from Florida Power & Light; a 50 MW combined cycle unit was installed, marking KUA's first entry into gas turbine technology and a re-entry into the steam electric generation business after many years of sole dependence on diesel type units.

2.1.2 A New Beginning

The year 1983 marked the turning point in the making of what KUA is today. During 1983, the City Commission established an Ad-Hoc Committee to explore the concept of making the electric utility department of the City into a separate authority. The Committee also investigated the best way to manage the utility. The conclusion was that the authority would best be run by an independent board consisting of individuals with strong business backgrounds.

In 1984, the Ad-Hoc Committee presented its recommendation of making the electric utility department of the City into a separate authority. Subsequently, the City Commission reappointed the Ad-Hoc Committee members to a Charter Committee. This latter committee had the difficult task of developing a charter for the utility. In 1985, the City Commission approved the charter, subject to a vote of the people of the City of Kissimmee. A month later, voters accepted the Kissimmee Utility Authority Charter by a 2 to 1 margin.

2.1.3 KUA Today

Today, KUA is a municipal electric utility under the direction of a six member board of directors. In addition, KUA acts as a billing and customer service agent for the Water and Sewer and Refuse Departments of the City of Kissimmee. Its service area covers the City of Kissimmee and some unincorporated areas, totaling approximately 85 square miles.

The primary goal of KUA is to provide reliable electric service to its customers at the lowest possible cost in the best environmentally acceptable method. In order to accomplish this, KUA has diversified its power supply resources, which are based on KUA's own generation, offsite generation through joint participation projects, and through long- and short-term purchase power contracts.

2.2 Kissimmee Utility Authority

2.2.1 General

The Kissimmee Utility Authority (KUA) is a body politic organized and legally existing as part of the government of the City of Kissimmee. On October 1, 1985, the City of Kissimmee transferred ownership and operational control of the electric generation, transmission, and distribution system to KUA. KUA has all the powers and duties of the City of Kissimmee to construct, acquire, expand, and operate the system in an orderly and economic manner.

2.2.2 Load and Electrical Characteristics

KUA's load and electrical characteristics have many similarities to other Peninsular Florida utilities. Except during years with extreme winter weather conditions, KUA's system peak demand occurs during the summer months. KUA's system peak demand during 2000 was 250 MW.

KUA's historical and projected peak demands for the period 1990 through 2020 are presented in Table 2-1. Further details of KUA's load and electrical characteristics are contained in Section 3.0, Forecast of Electrical Power Demand and Energy Consumption.

KUA is a member of the Florida Municipal Power Pool (FMPP), along with Orlando Utilities Commission (OUC), the Florida Municipal Power Agency (FMPA), All Requirements Project, and the City of Lakeland. FMPP operates as an hourly energy pool. Commitment and dispatch services for FMPP are provided by OUC. Each member of the FMPP retains the responsibility of adequately planning its own system to meet native load and Florida Reliability Coordinating Council (FRCC) reserve requirements.

2.2.3 Generation Resources

KUA owns and operates or has ownership interest in generating units comprising several technologies, including nuclear, coal fired, diesel, simple cycle, and combined cycle. Table 2-2 provides a summary of KUA's existing generating resources. The following paragraphs describe KUA's generating assets and ownership interests in detail.

KUA owns and operates eight diesel generating units ranging in age from 17 to 41 years. Each of these diesel units is located at the Roy B. Hansel Generating Station in Kissimmee. Six of these diesel units are fueled by natural gas, while the remaining two burn No. 2 oil. The total nameplate capacity of the eight diesels is 18.35 MW. In addition, KUA owns and operates a natural gas fired (with No. 2 oil as backup) combined cycle plant, which is also located at the Hansel site. Hansel CC comprises a 35 MW (nameplate) combustion turbine and two 10 MW (nameplate) steam turbine generators powered by the CT's waste heat. The total nameplate generating capability at the Hansel site is approximately 73.35 MW.

KUA and FMPA are both 50 percent joint owners of Cane Island Units 1 and 2. Unit 1 is a simple cycle General Electric LM6000 aero-derivative combustion turbine with a nameplate rating of 42 MW. Unit 2 is a one-on-one General Electric Frame 7EA combined cycle with a nameplate rating of 120 MW. KUA and FMPA have also

Table 2-1
Summary of Load Forecast

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
1990	200	--	--	151	--	--
1991	147	--	--	157	--	--
1992	158	--	--	169	--	--
1993	158	--	--	183	--	--
1994	173	--	--	180	--	--
1995	196	--	--	195	--	--
1996	218	--	--	206	--	--
1997	198	--	--	216	--	--
1998	180	--	--	233	--	--
1999	219	--	--	236	--	--
2000	221	--	--	250	--	--
2001	257	259	255	267	269	265
2002	273	281	265	283	292	275
2003	288	304	274	299	315	285
2004	302	325	282	313	337	293
2005	313	342	289	325	354	300
2006	325	362	293	337	375	304
2007	334	379	295	347	393	306
2008	344	398	297	357	412	309
2009	355	417	300	368	432	311
2010	365	438	302	379	454	314
2011	376	459	302	390	476	314
2012	387	481	301	401	499	313
2013	398	504	300	413	522	312
2014	409	528	299	425	547	310
2015	421	553	298	437	574	309
2016	432	579	296	449	601	307
2017	444	606	292	461	629	304
2018	456	634	289	473	658	300
2019	468	663	286	485	688	297
2020	480	694	284	498	720	294

Table 2-2
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Hansel	8	Osceola	IC	NG	FO2	02/59	Unknown	3.00	2.0	2.0	PL	TK
	14	County	IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	15	27,T255/R29E	IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	16		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	17		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	18		IC	NG	FO2	02/72	Unknown	2.07	1.8	1.8	PL	TK
	19		IC	FO2	--	02/83	Unknown	2.50	2.5	2.5	TK	--
	20		IC	FO2	--	02/83	Unknown	2.50	2.5	2.5	TK	--
	21		CT	NG	FO2	02/83	Unknown	35.00	25.0	25.0	PL	TK
	22		ST	WH	--	02/83	Unknown	10.00	10.0	10.0	--	--
	23		ST	WH	--	02/83	Unknown	10.00	10.0	10.0	--	--
Plant Total								73.35	61.0	61.0		
Crystal River	3	Citrus County 33,T17S/R16E	N	UR	--	03/77	Unknown	890.46	5.6(1)	5.6(1)	TK	--
Plant Total								890.46	5.6	5.6		
Stanton Energy Center	1	Orange County 13,14,23,24/ R31E/T23S and 18,19/ T23S/R32E	ST	BIT	--	07/87	Unknown	464.58	21.0(2)	21.0(2)	RR	--
Plant Total								464.58	21.0	21.0		

Table 2-2 (Continued)
Kissimmee Utility Authority Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (MW)	Net Capability Summer (MW)	Net Capability Winter (MW)	Fuel Transportation Primary	Fuel Transportation Alternate
Indian River	A	Brevard	CT	NG	FO2	07/89	Unknown	41.40	4.00(3)	4.0(3)	PL	TK
	B	County	CT	NG	FO2	07/89	Unknown	41.40	4.00(3)	4.0(3)	PL	TK
		12/T23S/R35E										
Plant Total								82.80	8.0	8.0		
Cane Island	1	Osceola	CT	NG	FO2	11/94	Unknown	42.00	15.2(4)	20.3(4)	PL	TK
	2	County	CT	NG	FO2	06/95	Unknown	80.00	34.4(4)	40.2(4)	PL	TK
	2	29,32/R28E/	ST	WH	--	06/95	Unknown	40.00	20.0(4)	20.0(4)	--	--
		T25S										
Plant Total								162.00	69.6	80.5		
System Total as of January 1, 2000									165.2	176.1		

Notes:

(1) KUA's 0.6754 percent portion of joint ownership.

(2) KUA's 4.8193 percent ownership portion.

(3) KUA's 12.2 percent portion of joint ownership.

(4) KUA's 50 percent ownership portion.

committed to build Cane Island 3, which is a nominal 250 MW combined cycle unit. This unit is currently under construction and is expected to be on line in mid-2001. KUA's 50 percent ownership share of the Cane Island Units is 206 MW (nameplate).

KUA owns a 0.6754 percent interest, or 6 MW (nameplate), in the Florida Power Corporation's (FPC) Crystal River Nuclear Unit 3, located in Citrus County, Florida. KUA also has a 4.8193 percent ownership interest, or 22,300 kW (nameplate), in the Orlando Utilities Commission's (OUC) Stanton Energy Center Unit 1 and a 12.2 percent, or 10 MW (nameplate), interested in OUC's Indian River Combustion Turbine Project Units A and B.

2.2.4 Purchase Power Resources

KUA is a member of the Florida Municipal Power Agency (FMPA), a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 15 other members of the FMPA. KUA's entitlement share of this unit, based on a power purchase contract and adjusted for transmission losses, is 6.9 MW. FMPA has also entered into a Reliability Exchange Agreement with FPL, under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit 1 and half from Unit 2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has a contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases up to an additional 50 MW if the capacity is available from OUC. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton 1 Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton 2 Project. The Stanton 2 percentage includes recently acquired Homestead and Lake Worth shares totaling 3.8314 percent.

KUA, FMPA, OUC, and Southern-Florida have filed a Need for Power Application (NFP) with the FPSC. The NFP proposes the construction of a third unit at the Stanton Energy Center site (Stanton A), a 2 x 1 GE 7FA, the net output of which will be 633 MW at 70° F. KUA will receive 10 percent (approximately 41.7 MW) of the

65 percent capacity owned by Southern-Florida and supplied under a purchase power agreement. Table 2-3 presents KUA's purchase power resources.

2.2.5 Transmission and Interconnections

KUA is a member of the Florida Reliability Coordinating Council (FRCC). The FRCC has established an energy broker system that provides economic interchange of electric energy between member utilities, including KUA. KUA has purchased and sold energy through this broker system, and intends to continue such transactions whenever conditions are favorable. Currently, these economy transactions are conducted through FMPP.

KUA has direct transmission interconnections with: (i) FPC, delivered at 69 kV from the FPC Lake Bryan substation and at 230 kV at OUC=s Taft substation; (ii) OUC (two lines and an auto-transformer), delivered at 230 kV at OUC=s Taft substation; (iii) the City of St. Cloud, Florida, at KUA's 69 kV interconnection with St. Cloud's transmission facilities; and (iv) TECO, one 230 kV circuit through the interconnection with the Osceola and Lake Jewell circuits.

Electric power and energy supplied from KUA-owned generation and purchased capacity is delivered through 230 kV and 69 kV transmission lines to eight distribution substations. KUA provides electric service to retail customers primarily by 13.2 kV feeder circuits from the distribution substations.

2.2.6 Service Area

KUA serves a total area of approximately 85 square miles, including the city's 10 square mile area near the center. As of December 2000, KUA served approximately 49,332 electric customers. Of these, 40,394 were residential, 8,194 were general service non-demand, and the remaining 744 were general service demand. KUA's electric service area, shown on Figure 2-1, is entirely located in Osceola County.

Table 2-3
Purchase Power Resources (1)

CY	Utility/Unit (MW) St. Lucie 1 and 2	Stanton 1(2)	Stanton 2(3)	OUC D(4)	Southern PPA(5)	Future Purchase(6)	Amount Total
2001	6.9	7.9	33.3	20.0	0.0	0.0	68.1
2002	6.9	7.9	33.3	20.0	0.0	0.0	68.1
2003	6.9	7.9	33.3	20.0	0.0	0.0	68.1
2004	6.9	7.9	33.3	0.0	2.3	0.0	50.4
2005	6.9	7.9	33.3	0.0	18.3	0.0	66.4
2006	6.9	7.9	33.3	0.0	33.3	0.0	81.4
2007	6.9	7.9	33.3	0.0	41.3	0.0	89.4
2008	6.9	7.9	33.3	0.0	41.3	7.0	96.4
2009	6.9	7.9	33.3	0.0	41.3	20.0	109.4
2010	6.9	7.9	33.3	0.0	41.3	32.0	121.4
2011	6.9	7.9	33.3	0.0	41.3	45.0	134.4
2012	6.9	7.9	33.3	0.0	41.3	58.0	147.4
2013	6.9	7.9	33.3	0.0	41.3	71.0	160.4
2014	6.9	7.9	33.3	0.0	41.3	85.0	174.4
2015	6.9	7.9	33.3	0.0	41.3	99.0	188.4
2016	6.9	7.9	33.3	0.0	41.3	113.0	202.4
2017	6.9	7.9	33.3	0.0	41.3	126.0	215.4
2018	6.9	7.9	33.3	0.0	41.3	140.0	229.4
2019	6.9	7.9	33.3	0.0	41.3	155.0	244.4
2020	6.9	7.9	33.3	0.0	41.3	169.0	258.4

Notes:

(1) No reserves are supplied by the selling utility. KUA provides for 15 percent reserves.
(2) KUA share of Stanton 1 through FMPA Stanton 1 Project is 1.80725 percent.
(3) KUA share of Stanton 2 through FMPA Stanton 2 Project is 7.6628 percent. Total percentage represents KUA's original purchase percentage plus the sum of recently acquired Homestead and Lake Worth purchase percentages, equal to 3.8314 percent.
(4) 20 MW Schedule D ending in December 2003.
(5) Stanton A Purchase beginning in 2004.
(6) Unspecified purchases to maintain 15 percent reserve requirement.

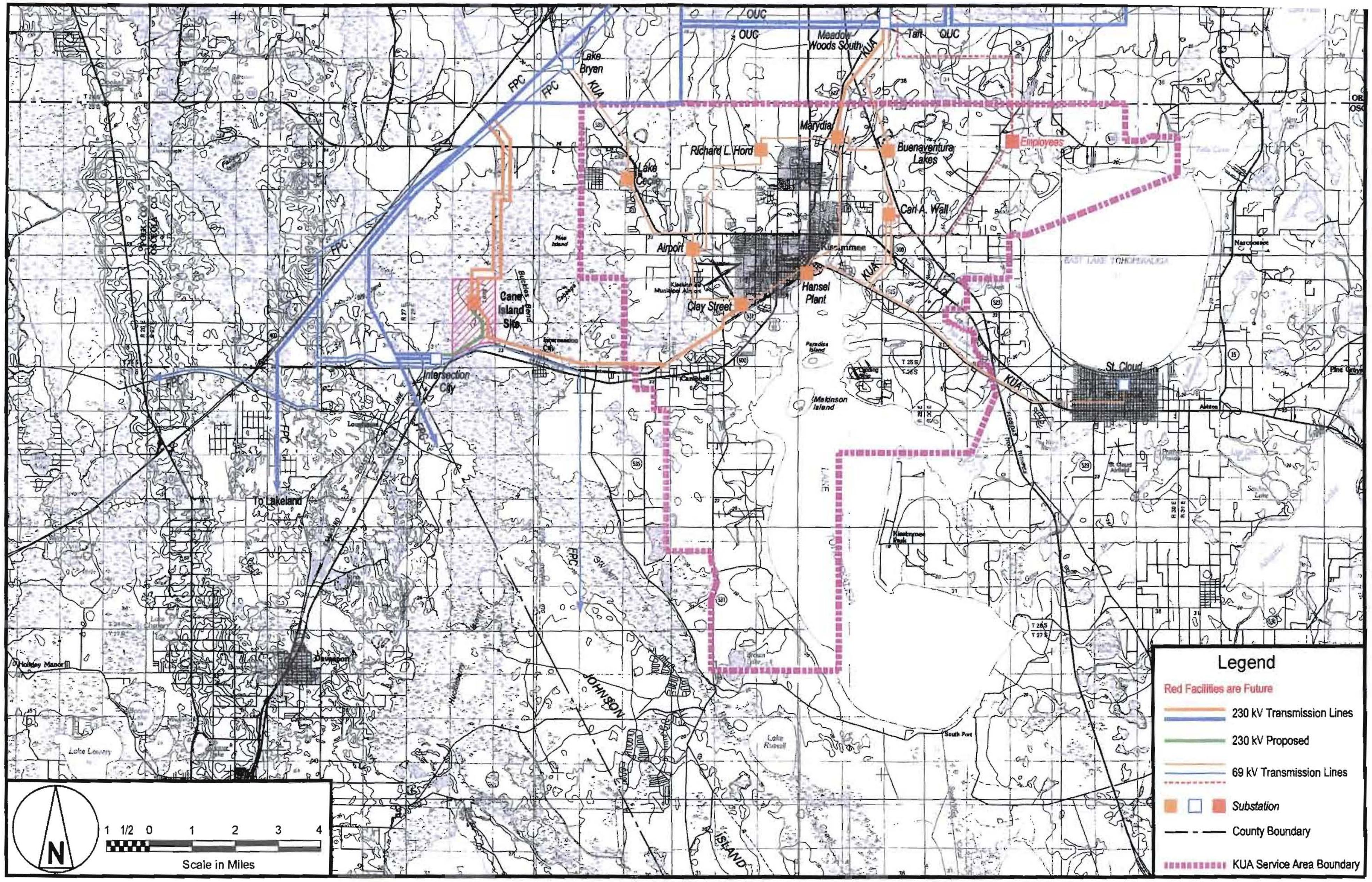


Figure 2-1
Service Area Map

3.0 Forecast of Demand and Energy Consumption

Annually, KUA prepares a detailed long-term electric load and energy forecast using econometric techniques. This detailed forecast is developed on a fiscal year basis (October through September) and serves as a primary driver in annual planning activities. The information presented has been summarized in calendar year format in accordance with FRCC guidelines. KUA's fiscal year forecast has been converted to a calendar year basis, except where specifically noted, and is aggregated as required by FRCC.

The following sections describe KUA's general forecasting approach. Each of the forecasting models is explained, and the summary results of the forecasts are presented.

3.1 Forecast Modeling Approach

Econometric forecast models have been used to project monthly sales by customer class. The econometric models and associated statistical relationships were developed to forecast annual changes in electricity consumption by rate classification as a function of demographic, weather, and economic factors such as income, temperature, and real price of electricity. The models were developed using statistical relationships between historical, economic, weather, and electric system data.

The statistical estimating technique used in the development of the models was ordinary least squares multiple regression. This method is used to determine the linear relationship between a dependent variable, such as energy usage, and multiple independent econometric variables based on changes in the values of the variables through time. Implicit in the model development is the assumption that customer class energy usage will be affected by the same key factors in the future as in the past. The following equation represents this linear relationship:

$$Y = a + \sum_{i1}^{n} [b_i * X_i] + e$$

where,

Y	=	dependent variable (predicted)
a	=	constant term
b_i	=	coefficient terms
X_i	=	independent variables
e	=	error term

The calculated equation minimizes the sum of the squared errors between the actual and predicted values of the dependent variable.

An important consideration in regression analysis is the selection of variables. Independent variables explain changes in the dependent variable. Therefore, sufficient historical data for both dependent and independent variables must be available to produce a reliable regression equation. Also, to forecast values of the dependent variable, the independent variables must have the potential to be projected into the future.

All regression equations were tested using five primary statistical measures. The first measure is the adjusted R^2, the coefficient of determination corrected for reduced degrees of freedom due to inclusion of additional independent variables in the regression equation. The coefficient of determination (perfect = 1.0) is the proportion of variability in the dependent variable that is explained by the independent variables. The second measure is the F statistic, which is a test of whether there is a significant linear relationship between the dependent variable and the entire set of independent variables. The F-test is performed by determining the calculated F statistic (F_{CALC}) and comparing this value with the corresponding value of the F distribution (F_{DIST}). The third measure is the T statistic, which is a test for multi-collinearity of the independent variables. This test is performed by determining the calculated T statistic (T_{CALC}) and comparing this value with the corresponding value of the T distribution (T_{DIST}). The fourth measure is the Durbin-Watson (DW) statistic, which is a test for serial correlation of adjacent error terms. The fifth, and final, measure is the Bayesian Information Criterion (BIC). The BIC serves as a guide to the selection of the number of terms in an equation by placing a penalty on additional coefficients.

3.2 Econometric Data and Projections

This section describes the data sources used in the development of the econometric variable projections for the forecast period. As in previous forecasts, economic and population forecasts from the Bureau of Economic and Business Research (BEBR) were included in the analysis as econometric variables.

3.2.1 Historical Data

A careful compilation of historical data was developed to formulate a reliable econometric model for forecasting electricity sales. Monthly historical sales data were compiled for each major customer classification for the period of January 1985 through September 2000. Additional data including temperature, population, employment, households, real personal income, and total housing starts was also compiled. The econometric data used was obtained from BEBR data applicable to the MSA in which Kissimmee is located.

MSAs are Metropolitan Statistical Areas defined by the Census Bureau for various regions within each state. Kissimmee is located within the Orlando MSA. The Orlando MSA also includes Lake, Orange, Osceola, and Seminole Counties. Although some variance in general MSA versus Kissimmee data can be expected, the homogeneous nature of the surrounding region provided well-aligned trend relationships between historical electricity use and the econometric variables selected for the forecast.

3.2.2 Econometric Projections

The BEBR has estimated that, during the next 15 years, employment will grow at an average annual rate of 2.5 percent, down from 3.5 percent from 1980 through 1995. Real personal income is estimated to grow at an average annual rate of 3.4 percent, down from 3.9 percent from 1980 through 1995. In general, the slower percentage growth rates of employment and income for Florida are related to a slowing annual population growth rate. Florida's average annual population growth rate is forecast to be 1.6 percent from 1995 through 2010, down from 2.5 percent from 1980 through 1995. Although Osceola

County economic and population forecasts show slower growth, Osceola County's annual growth rate continues to exceed the surrounding counties. In contrast, the forecast growth rate of real per capita income, a measure of the average Floridian standard of living, accelerates from the previous 15 years. Real per capita income is forecast to grow at 1.8 percent per year, up from 1.4 percent.

Due to publication delays, KUA used 1999's Long-Term Economic Forecast for economic data. However, the 2000 population forecast was available and was used in the projection of economic data beyond 2010.

3.3 Forecasting Assumptions

The first key assumption included in the load forecast analysis is related to regional weather patterns. Because predicting future weather patterns is not possible, normal weather conditions were assumed for the load forecast model. Monthly average temperatures for the last 10 years were used as a representation of normal weather. For weather projections, the weather for every month of the forecast period was set equal to that month's 10 year average of monthly temperatures for the historical period. The same methodology was applied uniformly to all other weather-related variables used in the analysis.

The second key assumption of significance to the 2001 sales forecast is the inclusion of estimated annual rate increases scheduled for implementation beginning in October 2000. Currently, rate increases are scheduled as follows:

Effective Date	Average Across-the-Board Rate Increase
10/2000	1.6505 percent
10/2001	1.6508 percent

3.4 Sales Forecast

3.4.1 Residential Sales

To forecast residential electricity sales, annual forecasts of residential electricity use per customer, and number of customers were developed using ordinary least squares multiple regression models. The product of residential service customers and electricity use per customer forecasts yields total annual residential electricity sales.

3.4.1.1 Residential Customers. In the development of the 2001 econometric model for residential customers, Osceola County population (POPA), Average Household Size (AHS), Employment (EWS), Employment (E), Households (HH), and Cumulative Housing Starts (CTS) estimates were used as potential explanatory variables. Based on KUA's statistical evaluation, POPA and CTS were both statistically significant in representing monthly fluctuations in residential customers. Autoregressive (_AUTO[*]) terms were introduced to minimize the effects of serial correlation. In effect, the _AUTO[*] variable incorporates the residual from previous observations into the regression model for the current observation. The resulting equation and statistics are shown in Table 3-1.

3.4.1.2 Residential Energy Use Per Customer. The 2001 econometric model for residential electricity use per customer evaluated the real price of electricity (PRICERES), Income Per Household (INCPERHH), Real Taxable Sales (RTS100), Real Income Per Capita (RYPC), Real Personal Income (RYTOT), and Billing Month Adjusted Heating and Cooling Degree Days (BM_HDD, BM_CDD) as potential explanatory variables. Based on KUA's statistical evaluation, PRICERES, INCPERHH, BM_CDD, and BM_HDD were statistically significant in representing monthly fluctuations in residential energy use per customer. An autoregressive (_AUTO[*]) term was introduced to minimize the effects of serial correlation. The resulting equation and statistics are shown in Table 3-1.

3.4.1.3 Weather Impacts. Temperature and billing data were adjusted to compensate for different reporting periods. The degree days were shifted from calendar month to

<table>
<tr><td colspan="2">Table 3-1
Sales Forecast Equations and Statistics</td></tr>
<tr><td>RSCUSTT = 112.334*CTS + 213.373*POPA + 0.479*_AUTO[-1] + 0.434*_AUTO[-2]

RSCUSTT: Total Residential Customers
CTS: Cumulative Total Housing Starts
POPA: Total Population in Osceola County
_AUTO[-1]: First Order Autoregressive Term
_AUTO[-2]: Second Order Autoregressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9984
Durbin-Watson: 2.0860
Bayesian Information Criterion: 267.3</td></tr>
<tr><td>RSUPC = - 7.206*PRICERES + 19.241*INCPERHH + 1.394*BM_CDD + 2.181*BM_HDD + 0.490*BM_CDD[-1] + 0.709*BM_HDD[-1] + 0.321*_AUTO[-1]

RSUPC: Residential Use Per Customer
PRICERES: Residential Real Price of Electricity
INCPERHH: Real Personal Income Per Household
BM_CDD: Billing Month Adjusted Cooling Degree Days
BM_HDD: Billing Month Adjusted Heating Degree Days
_AUTO[-1]: First Order Autoregressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9177
Durbin-Watson: 2.041
Bayesian Information Criterion: 70.89</td></tr>
<tr><td>GSNCUSTT = 56.304*POPA + 0.754*_AUTO[-1] + 0.238*_AUTO[-2]

GSNCUSTT: Total General Service Non-Demand Customers
POPA: Total Population in Osceola County
_AUTO[-1]: First Order Autoregressive Term
_AUTO[-2]: Second Order Autoregressive Term</td><td><u>Key Statistics</u>:
Adjusted R^2: 0.9976
Durbin-Watson: 2.01
Bayesian Information Criterion: 110.6</td></tr>
</table>

Table 3-1 (Continued)
Sales Forecast Equations and Statistics

GSNKWHT = - 77727.942*PRICEGSN(-12) + 267026.062*INCPERHH + 951.982*BMC_TIME + 2823681.888*RATECHANGE + 0.661*_AUTO[-1] GSNKWHT: Total General Service Non-Demand Energy Sales PRICEGSN: General Service Non-Demand Real Price of Electricity BMC_TIME: Increasing Saturation of Cooling-Related Load RATECHANGE: Change in Rate Classification in October 1990 _AUTO[-1]: First Order Autoregressive Term	Key Statistics: Adjusted R^2: 0.9724 Durbin-Watson: 2.117 Bayesian Information Criterion: 7.472e+005
OLSKWHT = Holt Exponential Smoothing: linear trend, no seasonality Level Component: Smoothing Weight: 0.30765 Final Value: 7.7362e+005 Trend Component: Smoothing Weight: 0.02350 Final Value: 4181.8	Key Statistics: Adjusted R^2: 0.9868 Durbin-Watson: 1.94 Bayesian Information Criterion: 1.337e+004

billing month to more accurately reflect the relationship between temperature and energy consumption. An example of this shifting is described as follows:

> *A customer has his electric meter read on billing cycle 2. In February, billing cycle 2 corresponds with a meter reading date of February 2nd. Sales to this customer are billed in February, but primarily occur in January. If the remainder of February is bitterly cold, the corresponding degree days are not reflected in the customer's February bill. As a result, error is introduced.*
>
> *By aligning the sales and degree days, the model is more responsive to changes in temperature.*

3.4.2 General Service Non-Demand Forecast

The model for the general service non-demand rate classification comprises forecasts for customers and energy sales and includes temporary service and KUA rate classifications.

3.4.2.1 General Service Non-Demand Customers. In the development of the 2001 econometric model for general service non-demand customers, Osceola County Population (POPA), Average Household Size (AHS), Employment EWS), Employment (E), Households (HH), and Cumulative Housing Starts (CTS) estimates were used as potential explanatory variables. Based on KUA's statistical evaluation, only POPA was statistically significant in representing monthly fluctuations in general service non-demand customers. Autoregressive (_AUTO[*]) terms were introduced to minimize the effects of serial correlation. The resulting equation and statistics are shown in Table 3-1.

3.4.2.2 General Service Non-Demand Electricity Sales. The 2001 econometric model for general service non-demand energy sales evaluated the real price of electricity (PRICEGSN), Income Per Household (INCPERHH), Real Taxable Sales (RTS100), Real Income Per Capita (RYPC), Real Personal Income (RYTOT), and Billing Month Adjusted Heating and Cooling Degree Days (BM_HDD, BM_CDD) as potential explanatory variables. In addition, a variable to reflect the impact of a rate reclassification in October 1990 on sales (RATECHANGE) was considered.

Based on KUA's statistical evaluation, PRICEGSN, INCPERHH, BM_CDD, BM_HDD, and RATECHANGE were statistically significant in representing monthly fluctuations in general service non-demand energy sales. An autoregressive (_AUTO[*]) term was also introduced to minimize the effects of serial correlation. The resulting equation and statistics are shown in Table 3-1.

3.4.3 General Service Demand Forecast

Modeling the general service demand rate classification continues to be the Achilles' heel of the energy forecast. For the purposes of this load forecast, general service demand comprises GSD, GSDT, GSLD, Interruptible, and Contract Rate classifications. General service demand represents approximately 30 percent of total energy sales with 742 customers (September 2000). Because general service demand represents such a large percentage of total energy consumption, assumptions and models used to forecast have a significant impact on the overall energy forecast.

The number of customers in the general service demand rate classification (GSD) has remained unpredictable over the course of the last several years. The initial and most abrupt change occurred as a result of a shift in rate classification (October 1990) that encouraged the migration of smaller GSD customers to the non-demand classification (GSND). Since September 1992, the net change in customers is zero.

During the interim, the number of customers has been as low as 713 (March 1995) and as high as 792 (April 1997). Econometric, exponential smoothing, and Box-Jenkins methods have been used to analyze the GS Demand customers. At this point in time, the best estimate for the future is the current level of customers, 742.

The forecast of no growth is reasonable given the unexplained variation in general service demand customers. The fluctuations in customers have been as great as 9 percent in 3 months. This size of drop in general service demand is certainly suspicious. Without understanding the reasons behind data volatility, it continues to be a challenge to forecast. Meetings with key personnel have brought no additional insight to this situation and, until it is better understood, forecasting no customer growth for general service demand customers is recommended.

Using OLS, a model was prepared for general service demand energy sales. The final model fit the historical data well, but when used to forecast, it produced unreasonable results. Because a model for general service demand customers had already been determined, the OLS model for general service demand energy sales was theoretically indicating that the use per customer would double over the forecast horizon. This conclusion is unreasonable.

Planners from the City of Kissimmee were subsequently consulted regarding future large customer expansions. Over the next 5 years, City plans include the addition of approximately 56 GWh of energy requirements. These energy requirements have been added in the general service demand forecast as spot loads.

In addition to the information provided by City Planners and KUA Staff, a review of the energy sales growth rates in general service demand shows the smallest increase in energy sales to be approximately 1 percent. The forecast of general service demand sales comprises a level that is held constant for 5 years and then increases at 1 percent per year (estimates for the World Expo Center and estimated spot loads). Table 3-2 outlines the specifics of each case.

In the Base, High, and Low Cases, general service demand sales growth fluctuates drastically in the forecast period (2002 through 2006). These fluctuations are a result of phased World Expo Center construction.

3.4.4 World Expo Center

The developers of the World Exposition Center (Expo Center) are planning a major commercial development on an 800 acre site in the northwest quarter of KUA's service territory in Osceola County. The construction of this world-class, mixed-use facility is currently in the planning stages and was, at one point, expected to be operational in 2000.

Table 3-2 Sensitivity Case Summary			
Description	Base Case	High Case	Low Case
Residential Customers	Base Case Cumulative Total Housing Starts and Population figures	High Case Cumulative Total Housing Starts and Population figures	Low Case Cumulative Total Housing Starts and Population figures
Residential Energy Sales	Base Case Income Per Household	High Case Income Per Household	Low Case Income Per Household
GS Non-Demand Customers	Base Case Population	High Case Population	Low Case Population
GS Non-Demand Energy Sales	Base Case Income Per Household	High Case Income Per Household	Low Case Income Per Household
GS Demand Customers	Hold flat at 742	Hold flat at 742	Hold flat at 742
GS Demand Energy Sales	No growth until 2006, then grow at 1 percent	No growth until 2006, then grow at 2 percent	No growth in energy sales
World Expo Center	Base Case Estimates	High Case Estimates	Low Case Estimates
Spot Loads	Brought on line evenly over 5 years	Brought on line evenly over 5 years	Brought on line evenly over 5 years
Outdoor Lighting	Base Case Model	Upper Limit	Lower Limit

Phase I of the original plan, slated to be completed by the first part of 2001, includes a 2.4 million square foot exposition hall, 1.3 million square foot outside parking area, and 8.6 million square foot parking garage. Phase 1A, originally scheduled to be completed by the first part of 2002, includes a 1.0 million square foot hotel, 1.3 million square foot county convention center, and 79,000 square feet of commercial office space.

Phase II of the construction is projected to be complete during 2003 through 2005 in stages after Phase I and Phase IA are operational. Phase II facilities include three resort hotels totaling 1.6 million square feet, two office buildings totaling 0.5 million square feet, a 1.0 million square foot retail and entertainment complex, a public safety facility, and 2.0 million square feet of additional parking.

At this time, the World Expo Center team is still engaged in planning and negotiating, and plans to build are not yet certain. An article in the July 1999 edition of the Journal for Osceola County Business stated that the project has been scaled down. Articles in January, August, and November of 2000 have given estimates that the scaled-down exposition center would be 1.4 million square feet. Additionally, the project would include a 140,000 square foot convention center, 2 hotels with 3,000 rooms, and 700,000 square feet of retail and entertainment space. The articles also mention that the legal hurdles have almost all been cleared, and the primary concern at this point is whether the project has the financial backing to proceed. The State Supreme Court has authorized Osceola County to finance the 140,000 square foot convention center, but construction cannot begin until the larger project is approved.

Regardless of scaling down the project, the peak demand and energy requirements of the Expo Center will significantly impact KUA's current system demand and least-cost planning methodology.

At the outset of the World Expo Center planning process, our consultants (Black & Veatch) prepared a detailed consumption analysis to determine the potential peak demand and energy use of this facility. Due to the lack of data on facilities of this magnitude, demand and energy consumption per square foot from similar-use facilities were used as planning-level estimates.

Table 3-3 shows the Base, High, and Low Case annual peak demand and energy forecasts for the World Expo Center. For the 2001 forecast, this project has been slated to begin in fiscal year 2002. This assumption is based on delays that have already taken place, and seem to be approaching resolution. In addition, the project has been scaled down by 50 percent to reflect revised project estimates provided through recent reports.

3.4.5 Outdoor Lighting Forecast

Street lighting, vapor lighting, and outdoor lighting were combined into one class for forecasting purposes. This year, outdoor lighting was forecast using exponential smoothing. When viewing the historical data after October 1992, outdoor lighting sales appear to be trended and unseasonable, the characteristics of a Holt model for exponential smoothing. The resulting equation and statistics are shown in Table 3-1.

3.5 Net Energy for Load and Peak Demand Forecast

3.5.1 Net Energy For Load

During the past several years, net energy for load (NEL) was projected by applying an efficiency factor of 95 percent to the projection of total sales. During 1997, an attempt was made to develop an econometric model for NEL using the relationship of NEL to total sales and certain monthly variables. After further review, it was decided that the econometric model did not provide significant accuracy to the projection of NEL and KUA returned to the 95 percent efficiency factor methodology. Tables 3-4, 3-5, and 3-6 present KUA's Base, High, and Low Case NEL forecasts. Net energy for load is projected to grow at an average annual rate of 3.6 percent from 2001 through 2010 compared to 5.0 percent from 1991 through 2000.

3.5.2 Peak Demand Forecast

The forecast of peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. Our attempts to use econometrics to model peak load in the past have been unsuccessful due to a lack of data.

Table 3-3
World Exposition Center Load Forecast
Annual Peak Demand and Energy

	Low Forecast		Base Forecast		High Forecast	
Fiscal Year	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)
2002	4.0	5,710	6.6	12,850	10.0	22,355
2003	7.6	10,956	12.9	22,952	19.8	39,703
2004	9.9	15,019	17.5	31,160	27.6	54,195
2005	11.0	20,229	19.6	47,245	30.8	73,398
2006	12.4	23,804	22.3	48,680	35.4	84,453
2007-2025	12.4	23,804	22.3	48,680	35.4	84,453

Source: 1998 Cane Island 3 Need for Power Application Table 1B.5-3, delayed and reduced by 50 percent from the Journal for Osceola County Business.

Table 3-4
2001 Base Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand						Total		
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Net Energy for Load (MWh)
1986	19,857	215,331	2,279	30,337	609	182,789	0	0	182,789	838	22.745	429,295	455.520
1987	21,294	232,646	2,453	31,400	705	206,688	0	0	206,688	934	24,452	471,669	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	0	0	235,618	2,508	26.320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	0	0	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	0	0	277,828	1,696	32,956	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	0	0	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	0	0	270,110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	0	0	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	0	0	295,446	5,546	40,418	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	0	0	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	0	0	304,918	6,725	43,164	892,014	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	0	0	323,844	7,212	44,088	920,752	970,415
1998	36,573	508,138	7,856	153,422	731	336,475	0	0	336,475	7,796	45,160	1,005,832	1,042,380
1999	38,095	505,037	7,920	151,443	740	342,815	0	0	342,815	8,366	46,755	1,007,662	1.049,523
2000	39,971	536,388	8,098	160,614	756	359,111	0	0	359,111	9,241	48,825	1,065,354	1,116,042
2001	41,088	567,625	8,381	161,400	742	359,111	3,213	14,015	376,338	9,760	50,211	1,115,124	1,173,814
2002	42,191	587,183	8,686	168,023	742	359,111	15.376	25,227	399,713	10,362	51,618	1,165,282	1,226,613
2003	43,345	609,846	8,995	172,454	742	359,111	25.004	36,438	420,553	10,965	53,083	1.213,819	1,277,704
2004	44,543	633,434	9,311	177,574	742	359,111	35,181	47,650	441,942	11,567	54,595	1,264,517	1,331,071
2005	45,779	657,912	9,632	182,680	742	359,982	47,604	56,059	463,645	12,169	56,153	1,316,406	1,385,690

Table 3-4 (Continued)
2001 Base Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand						Total		
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Average Accounts	Sales (MWh)	Net Energy for Load (MWh)
2006	47,113	685,900	9,958	188,280	742	363,582	48,680	56,059	468,321	12,771	57,813	1,355,273	1,426,603
2007	48,540	717,234	10,289	194,311	742	367,218	48,680	56,059	471.957	13,373	59,570	1,396,875	1,470,395
2008	50,010	749,886	10,627	200,350	742	370,890	48.680	56,059	475,629	13,975	61,379	1,439,841	1,515,622
2009	51,525	783,907	10,973	206,399	742	374,599	48,680	56,059	479.338	14,578	63,240	1,484,221	1,562,337
2010	53,086	819,352	11,326	212,456	742	378,345	48,680	56,059	483,084	15,180	65,155	1,530,072	1,610,602
2011	54,637	855,055	11,676	218,448	742	382,128	48,680	56,059	486,867	15,782	67,055	1,576,153	1,659,108
2012	56,184	891,167	12,024	224,384	742	385,949	48,680	56,059	490,688	16,384	68,950	1,622,624	1,708,026
2013	57,774	928,686	12,379	230,328	742	389,809	48,680	56,059	494,548	16,986	70,896	1,670,549	1,758,472
2014	59,410	967,665	12,743	236,281	742	393,707	48,680	56,059	498,446	17,589	72.895	1.719,981	1,810,507
2015	61,092	1,008,162	13,115	242.244	742	397,644	48,680	56,059	502,383	18,191	74,949	1.770,980	1,864,190
2016	62,713	1,047,762	13,473	248,082	742	401,620	48.680	56,059	506,359	18,793	76,928	1,820,996	1,916,838
2017	64,283	1,086,726	13,819	253,813	742	405,637	48,680	56,059	510,376	19,395	78,844	1,870,310	1,968,747
2018	65,892	1,127,024	14,173	259,550	742	409,693	48,680	56,059	514,432	19,997	80,806	1,921,003	2.022,109
2019	67,541	1,168,701	14,534	265,292	742	413,790	48,680	56.059	518,529	20.600	82.817	1,973,122	2,076,970
2020	69,232	1,211,804	14,903	271,041	742	417,928	48,680	56,059	522.667	21,202	84,877	2,026.714	2,133,384

Note Historical data is complete through calendar year 2000

Table 3-5
2001 High Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand					Outdoor Lighting Sales (MWh)	Total		Net Energy for Load (MWh)
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)		Average Accounts	Sales (MWh)	
1986	19,857	215,331	2,279	30,337	609	182,789	0	0	182,789	838	22,745	429,295	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	0	0	206.688	934	24,452	471,669	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	0	0	235,618	2,508	26,320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	0	0	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	0	0	277,828	1,696	32,956	658,333	698.045
1991	29.014	325,317	5,272	77,954	785	273,275	0	0	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5.912	92,306	744	270,110	0	0	270,110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	0	0	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	0	0	295,446	5,546	40,418	803,676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	0	0	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	0	0	304,918	6,725	43,164	892,014	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	0	0	323,844	7,212	44,088	920,752	970,415
1998	36,573	508,138	7,856	153,422	731	336,475	0	0	336,475	7,796	45,160	1,005,832	1,042,380
1999	38,095	505,037	7,920	151,443	740	342,815	0	0	342,815	8,366	46,755	1,007,662	1,049,523
2000	39,971	536,388	8,098	160,614	756	359,111	0	0	359,111	9,241	48,825	1,065,354	1,116,042
2001	41,088	567,625	8,381	161,400	742	359,111	3.213	14.015	376,338	9,760	50,211	1,115,124	1,173,814
2002	42,191	587,183	8,686	168,023	742	359,111	15,376	25,227	399,713	10,362	51,618	1,165,282	1,226,613
2003	43,345	609,846	8,995	172,454	742	359,111	25,004	36,438	420,553	10,965	53,083	1,213,819	1,277,704
2004	44,543	633,434	9,311	177,574	742	359,111	35,181	47,650	441,942	11,567	54,595	1,264,517	1,331,071

Table 3-5 (Continued)
2001 High Case Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential Service Average Accounts	Residential Service Sales (MWh)	GS Non-Demand Average Accounts	GS Non-Demand Sales (MWh)	GS Demand Average Accounts	GS Demand Base GSD Sales (MWh)	GS Demand WEC Sales (MWh)	GS Demand Spot Load Sales (MWh)	GS Demand Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Total Average Accounts	Total Sales (MWh)	Net Energy for Load (MWh)
2005	45,779	657,912	9,632	182,680	742	359,982	47,604	56,059	463,645	12,169	56,153	1,316,406	1,385,690
2006	47,113	685,900	9,958	188,280	742	363,582	48,680	56,059	468,321	12,771	57,813	1,355,273	1,426.603
2007	48,540	717,234	10,289	194,311	742	367,218	48,680	56,059	471,957	13,373	59,570	1,396,875	1,470,395
2008	50,010	749,886	10,627	200,350	742	370,890	48,680	56,059	475,629	13,975	61,379	1,439,841	1,515,622
2009	51,525	783,907	10,973	206,399	742	374,599	48,680	56,059	479,338	14,578	63,240	1,484,221	1.562,337
2010	53,086	819,352	11,326	212,456	742	378,345	48,680	56,059	483,084	15,180	65,155	1,530,072	1,610,602
2011	54,637	855,055	11,676	218,448	742	382,128	48.680	56,059	486,867	15,782	67,055	1,576,153	1,659,108
2012	56,184	891,167	12,024	224,384	742	385,949	48,680	56,059	490,688	16,384	68,950	1,622,624	1,708,026
2013	57,774	928,686	12,379	230,328	742	389,809	48,680	56,059	494,548	16,986	70,896	1,670,549	1,758,472
2014	59,410	967,665	12,743	236,281	742	393,707	48,680	56,059	498,446	17,589	72,895	1,719,981	1,810,507
2015	61,092	1,008,162	13,115	242,244	742	397,644	48,680	56,059	502,383	18.191	74,949	1,770,980	1,864,190
2016	62,713	1,047,762	13,473	248,082	742	401,620	48,680	56,059	506,359	18,793	76,928	1.820,996	1,916,838
2017	64,283	1,086,726	13,819	253,813	742	405,637	48,680	56,059	510,376	19,395	78.844	1,870,310	1,968,747
2018	65,892	1,127,024	14,173	259,550	742	409,693	48,680	56,059	514,432	19,997	80,806	1,921,003	2,022,109
2019	67,541	1,168,701	14,534	265,292	742	413,790	48,680	56,059	518,529	20,600	82,817	1,973,122	2,076,970
2020	69,232	1,211,804	14,903	271,041	742	417,928	48,680	56,059	522,667	21,202	84,877	2,026,714	2,133,384

Note: Historical data is complete through calendar year 2000.

Table 3-6
2001 Low Case Load Forecast
Annual Summary of Historical and Projected Data

Calendar Year	Residential Service Average Accounts	Residential Service Sales (MWh)	GS Non-Demand Average Accounts	GS Non-Demand Sales (MWh)	GS Demand Average Accounts	GS Demand Base GSD Sales (MWh)	GS Demand WEC Sales (MWh)	GS Demand Spot Load Sales (MWh)	GS Demand Total GSD Sales (MWh)	Outdoor Lighting Sales (MWh)	Total Average Accounts	Total Sales (MWh)	Net Energy for Load (MWh)
1986	19,857	215,331	2,279	30,337	609	182,789	0	0	182,789	838	22,745	429,295	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	0	0	206,688	934	24,452	471,669	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	0	0	235,618	2,508	26,320	528,431	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	0	0	255,167	1,925	29,696	594,997	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	0	0	277,828	1.696	32,956	658,333	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	0	0	273,275	4,686	35,071	681,232	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	0	0	270.110	4,962	36,784	708,720	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	0	0	283,911	5,046	38,553	760,022	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	0	0	295,446	5,546	40,418	803.676	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	0	0	299,255	6,237	42,051	857,503	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	0	0	304,918	6,725	43,164	892,014	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	0	0	323,844	7,212	44,088	920,752	970,415
1998	36,573	508,138	7,856	153,422	731	336,475	0	0	336,475	7,796	45,160	1,005,832	1,042,380
1999	38,095	505,037	7,920	151,443	740	342,815	0	0	342,815	8,366	46,755	1,007,662	1,049,523
2000	39,971	536,388	8,098	160,614	756	359,111	0	0	359,111	9,241	48,825	1,065,354	1,116,042
2001	41,088	567,625	8,381	161,400	742	359,111	3,213	14,015	376,338	9,760	50,211	1,115,124	1,173,814
2002	42,191	587,183	8,686	168,023	742	359,111	15,376	25,227	399,713	10,362	51.618	1,165,282	1,226,613
2003	43,345	609,846	8,995	172,454	742	359.111	25,004	36,438	420,553	10,965	53,083	1,213.819	1,277,704

Table 3-6 (Continued)
2001 Low Case Load Forecast
Annual Summary of Historical and Projected Data

	Residential Service		GS Non-Demand		GS Demand					Outdoor Lighting Sales	Total		Net Energy for Load
Calendar Year	Average Accounts	Sales (MWh)	Average Accounts	Sales (MWh)	Average Accounts	Base GSD Sales (MWh)	WEC Sales (MWh)	Spot Load Sales (MWh)	Total GSD Sales (MWh)	(MWh)	Average Accounts	Sales (MWh)	(MWh)
2004	44,543	633,434	9,311	177,574	742	359,111	35,181	47,650	441,942	11,567	54,595	1,264,517	1,331,071
2005	45,779	657,912	9,632	182,680	742	359,982	47,604	56,059	463,645	12,169	56,153	1,316,406	1,385,690
2006	47,113	685,900	9,958	188,280	742	363,582	48,680	56,059	468,321	12,771	57,813	1,355,273	1,426,603
2007	48,540	717,234	10,289	194,311	742	367,218	48,680	56,059	471,957	13,373	59,570	1,396,875	1,470,395
2008	50,010	749,886	10,627	200,350	742	370,890	48,680	56,059	475,629	13,975	61,379	1,439,841	1,515,622
2009	51,525	783,907	10,973	206,399	742	374,599	48,680	56,059	479,338	14,578	63,240	1,484,221	1,562,337
2010	53,086	819,352	11,326	212,456	742	378,345	48,680	56,059	483,084	15,180	65,155	1,530,072	1,610,602
2011	54,637	855,055	11,676	218,448	742	382,128	48,680	56,059	486,867	15,782	67,055	1,576,153	1,659,108
2012	56,184	891,167	12,024	224,384	742	385,949	48,680	56,059	490,688	16,384	68,950	1,622,624	1,708,026
2013	57,774	928,686	12,379	230,328	742	389,809	48.680	56,059	494,548	16,986	70,896	1,670,549	1,758,472
2014	59,410	967,665	12,743	236,281	742	393,707	48,680	56,059	498,446	17,589	72,895	1,719,981	1,810,507
2015	61,092	1,008,162	13,115	242,244	742	397,644	48,680	56,059	502.383	18,191	74,949	1.770,980	1,864,190
2016	62,713	1,047,762	13,473	248,082	742	401,620	48,680	56,059	506,359	18,793	76,928	1,820,996	1,916,838
2017	64,283	1,086,726	13,819	253,813	742	405,637	48,680	56,059	510,376	19,395	78,844	1,870,310	1,968,747
2018	65,892	1,127,024	14,173	259,550	742	409,693	48,680	56,059	514,432	19,997	80,806	1,921,003	2,022,109
2019	67,541	1,168,701	14,534	265,292	742	413,790	48,680	56,059	518,529	20.600	82,817	1,973,122	2,076,970
2020	69,232	1,211,804	14,903	271,041	742	417,928	48,680	56,059	522,667	21,202	84,877	2,026,714	2,133,384

Note. Historical data is complete through calendar year 2000

It is important to note that the latter methodology for estimating winter and summer peak demands only provides the seasonal peaks. For some of KUA's planning and financial models, monthly peaks are required. In order to accommodate this need, monthly peaks were estimated by shaping the seasonal peak estimates with a reference monthly load pattern. Because the load and energy forecast is a normal weather forecast and 1993 represents the closest to a normal weather year, the 1993 monthly peak load pattern was selected.

Using the projected winter and summer peaks, the remaining monthly peaks are developed by applying the 1993 percent of annual peak factor to the year of concern's annual peak. This calculation is performed for each year of the forecast period.

The forecast of peak load was prepared using average winter and summer load factors of 52 percent and 50 percent, respectively. Previous attempts to model peak load have been unsuccessful due to a lack of data. The estimate of peak load conditions is very dependent on weather and customer equipment. Although relatively reliable temperature data are available, peak load is also sensitive to other variables such as cloud cover, humidity, and barometric pressure.

Table 3-7 presents KUA's winter and summer base-, high-, and low-case peak demand forecasts. A 4.0 percent annual summer peak demand growth rate is projected for 2001 through 2010. This growth rate is lower than KUA's historical annual growth rate of 5.3 percent during the last 10 years.

3.6 High and Low Sensitivities

The high and low sensitivities represent changes in the independent economic variables. The high and low load forecasts sensitivities are driven by the BEBR's high and low population forecasts. The economic forecast provided by BEBR is projected to 2010, and BEBR's long-term population forecast is projected to 2020. The BEBR economic forecast was used through 2010.

In order to develop economic data beyond 2010, the economic data have been adjusted by using their rate of change with respect to population in the Base Case, and maintaining that ratio in the High and Low Cases.

Table 3-7
2001 Load Forecast Annual Summary of Gross Peak Demand

Calendar Year	Winter Peak Base Case (MW)	Winter Peak High Case (MW)	Winter Peak Low Case (MW)	Summer Peak Base Case (MW)	Summer Peak High Case (MW)	Summer Peak Low Case (MW)
1986	128	---	---	101	---	---
1987	110	---	---	115	---	---
1988	131	---	---	121	---	---
1989	148	---	---	141	---	---
1990	200	---	---	151	---	---
1991	147	---	---	157	---	---
1992	158	---	---	169	---	---
1993	158	---	---	183	---	---
1994	173	---	---	180	---	---
1995	196	---	---	195	---	---
1996	218	---	---	206	---	---
1997	198	---	---	216	---	---
1998	180	---	---	233	---	---
1999	219	---	---	236	---	---
2000	221	---	---	250	---	---
2001	257	259	255	267	269	265
2002	273	281	265	283	292	275
2003	288	304	274	299	315	285
2004	302	325	282	313	337	293
2005	313	342	289	325	354	300
2006	325	362	293	337	375	304
2007	334	379	295	347	393	306
2008	344	398	297	357	412	309
2009	355	417	300	368	432	311
2010	365	438	302	379	454	314
2011	376	459	302	390	476	314

Table 3-7 (Continued)
2001 Load Forecast Annual Summary of Gross Peak Demand

Calendar Year	Winter Peak Base Case (MW)	Winter Peak High Case (MW)	Winter Peak Low Case (MW)	Summer Peak Base Case (MW)	Summer Peak High Case (MW)	Summer Peak Low Case (MW)
2012	387	481	301	401	498	313
2013	398	503	300	413	522	312
2014	409	528	299	424	547	310
2015	421	553	298	437	574	309
2016	432	579	296	449	601	307
2017	444	606	292	461	628	304
2018	455	634	289	473	658	300
2019	468	663	286	485	688	297
2020	480	694	284	498	720	294

Note: Historical data is complete through calendar year 2000.

It is important to understand that the BEBR high and low population forecasts do not represent a particular high and low economic scenario. Rather, the high and low forecasts represent a range in which two-thirds of the population estimates are likely to fall. This range is developed by an analysis of error in previous forecast years.

The economic variables affect the residential, general service, and lighting forecasts, but do not affect the general service demand (GSD) classification. The uncertainty of the future competitive environment drives the assumptions for the high and low scenarios of GSD.

In order to simulate the high scenario for GSD, the annual growth in energy sales is assumed to be 2 percent from 2006 onward. In this scenario, a strong economy results in greater growth and relatively little competition. For the low scenario, there is no annual energy sales growth other than spot loads. In this scenario, KUA continues to grow, but overall growth is offset by large consumers leaving KUA's system for a competitor.

4.0 Demand-Side Programs

Kissimmee Utility Authority (KUA) has tested potential demand-side management (DSM) measures for cost-effectiveness. Measures were evaluated using the FPSC approved Florida Integrated Resource Evaluator (FIRE) model. The FIRE model evaluates the economic impact of existing and proposed 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.

4.1 Existing Conservation Programs

KUA is committed to conservation and load management programs and will continue to evaluate both old and new DSM programs on a frequent and regular basis in an attempt to identify cost-effective programs for the electric system that add value for the customers. KUA's energy conservation specialist performs approximately 600 free audits annually, advising customers on the appropriate conservation programs to implement.

KUA's conservation programs were originally established for the City of Kissimmee under the Florida Energy Efficiency and Conservation Act (FEECA) program. KUA is no longer classified as a FEECA utility. The following is a list of conservation programs outlined in KUA's submission to the FPSC when KUA was subject to FEECA:

- Residential energy audit.
- Commercial and industrial energy analysis.
- Fixup program - KUA will assist or arrange to have installed in residences:
  - Electrical outlet gaskets.
  - Solar screen/reflective film.
  - Water heater jackets.
  - Water flow restrictors.
  - Weatherstripping.

  - Caulking.
  - Energy conserving lamps.
  - Duct tape.
  - Pool timers.
  - Clock thermostats.
  - Water heater thermostat set back.
  - Hot water pipe insulation.
  - Water heater timers.
  - Ceiling insulation.
- High-pressure sodium street lighting/private area lighting conversion (from mercury vapor and incandescent).
- Water heater conversion from resistance heating to:
  - Dedicated heat pump water heaters.
  - Natural gas.
  - Solar.
  - Air conditioning/heat pump.
- Elimination of electric strip heating.
- Public awareness programs.
- Natural gas.
- Cogeneration plans.

The following sections discuss the DSM programs KUA now has in place.

4.1.1 Residential Load Management (SAVE)

KUA currently offers a residential direct load control program that has been in place since 1992. This program is called Shifting Adds Value to Energy (SAVE). SAVE is designed to cycle residential air conditions, electric water heaters, and electric space heaters to reduce KUA's system peak demand. The SAVE program was administered to over 4,590 customers as of December 31, 2000. The program is voluntary for all residential customers. For participating in the program, customers receive a monthly credit on their bills. KUA installs load control receivers on eligible equipment, and transmits radio signals to cycle equipment for peak demand reduction. The SAVE program provides a utility controlled process that ensures a direct capacity value to KUA, while minimizing impacts to the customer's lifestyle.

There are no significant reductions in energy consumption from this program. Table 4-1 shows KUA's historical and forecasted estimate of peak demand reductions resulting from this load management program.

Table 4-1
KUA Load Management Impact

Fiscal Year	Average Active Customers	Low Case (MW)	Base Case (MW)	High Case (MW)
1993	1,382	---	3.16	---
1994	4,399	---	8.32	---
1995	6,799	---	11.90	---
1996	7,675	---	12.62	---
1997	7,025	---	11.98	---
1998	6,355	---	12.15	---
1999	5,705	---	12.00	---
2000	5,035	---	11.00	---
2001	---	10.10	10.25	10.40
2002	---	9.10	9.25	9.40
2003	---	8.10	8.25	8.40
2004	---	7.85	8.00	8.15
2005	---	7.85	8.00	8.15
2006	---	7.85	8.00	8.15
2007	---	7.85	8.00	8.15
2008	---	7.85	8.00	8.15
2009	---	7.85	8.00	8.15
2010	---	7.85	8.00	8.15

4.1.1.1 Delivery Strategy. The approach for delivering the program is based on two design components: (i) promoting the program to existing customers through bill inserts and general media; and (ii) granting bill credits for participants based on the number and type of appliances being controlled. A schedule reflecting bill credits is presented in Table 4-2.

Table 4-2
SAVE Program, Load Management Credits

Appliance	Control Period	Monthly Credit	With Water Heater Control
Water Heater	Year Round	$2.50	--
Central Air Conditioning (15 minutes per 1/2 hour)	April-October	$4.50	$7.00
Central heating (15 minutes per 1/2 hour)	November-March	$4.50	$7.00

4.1.1.2 Implementation Activities. Because KUA has operated the program since 1992, current implementation activities focus on ongoing installation and maintenance of load switches, and updating and maintaining tracking systems to monitor participation.

4.1.2 Residential Appliance Efficiency

The Residential Appliance Efficiency Program is designed to encourage the specification and installation of energy efficient appliances such as high efficiency central air conditioners, heat pumps, and pool pumps.

Promotion of these high efficiency residential appliances helps to reduce residential cooling loads, which contribute to KUA's system peak. Additionally, since the useful lifetime estimates of these appliances are relatively long (15 years or greater), this program serves to address "lost opportunities," particularly in the new construction market.

The program is targeted to residential homeowners in the replacement and new construction market. Customers include those who currently have standard air conditioners, heat pumps, and/or pool pumps. When applicable equipment requires replacement, customers become candidates for an upgrade to high efficiency systems.

4.1.3 Commercial Cooling

The Commercial Cooling Program is designed to use customer and trade ally information and education to encourage the specification and installation of energy efficient cooling systems in the commercial markets.

The promotion of these high efficiency commercial systems helps to reduce commercial cooling loads that contribute to KUA's system peak. Additionally, since the useful lifetime estimates of these systems are relatively long (15 years or greater), this program serves to address "lost opportunities," particularly in the new construction market.

Although difficult to estimate, KUA's energy and summer demand are reduced with this program.

4.1.4 Residential Fix Up

This program is designed to make residential dwellings more efficient, focusing on the thermal envelope. This includes the following measures for existing residential buildings:

- Ceiling insulation.
- Duct leak repair (also for new homes).
- Hot water saving measures.

Duct leak repair is recommended for new homes because inspections often reveal installation problems that cause significant inefficiencies. Although difficult to estimate, this program achieves energy savings and some peak reduction in both the summer and winter.

4.2 Analysis of Demand-Side Management Alternatives

KUA 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.8.0. For the residential sector, KUA is already implementing the following three DSM measures that were found to be the most cost-effective based on the Rate Impact Test in FPL's 2000 Demand-Side Management Plan:

- Residential Load Control--Existing Construction.
- Residential Load Control--New Construction.
- Ceiling Insulation R0 - R19--Existing Construction.

Therefore, KUA analyzed the next most cost-effective residential DSM measure in FPL's 2000 Demand-Side Management Plan that is the BuildSmart EPI less than 90 for new construction. The results of that analysis follow along with the analysis of the commercial off-peak battery charging measure.

4.2.1 FIRE Model Output Analysis

KUA 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, KUA has concluded that there are no cost-effective DSM measures available that would avoid or defer the need for Stanton A. Table 4-3 presents the FIRE model results of the DSM analysis.

Table 4-3
FIRE Model Results

Program Description	Rate Impact Test	Participant's Test	Total Resource Cost Test
Residential			
BuildSmart - EPI Less Than 90 - New Construction	0.44	0.71	0.07
Commercial			
Off-Peak Battery Charging	0.37	0.04	0.48

The results of the DSM analysis are not surprising due to the previously performed analyses for similarly situated utilities. The failing cost-effectiveness of DSM has been exhibited in the Need for Power Dockets for KUA and 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 OUC (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.

5.0 Forecast of Facilities Requirements

5.1 Florida Municipal Power Pool

KUA is a member, along with the Orlando Utilities Commission (OUC), City of Lakeland, and the All-Requirements Project of the Florida Municipal Power Agency (FMPA), of the Florida Municipal Power Pool (FMPP). The four utilities operate as one large control area. All FMPP capacity resources, totaling approximately 2,300 MW, are committed and dispatched together from the OUC operations center.

The FMPP does not provide for the sharing of planning reserves among its members. Members are required to provide their own reserves. A member of the FMPP can withdraw from FMPP with 1 year's written notice. Therefore, KUA must ultimately plan on a stand-alone basis.

5.2 Need for Capacity

This section addresses the need for additional electric capacity to serve the needs of KUA's electric customers in the future. The need for capacity is based on KUA's load forecast, reserve margin requirements, existing generating and purchase power capacity, scheduled retirements of generating units, and expiration of purchase power contracts. Based on the results of the capacity balance analysis of KUA's existing resources, KUA is expected to experience a capacity deficit of approximately 7 MW in 2008, growing to approximately 32 MW in 2010. The estimated deficit is based on the base case summer peak demand forecast. Table 5-1 presents the results of the capacity balance analysis.

5.2.1 Load Forecast

KUA's 2001 load forecast, described in Section 3.0, was used to determine the need for capacity. A summary of the load forecast is shown in Table 5-2. The peak demands presented in Table 5-2 do not reflect the demand reductions achieved through KUA's load management program further described in Section 4.0.

Table 5-1
Capacity Balance

Year	Existing/ Committed Generation(1)	Existing/ Committed Purchases(2)	Summer Peak Demand (MW)			DSM Impacts (MW)			Reserve Margin		
			Base	High	Low	Base	High	Low	Base	High	Low
2001	283.7	68.1	267.3	269.1	265.4	10.0	10.2	9.9	36.7%	35.8%	37.7%
2002	283.7	68.1	283.1	291.9	275.2	9.0	9.2	8.9	28.3%	24.4%	32.1%
2003	283.7	68.1	298.9	315.0	284.7	8.0	8.2	7.9	20.9%	14.6%	27.0%
2004	305.4	50.4	313.3	336.8	293.1	8.0	8.2	7.9	16.5%	8.2%	24.7%
2005	305.4	66.4	325.0	354.3	299.7	8.0	8.2	7.9	17.3%	7.4%	27.4%
2006	305.4	81.4	336.8	374.8	304.0	8.0	8.2	7.9	17.6%	5.5%	30.6%
2007	305.4	89.4	346.8	392.8	306.4	8.0	8.2	7.9	16.5%	2.6%	32.2%
2008	305.4	89.4	357.2	412.0	308.8	8.0	8.2	7.9	13.1%	-2.3%	31.2%
2009	305.4	89.4	367.8	432.4	311.2	8.0	8.2	7.9	9.7%	-6.9%	30.2%
2010	305.4	89.4	378.9	454.0	313.5	8.0	8.2	7.9	6.4%	-11.5%	29.1%
2011	305.4	89.4	389.9	476.0	313.9	8.0	8.2	7.9	3.4%	-15.6%	29.0%
2012	305.4	89.4	401.1	498.5	312.7	8.0	8.2	7.9	0.4%	-19.5%	29.5%
2013	305.4	89.4	412.6	522.2	311.6	8.0	8.2	7.9	-2.4%	-23.2%	30.0%
2014	305.4	89.4	424.5	547.3	310.4	8.0	8.2	7.9	-5.2%	-26.8%	30.5%
2015	305.4	89.4	436.7	573.9	309.3	8.0	8.2	7.9	-7.9%	-30.2%	31.0%
2016	305.4	89.4	448.8	600.9	306.9	8.0	8.2	7.9	-10.4%	-33.4%	32.0%
2017	305.4	89.4	460.6	628.5	303.6	8.0	8.2	7.9	-12.8%	-36.4%	33.5%
2018	305.4	89.4	472.8	657.5	300.4	8.0	8.2	7.9	-15.1%	-39.2%	34.9%
2019	305.4	89.4	485.3	688.1	297.3	8.0	8.2	7.9	-17.3%	-41.9%	36.4%
2020	305.4	89.4	498.2	720.4	294.4	8.0	8.2	7.9	-19.5%	-44.6%	37.8%

(1)Includes Cane Island Unit 3 and Stanton A.
(2)Includes Southern PPA.

Table 5-2 Summary of Gross Peak Demands						
	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
Year	Base	High	Low	Base	High	Low
2000	221	---	---	250	---	---
2001	257	259	255	267	269	265
2002	273	281	265	283	292	275
2003	288	304	274	299	315	285
2004	302	325	282	313	337	293
2005	313	342	289	325	354	300
2006	325	362	293	337	375	304
2007	334	379	295	347	393	306
2008	344	398	297	357	412	309
2009	355	417	300	368	432	311
2010	365	438	302	379	454	314
2011	376	459	302	390	476	314
2012	387	481	301	401	498	313
2013	398	503	300	413	522	312
2014	409	528	299	424	547	310
2015	421	553	298	437	574	309
2016	432	579	296	449	601	307
2017	444	606	292	461	628	304
2018	455	634	289	473	658	300
2019	468	663	286	485	688	297
2020	480	694	284	498	720	294

5.2.2 Reserve Requirements

KUA has adopted a 15 percent reserve margin for capacity planning in accordance with FAC 25-6.035. A 15 percent reserve margin is typical for utilities in Florida and throughout the Southeast.

5.2.3 Existing Generating Capacity

KUA's current generating capacity, as outlined in Section 2.0, consists of the Hansel and Cane Island Plants, which provide KUA 131 MW during the summer, increasing to 249 MW in 2001 with the introduction of the third Cane Island unit. In addition, KUA's joint ownership share of capacity installed at the Stanton Energy Center, Crystal River, and Indian River provides 35 MW of capacity during the summer.

5.2.4 Existing Purchases

KUA is a member of the FMPA, a legal entity organized in 1978 and existing under the laws of Florida. During 1983, FMPA acquired an 8.8060 percent (73.9 MW) undivided ownership interest in St. Lucie Unit 2 on behalf of KUA and 15 other members of the FMPA. KUA's entitlement share of this unit, based on a power purchase contract and adjusted for transmission losses, is 6.9 MW. FMPA has also entered into a Reliability Exchange Agreement with FPL under which half of KUA's entitlement share of capacity and energy will be supplied from St. Lucie Unit 1 and half from Unit 2.

In addition to the above resources, KUA purchases electric power and energy from other utilities. KUA has a contract to purchase 20 MW of firm capacity from OUC through December 2003. This contract also provides for supplemental purchases of up to 50 MW if the capacity is available from OUC. KUA has a 1.80725 percent (7.9 MW) entitlement share of Stanton 1 through the FMPA Stanton 1 Project and a 7.6628 percent (33.3 MW) share of Stanton 2 through the FMPA Stanton 2 Project. The Stanton 2 percentage includes recently acquired Homestead and Lake Worth shares totaling 3.8314 percent.

In 2001, units at Hansel Plant will range from 19 to 42 years old. Some units will be approaching the end of their economic life. In spite of the ages of the units at Hansel Plant, KUA will continue to operate Hansel Plant until it has a major failure or until maintenance costs become prohibitive. Over the past several years, units at Hansel Plant have been reliably maintained and even upgraded as necessary. Though the units are not as efficient as newer units, they do generate reliably.

5.3 Fuel Price Forecast and Availability

The fuel forecast presents KUA's analysis of fuel prices and current market projections based on the Standard & Poor's Platt's Fuel Price Service fuel price forecast study, which was completed in January 2001 for KUA. The fuel price forecast includes coal, No. 6 fuel oil, No. 2 fuel oil, nuclear, and natural gas in Table 5-3.

5.4 Description of Generation Capacity Additions

KUA has already begun construction of the Cane Island 3 combined cycle currently scheduled for commercial operation in June 2001. Using the Base Case load forecast, further capacity additions are required by the summer of 2004.

To address this capacity requirement, KUA is currently in the Need for Power process, and has already submitted a Need For Power application for a jointly owned combined cycle unit at the OUC Stanton Energy Center site. This unit will be referred to as Stanton A.

KUA's participation in the Stanton A project will have both an ownership share and power purchase. The ownership share is approximately 22 MW, and the power purchase from Southern-Florida is approximately 41 MW.

Because KUA is committed to Cane Island Unit 3 and Stanton A, the corresponding capacity has been included as part of Total Firm Capacity. Any additional capacity requirements were met with unspecified purchases.

Tables 5-4.1, 5-4.2, and 5-4.3 outline KUA's expansion plan under the Base, High, and Low load forecast scenarios.

Table 5-3
Delivered Fuel Price Forecast--Base Case
($/Mbtu)

Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas[1]
2001	1.38	3.62	5.68	0.58	7.04
2002	1.37	3.44	5.45	0.60	6.16
2003	1.41	3.35	5.39	0.62	5.54
2004	1.42	3.23	5.31	0.63	5.30
2005	1.45	3.18	5.29	0.65	4.59
2006	1.47	3.23	5.40	0.66	3.91
2007	1.51	3.29	5.52	0.68	4.01
2008	1.50	3.34	5.64	0.70	4.13
2009	1.54	3.40	5.76	0.71	4.26
2010	1.57	3.46	5.89	0.73	4.46
2011	1.57	3.52	6.02	0.75	4.59
2012	1.58	3.66	6.23	0.76	4.75
2013	1.59	3.81	6.46	0.78	4.92
2014	1.59	3.95	6.67	0.79	5.07
2015	1.58	4.08	6.87	0.80	5.30
2016	1.58	4.22	7.07	0.81	5.54
2017	1.59	4.36	7.28	0.82	5.73
2018	1.61	4.49	7.49	0.84	5.96
2019	1.63	4.63	7.71	0.85	6.17
2020	1.64	4.78	7.95	0.87	6.43

(1) Commodity only.

Table 5-4.1
Schedule of Capacity Additions--Base Case
(MW)

Year	Total Firm Capacity(1)	Net Peak Demand(2)	Reserves	Capacity Additions	Revised Reserves
2001	351.8	257.3	36.7%	0	36.7%
2002	351.8	274.1	28.3%	0	28.3%
2003	351.8	290.9	20.9%	0	20.9%
2004	355.8	305.3	16.5%	0	16.5%
2005	371.8	317.1	17.3%	0	17.3%
2006	386.8	328.8	17.6%	0	17.6%
2007	394.8	338.8	16.5%	0	16.5%
2008	394.8	349.2	13.1%	7	15.1%
2009	394.8	359.8	9.7%	13	15.3%
2010	394.8	370.9	6.4%	12	15.1%
2011	394.8	381.9	3.4%	13	15.1%
2012	394.8	393.1	0.4%	13	15.2%
2013	394.8	404.6	-2.4%	13	15.1%
2014	394.8	416.5	-5.2%	14	15.2%
2015	394.8	428.8	-7.9%	14	15.2%
2016	394.8	440.8	-10.4%	14	15.2%
2017	394.8	452.6	-12.8%	13	15.1%
2018	394.8	464.8	-15.1%	14	15.1%
2019	394.8	477.3	-17.3%	15	15.2%
2020	394.8	490.2	-19.5%	14	15.0%

(1) Includes Cane Island 3, Stanton A, and Southern PPA.
(2) Peak demand net of Load Management.

Table 5-4.2
Schedule of Capacity Additions--High Case
(MW)

Year	Total Firm Capacity(1)	Net Peak Demand(2)	Reserves	Capacity Additions	Revised Reserves
2001	351.8	259.0	35.8%	0	35.8%
2002	351.8	282.8	24.4%	0	24.4%
2003	351.8	306.9	14.6%	0	15.0%
2004	355.8	328.7	8.2%	23	15.3%
2005	371.8	346.2	7.4%	4	15.2%
2006	386.8	366.6	5.5%	8	15.0%
2007	394.8	384.7	2.6%	13	15.1%
2008	394.8	403.9	-2.3%	22	15.1%
2009	394.8	424.2	-6.9%	24	15.2%
2010	394.8	445.9	-11.5%	24	15.0%
2011	394.8	467.9	-15.6%	26	15.2%
2012	394.8	490.3	-19.5%	26	15.2%
2013	394.8	514.1	-23.2%	27	15.1%
2014	394.8	539.2	-26.8%	29	15.1%
2015	394.8	565.8	-30.2%	30	15.0%
2016	394.8	592.8	-33.4%	31	15.0%
2017	394.8	620.3	-36.4%	32	15.1%
2018	394.8	649.4	-39.2%	33	15.0%
2019	394.8	680.0	-41.9%	36	15.1%
2020	394.8	712.2	-44.6%	37	15.1%

(1) Includes Cane Island 3, Stanton A, and Southern PPA.
(2) Peak demand net of Load Management.

Table 5-4.3 Schedule of Capacity Additions--Low Case (MW)					
Year	Total Firm Capacity(1)	Net Peak Demand(2)	Reserves	Capacity Additions	Revised Reserves
2001	351.8	255..5	37.7%	0	37.7%
2002	351.8	266.4	32.1%	0	32.1%
2003	351.8	276.9	27.0%	0	27.0%
2004	355.8	285.3	24.7%	0	24.7%
2005	371.8	291.8	27.4%	0	27.4%
2006	386.8	296.1	30.6%	0	30.6%
2007	394.8	298.5	32.2%	0	32.2%
2008	394.8	300.9	31.2%	0	31.2%
2009	394.8	303.3	30.2%	0	30.2%
2010	394.8	305.7	29.1%	0	29.1%
2011	394.8	306.1	29.0%	0	29.0%
2012	394.8	304.9	29.5%	0	29.5%
2013	394.8	303.7	30.0%	0	30.0%
2014	394.8	302.6	30.5%	0	30.5%
2015	394.8	301.4	31.0%	0	31.0%
2016	394.8	299.1	32.0%	0	32.0%
2017	394.8	295.8	33.5%	0	33.5%
2018	394.8	292.6	34.9%	0	34.9%
2019	394.8	289.5	36.4%	0	36.4%
2020	394.8	286.5	37.8%	0	37.8%

(1) Includes Cane Island 3.
(2) Peak demand net of Load Management.

Appendix A
Schedules

Schedule 1
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt. Fuel Days Use				Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt		Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Summer MW	Winter MW
Hansel Plant		Osceola County Sec 27/T25S/ R29E											
	8		IC	NG	FO2	PL	TK		02/59	Unknown	3,000	2.0	2.0
	14		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	15		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	16		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1.8	1.8
	17		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1 8	1.8
	18		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	1 8	1.8
	19		IC	FO2	--	TK	--		02/83	Unknown	2,500	2 5	2.5
	20		IC	FO2	--	TK	--		02/83	Unknown	2,500	2.5	2.5
	21		CT	NG	FO2	PL	TK		02/83	Unknown	35,000	35.0	35.0
	22		ST	WH	--	--	--		02/83	Unknown	10,000	10.0	10.0
	23		ST	WH	--	--	--		02/83	Unknown	10,000	10.0	10.0
Plant Total											73,350	61 0	61.0

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Summer MW	Winter MW
Crystal River		Citrus County Sec 33/T17S/ R16E											
	8		N	UR	--	TK	--		03/77	Unknown	890,460	5.6[1]	5.6[1]
Plant Total											890,460	5.6	5.6

(1) KUA's 0.6754 percent portion of joint ownership.

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max. Nameplate kW	Summer MW	Winter MW
Stanton Energy Center		Orange County Sec 13, 14, 23, 24/R31E/T23S and Sec 18, 19/T23S/R32E											
	1		ST	BIT	--	RR	--		07/87	Unknown	464,580	21.0(2)	21.0(2)
Plant Total											464.580	21.0	21.0

(2) KUA's 4 8193 percent ownership portion

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability	
Plant Name	Unit No	Location	Unit Type	Pri	Alt	Pri	Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Summer MW	Winter MW
Indian River		Brevard County Sec. 12/T23S/ R35E											
	A		CT	NG	FO2	PL	TK		07/89	Unknown	41,400	4.0[3]	4.0[3]
	B		CT	NG	FO2-	PL	TK		07/89	Unknown	41,400	4.0[3]	4.0[3]
Plant Total											890.460	8 0	8.0

(3) KUA's 12.2 percent portion of joint ownership.

Schedule 1 (Continued)
Existing Generating Facilities
As of December 31, 2000

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport		Alt.				Net Capability	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen Max Nameplate kW	Summer MW	Winter MW
Cane Island		Osceola County Sec. 29, 32/ R28E/T25S											
	1		CT	NG	FO2	PL	TK		11/94	Unknown	42,000	15.2(1)	20.3(4)
	2		CT	NG	FO2	PL	TK		06/95	Unknown	80,000	34.4(1)	40.2(4)
	2		ST	WH	--	--	--		06/95	Unknown	40,000	20.0(1)	20.0(4)
Plant Total											162,000	69.6	80.5

(4) KUA's 50 percent ownership portion.

Schedule 2.1
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential				Commercial		
Year	Population	Members per Household	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr
1990	67453	2.083	323	28,002	11,550	333	4,954	67,262
1991	71889	2.88	325	29,014	11,212	351	6,056	57,993
1992	75515	2.916	341	30,128	11,330	362	6,656	54,454
1993	73342	2.954	369	31,553	11,684	386	7,000	55,187
1994	83615	3.002	387	32,699	11,831	411	7,719	53,280
1995			425	34,053	12,494	426	7,997	53,244
1996			447	35,015	12,771	438	8,149	53,763
1997			448	35,603	12,591	465	8,485	54,834
1998			508	36,573	13,894	490	8,587	57,051
1999			505	38,095	13,257	494	8,660	57,073
2000			536	39,971	13,419	520	8,854	58,699
2001			568	41,088	13,815	538	9,123	58,943
2002			587	42,191	13,917	568	9,428	60,220
2003			610	43,345	14,069	593	9,737	60,901
2004			633	44,543	14,221	620	10,053	61,628
2005			658	45,779	14,371	646	10,374	62,304
2006			686	47,113	14,559	657	10,700	61,367

Schedule 2.1 (Continued)
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential				Commercial		
Year	Population	Members per Household	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr
2007			717	48,540	14,776	666	11,031	60,401
2008			750	50,010	14,995	676	11,369	59,459
2009			784	51,525	15,214	686	11,715	58,536
2010			819	53,086	15,434	696	12,068	57,633
2011			855	54,637	15,650	705	12,418	56,796
2012			891	56,184	15,862	715	12,766	56,014
2013			929	57,774	16,074	725	13,121	55,245
2014			968	59,410	16,288	735	13,485	54,485
2015			1,008	61,092	16,502	745	13,857	53,736
2016			1,048	62,713	16,707	754	14,215	53,073
2017			1,087	64,283	16,905	764	14,561	52,481
2018			1,127	65,892	17,104	774	14,915	51,894
2019			1,169	67,541	17,303	784	15,276	51,312
2020			1,212	69,232	17,503	794	15,645	50,733

Note: Historical data is complete through calendar year 2000.

Schedule 2.2
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1990	--	--	--	--	2	--	658
1991	--	--	--	--	5	--	681
1992	--	--	--	--	5	--	709
1993	--	--	--	--	5	--	760
1994	--	--	--	--	6	--	804
1995	--	--	--	--	6	--	858
1996	--	--	--	--	7	--	892
1997	--	--	--	--	7	--	921
1998	--	--	--	--	8	--	1,006
1999	--	--	--	--	8	--	1,008
2000	--	--	--	--	9	--	1,065
2001	--	--	--	--	10	--	1,115
2002	--	--	--	--	10	--	1,165
2003	--	--	--	--	11	--	1,214
2004	--	--	--	--	12	--	1,265
2005	--	--	--	--	12	--	1,316

Schedule 2.2 (Continued)
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWh	Avg. No. of Customers	Avg. kWh per Customer/Yr	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
2006	--	--	--	--	13	--	1,355
2007	--	--	--	--	13	--	1,397
2008	--	--	--	--	14	--	1,440
2009	--	--	--	--	15	--	1,484
2010	--	--	--	--	15	--	1,530
2011	--	--	--	--	16	--	1,576
2012	--	--	--	--	16	--	1,623
2013	--	--	--	--	17	--	1,671
2014	--	--	--	--	18	--	1,720
2015	--	--	--	--	18	--	1,771
2016	--	--	--	--	19	--	1,821
2017	--	--	--	--	19	--	1,870
2018	--	--	--	--	20	--	1,921
2019	--	--	--	--	21	--	1,973
2020	--	--	--	--	21	--	2,027

Note: Historical data is complete through calendar year 2000.

Schedule 2.3
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Avg. No. of Other Customers	(6) Total Avg. No. of Customers
1990	0	40	698	0	32,956
1991	0	40	721	0	35,071
1992	8	36	745	0	36,784
1993	0	41	801	0	38,553
1994	0	37	841	0	40,418
1995	0	58	915	0	42,051
1996	0	51	943	0	43,164
1997	0	50	970	0	44,088
1998	0	37	1,042	0	45,160
1999	0	42	1,050	0	46,755
2000	0	51	1,116	0	48,825
2001	0	59	1,174	0	50,211
2002	0	61	1,227	0	51,618
2003	0	64	1,278	0	53,083
2004	0	67	1,331	0	54,595
2005	0	69	1,386	0	56,153

Schedule 2.3 (Continued)
Historical and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Avg. No. of Other Customers	(6) Total Avg. No. of Customers
2006	0	71	1,427	0	57,813
2007	0	74	1,470	0	59,570
2008	0	76	1,516	0	61,379
2009	0	78	1,562	0	63,240
2010	0	81	1,611	0	65,155
2011	0	83	1,659	0	67,055
2012	0	85	1,708	0	68,950
2013	0	88	1,758	0	70,896
2014	0	91	1,811	0	72,895
2015	0	93	1,864	0	74,949
2016	0	96	1,917	0	76,928
2017	0	98	1,969	0	78,844
2018	0	101	2,022	0	80,806
2019	0	104	2,077	0	82,817
2020	0	107	2,133	0	84,877

Note: Historical data is complete through calendar year 2000.

Schedule 3.1
Historical and Forecast of Summer Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
1990	151	0	151	0	0	0	0	0	151
1991	157	0	157	0	0	0	0	0	157
1992	169	0	169	0	0	0	0	0	169
1993	183	0	183	0	3	0	0	0	180
1994	180	0	180	0	8	0	0	0	172
1995	195	0	195	0	12	0	0	0	183
1996	206	0	206	0	13	0	0	0	193
1997	216	0	216	0	12	0	0	0	204
1998	233	0	233	0	12	0	0	0	221
1999	236	0	236	0	12	0	0	0	224
2000	250	0	250	0	11	0	0	0	239
2001	267	0	267	0	10	0	0	0	257
2002	283	0	283	0	9	0	0	0	274
2003	299	0	299	0	8	0	0	0	291
2004	313	0	313	0	8	0	0	0	305
2005	325	0	325	0	8	0	0	0	317
2006	337	0	337	0	8	0	0	0	329

Schedule 3.1 (Continued)
Historical and Forecast of Summer Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
2007	347	0	347	0	8	0	0	0	339
2008	357	0	357	0	8	0	0	0	349
2009	368	0	368	0	8	0	0	0	360
2010	379	0	379	0	8	0	0	0	371
2011	390	0	390	0	8	0	0	0	382
2012	401	0	401	0	8	0	0	0	393
2013	413	0	413	0	8	0	0	0	405
2014	424	0	424	0	8	0	0	0	416
2015	437	0	437	0	8	0	0	0	429
2016	449	0	449	0	8	0	0	0	441
2017	461	0	461	0	8	0	0	0	453
2018	473	0	473	0	8	0	0	0	465
2019	485	0	485	0	8	0	0	0	477
2020	498	0	498	0	8	0	0	0	490

Note: Historical data is complete through calendar year 2000.

Schedule 3.2
Historical and Forecast of Winter Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
1990	200	0	200	0	0	0	0	0	200
1991	147	0	147	0	0	0	0	0	147
1992	158	0	158	0	0	0	0	0	158
1993	158	0	158	0	3	0	0	0	155
1994	173	0	173	0	8	0	0	0	165
1995	196	0	196	0	12	0	0	0	184
1996	218	0	218	0	13	0	0	0	205
1997	198	0	198	0	12	0	0	0	186
1998	180	0	180	0	12	0	0	0	168
1999	219	0	219	0	12	0	0	0	207
2000	221	0	221	0	11	0	0	0	210
2001	257	0	257	0	10	0	0	0	247
2002	273	0	273	0	9	0	0	0	264
2003	288	0	288	0	8	0	0	0	280
2004	302	0	302	0	8	0	0	0	294
2005	313	0	313	0	8	0	0	0	305
2006	325	0	325	0	8	0	0	0	317

Schedule 3.2 (Continued)
Historical and Forecast of Winter Peak Demand
Base Case - MW

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Commercial/ Industrial Load Management	(9) Commercial/ Industrial Conservation	(10) Net Firm Demand
2007	334	0	334	0	8	0	0	0	326
2008	344	0	344	0	8	0	0	0	336
2009	355	0	355	0	8	0	0	0	347
2010	365	0	365	0	8	0	0	0	357
2011	376	0	376	0	8	0	0	0	368
2012	387	0	387	0	8	0	0	0	379
2013	398	0	398	0	8	0	0	0	390
2014	409	0	409	0	8	0	0	0	401
2015	421	0	421	0	8	0	0	0	413
2016	432	0	432	0	8	0	0	0	424
2017	444	0	444	0	8	0	0	0	436
2018	455	0	455	0	8	0	0	0	447
2019	468	0	468	0	8	0	0	0	460
2020	480	0	480	0	8	0	0	0	472

Note: Historical data is complete through calendar year 2000.

Schedule 3.3
Historical and Forecast of Annual Net Energy for Load
Base Case - GWh

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use and Losses	(8) Net Energy for Load	(9) Load Factor (%)
1990	658	0	0	658	0	40	698	39.8%
1991	681	0	0	681	0	40	721	52.4%
1992	709	0	0	709	0	36	745	50.3%
1993	760	0	0	760	0	41	801	50.0%
1994	804	0	0	804	0	37	841	53.3%
1995	858	0	0	858	0	58	915	53.3%
1996	892	0	0	892	0	51	943	49.4%
1997	921	0	0	921	0	50	970	51.3%
1998	1,006	0	0	1,006	0	37	1,042	51.1%
1999	1,008	0	0	1,008	0	42	1,050	50.8%
2000	1,065	0	0	1,065	0	51	1,116	51.0%
2001	1,115	0	0	1,115	0	59	1,174	50.1%
2002	1,165	0	0	1,165	0	61	1,227	49.5%
2003	1,214	0	0	1,214	0	64	1,278	48.8%
2004	1,265	0	0	1,265	0	67	1,331	48.5%
2005	1,316	0	0	1,316	0	69	1,386	48.7%
2006	1,355	0	0	1,355	0	71	1,427	48.3%

Schedule 3.3 (Continued)
Historical and Forecast of Annual Net Energy for Load
Base Case - GWh

(1) Year	(2) Total	(3) Residential Conservation	(4) Commercial/ Industrial Conservation	(5) Retail	(6) Wholesale	(7) Utility Use and Losses	(8) Net Energy for Load	(9) Load Factor (%)
2007	1,397	0	0	1,397	0	74	1,470	48.4%
2008	1,440	0	0	1,440	0	76	1,516	48.4%
2009	1,484	0	0	1,484	0	78	1,562	48.5%
2010	1,530	0	0	1,530	0	81	1,611	48.5%
2011	1,576	0	0	1,576	0	83	1,659	48.6%
2012	1,623	0	0	1,623	0	85	1,708	48.6%
2013	1,671	0	0	1,671	0	88	1,758	48.7%
2014	1,720	0	0	1,720	0	91	1,811	48.7%
2015	1,771	0	0	1,771	0	93	1,864	48.7%
2016	1,821	0	0	1,821	0	96	1,917	48.8%
2017	1,870	0	0	1,870	0	98	1,969	48.8%
2018	1,921	0	0	1,921	0	101	2,022	48.8%
2019	1,973	0	0	1,973	0	104	2,077	48.9%
2020	2,027	0	0	2,027	0	107	2,133	48.9%

Note: Historical data is complete through calendar year 2000.

Schedule 4
Previous Year and 2 Year Forecast of Retail Peak Demand and
Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2000		2001		2002	
Year	Peak Demand MW	NEL GWh	Peak Demand MW	NEL GWh	Peak Demand MW	NEL GWh
January	221	80	257	84	273	88
February	184	74	200	85	212	89
March	169	78	231	82	244	86
April	170	81	164	83	173	87
May	230	104	196	89	207	93
June	238	109	247	109	261	114
July	250	115	264	116	280	121
August	238	118	267	120	283	125
September	234	109	251	119	266	124
October	169	74	221	109	234	114
November	214	83	181	92	192	96
December	244	91	253	85	268	89

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements		Units	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Nuclear		Gbtu	501	388	425	425	425	425	425	425	425	424	425
(2)	Coal		1,000 Ton	54	53	54	57	57	57	57	57	58	58	58
	Residual													
(3)		Steam	1,000 BBL											
(4)		CC	1,000 BBL											
(5)		CT	1,000 BBL											
(6)		Total	1,000 BBL											
	Distillate													
(7)		Steam	1,000 BBL											
(8)		CC	1,000 BBL											
(9)		CT	1,000 BBL	1	5	6	3	1	0	0	0	0	0	0
(10)		Total	1,000 BBL	1	5	6	3	1	0	0	0	0	0	0
	Natural Gas													
(11)		Steam	1,000 MCF											
(12)		CC	1,000 MCF	3,624	2,097	2,695	2,616	2,526	2,650	2,873	3,122	3,097	3,187	3,257
(13)		CT	1,000 MCF	196	68	25	27	22	24	19	29	23	19	22
(14)		Total	1,000 MCF	3,820	2,165	2,720	2,643	2,548	2,674	2,892	3,151	3,120	3,206	3,279
(15)	Other (Specify)		GBtu											

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Inter-region Interchange		GWH											
(2)	Nuclear		GWH	48	37	40	40	40	40	40	40	40	40	40
(3)	Coal		GWH	152	140	142	152	152	152	152	152	153	154	153
	Residual													
(4)		Steam	GWH											
(5)		CC	GWH											
(6)		CT	GWH											
(7)		Total:	GWH	0	0	0	0	0	0	0	0	0	0	0
	Distillate													
(8)		Steam	GWH											
(9)		CC	GWH											
(10)		CT	GWH	0	2	3	1	0	0	0	0	0	0	0
(11)		Total:	GWH	0	2	3	1	0	0	0	0	0	0	0

Schedule 6.1 (Continued)
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	Natural Gas													
(12)		Steam	GWH											
(13)		CC	GWH	405	252	355	340	316	334	366	400	403	417	434
(14)		CT	GWH	22	8	3	4	3	3	2	4	3	2	3
(15)		Total:	GWH	427	260	358	344	319	337	368	403	406	420	437
(16)	NUG		GWH											
(17)	Hydro		GWH											
(18)	Other (Specify)	Net Interchange	GWH	489	731	680	737	816	854	863	871	913	945	978
(19)	Net Energy for Load		GWH	1,116	1,171	1,224	1,275	1,328	1,383	1,424	1,467	1,513	1,559	1,608

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Actual										
	Energy Sources		Units	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
(1)	Annual Firm Inter-Region Interchange		%											
(2)	Nuclear		%	4%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%
(3)	Coal		%	14%	12%	12%	12%	11%	11%	11%	10%	10%	10%	10%
	Residual													
(4)		Steam	%											
(5)		CC	%											
(6)		CT	%											
(7)		Total:	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Distillate													
(8)		Steam	%											
(9)		CC	%											
(10)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		Total:	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Schedule 6.2 (Continued)
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Energy Sources		Units	Actual 2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
	Natural Gas													
(12)		Steam	%											
(13)		CC	%	36%	22%	29%	27%	24%	24%	26%	27%	27%	27%	27%
(14)		CT	%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(15)		Total:	%	38%	22%	29%	27%	24%	24%	26%	27%	27%	27%	27%
(16)	NUG		%											
(17)	Hydro		%											
(18)	Other (Specify)	Net Interchange	%	44%	62%	56%	58%	61%	62%	61%	59%	60%	61%	61%
(19)	Net Energy for Load		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance
at the Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	Qualifying Facilities	Total Available Capacity	System Firm Net Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin Before Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2000	165	108	0	0	274	239	35	14	0	0	0
2001	284	68	0	0	352	257	94	37	0	0	0
2002	284	68	0	0	352	274	78	28	0	0	0
2003	284	68	0	0	352	291	61	21	0	0	0
2004	305	50	0	0	356	305	50	17	0	0	0
2005	305	66	0	0	372	317	55	17	0	0	0
2006	305	81	0	0	387	329	58	18	0	0	0
2007	305	89	0	0	395	339	56	17	0	0	0
2008	312	89	0	0	402	349	53	15	0	0	0
2009	325	89	0	0	415	360	55	15	0	0	0
2010	337	89	0	0	427	371	56	15	0	0	0

Note: Calendar year 2000 is historical data.

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at the Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	Qualifying Facilities	Total Available Capacity	System Firm Net Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin Before Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2000	176	108	0	0	284	210	74	35	0	0	0
2001	176	118	0	0	294	247	47	19	0	0	0
2002	295	68	0	0	363	264	99	38	0	0	0
2003	295	68	0	0	363	280	83	30	0	0	0
2004	316	50	0	0	367	294	73	25	0	0	0
2005	316	66	0	0	383	305	77	25	0	0	0
2006	316	81	0	0	398	317	81	26	0	0	0
2007	316	89	0	0	406	326	79	24	0	0	0
2008	323	89	0	0	413	336	76	23	0	0	0
2009	336	89	0	0	426	347	79	23	0	0	0
2010	348	89	0	0	438	357	81	23	0	0	0

Note: Calendar year 2000 is historical data.

Schedule 8.1
Planned and Prospective Generating Facility Additions and Changes

Plant Name	Unit No.	Location (County)	Unit Type	Fuel Pri	Alt	Fuel Transportation Pri	Alt	Construction Start Mo/YYYY	C.O.D. Mo/YYYY	Expected Retirement Mo/YY/YY	Gross Capability Sum MW	Win MW	Net Capability Sum MW	Win MW	Status
Stanton EnergyCenter	A	Orange	CC	NG	DFO	PL	TK	10/2001	10/2003	10/2033	21 34	23.15	20 81	22.65	L

Schedule 8.2
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Const. Start Mo/Yr	Commercial In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen. Max. Nameplate KW	Summer MW	Winter MW	Status
Cane Island		Osceola County Sec 29, 32/R28E / T25S												
	3		CT	NG	FO	PL	TK	08/99	06/01	Unknown				
	3		ST	WH	2 C	C	C	08/99	06/01	Unknown				

Schedule 9.1
Status Report and Specifications of Proposed Generating Facilities

		Stanton Energy Center Combined Cycle Unit A
(1)	Plant Name and Unit Number	
(2)	Capacity	
	a. Summer	20.81
	b. Winter	22.65
(3)	Technology Type	Combined Cycle
(4)	Anticipated Construction Timing	
	a. Field construction start date	10/2001
	b. Commercial in-service date	10/2003
(5)	Fuel	
	a. Primary fuel	NG
	b. Alternate fuel	DFO
(6)	Air Pollution Control Strategy	Dry Low NO_x Combustors
(7)	Cooling Method	Mechanical Draft
(8)	Total Site Area	
(9)	Construction Status	Planned
(10)	Certification Status	In Progress
(11)	Status with Federal Agencies	
(12)	Projected Unit Performance Data	
	a. Planned Outage Factor (POF)	Confidential
	b. Forced Outage Factor (FOF)	Confidential
	c. Equivalent Availability Factor (EAF)	Confidential

Schedule 9.1 (Continued)
Status Report and Specifications of Proposed Generating Facilities

		Stanton Energy Center Combined Cycle Unit A
	d. Resulting Capacity Factor	Confidential
	e. Average Net Operating Heat Rate	Confidential
(13)	Projected Unit Financial Data	
	a. Book Life (Years)	Confidential
	b. Total Installed Cost (In-service year $/kW)	Confidential
	c. Direct Construction Cost ($/kW)	Confidential
	d. AFUDC Amount ($/kW)	Confidential
	e. Escalation ($/kW)	Confidential
	f. Fixed O&M ($/kW-Yr)	Confidential
	g. Variable O&M ($/MWh)	Confidential

Schedule 9.2
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number	Cane Island 3
(2)	Capacity	
	a. Summer:	243.7 MW
	b. Winter:	267 MW
(3)	Technology Type:	1 x 1 F-Class Combined-Cycle
(4)	Anticipated Construction Timing	
	a. Field construction start-date:	10/99
	b. Commercial in-service date:	06/01
(5)	Fuel	
	a. Primary fuel:	Natural Gas
	b. Alternate fuel:	No. 2 Oil
(6)	Air Pollution Control Strategy:	Dry Low NO_x Combustors
(7)	Cooling Method:	Mechanical Cooling Towers
(8)	Total Site Area:	1,023 Acres
(9)	Construction Status:	On Schedule
(10)	Certification Status:	Currently preparing Title 5 Operating Permit Application
(11)	Status with Federal Agencies:	No outstanding issues

Schedule 9.2 (Continued)
Status Report and Specifications of Proposed Generating Facilities

(12)	Projected Unit Performance Data	
	Planned Outage Factor (POF):	4.3%
	Forced Outage Factor (FOF):	4.1%
	Equivalent Availability Factor (EAF):	91.8%
	Resulting Capacity Factor (%):	91.8%
	Average Net Operating Heat Rate (ANOHR):	6,815 Btu/kWh
(13)	Projected Unit Financial Data	
	Book Life (Years):	30
	Total installed Cost (In-Service year $/kW):	543
	Direct Construction Cost ($/kW):	507
	AFUDC Amount ($/kW):	13
	Escalation ($/kW):	C
	Fixed O&M ($/kW-yr):	3.
	Variable O&M ($/MWh):	2.82
	K Factor:	NA

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	Cane Island/Intercession City
(2)	Number of Lines:	One
(3)	Right-of-Way:	N/A
(4)	Line Length:	3.5 Miles
(5)	Voltage:	230 kV
(6)	Anticipated Construction Timing:	Completed by June 2001
(7)	Anticipated Capital Investment:	N/A
(8)	Substations:	KUA's Cane Island/FPC's Intercession City
(9)	Participation with Other Utilities:	FMPA