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March 31, 2000

Florida Public Service Commission
Division of Records and Reporting
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Attention: Ms. Blanca S. Bayo
Director

Subject: KUA 2000 Ten Year Site Plan

Dear Ms. Bayo:

Enclosed are 25 copies of Kissimmee Utility Authority's 2000 Ten Year Site Plan in accordance with 25-22.07 Florida Administrative Code.

Very truly yours,

BLACK & VEATCH

Myron Rollins

Myron Rollins

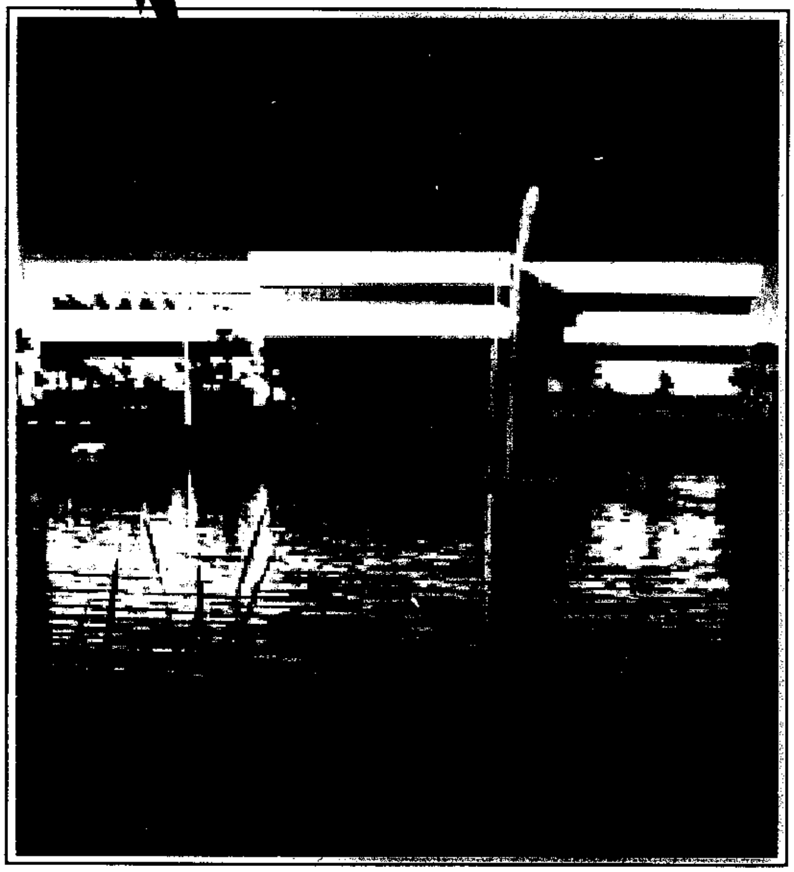
MRR:slm
Enclosure[s]
KUA 2000 Ten Year Site Plan (25 copies)

cc: Ben Sharma

AFA
APP
CAF
CMU
~~CTR~~
EAG
LEG
MAS
OPC
RRR
SEC
WAW
OTH

2000 10-Year Site Plan

KUA
KISSIMMEE
UTILITY
AUTHORITY



April 2000

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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 288 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 4.6 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 5.1 percent during the last 10 years.

Net energy for load is projected to grow at an average annual rate of 4.3 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 Conservation and Demand-Side Management

Section 4.0 provides descriptions of KUA's existing conservation and demand-side management (DSM) programs and additional programs that have been evaluated. Over 80 DSM measures were analyzed based on the generic Central Florida Technology Database using the

Comprehensive Market Planning and Analysis System (COMPASS) model. With the exception of direct load control, the cost-effectiveness of the evaluated alternatives was determined to be marginal.

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 (2000-2019).

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 twenty years.

Initially, Kissimmee Light Co. agreed to supply consumers electricity at a cost of 3¢ 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 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 its importance when Kissimmee and St. Cloud intertied 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 & General Manager, replaced Don Hornak as Utility Director. As KUA settled in with a new Director, many accomplishments were realized: KUA became owners 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 reentry 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 6-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, off-site 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 1999 was 236 MW.

KUA's historical and projected peak demands, for the period 1990 through 2019, 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.

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	243	250	237	252	260	246
2001	254	266	237	277	315	246
2002	272	293	243	282	304	253
2003	290	321	250	301	333	260
2004	307	345	257	319	358	267
2005	321	367	261	333	380	271
2006	334	389	264	346	403	274
2007	344	407	264	356	422	275
2008	354	427	265	367	443	275
2009	364	447	266	378	464	276
2010	375	469	266	389	486	277
2011	386	491	266	400	509	276

Table 2-1
Summary of Load Forecast

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
2012	397	513	265	412	532	275
2013	408	537	264	423	557	274
2014	419	562	262	435	583	272
2015	431	588	261	448	610	271
2016	443	614	259	460	637	268
2017	455	641	256	472	665	265
2018	467	669	253	485	694	262
2019	480	699	250	498	725	259

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. This plant consists of a 35 MW (nameplate) combustion turbine which provides waste heat for two 10 MW (nameplate) steam turbine generators. 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 has also 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), of OUC's Indian River Combustion Turbine Project Units A and B.

Table 2-2
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
Hansel	8	Osceola County 27,T255/R29E	IC	NG	FO2	02/59	Unknown	3.00	3	3	PL	TK
	14		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	15		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	16		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	17		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	18		IC	NG	FO2	02/72	Unknown	2.07	2	2	PL	TK
	19		IC	FO2	---	02/83	Unknown	2.50	3	3	TK	---
	20		IC	FO2	---	02/83	Unknown	2.50	3	3	TK	---
	21		CT	NG	FO2	02/83	Unknown	35.00	28	32	PL	TK
	22		ST	WH	---	02/83	Unknown	10.00	10	10	---	---
	23		ST	WH	---	02/83	Unknown	10.00	10	10	---	---
Plant Total								73.35	67	71		
Crystal River	3	Citrus County 33,T17S/R16E	N	UR	---	03/77	Unknown	890.46	6^(1)	6^(1)	TK	---
Plant Total								890.46	6	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^(2)	21^(2)	RR	---
Plant Total								464.58	21	21		
Indian River	A	Brevard County 12/T23S/R35E	CT	NG	FO2	07/89	Unknown	41.40	4.5^(3)	5.5^(3)	PL	TK
	B		CT	NG	FO2	07/89	Unknown	41.40	4.5^(3)	5.5^(3)	PL	TK

Table 2-2
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
Plant Total								82.80	9	11		
Cane Island	1	Osceola County	CT	NG	FO2	11/94	Unknown	42.00	15(4)	20(4)	PL	TK
	2	29,32/R28E	CT	NG	FO2	06/95	Unknown	80.00	34(4)	40(4)	PL	TK
	2	/T25S	ST	WH	---	06/95	Unknown	40.00	20(4)	20(4)	---	---
Plant Total								162	69	80		
System Total as of January 1, 2000									172	189		

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.

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 No. 1 and half from Unit No. 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 also has a contract with OUC to purchase up to 40 MW from the Stanton 2 plant. The contract ends in December 2000. 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. 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 which 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.

Table 2-3
KUA's Purchase Power [1]

CY	Utility/Unit (MW)					Annual Total
	St. Lucie 1 & 2	Stanton 1[2]	Stanton 2[3]	OUC[4]	Unspecified Purchases [5]	
2000	6.9	7.9	33.3	60	0	108.1
2001	6.9	7.9	33.3	20	30	98.1
2002	6.9	7.9	33.3	20	0	68.1
2003	6.9	7.9	33.3	20	0	68.1
2004	6.9	7.9	33.3	0	0	48.1
2005	6.9	7.9	33.3	0	0	48.1
2006	6.9	7.9	33.3	0	0	48.1
2007	6.9	7.9	33.3	0	0	48.1
2008	6.9	7.9	33.3	0	0	48.1
2009	6.9	7.9	33.3	0	0	48.1
2010	6.9	7.9	33.3	0	0	48.1
2011	6.9	7.9	33.3	0	0	48.1
2012	6.9	7.9	33.3	0	0	48.1
2013	6.9	7.9	33.3	0	0	48.1
2014	6.9	7.9	33.3	0	0	48.1
2015	6.9	7.9	33.3	0	0	48.1
2016	6.9	7.9	33.3	0	0	48.1
2017	6.9	7.9	33.3	0	0	48.1
2018	6.9	7.9	33.3	0	0	48.1
2019	6.9	7.9	33.3	0	0	48.1

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 sum of recently acquired Homestead and Lake Worth purchase percentages equal to 3.8314 percent.
(4) 20 MW Schedule D and 40 MW short-term purchase in 2000.
(5) 30 MW firm purchase for first half of 2001, contingent on convention center load.

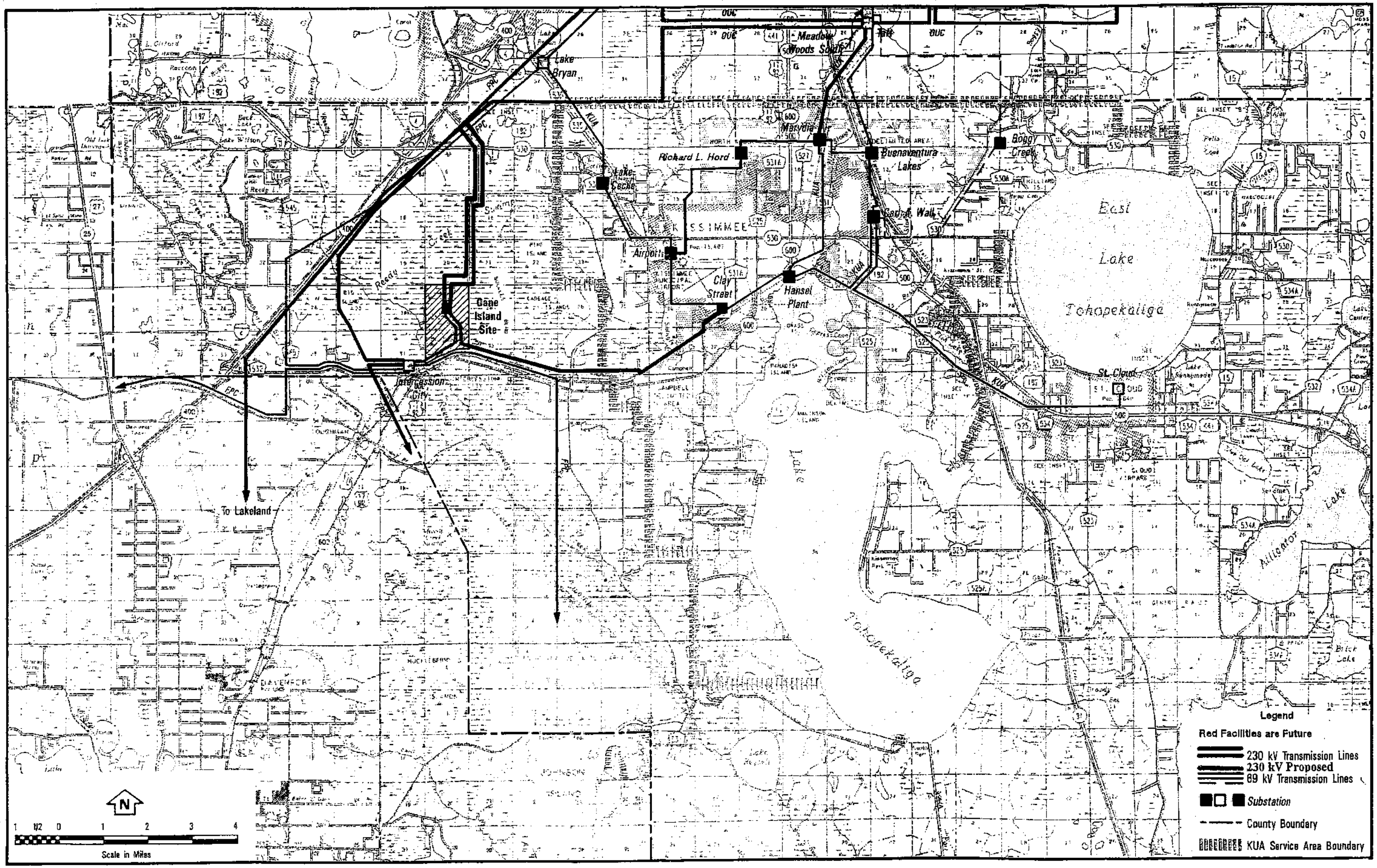

Figure 2-1
Service Area Map

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 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. Additional statistics and data can be found in Appendix B.

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:

$$Y = a + \sum_{i-1}^{n} [b_i * X_i] + e$$

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 1999. 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 fifteen years, employment will grow at an average annual rate of 2.2 percent, down from 3.5 percent from 1980 through 1995. Real personal income is estimated to grow at an average annual rate of 3.0 percent, down from 4.1 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.

Due to publication delays, KUA was forced to use 1998's Long-Term Economic Forecast for economic data. However, the 1999 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 2000 sales forecast is the inclusion of estimated annual rate increases of scheduled for implementation beginning in October 1999. Currently, rate increases are scheduled as follows:

Effective Date	Average Across-the-Board Rate Increase
10/1999	1.6500%
10/2000	1.6505%
10/2001	1.6508%

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 yielded total annual residential electricity sales.

3.4.1.1 Residential Customers

In the development of the 1999 econometric model for residential customers, Osceola County population (POPA) estimates were used as a potential explanatory variable. Based on KUA's statistical evaluation, POPA outperformed Osceola County total housing starts (TS) in representing the fluctuations in residential customers. Autoregressive (AR) factors were introduced to minimize the effects of serial correlation. In effect, the AR 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**. Detailed statistical results for the equation are listed in Appendix B.

3.4.1.2 Residential Energy Use Per Customer

Residential electricity use per customer was based on the relationship between historical income per household, the previous year's real price of electricity and weather impacts.

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 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 became 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 a number of customers and energy sales and includes temporary service and KUA rate classifications.

3.4.2.1 General Service Non-Demand Customers

Osceola County population was used as the basis for forecasting the number of general service non-demand customers. The resulting equation and statistics developed to forecast the number of general service non-demand customers are shown in Table 3-1.

Table 3-1
Sales Forecast Equations and Statistics

Equation	Statistics
RSCUSTT = 246.750*POPA + 0.487*_AUTO[-1] + 0.441*AUTO[-2] RSCUSTT :Total Residential Customers POPA :Total Population in Osceola County _AUTO[-1] :First Order Auto-Regressive Term _AUTO[-2] :Second Order Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9982 Durbin-Watson: 2.0970 Bayesian Information Criterion: 270
RSUPC = - 8.562*PRICERES[-12] + 21.805*INCPERHH + 1.367*BM_CDD + 2.295*BM_HDD + 0.534*BM_CDD[-1] + 0.806*BM_HDD[-1] + 0.431*_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 Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9201 Durbin-Watson: 2.078 Bayesian Information Criterion: 68.19
GSNCUSTT= 146.836*POPA + 0.994*_AUTO[-1] GSNCUSTT :Total General Service Non-Demand Customers POPA :Total Population in Osceola County _AUTO[-1] :First Order Auto-Regressive Term	Key Statistics: Adjusted R^2: 0.9981 Durbin-Watson: 1.936 Bayesian Information Criterion: 94.86

Table 3-1
Sales Forecast Equations and Statistics

GSNKWHT = - 69023.372*PRICEGSN(-12) + 5956.965*RYTOT + 9159.405*BM_CDD + 6367.537*BM_HDD + 5359.291*BM_CDD(-1) + 4364.508*BM_HDD(-1) + 0.324*_AUTO[-1]

GSNKWHT	:Total General Service Non-Demand Energy Sales
PRICEGSN	:General Service Non-Demand Real Price of Electricity
RYTOT	:Real Personal Income Osceola County
BM_CDD	:Billing Month Adjusted Cooling Degree Days
BM_HDD	:Billing Month Adjusted Heating Degree Days
_AUTO[-1]	:First Order Auto-Regressive Term

<u>Key Statistics</u>:
Adjusted R^2: 0.9539
Durbin-Watson: 1.934
Bayesian Information Criterion: 6.905e+005

3.4.2.2 General Service Non-Demand Electricity Sales

The general service non-demand model for annual electricity sales is primarily driven by the real price of electricity and real personal income. Weather is also a strong influence on general service non-demand sales. Last year, the model included a variable to reflect the impact of a rate reclassification in October 1990 on customers and sales. This year the model was developed by excluding data prior to October 1991, thereby bypassing the rate reclassification completely. The resulting equation, used to forecast the energy sales in kilowatt-hours for the general service non-demand customer class, is shown in Table 3-1.

3.4.3 General Service Demand 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% of total energy sales with approximately 760 customers. 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 continued to decline over the course of the last several years. The initial, and most abrupt, decrease occurred as a result of a shift in rate classification (October 1990) which encouraged the migration of smaller GSD customers to the non-demand classification (GSND). However, the decline did not stop there. In fact, since the beginning of 1992, the net gain in customers is 2.

Generally, the general service demand class is a more diversified mix of customers, and are typically fewer in number. Because of class diversity, the general service demand rate classification is also less amenable to statistical methods.

The general service demand customer forecast was evaluated using Box-Jenkins and exponential smoothing models. The historical series for general service non-demand customers does not increase linearly and uniformly or vary with seasons or regularity. The exponential smoothing model forecasts level 763 customers with no projected increase over the forecast horizon.

The forecast of no growth is reasonable given the unexplained variation in general service demand customers. Though the net gain is customers since the beginning of 1992 is 2, the fluctuations in customers have been as great as 9% in 3 months. This size of a drop in general service demand is certainly suspicious. Without understanding the reasons behind data volatility it is difficult 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.

KUA's Manager of Distribution and Planners from the City of Kissimmee were subsequently consulted regarding future large customer expansions. 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%. Based on conversations with KUA Staff and City Planners and review of past performance, an annual energy sales increase of 1% is recommended for the forecast horizon. It is important to note that the World Expo Center energy sales are in addition to this projected annual growth of 1%.

3.4.4 Outdoor Lighting Forecast

Street lighting, vapor lighting, and outdoor lighting were combined into one class for forecasting purposes. This year the best prediction of future outdoor lighting is simply a linear trend. Because outdoor lighting's contribution to total energy sales is stable and represents less than 0.8%, this method of forecasting is both acceptable and relatively accurate.

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 3-2 through 3-4 presents KUA's Base, High and Low Case NEL forecasts. Net energy for load is projected to grow at an average annual rate of 4.2 percent from 1999 through 2008 compared to 5.4 percent from 1989 through 1998.

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. 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 is available, peak load is also sensitive to other variables such as cloud cover, humidity and barometric pressure.

Table 3-5 presents KUA's winter and summer base-, high-, and low-case peak demand forecasts. A 4.9 percent annual summer peak demand growth rate is projected for 1999 through 2008. This growth rate is lower than KUA's historical annual growth rate of 5.7 percent during the last 10 years.

3.6 High and Low Sensitivities

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).

The high and low load forecast sensitivities were developed based on changes in the independent economic variables, specifically, the BEBR's high and low population forecast. 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. To develop economic data beyond 2010, the economic data were 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 3-2
2000 Base Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

	RESIDENTIAL		GS NON-DEMAND		GS DEMAND						
Calendar Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1985	18,425	192,917	2,157	29,292	533	157,296	810	21,115	380,315	38,262	418,577
1986	19,857	215,331	2,279	30,337	609	182,789	838	22,745	429,295	26,225	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	934	24,452	471,669	38,920	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	2,508	26,320	528,431	28,289	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	3,340	29,696	596,411	55,641	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	3,747	32,956	660,384	37,662	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	4,686	35,071	681,232	39,517	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	4,962	36,784	708,720	35,834	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	5,046	38,553	760,022	41,091	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	5,546	40,418	803,676	37,274	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	6,237	42,051	857,503	57,725	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	6,725	43,164	892,014	51,391	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	7,212	44,088	920,752	49,663	970,415
1998	36,540	508,138	7,755	154,668	713	336,475	7,796	45,008	1,007,078	35,302	1,042,380

Table 3-2
2000 Base Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

	RESIDENTIAL		GS NON-DEMAND		GS DEMAND						
Calendar Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1999	37,936	514,388	7,724	155,966	686	343,834	8,345	46,347	1,022,533	56,850	1,079,383
2000	39,766	525,936	8,818	164,977	763	358,262	8,899	49,347	1,058,073	55,688	1,113,762
2001	41,082	554,147	9,146	174,282	763	375,902	9,367	50,991	1,113,699	58,616	1,172,314
2002	42,357	579,853	9,474	183,376	763	402,493	9,853	52,594	1,175,575	61,872	1,237,448
2003	43,642	607,124	9,808	193,098	763	426,550	10,354	54,213	1,237,126	65,112	1,302,238
2004	44,949	637,861	10,148	203,911	763	452,011	10,870	55,861	1,304,653	68,666	1,373,319
2005	46,255	668,996	10,488	214,877	763	467,880	11,388	57,506	1,363,141	71,744	1,434,885
2006	47,427	697,487	10,795	224,938	763	472,438	11,855	58,985	1,406,717	74,038	1,480,755
2007	48,604	726,408	11,102	235,132	763	475,954	12,324	60,468	1,449,818	76,306	1,526,124
2008	49,808	756,254	11,413	245,641	763	479,505	12,805	61,984	1,494,204	78,642	1,572,847
2009	51,041	787,063	11,730	256,479	763	483,092	13,298	63,535	1,539,931	81,049	1,620,980
2010	52,293	818,629	12,050	267,570	763	486,715	13,798	65,107	1,586,712	83,511	1,670,223
2011	53,518	849,962	12,362	278,548	763	490,374	14,287	66,643	1,633,172	85,956	1,719,128
2012	54,763	882,095	12,678	289,794	763	494,069	14,785	68,204	1,680,744	88,460	1,769,204
2013	56,036	915,207	12,999	301,382	763	497,802	15,295	69,799	1,729,686	91,036	1,820,722
2014	57,340	949,329	13,326	313,326	763	501,571	15,816	71,429	1,780,043	93,686	1,873,729

Table 3-2
2000 Base Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

	RESIDENTIAL		GS NON-DEMAND		GS DEMAND						
Calendar Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
2015	58,662	984,218	13,656	325,540	763	505,379	16,345	73,081	1,831,482	96,394	1,927,876
2016	59,953	1,018,762	13,978	337,610	763	509,225	16,861	74,694	1,882,458	99,077	1,981,534
2017	61,264	1,054,117	14,304	349,964	763	513,109	17,385	76,331	1,934,575	101,820	2,036,395
2018	62,603	1,090,481	14,635	362,684	763	517,032	17,921	78,002	1,988,118	104,638	2,092,756
2019	63,972	1,127,884	14,973	375,784	763	520,994	18,469	79,708	2,043,131	107,533	2,150,664

Table 3-3
2000 High Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

Calendar Year	RESIDENTIAL Average Accounts Billed	RESIDENTIAL Sales (MWh)	GS NON-DEMAND Average Accounts Billed	GS NON-DEMAND Sales (MWh)	GS DEMAND Average Accounts Billed	GS DEMAND Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1985	18,425	192,917	2,157	29,292	533	157,296	810	21,115	380,315	38,262	418,577
1986	19,857	215,331	2,279	30,337	609	182,789	838	22,745	429,295	26,225	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	934	24,452	471,669	38,920	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	2,508	26,320	528,431	28,289	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	3,340	29,696	596,411	55,641	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	3,747	32,956	660,384	37,662	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	4,686	35,071	681,232	39,517	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	4,962	36,784	708,720	35,834	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	5,046	38,553	760,022	41,091	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	5,546	40,418	803,676	37,274	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	6,237	42,051	857,503	57,725	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	6,725	43,164	892,014	51,391	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	7,212	44,088	920,752	49,663	970,415
1998	36,540	508,138	7,755	154,668	713	336,475	7,796	45,008	1,007,078	35,302	1,042,380

Table 3-3
2000 High Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

Calendar Year	RESIDENTIAL Average Accounts Billed	RESIDENTIAL Sales (MWh)	GS NON-DEMAND Average Accounts Billed	GS NON-DEMAND Sales (MWh)	GS DEMAND Average Accounts Billed	GS DEMAND Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1999	37,978	515,411	7,734	161,208	686	343,834	8,399	46,398	1,028,851	57,183	1,086,034
2000	40,220	536,419	8,990	187,849	763	361,869	9,652	49,973	1,095,789	57,673	1,153,462
2001	41,934	574,115	9,487	204,252	763	385,493	10,599	52,184	1,174,458	61,814	1,236,272
2002	43,675	611,205	9,990	222,597	763	424,631	11,435	54,428	1,269,868	66,835	1,336,703
2003	45,500	651,672	10,514	242,726	763	459,300	12,278	56,777	1,365,975	71,893	1,437,869
2004	47,413	697,465	11,061	265,066	763	476,681	13,155	59,237	1,452,367	76,440	1,528,807
2005	49,385	745,391	11,623	288,592	763	500,758	14,056	61,771	1,548,797	81,516	1,630,312
2006	51,274	791,700	12,160	311,561	763	516,098	14,918	64,197	1,634,277	86,015	1,720,292
2007	53,221	840,111	12,711	335,707	763	523,288	15,807	66,696	1,714,914	90,259	1,805,172
2008	55,252	891,327	13,285	361,403	763	530,622	16,735	69,301	1,800,087	94,741	1,894,828
2009	57,370	945,514	13,883	388,759	763	538,103	17,704	72,016	1,890,079	99,478	1,989,557
2010	59,551	1,002,178	14,497	417,525	763	545,733	18,702	74,812	1,984,137	104,428	2,088,566
2011	61,682	1,058,666	15,097	446,254	763	553,516	19,677	77,542	2,078,112	109,374	2,187,487
2012	63,878	1,117,744	15,713	476,454	763	561,454	20,682	80,355	2,176,334	114,544	2,290,878
2013	66,161	1,179,968	16,354	508,467	763	569,551	21,728	83,278	2,279,714	119,985	2,399,699

Table 3-3
2000 High Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

	RESIDENTIAL		GS NON-DEMAND		GS DEMAND						
Calendar Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
2014	68,533	1,245,511	17,019	542,410	763	577,810	22,816	86,316	2,388,547	125,713	2,514,260
2015	70,971	1,313,816	17,703	577,995	763	586,235	23,934	89,437	2,501,980	131,683	2,633,663
2016	73,361	1,381,967	18,371	613,591	763	594,828	25,030	92,495	2,615,415	137,653	2,753,069
2017	75,818	1,453,018	19,059	650,907	763	603,592	26,157	95,640	2,733,674	143,878	2,877,552
2018	78,365	1,527,576	19,772	690,322	763	612,532	27,326	98,900	2,857,756	150,408	3,008,165
2019	81,005	1,605,821	20,510	731,960	763	621,651	28,539	102,278	2,987,972	157,262	3,145,233

Table 3-4
2000 Low Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

	RESIDENTIAL		GS NON-DEMAND		GS DEMAND						
Calendar Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1985	18,425	192,917	2,157	29,292	533	157,296	810	21,115	380,315	38,262	418,577
1986	19,857	215,331	2,279	30,337	609	182,789	838	22,745	429,295	26,225	455,520
1987	21,294	232,646	2,453	31,400	705	206,688	934	24,452	471,669	38,920	510,589
1988	22,588	251,281	2,963	39,023	769	235,618	2,508	26,320	528,431	28,289	556,720
1989	25,225	289,481	3,641	48,425	831	255,167	3,340	29,696	596,411	55,641	652,052
1990	28,002	323,416	4,071	55,393	883	277,828	3,747	32,956	660,384	37,662	698,045
1991	29,014	325,317	5,272	77,954	785	273,275	4,686	35,071	681,232	39,517	720,749
1992	30,128	341,341	5,912	92,306	744	270,110	4,962	36,784	708,720	35,834	744,554
1993	31,553	368,682	6,270	102,384	730	283,911	5,046	38,553	760,022	41,091	801,114
1994	32,699	386,879	7,000	115,804	719	295,446	5,546	40,418	803,676	37,274	840,950
1995	34,053	425,453	7,280	126,558	718	299,255	6,237	42,051	857,503	57,725	915,228
1996	35,015	447,161	7,408	133,209	741	304,918	6,725	43,164	892,014	51,391	943,404
1997	35,603	448,281	7,738	141,416	747	323,844	7,212	44,088	920,752	49,663	970,415
1998	36,540	508,138	7,755	154,668	713	336,475	7,796	45,008	1,007,078	35,302	1,042,380
1999	37,890	513,381	7,712	158,485	686	343,834	8,291	46,288	1,023,990	56,927	1,080,917

Table 3-4
2000 Low Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

	RESIDENTIAL		GS NON-DEMAND		GS DEMAND						
Calendar Year	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Average Accounts Billed	Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
2000	38,633	506,234	8,590	153,483	763	351,048	8,003	47,986	1,018,768	53,619	1,072,387
2001	38,724	513,320	8,686	147,813	763	359,689	7,718	48,174	1,028,541	54,134	1,082,675
2002	38,840	517,859	8,785	148,818	763	372,497	7,653	48,387	1,046,828	55,096	1,101,924
2003	38,968	523,321	8,882	151,368	763	384,662	7,682	48,612	1,067,033	56,160	1,123,192
2004	39,107	531,152	8,978	155,002	763	396,225	7,754	48,848	1,090,133	57,375	1,147,509
2005	39,213	538,190	9,061	158,289	763	401,027	7,824	49,037	1,105,330	58,175	1,163,505
2006	39,100	540,843	9,085	159,728	763	403,708	7,796	48,948	1,112,075	58,530	1,170,605
2007	38,963	542,910	9,099	160,874	763	403,708	7,757	48,825	1,115,249	58,697	1,173,946
2008	38,833	544,940	9,112	161,982	763	403,708	7,719	48,708	1,118,349	58,860	1,177,209
2009	38,709	546,931	9,124	163,050	763	403,708	7,682	48,596	1,121,371	59,020	1,180,391
2010	38,550	548,091	9,125	163,766	763	403,708	7,627	48,438	1,123,192	59,115	1,182,307
2011	38,192	545,194	9,071	162,823	763	403,708	7,476	48,027	1,119,202	58,905	1,178,107
2012	37,813	541,765	9,010	161,653	763	403,708	7,314	47,586	1,114,439	58,655	1,173,094
2013	37,440	538,315	8,949	160,483	763	403,708	7,152	47,152	1,109,658	58,403	1,168,061
2014	37,074	534,845	8,887	159,315	763	403,708	6,992	46,724	1,104,859	58,150	1,163,010

Table 3-4
2000 Low Case Load Forecast
Annual Summary of Historical and Projected Data
Includes World Expo Center

Calendar Year	RESIDENTIAL Average Accounts Billed	RESIDENTIAL Sales (MWh)	GS NON-DEMAND Average Accounts Billed	GS NON-DEMAND Sales (MWh)	GS DEMAND Average Accounts Billed	GS DEMAND Sales (MWh)	Outdoor Lighting (MWh)	Total Customer Accounts	Total KUA Sales (MWh)	Energy Losses (MWh)	Net Energy for Load (MWh)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
2015	36,668	530,444	8,814	157,795	763	403,708	6,812	46,245	1,098,759	57,829	1,156,589
2016	36,034	521,410	8,680	154,474	763	403,708	6,524	45,477	1,086,116	57,164	1,143,280
2017	35,380	511,920	8,539	150,993	763	403,708	6,225	44,682	1,072,846	56,466	1,129,312
2018	34,740	502,578	8,400	147,613	763	403,708	5,932	43,903	1,059,830	55,781	1,115,611
2019	34,113	493,382	8,263	144,331	763	403,708	5,644	43,139	1,047,064	55,109	1,102,172

Table 3-5
Summary of Gross Peak Demand

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
2000	243	250	237	252	260	246
2001	254	266	237	264	277	246
2002	272	293	243	282	304	253
2003	290	321	250	301	333	260
2004	307	345	257	319	358	267
2005	321	367	261	333	380	271
2006	334	389	264	346	403	274
2007	344	407	264	356	422	275
2008	354	427	265	367	443	275
2009	364	447	266	378	464	276
2010	375	469	266	389	486	277
2011	386	491	266	400	509	276
2012	397	513	265	412	532	275
2013	408	537	264	423	557	274
2014	419	562	262	435	583	272
2015	431	588	261	448	610	271
2016	443	614	259	460	637	268
2017	455	641	256	472	665	265
2018	467	669	253	485	694	262
2019	480	699	250	498	725	259

3.7 Major Additional Loads

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-used facility is currently in the planning stages and was, at one point, expected to be operational in 2000.

Phase I of the current plan, slated to be completed by the first part of 2000, 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, scheduled to be completed by the first part of 2001, 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 construction is projected to be completed during 2002-2004 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.

Complete build-out of this facility may require an estimated $1.1 billion. The total employment projection for the project and supporting industries is nearly 30,000 jobs with an estimated annual payroll of $700 million.

At this time, the World Expo Center team is still engaged in planning and negotiating, and plans to build are not yet certain. However, if completed in accordance with current plans, the peak demand and energy requirements of the Expo Center will significantly impact KUA's current system demand and least-cost planning methodology. Accordingly, KUA has conducted 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.

The Table 3-6 shows the Base, High and Low Case annual peak demand and energy forecasts for the World Expo Center. For the current forecast, this project has been delayed one year from the original construction plans. This assumption is based on delays which have already taken place, and seem likely to continue on into 1999.

Table 3-6
World Exposition Center Load Forecast
Annual Peak Demand and Energy

Year	Low Forecast		Base Forecast		High Forecast	
	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
2007-2019	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 two years, and reduced by 50% based on revised projections shown in the Journal of Osceola County Business (7/99).

4.0 Conservation and Demand-Side Management

KUA considers conservation and demand-side management (DSM) an integral component in managing the efficiency of its electric system and providing choice to its customers. In response to Florida Public Service Commission (FPSC) Docket 930555-EG, KUA performed a cost-effectiveness analysis for over 80 proposed DSM measures. The results of the analysis indicated that, except for residential load control, no DSM measures were cost-effective. KUA submitted their findings for FPSC review.

4.1 Current Conservation and DSM Programs

Although KUA's DSM analysis identified only one cost-effective measure, KUA is committed to conservation and load management programs. 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 Florida Public Service Commission:

- 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.

KUA's energy conservation specialist performs approximately 600 free audits annually advising customers on the appropriate conservation programs to implement.

4.1.1 Residential Load Management (SAVE)

KUA currently offers a residential direct load control program which 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 5,000 customers by the end of 1999. 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 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

Year	Average Active Customers	Low Case Load Management Impact (MW)	Base Case Load Management Impact (MW)	High Case Load Management Impact (MW)
1993	1,914	-	3.16	-
1994	5,040	-	8.32	-
1995	7,213	-	11.90	-
1996	7,648	-	12.62	-
1997	6,870	-	11.98	-
1998	6,201	-	12.15	-
1999	5,532	-	12.00	-
2000	-	8.9	11.00	13.1
2001	-	7.9	10.00	12.1
2002	-	7.9	10.00	12.1
2003	-	7.9	10.00	12.1
2004	-	7.9	10.00	12.1
2005	-	7.9	10.00	12.1
2006	-	7.9	10.00	12.1
2007	-	7.9	10.00	12.1
2008	-	7.9	10.00	12.1
2009	-	7.9	10.00	12.1

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
Credits - SAVE Program

Load Management Credit			
Appliance	Control Period	Monthly Credit	With Water Heater Control
Water Heater	Year Round	\$2.50	--
Central AC (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.

4.2 Additional Conservation and DSM Programs

With the exception of direct load control, the cost-effectiveness of the evaluated DSM programs was marginal. Three marginally cost-effective DSM resources, however, were transferred into EGEAS from the COMPASS analysis. These are described below.

4.2.1 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 upgrade to high efficiency systems.

4.2.2 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 which 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.

4.2.3 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.

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. Each member is required to provide their own reserves and a member of the FMPP can withdraw from FMPP with 1 year 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 11 MW in 2004 and growing to approximately 78 MW in 2009. 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 2000 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
KUA Capacity Balance

Year	Existing/ Committed Generation [1]	Existing Purchases	Summer Peak Demand (MW)			DSM Impacts (MW)			Reserve Margin		
			Base	High	Low	Base	High	Low	Base	High	Low
1999	175.8	98.1	236	236	236	12.0	12.0	12.0	22.3%	22.3%	22.3%
2000	175.8	108.1	252	260	246	11.0	13.1	8.9	17.8%	15.0%	19.7%
2001	296.7	68.1	264	277	246	10.0	12.1	7.9	43.6%	37.7%	53.2%
2002	296.7	68.1	282	304	253	10.0	12.1	7.9	34.1%	25.0%	48.8%
2003	296.7	68.1	301	333	260	10.0	12.1	7.9	25.4%	13.7%	44.7%
2004	296.7	48.1	319	358	267	10.0	12.1	7.9	11.6%	-0.3%	33.1%
2005	296.7	48.1	333	380	271	10.0	12.1	7.9	6.7%	-6.3%	31.1%
2006	296.7	48.1	346	403	274	10.0	12.1	7.9	2.6%	-11.8%	29.6%
2007	296.7	48.1	356	422	275	10.0	12.1	7.9	-0.3%	-15.9%	29.1%
2008	296.7	48.1	367	443	275	10.0	12.1	7.9	-3.4%	-20.0%	29.1%
2009	296.7	48.1	378	464	276	10.0	12.1	7.9	-6.3%	-23.7%	28.6%
2010	296.7	48.1	389	486	277	10.0	12.1	7.9	-9.0%	-27.2%	28.1%
2011	296.7	48.1	400	509	276	10.0	12.1	7.9	-11.6%	-30.6%	28.6%
2012	296.7	48.1	412	532	275	10.0	12.1	7.9	-14.2%	-33.7%	29.1%
2013	296.7	48.1	423	557	274	10.0	12.1	7.9	-16.5%	-36.7%	29.6%

Table 5-1
KUA Capacity Balance

Year	Existing/ Committed Generation (1)	Existing Purchases	Summer Peak Demand (MW)			DSM Impacts (MW)			Reserve Margin		
			Base	High	Low	Base	High	Low	Base	High	Low
2014	296.7	48.1	435	583	272	10.0	12.1	7.9	-18.9%	-39.6%	30.6%
2015	296.7	48.1	448	610	271	10.0	12.1	7.9	-21.3%	-42.3%	31.1%
2016	296.7	48.1	460	637	268	10.0	12.1	7.9	-23.4%	-44.8%	32.6%
2017	296.7	48.1	472	665	265	10.0	12.1	7.9	-25.4%	-47.2%	34.1%
2018	296.7	48.1	485	694	262	10.0	12.1	7.9	-27.4%	-49.4%	35.7%
2019	296.7	48.1	498	725	259	10..0	12.1	7.9	-29.3%	-51.6%	37.3%

(1) Includes Cane Island 3.

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 138 MW during the summer increasing to 260 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 36 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 No. 1 and half from Unit No. 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 also has a contract with OUC to purchase up to 50 MW of capacity from the Stanton 2 plant ending in December 2000. 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.

Table 5-2
Summary of Gross Peak Demands

Year	Winter Peak Demand (MW)			Summer Peak Demand (MW)		
	Base	High	Low	Base	High	Low
2000	243	250	237	252	260	246
2001	254	266	237	277	315	246
2002	272	293	243	282	304	253
2003	290	321	250	301	333	260
2004	307	345	257	319	358	267
2005	321	367	261	333	380	271
2006	334	389	264	346	403	274
2007	344	407	264	356	422	275
2008	354	427	265	367	443	275
2009	364	447	266	378	464	276
2010	375	469	266	389	486	277
2011	386	491	266	400	509	276
2012	397	513	265	412	532	275
2013	408	537	264	423	557	274
2014	419	562	262	435	583	272
2015	431	588	261	448	610	271
2016	443	614	259	460	637	268
2017	455	641	256	472	665	265
2018	467	669	253	485	694	262
2019	480	699	250	498	725	259

In 2000, units at Hansel Plant will range in years from 17 to 41 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 February of 1999 for KUA. The fuel price forecast includes coal, No. 6 fuel oil, No. 2 fuel oil, nuclear and natural gas.

Table 5-3 Delivered Fuel Price Forecast--Base Case ($/MBtu)					
Year	Coal	No. 6 Oil	No. 2 Oil	Nuclear	Natural Gas(1)
1998	1.45	2.04	3.29	0.52	2.20
1999	1.41	2.69	4.13	0.54	2.49
2000	1.41	2.98	4.60	0.55	2.85
2001	1.31	2.77	4.47	0.56	2.61
2002	1.38	2.75	4.48	0.58	2.63
2003	1.43	2.78	4.56	0.59	2.72
2004	1.44	2.81	4.65	0.61	2.76
2005	1.49	2.83	4.73	0.62	2.79
2006	1.51	2.88	4.82	0.64	2.86
2007	1.56	2.98	5.00	0.66	2.96
2008	1.60	3.10	5.18	0.67	3.07
2009	1.64	3.25	5.42	0.69	3.20
2010	1.68	3.41	5.65	0.71	3.32
2011	1.70	3.58	5.91	0.73	3.48
2012	1.75	3.76	6.17	0.75	3.64
2013	1.80	3.94	6.44	0.77	3.81
2014	1.83	4.12	6.72	0.79	3.98
2015	1.86	4.30	7.00	0.81	4.15
2016	1.89	4.49	7.28	0.84	4.33
2017	1.92	4.69	7.59	0.86	4.51
2018	1.95	4.88	7.88	0.89	4.70
2019	1.98	5.06	8.16	0.91	4.91
(1) Commodity only.					

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 plans to add a unit similar to Cane Island 3. This unit will be referred to as Cane Island 4. Any additional capacity requirements were met with unspecified purchases.

The following tables outline KUA's expansion plan under the Base, High and Low load forecast scenarios:

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

Year	Total Firm Capacity (1)	Net Peak Demand (2)	Reserve %	Capacity Additions	Revised Reserves %
1998	274	221	24.0%	0	24.0%
1999	274	224	22.3%	0	22.3%
2000	284	241	17.8%	0	17.8%
2001	365	254	43.6%	0	43.6%
2002	365	272	34.1%	0	34.1%
2003	365	291	25.4%	122	25.4%
2004	345	309	11.6%	0	51.0%
2005	345	323	6.8%	0	44.5%
2006	345	336	2.6%	0	38.9%
2007	345	346	-0.3%	0	34.9%
2008	345	357	-3.4%	0	30.7%
2009	345	368	-6.3%	0	26.8%
2010	345	379	-9.0%	0	23.1%
2011	345	390	-11.6%	0	19.7%
2012	345	402	-14.2%	0	16.1%
2013	345	413	-16.5%	9	15.2%
2014	345	425	-18.9%	14	15.2%
2015	345	438	-21.3%	15	15.2%
2016	345	450	-23.4%	13	15.0%
2017	345	462	-25.4%	14	15.1%
2018	345	475	-27.4%	15	15.1%
2019	345	488	-29.3%	15	15.1%

(1) Includes Cane Island 3.
(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)	Reserve %	Capacity Additions	Revised Reserves %
1998	274	221	24.0%	0	24.0%
1999	274	224	22.3%	0	22.3%
2000	284	247	15.0%	0	15.0%
2001	365	265	37.7%	0	37.7%
2002	365	292	25.0%	0	25.0%
2003	365	321	13.7%	122	51.7%
2004	345	346	-0.3%	0	34.9%
2005	345	368	-6.3%	0	26.8%
2006	345	391	-11.8%	0	19.4%
2007	345	410	-15.9%	5	15.1%
2008	345	431	-20.0%	24	15.0%
2009	345	452	-23.7%	25	15.2%
2010	345	474	-27.2%	25	15.1%
2011	345	497	-30.6%	26	15.0%
2012	345	520	-33.7%	27	15.1%
2013	345	545	-36.7%	28	15.0%
2014	345	571	-39.6%	30	15.0%
2015	345	598	-42.3%	31	15.0%
2016	345	625	-44.8%	31	15.0%
2017	345	653	-47.2%	33	15.1%
2018	345	682	-49.4%	33	15.1%
2019	345	713	-51.6%	36	15.1%

(1) Includes Cane Island 3.
(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)	Reserve %	Capacity Additions	Revised Reserves %
1998	274	221	24.0%	0	24.0%
1999	274	224	22.3%	0	22.3%
2000	284	237	19.8%	0	19.8%
2001	365	238	53.2%	0	53.2%
2002	365	245	48.9%	0	48.9%
2003	365	252	44.7%	0	44.7%
2004	345	259	33.1%	0	33.1%
2005	345	263	31.1%	0	31.1%
2006	345	266	29.6%	0	29.6%
2007	345	267	29.1%	0	29.1%
2008	345	267	29.1%	0	29.1%
2009	345	268	28.6%	0	28.6%
2010	345	269	28.1%	0	28.1%
2011	345	268	28.6%	0	28.6%
2012	345	267	29.1%	0	29.1%
2013	345	266	29.6%	0	29.6%
2014	345	264	30.6%	0	30.6%
2015	345	263	31.1%	0	31.1%
2016	345	260	32.6%	0	32.6%
2017	345	257	34.1%	0	34.1%
2018	345	254	35.7%	0	35.7%
2019	345	251	37.3%	0	37.3%

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

Appendix A
Schedules

Schedule 1
Existing Generating Facilities
As of December 31, 1999

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri	(6) Fuel Alt	(7) Fuel Transport Pri	(8) Fuel Transport Alt	(9) Alt. Fuel Days Use	(10) Commercial In-Service month/Year	(11) Expected Retirement Month/Year	(12) Gen Max. Nameplate KW	(13) Net Capability Summer MW	(14) Net Capability Winter MW
Hansel Plant		Osceola County Sec 27/T25S/ R29E											
	8		IC	NG	FO2	PL	TK		02/59	Unknown	3,000	3	3
	14		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	2	2
	15		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	2	2
	16		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	2	2
	17		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	2	2
	18		IC	NG	FO2	PL	TK		02/72	Unknown	2,070	2	2
	19		IC	FO2	--	TK	--		02/83	Unknown	2,500	3	3
	20		IC	FO2	--	TK	--		02/83	Unknown	2,500	3	3
	21		CT	NG	FO2	PL	TK		02/83	Unknown	35,000	28	32
	22		ST	WH	--	--	--		02/83	Unknown	10,000	10	10
	23		ST	WH	--	--	--		02/83	Unknown	10,000	10	10
Plant Total											73,350	67	71

Schedule 1
Existing Generating Facilities
As of December 31, 1999

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

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

Schedule 1
Existing Generating Facilities
As of December 31, 1999

(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
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 (2)	21 (2)
Plant Total											464,580	21	21

(2) KUA's 4.8193 percent ownership portion.

Schedule 1
Existing Generating Facilities
As of December 31, 1999

(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	4.5[3]	5.5[3]
	B		CT	NG	FO2-	PL	TK		07/89	Unknown	41,400	4.5[3]	5.5[3]
Plant Total											890,460	9	10

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

Schedule 1
Existing Generating Facilities
As of December 31, 1999

(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
Cane Island		Osceola County Sec. 29, 32/ R28E/T25S											
	1		CT	NG	FO2	PL	TK		11/94	Unknown	42,000	15[1]	20[4]
	2		CT	NG	FO2	PL	TK		06/95	Unknown	80,000	34[1]	40[4]
	2		ST	WH	--	--	--		06/95	Unknown	40,000	20[1]	20[4]
Plant Total											162,000	69	80

(4) KUA's 50 percent ownership portion.

Schedule 2.1
History 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	Average No. of Customers	Average kWh Consumption Per Customer/Yr	GWh	Average No. of Customers	Average kWh Consumption Per Customer/Yr
1990	67,453	2.083	323	28,002	11,550	333	4,954	67,263
1991	71,889	2.88	325	29,014	11,212	351	6,056	57,997
1992	75,515	2.916	341	30,128	11,330	362	6,656	54,450
1993	73,342	2.954	369	31,553	11,685	386	7,000	55,185
1994	83,615	3.002	387	32,699	11,832	411	7,719	53,278
1995			425	34,053	12,494	426	7,997	53,247
1996			447	35,015	12,771	438	8,149	53,765
1997			448	35,603	12,591	465	8,485	54,833
1998			508	36,540	13,906	491	8,469	57,993
1999			514	37,936	13,559	500	8,410	59,429
2000			526	39,766	13,226	523	9,581	54,612
2001			554	41,082	13,489	550	9,909	55,524
2002			580	42,357	13,690	586	10,237	57,231
2003			607	43,642	13,911	620	10,571	58,618
2004			638	44,949	14,191	656	10,911	60,116

Schedule 2.1
History 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	Average No. of Customers	Average kWh Consumption Per Customer/Yr	GWh	Average No. of Customers	Average kWh Consumption Per Customer/Yr
2005			669	46,255	14,463	683	11,251	60,684
2006			697	47,427	14,707	697	11,558	60,337
2007			726	48,604	14,945	711	11,865	59,931
2008			756	49,808	15,183	725	12,176	59,555
2009			787	51,041	15,420	740	12,493	59,199
2010			819	52,293	15,655	754	12,813	58,869
2011			850	53,518	15,882	769	13,125	58,585
2012			882	54,763	16,107	784	13,441	58,319
2013			915	56,036	16,332	799	13,762	58,072
2014			949	57,340	16,556	815	14,089	57,839
2015			984	58,662	16,778	831	14,419	57,627
2016			1,019	59,953	16,993	847	14,741	57,448
2017			1,054	61,264	17,212	863	15,067	57,282
2018			1,090	62,603	17,419	880	15,398	57,132
2019			1,128	63,972	17,631	897	15,736	56,989

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

(1) Year	(2) GWh	(3) Industrial Average No. of Customers	(4) Average kWh Consumption Per Customer	(5) Railroads and Railways GWh	(6) Street & Highway Lighting GWh	(7) Other Sales to Public Authorities GWh	(8) Total Sales to Ultimate Consumers GWh
1990	--	--	--	--	4	0	660
1991	--	--	--	--	5	0	681
1992	--	--	--	--	5	0	709
1993	--	--	--	--	5	0	760
1994	--	--	--	--	6	0	804
1995	--	--	--	--	6	0	858
1996	--	--	--	--	7	0	892
1997	--	--	--	--	7	0	921
1998	--	--	--	--	8	0	1,007
1999	--	--	--	--	8	0	1,023
2000	--	--	--	--	9	0	1,058
2001	--	--	--	--	9	0	1,114
2002	--	--	--	--	10	0	1,176
2003	--	--	--	--	10	0	1,237
2004	--	--	--	--	11	0	1,305
2005	--	--	--	--	11	0	1,363

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

(1) Year	(2) GWh	(3) Industrial Average No. of Customers	(4) Average kWh Consumption Per Customer	(5) Railroads and Railways GWh	(6) Street & Highway Lighting GWh	(7) Other Sales to Public Authorities GWh	(8) Total Sales to Ultimate Consumers GWh
2006	--	--	--	--	12	0	1,407
2007	--	--	--	--	12	0	1,450
2008	--	--	--	--	13	0	1,494
2009	--	--	--	--	13	0	1,540
2010	--	--	--	--	14	0	1,587
2011	--	--	--	--	14	0	1,633
2012	--	--	--	--	15	0	1,681
2013	--	--	--	--	15	0	1,730
2014	--	--	--	--	16	0	1,780
2015	--	--	--	--	16	0	1,831
2016	--	--	--	--	17	0	1,882
2017	--	--	--	--	17	0	1,935
2018	--	--	--	--	18	0	1,988
2019	--	--	--	--	18	0	2,043

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

(1) Year	(2) Sales for Resale GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
1990	0	38	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	35	1,042	0	45,008
1999	0	57	1,079	0	46,347
2000	0	56	1,114	0	49,347
2001	0	59	1,172	0	50,991
2002	0	62	1,237	0	52,594
2003	0	65	1,302	0	54,213
2004	0	69	1,373	0	55,861
2005	0	72	1,435	0	57,506

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

(1) Year	(2) Sales for Resale GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
2006	0	74	1,481	0	58,985
2007	0	76	1,526	0	60,468
2008	0	79	1,573	0	61,984
2009	0	81	1,621	0	63,535
2010	0	84	1,670	0	65,107
2011	0	86	1,719	0	66,643
2012	0	88	1,769	0	68,204
2013	0	91	1,821	0	69,799
2014	0	94	1,874	0	71,429
2015	0	96	1,928	0	73,081
2016	0	99	1,982	0	74,694
2017	0	102	2,036	0	76,331
2018	0	105	2,093	0	78,002
2019	0	108	2,151	0	79,708

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. 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	13	0	0	0	220
1999	236	0	236	0	12	0	0	0	224
2000	252	0	252	0	11	0	0	0	241
2001	264	0	264	0	10	0	0	0	254
2002	282	0	282	0	10	0	0	0	272
2003	301	0	301	0	10	0	0	0	291
2004	319	0	319	0	10	0	0	0	309

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2005	333	0	333	0	10	0	0	0	323
2006	346	0	346	0	10	0	0	0	336
2007	356	0	356	0	10	0	0	0	346
2008	367	0	367	0	10	0	0	0	357
2009	378	0	378	0	10	0	0	0	368
2010	389	0	389	0	10	0	0	0	379
2011	400	0	400	0	10	0	0	0	390
2012	412	0	412	0	10	0	0	0	402
2013	423	0	423	0	10	0	0	0	413
2014	435	0	435	0	10	0	0	0	425
2015	448	0	448	0	10	0	0	0	438
2016	460	0	460	0	10	0	0	0	450
2017	472	0	472	0	10	0	0	0	462
2018	485	0	485	0	10	0	0	0	475
2019	498	0	498	0	10	0	0	0	488

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. 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	12	0	0	0	206
1997	198	0	198	0	12	0	0	0	186
1998	180	0	180	0	13	0	0	0	167
1999	219	0	219	0	12	0	0	0	207
2000	243	0	243	0	11	0	0	0	232
2001	254	0	254	0	10	0	0	0	244
2002	272	0	272	0	10	0	0	0	262
2003	290	0	290	0	10	0	0	0	280
2004	307	0	307	0	10	0	0	0	297

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
2005	321	0	321	0	10	0	0	0	311
2006	334	0	334	0	10	0	0	0	324
2007	344	0	344	0	10	0	0	0	334
2008	354	0	354	0	10	0	0	0	344
2009	364	0	364	0	10	0	0	0	354
2010	375	0	375	0	10	0	0	0	365
2011	386	0	386	0	10	0	0	0	376
2012	397	0	397	0	10	0	0	0	387
2013	408	0	408	0	10	0	0	0	398
2014	419	0	419	0	10	0	0	0	409
2015	431	0	431	0	10	0	0	0	421
2016	443	0	443	0	10	0	0	0	433
2017	455	0	455	0	10	0	0	0	445
2018	467	0	467	0	10	0	0	0	457
2019	480	0	480	0	10	0	0	0	470

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1990	660	0	0	660	0	38	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	57	915	53.3
1996	892	0	0	892	0	51	943	49.4
1997	921	0	0	921	0	49	970	51.3
1998	1,007	0	0	1,007	0	35	1,042	51.1
1999	1,023	0	0	1,023	0	56	1,079	52.2
2000	1,058	0	0	1,058	0	56	1,114	50.4
2001	1,114	0	0	1,114	0	58	1,172	50.7
2002	1,172	0	0	1,172	0	65	1,237	50.0
2003	1,237	0	0	1,237	0	65	1,302	49.4
2004	1,305	0	0	1,305	0	68	1,373	49.2
2005	1,363	0	0	1,363	0	72	1,435	49.2

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
2006	1,407	0	0	1,407	0	74	1,481	48.8
2007	1,450	0	0	1,450	0	76	1,526	48.9
2008	1,494	0	0	1,494	0	79	1,573	48.9
2009	1,540	0	0	1,540	0	81	1,621	49.0
2010	1,587	0	0	1,587	0	83	1,670	49.0
2011	1,633	0	0	1,633	0	86	1,719	49.0
2012	1,681	0	0	1,681	0	88	1,769	49.1
2013	1,730	0	0	1,730	0	91	1,821	49.1
2014	1,780	0	0	1,780	0	94	1,874	49.1
2015	1,831	0	0	1,831	0	97	1,928	49.2
2016	1,882	0	0	1,882	0	100	1,982	49.2
2017	1,935	0	0	1,935	0	101	2,036	49.2
2018	1,988	0	0	1,988	0	105	2,093	49.2
2019	2,043	0	0	2,043	0	108	2,151	49.3

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)
	1999 Actual		2000 Forecast		2001 Forecast	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	219	76	243	82	254	86
February	175	67	189	81	198	86
March	151	70	218	77	228	80
April	201	83	154	78	162	82
May	199	89	185	85	193	90
June	218	97	233	96	244	102
July	231	116	249	109	261	115
August	236	116	252	114	264	120
September	236	99	237	116	248	121
October	196	89	208	104	218	109
November	158	71	171	89	179	94
December	160	77	238	83	250	88

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
Ln	Fuel Requirements		Units	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Nuclear		GBtu	459	517	424	399	424	424	413	414	421	428	421	432
(2)	Coal		1000 Ton	51	47	57	62	69	67	72	70	69	66	71	69
(3)	Residual	Total	1000 BBL												
(4)		Steam	1000 BBL												
(5)		CC	1000 BBL												
(6)		CT	1000 BBL												
(7)		Diesel	1000 BBL												
(8)	Distillate	Total	1000 BBL	5	3	42	8	3	4	2	0	2	2	1	2
(9)		Steam	1000 BBL												
(10)		CC	1000 BBL												
(11)		CT	1000 BBL												
(12)		Diesel	1000 BBL	5	3	42	8	3	4	2	0	2	2	1	2
(13)	Natural Gas	Total	1000 MCF	3764	4159	1813	3896	4872	4600	4812	4570	4533	4796	5073	5404
(14)		Steam	1000 MCF												
(15)		CC	1000 MCF												
(16)		CT	1000 MCF												
(17)	Other (Specify)		GBtu												

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
Ln	Energy Sources		Units	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		GWh	438	393	763	474	376	499	539	668	725	740	730	731
(2)	Nuclear		GWh	43	42	39	37	39	39	38	38	39	39	39	40
(3)	Coal		Gwh	143	134	152	165	184	179	190	185	184	174	190	184
(4)	Residual	Total	GWh												
(5)		Steam	GWh												
(6)		CC	GWh												
(7)		CT	GWh												
(8)		Diesel	GWh												
(9)	Distillate	Total	GWh	2	1	19	4	1	2	1	0	1	1	0	1
(10)		Steam	GWh												
(11)		CC	GWh												
(12)		CT	GWh												
(13)		Diesel	GWh	2	1	19	4	1	2	1	0	1	1	0	1
(14)	Natural Gas	Total	GWh	421	480	141	492	637	583	605	544	532	572	614	665
(15)		Steam	GWh												
(16)		CC	GWh	404	462	129	489	636	581	603	543	531	571	613	664
(17)		CT	GWh	17	18	12	3	1	2	2	1	1	1	1	1
(18)	Other (Specify)		GWh												
(19)	Net Energy for Load		GWh	1047	1050	1114	1172	1237	1302	1373	1435	1481	1526	1573	1621

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Actual	Actual										
Ln	Energy Sources		Units	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Annual Firm Interchange		%	42	37	68	40	30	38	39	47	49	48	46	45
(2)	Nuclear		%	4	4	4	3	3	3	3	3	3	3	2	2
(3)	Coal		%	14	13	14	14	15	14	14	13	12	11	12	11
(4)	Residual	Total	%												
(5)		Steam	%												
(6)		CC	%												
(7)		CT	%												
(8)		Diesel	%												
(9)	Distillate	Total	%	0	0	2	0	0	0	0	0	0	0	0	0
(10)		Steam	%												
(11)		CC	%												
(12)		CT	%												
(13)		Diesel	%			2									
(14)	Natural Gas	Total	%	40	46	13	42	52	45	44	38	36	38	39	41
(15)		Steam	%												
(16)		CC	%	39	44	12	42	51	45	44	38	36	38	39	41
(17)		CT	%	1	2	1	0	1	0	0	0	0	0	0	0
(18)	Other (Specify)		%												
(19)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100	100

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	Summer System Firm Net Peak Demand	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999	176	98	0	0	274	224	50	22%	—	—	—
2000	176	108	0	0	284	241	43	18%	—	—	—
2001	297	68	0	0	365	254	111	44%	—	—	—
2002	297	68	0	0	365	272	93	34%	—	—	—
2003	297	68	0	0	365	291	74	25%	—	—	—
2004	419	48	0	0	467	309	158	51%	—	—	—
2005	419	48	0	0	467	323	144	45%	—	—	—
2006	419	48	0	0	467	336	131	39%	—	—	—
2007	419	48	0	0	467	346	121	35%	—	—	—
2008	419	48	0	0	467	357	110	31%	—	—	—
2009	419	48	0	0	467	368	99	27%	—	—	—

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at 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	QF	Total Capacity Available	Winter System Firm Net Peak Demand	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999	190	98	0	0	288	207	81	39%	—	—	—
2000	190	108	0	0	298	232	66	28%	—	—	—
2001	190	98	0	0	288	244	44	18%	—	—	—
2002	323	68	0	0	391	262	129	49%	—	—	—
2003	323	68	0	0	391	280	111	40%	—	—	—
2004	323	48	0	0	371	297	74	25%	—	—	—
2005	457	48	0	0	505	311	194	62%	—	—	—
2006	457	48	0	0	505	324	181	56%	—	—	—
2007	457	48	0	0	505	334	171	51%	—	—	—
2008	457	48	0	0	505	344	161	47%	—	—	—
2009	457	48	0	0	505	354	151	43%	—	—	—

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport						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	FO2	PL	TK	08/99	06/01	Unknown				
	3		ST	WH	—	—	—	08/99	06/01	Unknown				

Schedule 9
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 NOx Combustors
(7)	Cooling Method:	Mechanical Cooling Towers
(8)	Total Site Area:	1,023 Acres
(9)	Construction Status:	Not Started
(10)	Certification Status:	Site certification in progress. Application filed 8/5/98
(11)	Status with Federal Agencies:	Notice of intent to file PSD Air Construction Permit filed 1/8/99

Schedule 9
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 $/kW):	430
	Direct Construction Cost ($/kW):	—
	AFUDC Amount ($/kW):	—
	Escalation ($/kW):	—
	Fixed O&M ($/kW-yr):	2.27
	Variable O&M ($/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