REPORT

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

1998 Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines

Submitted to
Florida Public Service Commission

April 1998

BLACK & VEATCH
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Executive Summary

This report documents the 1998 City of Lakeland Ten-Year Site Plan pursuant to Florida Statutes 25-17.0852 Section 186.801. The Ten-Year Site Plan provides information required by this rule when available. The Plan is divided into eight main sections: Descriptions of Existing Facilities, Forecast of Electrical Power Demand and Energy Consumption, Conservation and Demand Side Management, Forecasting Methods and Procedures, Facilities Requirements, Environmental and Land Use Information, Analysis Results and Conclusions, and Ten-Year Site Plan Schedules. The Appendix contains details of Lakeland's load forecast and fuel forecast.

The existing City of Lakeland system includes wholly-owned and jointly-owned generation, power purchases, and FMPA membership. The total installed capacity based on Lakeland's ownership share is 640 MW winter and 597 MW summer for 1998. The existing supply system has a broad range of generation technology and fuel diversity.

The City of Lakeland has projected peak demand growth and energy consumption for the resource period. A banded forecast is provided with a base case growth, high growth, and low growth scenarios. The need for capacity considering the forecasted growth, existing units, retiring units, and purchase power contracts indicates a need for power in 1999.

The City of Lakeland currently employs an aggressive demand-side management (DSM) program to improve the efficiency of consumer electricity usage. The DSM program includes two residential and three commercial programs with additional energy savings and efficiency promotion programs.

Twenty one self build alternatives were considered in the screening analysis for capacity additions. The alternatives were screened on a bus-bar level to determine the potential generation resources to be modeled in greater detail. Two of the twelve were eliminated due to high costs and low efficiencies. The alternatives were modeled in Black & Veatch's POWROPT and POWRPRO to rank the expansion plan according to total cumulative present worth over a 20 year planning period. Several sensitivity analyses were performed to determine the impact on least-cost alternatives.

In addition to cost considerations, environmental and land use considerations were factored into the resource plans. This ensured that the least-cost plans selected were environmentally and socially responsible and demonstrate the City of Lakeland's commitment to the community.

Based on the detailed modeling of the City of Lakeland system, forecast of electrical demand and energy, forecast of fuel prices and availability, and environmental considerations; Table ES-1 presents the expansion plan that provides the City of Lakeland with the least-cost plan which meets strategic goals.

Table ES-1
Reference Plan

Year	Expansion Plan
1998	Regain Lost Capacity in McIntosh Unit 3
1999	Build McIntosh Unit 5, Westinghouse 501G Simple Cycle (Jan) Retire Larsen Units 7 & CT1 (June)
2000	
2001	
2002	
2003	Build McIntosh Unit 4, DOE PCFB (May)
2004	
2005	
2006	
2007	

1.0 Introduction

This report documents the 1998 City of Lakeland Ten-Year Site Plan (TYSP) pursuant to Florida Statutes. The City of Lakeland (Lakeland) Ten-Year Site Plan provides the information required by this rule as adopted by Order No. PSC-97-1373-FOF-EU on October 30, 1997. The Plan is divided into eight main sections: Description of Existing Facilities, Forecast of Electric Power Demand and Energy Consumption, Conservation and Demand Side Management, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Environmental and Land Use Information, Analysis Results and Conclusions, and Ten-Year Site Plan Schedules. Appendix A and B contains details of Lakeland's load forecast and fuel forecast.

1.1 Description of Existing Facilities

Section 2.0 of the Ten-Year Site Plan details existing generating and transmission facilities. The section includes a historical overview of Lakeland's system, description and table of existing power generating facilities, existing transmission details, and maps showing service area and transmission lines. Lakeland's two existing generating facilities provide Lakeland with 640 MW in the winter and 595 MW in the summer.

1.2 Forecast of Electrical Power Demand and Energy Consumption

Section 3.0 of the TYSP provides the summary of the load forecast for Lakeland's system. The detailed load forecast is contained in Appendix A.

Lakeland is projected to remain a winter peaking system for the remainder of this planning period. The projected annual growth rates in peak demand for the winter and summer are 2.85 and 2.25 percent respectively for 1998 through 2007.

Net energy for load is projected to grow at an average annual rate of 2.64 percent over the next 10 years compared to 3.71 percent over the last 10 years. Projections are also developed for high and low load growth scenarios.

1.3 Conservation and Demand Side Management

Section 4.0 provides descriptions of the existing conservation and demand side management programs and additional programs that are being evaluated. Additional details regarding Lakeland's demand side management programs on file with the PSC. Lakeland's current conservation and demand management programs include the following programs for which demand and energy savings can readily be demonstrated:

- Residential Programs
  - SMART Load Management Program
  - Loan Program
- Commercial Programs
  - Commercial Lighting Program
  - Thermal Energy Storage Program
  - High Pressure Sodium Outdoor Lighting Program

Lakeland also currently conducts the following conservation and demand side management programs which promote energy savings and efficiency:

- Residential Programs
  - Energy Audit Program
  - Public Awareness Program
  - Mobile Display Unit
  - Speakers Bureau
  - Informational Bill Inserts
- Commercial Programs
  - Commercial Audit Program

1.4 Forecasting Methods and Procedures

Section 5.0 provides the forecasting methods for the TYSP and outlines the assumptions applied for the system planning.

This section summarizes the integrated resource plan for Lakeland and provides planning criteria for the Florida Municipal Power Pool, in which Lakeland is a member. The integrated resource plan is fully integrated into the TYSP.

Fuel price projections are provided with brief descriptions of the methodology. Three scenarios are provided for the fuel price forecast: base case, high fuel prices, and low fuel prices. The fuel price forecasts are provided for coal, natural gas, oil, RDF, and petroleum coke. Additional details of the fuel price forecasts and availability forecasts are presented in Appendix B.

Assumptions for the economic parameters and evaluation criteria applied in the TYSP are also included in section 5.0. The criteria and assumptions are applied to supply-side and demand-side alternatives in the study. The economic evaluation applies an hourly chronological production cost model to determine the least-cost alternative for Lakeland. The model uses a least cost cumulative present worth revenue requirement (CPWRR) as the selection criteria for generating unit alternatives.

1.5 Forecast of Facilities Requirements

Section 6.0 integrates the electrical demand and energy forecast with the conservation and demand side management forecast to determine the facilities requirements for the 10 year planning horizon.

Generating unit alternatives were selected based on the need for capacity. The generating alternatives first underwent a screening analysis and units that exhibit potential were modeled. The alternatives were evaluated based on stated economic conditions and production costing modeling.

1.6 Environmental and Land Use Information

Section 7.0 discusses the land and environmental features of Lakeland's Ten-Year Site Plan. Preliminary design and siting information is provided.

1.7 Analysis Results and Conclusions

Section 8.0 provides a summary of the analysis results. This section rolls the results and issues of the proceeding sections into detailed conclusions and a recommended reference plan for the City of Lakeland.

1.8 Ten-Year Site Plan Schedules

Section 9.0 presents the schedules required by the Florida Public Service Commission for the Ten-Year Site Plan.

2.0 General Description of Utility

2.1 City of Lakeland Historical Background

2.1.1 Generation

The City of Lakeland was incorporated on January 1, 1885, when 27 citizens approved and signed the City Charter. The original light plant was built by Lakeland Light and Power Company at the corner of Cedar Street and Massachusetts Avenue in 1889. On May 26, 1891, Harry Sloan, the plant manager, threw the switch to light Lakeland by electricity with five arc lamps for the first time in history. Incandescent lights were installed in 1903. The original capacity of the first plant was 50 kW.

Public power in Lakeland was established nearly 90 years ago in 1904, when fore-sighted citizens and municipal officials purchased the small private 50 kW electric light plant from owner Bruce Neff for $7,500.

The need for an expansion led to construction of a new power plant on the north side of Lake Mirror in 1916. The initial capacity of the Lake Mirror Power Plant is unknown, but it probably was 500 kW. The plant was expanded three times. The first expansion of 2,500 kW in 1922; the second of 5,000 kW in 1925; and in 1938, the final expansion program was completed with the removal of 500 kW to make room for the addition of a new 5,000 kW generating unit, bringing the total peak capacity of the plant up to 12,500 kW.

As the community grew, the need for a new power plant emerged and the Charles Larsen Memorial Power Plant was constructed on the southeast shore of Lake Parker in 1949. The initial capacity of the new Larsen Plant Steam Unit No. 4, completed in 1950, was 20,000 kW. Steam Unit No. 5 was the first addition to Larsen Plant and increased its total capacity by 25,000 kW in 1956. Steam Unit No. 6 was the second addition to Larsen Plant and increased its total capacity again by a nominal 25,000 kW in 1959. Three gas turbines, each with a nominal rating 11,250 kW, were installed as peaking units in 1962. In 1966, a third steam unit capacity addition was made to Larsen Plant. Steam Unit No. 7 was constructed with a nominal 44,000 kW capacity at an estimated cost of $9.6 million. This brought the total Larsen Plant nameplate capacity up to nominally 147,750 kW.

In the meantime, the Lake Mirror Plant, with its old and obsolete equipment, became relatively inefficient and hence was no longer in active use. It was kept in cold standby until retired in 1971.

As the community continued to grow, the demand for power and electricity grew at an even more rapid rate. In the late 1960s, the need for a new power plant became evident. A site was purchased on the north side of Lake Parker and construction commenced during 1970. Initially, two diesel units with a peaking capacity of a nominal rating 2,500 kW each were placed into commercial operation in 1970.

Steam Unit No. 1, with a nominal rating of 90,000 kW, was put into commercial operation on February 24, 1971, for a total cost of $15.22 million.

In June of 1976, Steam Unit No. 2 at Plant 3 was placed in commercial operation, with a nominal rated capacity of 114,707 kW and at a cost of $25.77 million. This addition increased the capacity of the Lakeland system to approximately 360,000 kW. At this time, Plant 3 was renamed the C. D. McIntosh, Jr. Power Plant in recognition of a past Electric and Water Department Director.

On January 2, 1979, construction was started on McIntosh Unit No. 3, a nominal 334 megawatt coal fired steam generating unit, using low sulfur oil as an alternate fuel, supplemented by prepared solid waste and utilizing sewage effluent for cooling tower makeup water. This unit is jointly owned with the Orlando Utilities Commission (OUC) which possesses a 40 percent undivided interest to Lakeland's 60 percent. McIntosh Unit No. 3 became commercial on September 1, 1982.

As load continued to grow, Lakeland has continually studied and reviewed alternatives for accommodating the additional growth. Alternatives included both demand- and supply-side resources.

A wide variety of conservation and demand-side management programs were developed and marketed to Lakeland customers to encourage increased energy efficiency and conservation in keeping with the Florida Energy Efficiency and Conservation Act of 1980 (FEECA). These programs are discussed in further detail in Section 4.0.

In spite of the demand and energy savings from Lakeland's conservation and demand-side management programs, additional capacity was needed. Studies indicated that conversion of one of our existing steam units with a new combustion turbine to a combined cycle unit would result in the least cost to Lakeland's rate payers. These results led to the construction of our Larsen Unit No. 8, a natural gas fired combined cycle unit with a nameplate generating capability of 113 MW. Larsen Unit No. 8 began simple cycle operation in July, 1992, and combined cycle operation in November of 1992.

In 1994, Lakeland made the decision to retire the first unit at Larsen Plant, Steam Unit 4. This unit put in service in 1950 with a capacity of 20,000 kW had reached the end of its economic life. In March of 1997 Lakeland retired Larsen Unit No. 6. Larsen Unit No. 6 was a 25 MW oil fired unit that reached the end of its economic life. Lakeland's existing units are shown in Table 2-1.

2.1.2 Transmission

The first phase of the Lakeland 69 kV transmission system was placed in operation in 1961 with a step-down transformer at the Lake Mirror Plant to feed the 4 kV bus; nine 4 kV feeders; and a new substation in the southwest section of town, with two step--down transformers feeding four 12 kV feeders.

In 1966, a 69 kV line was completed from the Northwest Substation to the Southwest Substation, completing the loop around town. At the same time, the old tie to Bartow was reinsulated for a 69 kV line and placed in operation, feeding a new step-down substation in Highland City with four 12 kV feeders. In addition, a 69 kV line was completed from Larsen Plant around the southeast section of town to the Southwest Substation. By 1972, twenty sections of 69 kV lines, feeding a total of nine step-down substations, with a total of 41 distribution feeders, were completed and placed in service. By the fall of 1996, all of the original 4 kV equipment and feeders had been replaced and/or upgraded to 12 kV service. As Lakeland load and customers continued to grow, the need for additional transmission capacity prompted Lakeland to place into operation the first phase of its 230kV transmission system when McIntosh Unit 3 was built and placed in service in the early 1980's.

Table 2-1
Lakeland Electric and Water Utilities
Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (kW)	Net Capability **		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Charles Larsen Memorial	1	16-17/28S/24E Polk County	GT	NG	F02	10/62	06/99	11,500	10.0	14.0	PL	TK
	2		GT	NG	F02	11/62	Unknown	11,500	10.0	14.0	PL	TK
	3		GT	NG	F02	12/62	Unknown	11,500	10.0	14.0	PL	TK
	5		CW	WH		04/56	Unknown	25,000	29.0	31.0	PL	TK
	6		ST	NG	F06	12/59	Retired	25,000	--	--	--	--
	7		ST	NG	F06	02/66	06/99	50,000	41.5	41.5	PL	TK
	8		CT	NG	F02	07/92	Unknown	101,520	73.0	93.0	PL	TK
Plant Total									173.5	207.5		
C.D. McIntosh, Jr.	IC1	4-5/28S/24E Polk County	IC	F02	NA	01/70	Unknown	2,500	2.5	2.5	TK	--
	IC2		IC	F02	NA	01/70	Unknown	2,500	2.5	2.5	TK	--
	1		GT	NG	F02	05/73	Unknown	26,640	19.0	23.0	PL	TK
	1		ST	NG	F06	02/71	Unknown	103,500	92.0	92.0	PL	TK
	2		ST	NG	F06	06/76	Unknown	126,000	108.0	108.0	PL	TK
	3 *		ST	BIT	NG	09/82	Unknown	363,870	198.0	205.2	RR	TK
Plant Total									422	433.2		
System Total as of December 31, 1996									595.5	640.7		

*Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.

** Net normal.

Source: Lakeland Power Production Unit Rating Group 2/28/97

2.2 General Description: City of Lakeland--Department of Electric & Water Utilities

2.2.1 Load and Electrical Characteristics

Lakeland's load and electrical characteristics have many similarities to other Peninsular Florida utilities. The peak demand has historically occurred during the winter months. Lakeland's peak demand was 552 MW, occurring in February 1997.

Lakeland's historical and projected summer and winter peak demands and net energy for load are presented in section 3.0 for the base, high, and low cases, respectively. Further details of Lakeland's load and electrical characteristics are contained in Appendix A, Electric Load and Energy Forecast Fiscal Year 1996-1997.

Lakeland 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 Kissimmee Utility Authority (KUA). FMPP operates as an hourly energy pool. Commitment and dispatch services for FMPP are provided by OUC. Each member of the FMPP retains the responsibility of adequately planning its own system to meet native load and Florida Reliability Coordinating Council (FRCC) reserve requirements.

2.2.2 Transmission and Interconnections

Lakeland's electric system is interconnected with Florida Power Corporation (FPC) and Orlando Utilities Commission (OUC) via three 230 kV transmission lines, which connect to the West Substation and McIntosh Substation, respectively, and with Tampa Electric Company (TECO) via three 69 kV ties. In mid-1994, a new 69 kV tie-line was energized from the Larsen Plant to the Ridge Generating Station, an independent power producer. In early 1996, a new substation, East, was inserted in the Larsen Plant to Ridge 69 kV line. Later in 1996, the third tie line to TECO was built from East to TECO's Gapway Substation. These ties are sufficient to support the electric system in a peak period. The multiple 230 kV interconnection configuration of Lakeland is also tied into the state bulk transmission grid and provides access to the 500 kV transmission network via FPC. This ultimately provides for greater reliability; however, Lakeland's system has sufficient internal generation to supply its requirements in a peak period independent of its ties. Figure 2-1 shows the Lakeland service territory and transmission facilities.

At the present time, there are a total of twenty 69/12 kV substations, feeding 89 circuits. Included in this total are six 12 kV feeders connected directly to the generator bus at Larsen Plant. Two of the 69/12 kV substations--West and Eaton Park--have a 230/69 kV autotransformer to tie the 69 kV system to Lakeland's internal 230 kV transmission system via the North McIntosh 230 kV switchyard. A third 230/69 kV autotransformer is located at the McIntosh Plant that also ties the 69 kV and 230 kV system together.

2.3 Generating Capability

Lakeland's current generation capability is located at their two existing plants, Charles Larsen Memorial and C.D. McIntosh Jr, both in Polk County Florida. The two plants have multiple units with mixed technology at each plant. Tables 2-1 through 2-3 provide a summary of both plants.

The Larsen site is located on southeast shore of Lake Parker in downtown Lakeland. The site has 6 existing units with a total winter and summer capacity of 207.5 MW and 173.5.5 MW.

The McIntosh site is located on the north side of Lake Parker. The site has 5 existing units with a total winter and summer capacity of 433.2 MW and 422 MW. Figure 2-2 provides an aerial view of the McIntosh site.

2.4 Service Area

Lakeland's electric service area is shown on Figure 2-1 and is entirely located in Polk County. Lakeland serves approximately 246 square miles including approximately 199 square miles outside of Lakeland's city limits.

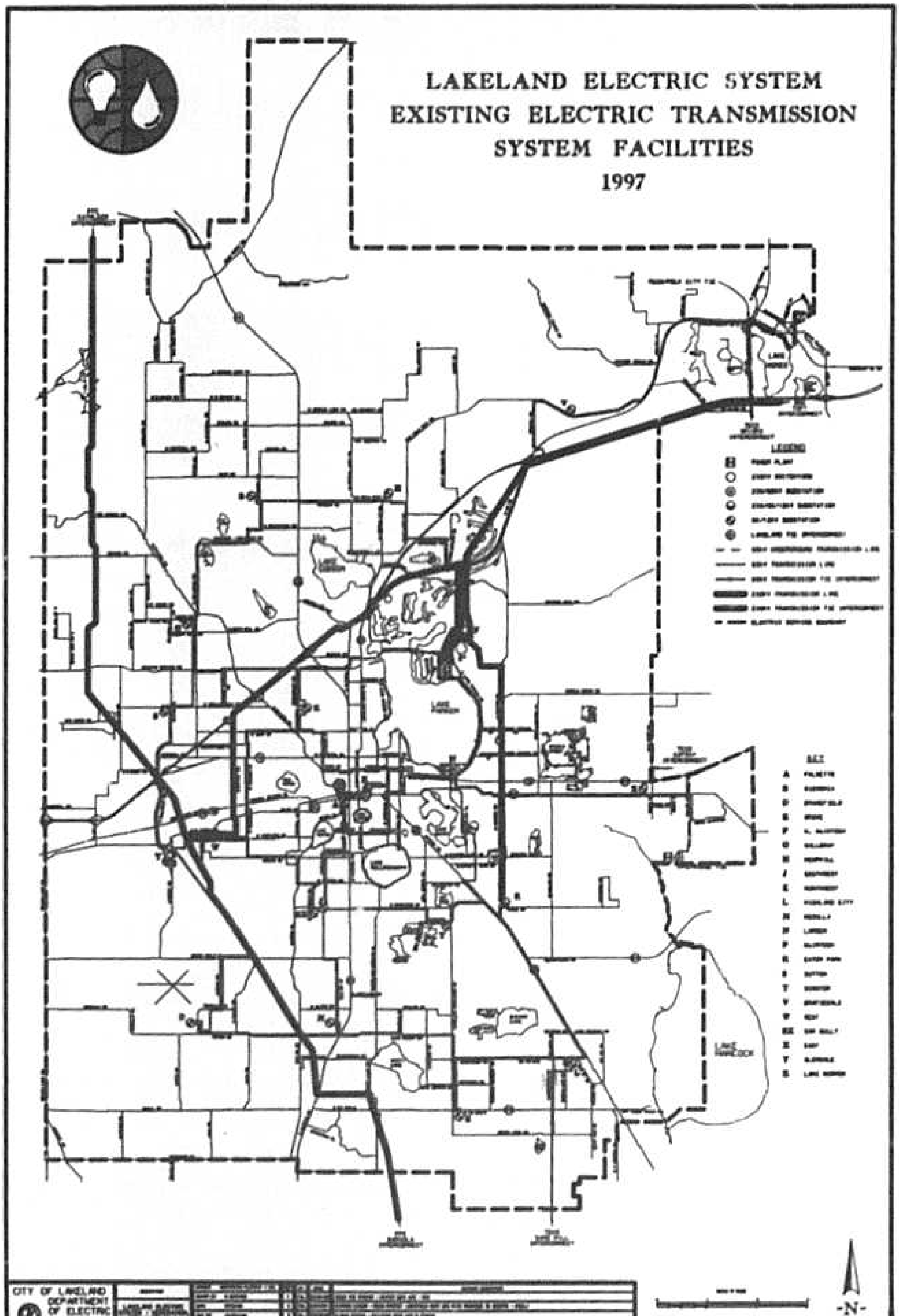
LAKELAND ELECTRIC SYSTEM
EXISTING ELECTRIC TRANSMISSION
SYSTEM FACILITIES
1997
CITY OF LAKELAND
DEPARTMENT
OF ELECTRIC
& WATER
UTILITIES
-N-

Table 2-2
Lakeland Electric and Water Utilities
Existing Generating Facilities Land Use and Investment

Plant Name	Land Area		Plant Capital Investment in $1,000			Total
	Total Acres	In-Use Acres	Land	Site Improvements	Buildings and Equipment	
Charles Larsen Memorial	17.4	8.7	28	N/A	86,905	86,433
C. D. McIntosh, Jr.*	370	300	2,805	N/A	446,820	449,625

*Includes 100 percent of capital investment in McIntosh Unit 3.

Source: Lakeland Finance (CPR System).

Table 2-3
Lakeland Electric and Water Utilities
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

Plant Name	Unit	Particulate	Flue Gas Cleaning		Type
			SO_x	NO_x	
Charles Larsen Memorial	7 8	None N/A	None N/A	None N/A	OTF OTF
C. D. McIntosh, Jr.	1 2 3	None None EP	None LS S	None FGR LNB	OTF WCTM WCTM

FGR = Flue gas recirculation
LNB = Low NO_x burners
EP = Electrostatic precipitators
LS = Low sulfur fuel
S = Scrubbed
OTF = Once-through flow
WCTM = Water cooling tower mechanical
N/A = Not applicable to waste heat applications

Source: Lakeland Environmental Staff

Table 2-3
Lakeland Electric and Water Utilities
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

Plant Name	Unit	Particulate	Flue Gas Cleaning		Type
			SO_x	NO_x	
Charles Larsen Memorial	7	None	None	None	OTF
	8	N/A	N/A	N/A	OTF
C. D. McIntosh, Jr.	1	None	None	None	OTF
	2	None	LS	FGR	WCTM
	3	EP	S	LNB	WCTM

FGR = Flue gas recirculation
LNB = Low NO_x burners
EP = Electrostatic precipitators
LS = Low sulfur fuel
S = Scrubbed
OTF = Once-through flow
WCTM = Water cooling tower mechanical
N/A = Not applicable to waste heat applications

Source: Lakeland Environmental Staff

3.0 Forecast of Electrical Power Demand and Energy Consumption

Lakeland conducts a detailed long-term electric load and energy forecast on an annual basis using econometric techniques for use in long-term planning. Lakeland also conducts a short-term forecast using time-series decomposition models for use in short-term budgeting and planning. Lakeland's detailed forecast is developed on a fiscal year basis and is contained in Appendix A. Lakeland's fiscal year ends on September 30.

Lakeland develops forecasts for the following areas:

- Population.
- Accounts.
- Sales.
- Net energy for load.
- Peak demand.

The following sections discuss each of the forecast areas. The information presented has been converted from Lakeland's fiscal year forecast to a calendar year basis except where specifically noted and is aggregated as required by FRCC.

3.1 Population Forecast

Lakeland utilizes the 1997 Annual Bureau of Economic and Business Research (BEBR) forecast for projections of Polk County population. The service territory population was derived by using the residential accounts inside and outside the city and multiplying by the number of persons per household from the 1994 Appliance Saturation Survey. Service territory population projections were based on a regression using year and Polk County population as independent variables. The projected Polk County and service territory annual populations are presented in Table 3-1. The service territory population is projected to increase at a 1.67 percent average annual growth rate (AAGR) from 1998 through 2007.

Table 3-1
Projected Population Estimates

Year	1997 BEBR Polk County Population	Historical Service Territory Population	Forecasted Service Territory Population
1988	389,720	172,162	
1989	398,938	178,282	
1990	407,717	184,897	
1991	416,149	188,609	
1992	422,729	194,456	
1993	431,654	200,416	
1994	438,528	203,891	
1995	444,870	208,586	
1996	452,873	211,047	
1997	460,876	213,569	
Forecast			
1998	468,880		217,949
1999	476,883		222,329
2000	484,886		226,708
2001	491,804		230,494
2002	498,723		234,280
2003	505,641		238,066
2004	512,560		241,852
2005	519,478		245,638
2006	526,166		249,298
2007	532,854		252,958

3.2 Accounts Forecast

Lakeland forecasts the number of accounts in the following categories:

- Residential.

--General Service.

--General Service Demand.

--General Service Large Demand.

- Other:

--Electric.

--Water.

--Municipal.

--Private Area and Lighting.

For residential, commercial, and industrial accounts, projections are developed for inside and outside the city. The following sections describe the projections which are presented in Table 3-2.

3.2.1 Residential Accounts

The residential account projection for inside the city was based on a regression model using the number of households as the independent variable. The residential account projection for outside the city was based on regression analysis using the Polk County population as the exploratory variable. The projection of the total number of residential accounts was the summation of forecasted residential accounts inside and outside the city. The projected AAGR for residential accounts is 1.47 percent for 1998 through 2007. Annual historical and projected residential accounts are presented in Table 3-2.

3.2.2 Commercial and Industrial Accounts

The General Service account projection for inside the city was based on a regression model using residential accounts as the independent variable. The General Service account projection for outside the city was based on the difference between total commercial accounts and inside the city accounts. The total General Service account projection is the based on historical growth rates for the General Service accounts projections for inside and outside the city.

Table 3-2
Forecast of Total Accounts and Sales For Lakeland

		Rural & Residential			Commercial		
Fiscal Year	Population	GWh	Average # of Customers	kWh/Cust	GWh	Average # of Customers	kWh/Cust
1988	172,162	842	67,712	12,435	462	8,432	54,791
1989	17[illegible]282	913	70,696	12,914	498	8,853	56,252
1990	184,897	948	73,480	12,901	525	9,164	57,289
1991	188,609	967	76,731	12,602	522	9,517	54,849
1992	194,456	987	77,863	12,676	526	9,664	54,429
1993	200,416	1,026	79,738	12,867	542	9,768	55,487
1994	203,891	1,080	81,542	13,245	574	9,967	57,590
1995	208,586	1,169	82,616	14,150	594	9,999	59,406
1996	211,047	1,201	84,089	14,282	589	9,729	60,541
1997	213,569	1,173	84,149	13,940	609	9,816	62,042
Forecast							
1998	217,949	1,233	86,222	14,300	627	9,931	63,136
1999	222,329	1,273	87,656	14,523	644	10,027	64,227
2000	226,708	1,309	89,091	14,693	659	10,122	65,106
2001	230,494	1,346	90,408	14,888	674	10,218	65,962
2002	234,280	1,383	91,727	15,077	690	10,314	66,899
2003	238,066	1,420	93,047	15,261	706	10,411	67,813
2004	241,852	1,457	94,369	15,439	721	10,508	68,614
2005	245,638	1,494	95,693	15,612	736	10,607	69,388
2006	249,298	1,532	96,997	15,794	751	10,704	70,161
2007	252,958	1,571	98,302	15,981	766	10,802	70,913

Table 3-2 (Continued) Forecast of Total Accounts and Sales For Lakeland									
	Industrial			Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Consumers	Resale	Utility Use & Losses	NEL
Fiscal Year	GWh	Average # of Customers	kWh/Cust	GWh	GWh	GWh	GWh	GWh	GWh
1988	310	39	7,948,718	11	56	1,681	0	165	1,846
1989	331	41	8,073,171	11	59	1,812	0	148	1,960
1990	346	44	7,863,636	8	62	1,889	0	108	1,997
1991	344	45	7,644,444	11	61	1,905	0	138	2,043
1992	356	47	7,574,468	13	65	1,947	0	143	2,090
1993	381	51	7,470,588	13	68	2,030	0	155	2,185
1994	400	51	7,843,137	14	69	2,137	0	146	2,283
1995	427	51	8,372,549	15	74	2,279	0	146	2,425
1996	589	59	9,983,051	15	78	2,472	0	102	2,574
1997	459	61	7,524,590	16	78	2,335	0	115	2,450
Forecast									
1998	479	63	7,603,175	16	83	2,438	0	140	2,578
1999	498	65	7,661,538	17	85	2,517	0	138	2,655
2000	514	67	7,671,642	18	89	2,589	0	143	2,732
2001	530	68	7,794,118	18	93	2,661	0	146	2,807
2002	546	70	7,800,000	19	95	2,733	0	149	2,882
2003	562	72	7,805,556	19	98	2,805	0	152	2,957
2004	578	73	7,917,808	20	101	2,877	0	155	3,032
2005	595	75	7,933,333	21	103	2,949	0	159	3,108
2006	611	76	8,039,474	21	108	3,023	0	161	3,184
2007	627	78	8,038,462	22	110	3,096	0	164	3,260

The General Service Large Demand Account projection for inside the city was based on a regression model using population as the independent variables. The General Service Large Demand accounts outside the city projection is the difference between the total number of General Service Large Demand accounts and the number of General Service Large demand accounts inside the city. The projection of the total number of General Service Large Demand accounts is the sum of the General Service Large Demand account projections for inside and outside the city.

The commercial and industrial customer forecasts are presented in Table 3-2. The number of commercial and industrial customers are projected to increase at AAGR of 0.94 and 2.40 percent, respectively from 1998 through 2007.

3.2.3 Other Accounts

The Electric account projection was based on historical growth rate. The Electric accounts are only 0.03 percent of the total accounts.

Water accounts are any nonelectric account including the water plant, water production, pumps, and wells. Water accounts are projected to grow at approximately one new account every 6 years.

The Municipal account projection was based on a regression model using labor and lagged population as the independent variables. The projections indicate approximately ten new accounts a year for the planning horizon.

The Private Area Lighting accounts projection was based on a weighted average of two regression models applying year and residential accounts inside the city as the independent variables. The projections indicate approximately 50 new private area lighting accounts a year inside the city.

3.3 Sales Forecast

Lakeland develops sales forecasts for each of the account categories presented in Section 3.2. The sales forecasts take into consideration a price reduction for anticipated deregulation.

3.3.1 Residential Sales

Residential sales projections inside the city were based on a regression model using residential accounts inside, population, heating and cooling degree days, and real per capita income as the independent variables. Residential sales outside the city were based on the difference between total residential sales and residential sales inside the city. Residential sales are projected to have an AAGR of 2.73 percent from 1998 through 2007 and are presented in Table 3-2.

3.3.2 Commercial and Industrial Sales

General Service sales projections inside the city were based on a regression model using General Service accounts inside the city, population, and labor as the independent variables. General Service sales outside the city were based on a regression model using General Service accounts outside the city and population as the independent variables. Total General Service sales are the sum of General Service sales inside and outside the city.

General Service Demand sales projections inside the city were based on a regression model using General Service Demand accounts inside and labor as the independent variables. The General Service Demand sales outside the city were based on a regression model using population and real per capita income as the independent variables. The total General Service Demand sales were the summation of the inside and outside General Service Demand sales.

General Service Large Demand sales projections inside the city were based on a regression model using heads of households and real per capita income as the independent variables. General Service Large Demand sales outside the city are the difference between the Total General Service Large Demand sales and total General Service Large Demand sales inside the city. Total General Service Large Demand Sales projections were based on a regression model using real per capita income and population as the independent variable.

Commercial and industrial sales have projected AAGR of 2.25 and 3.04 percent, respectively for 1998 through 2007, and are presented in Table 3-2.

3.3.3 Other Sales

Municipal sales projections were based on a regression model using year and real per capita income as the independent variables. Private Area Lighting sales were based on a regression model using private area light accounts and residential accounts inside as the independent variables. Water sales were projected based on the historical trend.

Unmetered sales are those derived from municipal lighting. Projections were based on a historical trend using Polk County population. Electric sales projections were based a historical trend of sales and accounts.

Street and highway lighting and other sales have projected AAGRs of 3.60 and 3.18 percent respectively for 1998 through 2007 and are presented in Table 3-2.

3.3.4 Total Sales

The total sales forecast for the City of Lakeland is a summation of the individual forecasts provided above. Summation of total sales indicates an AAGR of 2.69 percent from 1998 through 2007. This is a lower growth rate than experienced in the past. A 3.72 percent AAGR was experienced over the last 10 years of historical sales. Historical and projected total sales are presented in Table 3-2.

3.4 Net Energy for Load Forecast

Lakeland projects net energy for load based on a regression model using year as the independent variable. The model has an adjusted R-squared of 98.0 percent. Lakeland projects losses to remain relatively constant in the short-term and begin to decrease slightly in the long-term. Lakeland's projection of net energy for load includes the effect of conservation. Historical and projected utility use and losses and net energy for load are presented in Table 3-2.

The projected net energy for load including conservation for the base, high, and low cases are presented in Table 3-3. The projected AAGR for the base case is 2.64 percent for 1998 through 2007. The projected AAGR represents a reduction from the historical AAGR of 3.20 percent for the last 10 years.

3.5 Peak Demand

Lakeland forecasts winter and summer peak demands using regression models. The winter season is defined as November through March and the summer season is defined as April through October. The regression model for the winter peak demand used minimum temperature, day of the week, and prior day's average temperature as the independent variables. The regression model for the summer peak demand used maximum temperature and population as the independent variables. The minimum and maximum temperatures used for projecting peak demand were 30° F and 97° F, respectively.

Projections of the coincident demand for customers that are on the Interruptible Rate were made and used to reduce the projection of total peak demand. Projections of the effect of Lakeland's load management program were likewise made and used to reduce the projection of total peak demand.

Projections of summer peak demand for the base, high, and low cases are included in Tables 3-4, 3-5, and 3-6, respectively. The projected AAGR for the summer peak demand for the base case is 2.25 percent for 1998 through 2007.

Table 3-3
Projected Net Energy for Load Including Conservation (GWh)

Year	Base	High	Low
1998	2,578	2,578	2,578
1999	2,655	2,663	2,612
2000	2,732	2,768	2,662
2001	2,807	2,872	2,709
2002	2,882	2,978	2,755
2003	2,957	3,086	2,800
2004	3,032	3,196	2,843
2005	3,108	3,307	2,885
2006	3,184	3,422	2,928
2007	3,260	3,538	2,969

Table 3-4
Forecast of Summer Peak Demand (MW) - Base Case

Year	Total	Interruptible	Load Management	Net Firm Demand
1998	523	5	21	497
1999	537	5	22	510
2000	551	5	22	524
2001	563	5	23	535
2002	576	5	23	548
2003	589	5	24	560
2004	601	5	25	571
2005	614	5	25	584
2006	626	6	26	594
2007	639	6	26	607

Table 3-5
Forecast of Summer Peak Demand (MW) - High Growth

Year	Total	Interruptible	Load Management	Net Firm Demand
1998	523	5	21	497
1999	549	5	22	522
2000	577	5	22	550
2001	604	5	23	576
2002	633	5	23	604
2003	661	5	24	632
2004	691	5	25	661
2005	722	6	25	691
2006	754	6	26	722
2007	787	6	26	755

Table 3-6
Forecast of Summer Peak Demand (MW) - Low Growth

Year	Total	Interruptible	Load Management	Net Firm Demand
1998	523	5	21	497
1999	525	5	22	498
2000	524	5	22	497
2001	524	5	23	496
2002	520	5	23	494
2003	519	5	24	492
2004	518	5	25	490
2005	515	5	25	487
2006	514	6	25	484
2007	511	6	26	481

Projections of winter peak demand for the base, high, and low cases are included in Tables 3-7, 3-8, and 3-9, respectively. The projected AAGR for the winter peak demand for the base case is 2.85 percent for 1998 through 2007.

Table 3-7
Forecast of Winter Peak Demand (MW) - Base Case

Fiscal Year	Total	Interruptible	Load Management	Net Firm Demand
1998	626	5	51	570
1999	645	5	52	588
2000	665	5	53	607
2001	685	5	54	626
2002	705	5	55	645
2003	725	5	57	663
2004	745	5	58	682
2005	765	5	59	701
2006	785	5	60	720
2007	805	5	61	739

Table 3-8
Forecast of Winter Peak Demand (MW) - High Growth

Fiscal Year	Total	Interruptible	Load Management	Net Firm Demand
1998	626	5	51	570
1999	659	5	52	602
2000	695	5	53	637
2001	732	5	54	673
2002	770	5	55	710
2003	810	5	57	748
2004	851	5	58	788
2005	894	5	59	830
2006	938	5	60	873
2007	984	5	61	918

Table 3-9
Forecast of Winter Peak Demand (MW) - Low Growth

Fiscal Year	Total	Interruptible	Load Management	Net Firm Demand
1998	626	5	51	570
1999	630	5	52	573
2000	635	5	53	577
2001	640	5	54	581
2002	644	5	55	584
2003	648	5	57	586
2004	651	5	58	588
2005	653	5	59	589
2006	656	5	60	591
2007	657	5	61	591

4.0 Conservation and Demand Side Management

The City of Lakeland, Department of Electric & Water Utilities, is committed to reducing system demand and promoting more efficient use of electric energy, to the extent to which it is cost-effective, for all its consumers. Lakeland has in place several cost-effective Demand-Side Management (DSM) programs and is aggressively pursuing additional conservation and DSM programs. Presented in this section are the existing programs, the description and evaluation of additional programs, analysis of replacing oil as the primary fuel for Lakeland's existing plants, and Lakeland's DSM marketing plan. Further details can be found in Lakeland's Demand Side Management Plan which is on file with the Florida Public Service Commission. Savings due to the conservation and DSM programs have been updated to reflect the savings incorporated in the Electric Load and Energy Forecast Fiscal Year 1997-98 in Appendix A.

4.1 Existing Conservation and Demand Side Management Program

Lakeland has several existing conservation and demand-side management programs that are currently available and address four major areas of demand-side management:

- Reduction in weather-sensitive peak loads.
- Reduction of energy needs on a per-customer basis.
- Movement of energy to off-peak hours when it can be generated more efficiently.
- Reduce use of expensive petroleum fuels.

The programs can be divided into two groups: those programs with demonstrable demand and energy savings and programs that cannot measure the impact of demand and energy savings.

4.1.1 Existing Programs with Demonstrable Demand and Energy Savings

Lakeland has several programs that demonstrate demand and energy savings for the system. The following are programs that are in place currently:

- Residential Programs
  - SMART Load Management Program.
  - Loan Program.
- Commercial Programs.
  - Commercial Lighting Program.
    - Thermal Energy Storage Program.
    - High-Pressure Sodium Outdoor Lighting Program.

4.1.1.1 Residential Programs.

4.1.1.1.1 SMART Load Management Program. In 1981, Lakeland began the load management program. The program focused on the direct load control of electric water heaters to reduce peak demand. The program was changed in 1990 to cyclically control heating, air conditioning, and ventilation systems, combined with continuous control of water heating. This change came about as newer more cost effective control technologies became available. This made control of HVAC systems cost-effective along with continued control of hot water heaters.

Lakeland required all new residential construction projects to have mandatory controls when the program was expanded. Lakeland has since relaxed the mandatory portion of the program for new customers due to diminished cost-effectiveness of the program. The program remains as a voluntary program which is still enjoying good response from its customers and continued demand savings. The SMART program is projected to reduce winter and summer peak demand by 90 and 40 MW, respectively by 2007.

4.1.1.1.2 Loan Program. The City of Lakeland is the administrator for the Loan Program which provides assistance to customers to improve their home's thermal efficiency by upgrading strip heat and split type heating systems to more efficient and economical heat pumps. This program also covers additional insulation and caulking when the customer upgrades their heating system. This is accomplished through a secured utility subsidized, 8 percent low interest loan for 5 years provided through a specific local bank.

By 2007, this program is projected to save 1.7 MW and 1807 MWh annually.

4.1.1.2 Commercial Programs.

4.1.1.2.1 Commercial Lighting Program. The commercial lighting program began in 1996 to enhance/maintain customer lighting levels while reducing the facility's associated energy needs. Commercial/Industrial Account Managers, in conjunction with energy consultants perform a thorough lighting audit and provide customers with up-to-date lighting efficiency standards from the Florida Building Code and Federal Energy Policy Act of 1992. Customers are shown that through the installation of energy efficient fixtures these goals can be realized. Account Managers also show how quickly a lighting investment can be paid back based on associated energy savings. The commercial lighting program is projected to save 0.1 MW and 107 MWh annually by 2007.

4.1.1.2.2 Thermal Energy Storage Program. The Thermal Energy Storage (TES) program has provided Lakeland's commercial and industrial customers an effective method of transferring cooling and heating requirements to off-peak time periods. This is accomplished through TES systems that are on par in efficiency with standard systems. Lakeland is implementing two rate tariffs which are designed for load shift technologies, such as TES. This provides further economic incentive for customers to switch to TES technologies.

4.1.1.2.3 High-Pressure Sodium Outdoor Lighting Program. This program is structured to reduce lighting demands with the replacement of mercury vapor street lights with more energy efficient high-pressure sodium (HPS) lights. The HPS lights reduce energy consumption while maintaining the same level as lighting.

Currently, all street lights within the city limits are now high pressure sodium bulbs. Private-area lights will continue to be replaced as time allows, while all new lighting will use the HPS lights.

4.1.2 Existing Programs with No Demonstrable Demand and Energy Savings

The programs outlined in this section provide no demonstrable demand and energy savings that can be accounted for but are very important for several reasons. The value added of each of these programs is an important part to reducing energy consumption:

- Residential Programs:
  - Energy Audit Program.
  - Public Awareness Program.
  - Mobile Display Unit.
  - Speakers Bureau.
  - Informational Bill Inserts.
- Commercial Programs:
  - Commercial Audit Program.

4.1.2.1 Residential Programs.

4.1.2.1.1 Residential Energy Audits. The Energy Audit Program provides Lakeland with a valuable customer interface and a good avenue for increased customer awareness. The program promotes high energy efficiency in the home and gives the customer an opportunity to learn about other utility conservation programs.

4.1.2.1.2 Public Awareness Program. It is Lakeland's opinion that there exists no greater conservation resource than an informed public. Public awareness programs provide customers with information to help them reduce their electric bills by being more conscientious in their energy use.

4.1.2.1.3 Mobile Display Unit. The mobile display unit is presented at a number of area activities each year, including the Engineering Expo held at the University of South Florida and the Polk County Home Show. The display centers on themes of energy and water conservation, including electric safety.

4.1.2.1.4 Speakers Bureau. Lakeland provides speakers to local group meetings to help inform the public of new energy-efficiency technologies and ways to conserve energy in the commercial and residential sectors.

4.1.2.1.5 Informational Bill Inserts. Monthly billing statements provide an excellent avenue for communicating timely energy conservation information to its customers. In this way, the message of better utilizing their electric resources is presented on a regular basis in the most cost-effective manner.

4.1.2.2 Commercial Programs

4.1.2.2.1 Commercial Energy Audits. The Commercial Audit Program includes discussions of high-efficiency lighting and thermal energy storage analysis for customers to consider in their efforts to reduce costs associated with their electric usage.

4.1.3 Demand Side Management Technology Research

Lakeland has made a commitment to study and review promising technologies in the area of conservation and demand-side management when resources allow.

4.1.3.1 Direct Expansion Ground-Source Heat Pump Study. In cooperation with ECR Technologies of Lakeland, Lakeland was given the Governor's Energy Award for work in the evaluation and analysis of direct expansion ground-source heat pump (GSHP) technology. A study of the demand and energy savings associated with this technology has been completed in an effort to establish its cost-effectiveness for new construction, as well as retrofitting the technology to existing homes. This technology will reduce weather sensitive loads and promote greater energy efficiency for Lakeland's' system.

4.1.3.2 Whole-House Demand Controller Study. This technology is not cost-effective and cannot compete with other alternatives available at this time. A large amount of information is maintained by Lakeland for this technology and will be monitored for changes in the effectiveness.

4.1.3.3 Time-of-Day Rates. There has been limited interest by Lakeland's customers in this demand side management program. Lakeland is currently offering this program and will continue. It is the hope of Lakeland that Time-of-day rates will draw more attention combined with TES systems discussed earlier.

4.2 Description of Additional Conservation and Demand Side Management Programs

The City of Lakeland is considering several alternatives for future conservation and demand-side management programs. The application of solar technology in Lakeland's system has many promising aspects. Lakeland has three solar projects under current consideration:

(1) Distributed Generation Energy using Solar-Thermal Collectors.

(2) Utility-Interactive Residential Photovoltaic Systems.

(3) Integrated Photovoltaics for Florida Residences.

4.2.1 Distributed Generation Energy Using Solar-Thermal Collectors

Distributed generation produces the energy in end use form at the point of load by the customer, thereby, eliminating many of the costs, wastes, pollutants, and other objections to central station generation. Water heating provides the most reasonable opportunity to use the sun's energy. The sun's energy is stored directly in the energy of the heated water itself, reducing the effect of converting the energy to other forms. Lakeland is striving to remove the risk on the capital expenditure of a solar heating array with a utility owned solar heating system. The unit would not place risk on the consumer and can be installed and removed with minimal impact. The consumer would be billed for the service by a meter attached to the unit, but would not have to buy the unit itself.

4.2.2 Utility-Interactive Residential Photovoltaic Systems

This project is a collaborative effort between the Florida Energy Office (FEO), Florida Solar Energy Center (FESC), City of Lakeland, and Siemens Solar Industries. The primary objectives of this program are to develop approaches and designs that integrate photovoltaic (PV) arrays into residential buildings, and to develop reasonable requirements for the interconnection of PV systems into the utility grid.

The program will evaluate the operation and analyses of six residential photovoltaic systems. All six PV systems will be grid-interactive and will have a nominal power rating of approximately 2 kilowatts peak (kWp) at standard test conditions. The period of performance for this project is three years, starting in the spring of 1997.

4.2.3 Integrated Photovoltaics for Florida Residences

This program would provide research into the integrated photovoltaics into newly constructed homes. The program would construct two new homes of the same design and construction except one unit would contain a 3 kW PV system. The units would be measured for performance under two conditions: unoccupied and occupied. data would be collected for end use load, and PV system interface.

4.3 Evaluation of Additional Conservation and Demand Side Management Programs

Lakeland is in the process of evaluating additional conservation and demand side management programs on a continual basis. The evaluation method is consistent with the Demand Side Management Plan approved by the FPSC in April of 1995. The method of evaluation includes the Florida Integrated Resource Evaluator (FIRE) model with the Rate Impact Measure Test (RIM) and Total Resource Calculation Test (TRC). As new conservation and demand side management programs are determined to be cost-effective, they will be implemented.

4.4 Replacement of Oil as Boiler Fuel

4.4.1 Coal Generation at McIntosh Unit No. 3

Lakeland's current primary method to reduce oil consumption is the burning of coal in McIntosh Unit No. 3, a coal-fired steam generator plant rated at 342 MW. This unit is jointly owned with Orlando Utilities Commissions (OUC). This unit displaces approximately four million barrels of residual oil a year.

4.4.2 Refuse Generation at McIntosh Unit No. 3

McIntosh Unit No. 3 is capable of handling up to 25 tons of solid refuse per hour. Refuse is transported to a processing building at the plant and shredded. Ferrous material is removed from the refuse with the remainder blown into the boiler. Currently the unit can burn an amount in excess of the waste generated by Lakeland residents. This unit displaces approximately 50,000 barrels of oil a year through the burning of RDF.

4.4.3 Natural Gas Ignitor Retrofit

McIntosh UnitNo. 3 was orginally designed with #2 oil ignitors to start the unit and to add flame stabilization at certain load points. This unit has now had natural gas ignitors retrofitted to reduce the consumption of oil even further.

4.4.4 Natural Gas Generation at Larsen Unit No. 8

Larsen Unit 8 is a gas-fired combined cycle unit with a nameplate rating of 114 MW using natural gas as the primary fuel. This unit displaces approximately 580,000 barrels of oil yearly.

4.4.5 Additional Proposed Coal Generation at McIntosh Unit No. 4

With the proposed addition of McIntosh Unit No. 4, approximately 2 million barrels of oil will be displaced on an annual basis.

4.5 Demand Side Management Plan (Marketing Plan)

The development of Lakeland's Conservation Plan utilizes a combination of information acquired from several sources. One of these sources is the Department of Electric & Water Utilities' Demand-Side Management Plan.

The need for a DSM Plan stems from three requirements: first, to provide management with the information necessary to establish future utility policies and goals; second, to enhance customer awareness and participation in the utility demand-side management program and services; and third, to provide support data to serve as a basis for evaluating budget development and performance measurement of demand-side efforts. The DSM Plan attempts to address these needs by recommending objectives, priorities, schedules, and strategies for present and future demand-side efforts.

This plan is designed to actively market and track the performance of all utility conservation efforts. Utilizing a review of both historical and market research, the DSM Plan is modified annually for the upcoming year.

5.0 Forecasting Methods and Procedures

5.1 Integrated Resource Planning

Lakeland has used an integrated resource planning process for a number of years. Lakeland's planning process gives equal weight to conservation and demand side management measures in meeting its customers' requirements. The integrated resource planning process employed by Lakeland continuously monitors supply and demand side alternatives and as promising alternatives emerge, they are included in the evaluation process.

5.2 Florida Municipal Power Pool

Lakeland is a member, along with the Orlando Utilities Commission (OUC), Kissimmee Utility Authority, 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 (i.e., one conglomerate utility). All FMPP capacity resources, 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. Any member of the FMPP can withdraw from FMPP with 1 year written notice. Lakeland, therefore, must ultimately plan on a stand-alone basis.

5.3 Fuel Price Forecast and Availability

5.3.1 Fuel Price Projections

The forecast presents Lakeland's analysis of fuel prices and current market projections. The fuel price forecast covers coal, natural gas, fuel oil, refuse derived fuel (RDF), and petroleum coke.

Lakeland's delivered fuel cost projections for the base, high, and low cases are presented in Tables 5-1, 5-2, and 5-4, respectively. Details of the fuel cost projections are presented in Appendix B.

Lakeland's units are assumed to burn the primary fuel indicated in Table 2-1 in Section 2.0. For units shown burning No. 6 fuel oil, the high sulfur oil prices from Tables 5-1, 5-2, and 5-3 are assumed. McIntosh 3 burns a combination of RDF, petroleum coke, and coal. McIntosh 3 is assumed to burn approximately 58,000 tons of petroleum coke annually and 45,000, 60,000, and 40,000 tons annually of RDF under the base, high, and low cases, respectively. Table 5-4 presents the average fuel price for McIntosh 3.

Lakeland is currently purchasing approximately 90 percent of the coal requirements for McIntosh 3 under 1 year contracts with the remainder of coal requirements purchased on the spot market. Lakeland's current contracts are with Shamrock (Sun Coal) and Consol Coal. The contract with Shamrock is for the current year with the possibility of extending two additional years. The contract with Consol Coal is a one year term agreement.

Table 5-1
Delivered Fuel Price Forecast--Base Case

Year	Petroleum Coke	Coal	High Sulfur Oil	Low Sulfur Oil	Diesel	RDF	Natural Gas
1998	1.06	1.74	3.06	4.29	4.44	(2.25)	2.28
1999	1.09	1.76	3.09	4.33	4.53	(2.30)	2.30
2000	1.15	1.78	3.14	4.40	4.63	(2.36)	2.32
2001	1.17	1.80	3.19	4.47	4.73	(2.42)	2.34
2002	1.19	1.82	3.24	4.54	4.82	(2.47)	2.36
2003	1.21	1.84	3.30	4.63	4.92	(2.53)	2.39
2004	1.23	1.86	3.37	4.72	5.01	(2.58)	2.43
2005	1.25	1.88	3.44	4.82	5.13	(2.64)	2.47
2006	1.27	1.90	3.52	4.93	5.25	(2.70)	2.53
2007	1.29	1.92	3.60	5.05	5.45	(2.76)	2.59

Table 5-2
Delivered Fuel Price Forecast--High Price Forecast

Year	Petroleum Coke	Coal	High Sulfur Oil	Low Sulfur Oil	Diesel	RDF	Natural Gas
1998	1.06	1.74	3.06	4.29	4.44	(2.25)	2.28
1999	1.11	1.79	3.14	4.39	4.60	(2.27)	2.33
2000	1.18	1.83	3.23	4.53	4.77	(2.29)	2.39
2001	1.22	1.88	3.33	4.67	4.94	(2.32)	2.45
2002	1.26	1.93	3.44	4.81	5.11	(2.33)	2.50
2003	1.30	1.98	3.55	4.98	5.29	(2.35)	2.57
2004	1.34	2.03	3.68	5.15	5.47	(2.36)	2.65
2005	1.38	2.08	3.81	5.34	5.68	(2.38)	2.74
2006	1.43	2.14	3.96	5.54	5.90	(2.40)	2.85
2007	1.47	2.19	4.11	5.76	6.21	(2.42)	2.96

Table 5-3
Delivered Fuel Price Forecast--Low Price Forecast

Year	Petroleum Coke	Coal	High Sulfur Oil	Low Sulfur Oil	Diesel	RDF	Natural Gas
1998	1.06	1.74	3.06	4.29	4.44	(2.25)	2.28
1999	1.07	1.73	3.04	4.27	4.46	(2.33)	2.27
2000	1.12	1.73	3.05	4.27	4.49	(2.43)	2.25
2001	1.12	1.72	3.05	4.27	4.52	(2.53)	2.24
2002	1.12	1.71	3.05	4.28	4.54	(2.62)	2.22
2003	1.12	1.71	3.06	4.30	4.57	(2.72)	2.22
2004	1.13	1.70	3.08	4.32	4.58	(2.82)	2.22
2005	1.13	1.69	3.10	4.34	4.63	(2.92)	2.22
2006	1.13	1.69	3.13	4.38	4.66	(3.03)	2.25
2007	1.13	1.68	3.15	4.42	4.77	(3.15)	2.26

Table 5-4 McIntosh 3 Fuel Price	
Year	**$/MBtu**
1998	1.56
1999	1.58
2000	1.60
2001	1.62
2002	1.64
2003	1.66
2004	1.68
2005	1.70
2006	1.71
2007	1.73

Lakeland currently purchases natural gas transportation from Florida Gas Transmission Co. (FGT) under two contracts, FGTS1 and FGTS2. Lakeland's entitlement are presented in Table 5-5. In 1992, Lakeland entered a 10 year fixed price natural gas contract with Natural Gas Clearing House. The contract expires in 2002.

Lakeland currently has a 3 year contract for petroleum coke which expires at the end of 1998. Details of Lakeland's fuel and transportation contracts are presented in Appendix B.

5.4 Economic Parameters and Evaluation Criteria

This section presents the assumptions applied for economic parameters and projections of prices used in the Ten-Year Site Plan. The assumptions stated in this section are applied consistently throughout. Subsection 5.4.1.1 outlines the basic economic assumptions while Subsection 5.4.1.2 discusses the evaluation criteria.

5.4.1 Economic Parameters.

5.4.1.1 Escalation rates. A 2.5 percent annual escalation rate is used for operation and maintenance (O&M) costs based on the US Consumer Price Index (CPI). A 2.0 percent annual escalation rate is used for capital costs based on the Producer Price Index (PPI).

5.4.1.1.2 Present worth discount rate. The present worth discount rate is 10.0 percent.

5.4.2 Evaluation Criteria.

Lakeland is planning to pay for capital additions with internally generated funds. Capital cost estimates will, thus, be evaluated using overnight construction costs escalated to the date of commercial operation.

5.5 Economic Evaluation Methodology

Economic evaluation is conducted over a 20 year period from 1998 through 2017. The economic evaluation is based on the cumulative present worth of annual costs for capital costs, nonfuel O&M costs, fuel costs, and purchase power demand, energy, and transmission costs. Costs that are common to all expansion alternatives, such as demand charges for existing firm purchases, conservation and demand side management, transmission and distribution costs, and administrative and general costs are not included. Capital costs for new generating units are included in the year of commercial operation.

Evaluation of the generating unit alternatives was performed using Black & Veatch's optimal generation expansion model POWROPT. POWROPT evaluates all combinations of generating unit alternatives and selects the alternatives that provide the lowest cumulative present worth revenue requirements. POWROPT uses an hourly chronological approach to developing the production cost. The results of several scenarios are contained in the schedules provided following this report.

Black & Veatch's POWRPRO chronological production costing program is used to obtain the detailed system and unit performance of expansion plans selected by POWROPT. POWRPRO is used by POWROPT to determine production costs.

POWRPRO explicitly models operating and spinning reserve requirements. Lakeland's operating and spinning reserve requirements are determined by the FMPP operating agreement. Lakeland's operating and spinning reserves have been modeled as 18.3 MW of operating reserves plus 16 MW of spinning reserves.

Table 5-5
FGT Entitlements

Period 1998-1999	FGTS1 (MBtu/day)	FGTS2 (MBtu/day)	Total (MBtu/day)
January	3,261	13,444	16,705
February	3,261	13,444	16,705
March	3,261	13,444	16,705
April	4,172	16,748	20,920
May	8,306	20,223	28,529
June	8,306	20,223	28,529
July	8,306	20,223	28,529
August	8,306	20,223	28,529
September	8,306	20,223	28,529
October	9,952	20,948	30,900
November	3,261	13,444	16,705
December	3,261	13,444	16,705
Annual	2,196,901	6,275,991	8,472,892

Table 5-5 (Continued)
FGT Entitlements

Period 2000-2018	FGTS1 (MBtu/day)	FGTS2 (MBtu/day)	Total (MBtu/day)
January	0	13,444	13,444
February	0	13,444	13,444
March	0	13,444	13,444
April	0	16,748	16,748
May	0	20,223	20,223
June	0	20,223	20,223
July	0	20,223	20,223
August	0	20,223	20,223
September	0	20,223	20,223
October	0	20,948	20,948
November	0	13,444	13,444
December	0	13,444	13,444
Annual	0	6,275,991	6,275,991

6.0 Forecast of Facilities Requirements

6.1 Need for Capacity

This section addresses the need for additional electric capacity to serve the demands of Lakeland's electric customers in the future. The need for capacity is based on Lakeland's load forecast, reserve margin requirements, existing generating and purchase power capability, scheduled retirements of generating units, and expiration of purchase power contracts.

6.1.1 Load Forecast

The load forecast described in Section 3.0 and Appendix A will be used to determine the need for capacity. A summary of the load forecast for winter and summer peak demand for base, high, and low projections is provided in Table 6-1. The peak demands presented in Table 6-1 reflect reductions for Lakeland's conservation and demand side management programs.

6.1.2 Reserve Requirements

The FPSC currently requires a 15 percent reserve margin for all utilities to maintain a reliable system grid. Lakeland has adopted the FPSC's 15 percent reserve margin requirement. Inspection of the loss of load probability (LOLP) and expected unserved energy (EUE) is also viewed in the reliability analysis.

6.1.3 Existing Generating Capacity

Lakeland's current generating capacity, as outlined in Section 2.0, consists of the C.D. McIntosh and Larsen Memorial Plants. Lakeland's ownership of capacity installed at the McIntosh and Larsen Plants is 640 MW in the winter and 595 MW in the summer. Lakeland's McIntosh Unit 3 has lost capacity over the years due to normal wear and aging. The maintenance outage scheduled for spring of 1998 is expected to regain 15MW of that lost capacity. Lakeland's share of that capacity would be 9MW as a 60% owner in the unit.

6.1.4 Existing Purchases

Lakeland currently has one firm power purchase contract. The contract is with ENRON Power Marketing for 20 MW with a maximum annual capacity factor of 10 percent. The contract expires December 31, 2001. A second contract with Tampa Electric Company (TECO) for 10 MW that was intended to go through September 30, 2006, was terminated at TECO's request. Lakeland has since secured a short term seasonal capacity purchase from the Orlando Utilities Commission for the winter season of 1997/98. This contract is for 60 MW of firm capacity. Lakeland will secure other short term seasonal capacity purchases for the winter season of 1998/99 to cover peak load and reserve requirements until the next generation addition is completed and in service.

6.1.5 Retirements

Larsen Unit 6 reached the end of its economic life and was retired in March of 1997. Larsen CT1 has also reached the end of its economic life for Lakeland and will be retired by June of 1999. Larsen unit 7 is also reaching the end of its economic life and is expected to be retired shortly after commercial operation of Lakeland's next capacity addition. The target date for the Unit 7 retirement is also June 1999. These retirements will further reduce Lakeland's generating capacity by 55.5 MW in winter and 53.5 MW in summer.

6.1.6 Additional Capacity Requirements

Lakeland's requirements for additional capacity are presented in Table 6-2. The capacity requirements are based on the winter peak demand forecast presented in Table 6-1. While Lakeland's existing generating units have a higher net capability in winter than they do in summer (640 MW compared to 595 MW), the winter peak demand is also higher making the winter peak the governing load for capacity requirements. The additional capacity requirements in Table 6-2 reflect the retirements of the previously listed units. The additional capacity requirements in Table 6-2 does *not* include the reference plan identified in the economic evaluation. Table 8-1 in section 8.0 provides the same table with the identified reference plan.

Table 6-2
Additional Capacity Requirements

Year	Peak Demand (Winter)			Existing Generating Capacity	Reserve Margin (15%)			Existing Purchase	Excess/(Deficit)		
	Base	High	Low		Base	High	Low		Base	High	Low
1998	575	575	575	640	86	86	86	80	59	59	59
1999	593	607	578	585	89	91	87	80	(17)	(33)	0
2000	612	642	582	585	92	96	87	20	(99)	(133)	(64)
2001	631	678	586	585	95	102	88	20	(121)	(175)	(69)
2002	650	715	589	585	98	107	88	0	(163)	(237)	(92)
2003	668	753	591	585	100	112	89	0	(183)	(280)	(95)
2004	687	793	593	585	103	119	89	0	(205)	(327)	(97)
2005	706	835	594	585	106	125	89	0	(227)	(375)	(98)
2006	725	878	596	585	109	132	89	0	(249)	(425)	(100)
2007	744	923	596	585	112	138	89	0	(271)	(476)	(100)

*Existing Generating Capacity does not include planned addition of generating units.

6.2 Description of Generating Unit Alternatives

Twenty one generating unit alternatives were selected for consideration in Lakeland's expansion plan. The alternatives cover a broad range of fuel types, sizes, and technologies. The size of the alternatives selected considers Lakeland's need for capacity, the size of Lakeland's system, and consideration of the impact of the loss of a unit. The alternatives considered include specific alternatives that Lakeland has studied in the past as well as generic alternatives. Combustion turbine based alternatives are based on the specific size and performance of specific machines, but are not intended to limit consideration to only those machines. There are a number of combustion turbines available from different manufacturers with similar sizes and performance characteristics. Generating unit alternatives that are currently being considered for capacity expansion include the following:

- Pressurized Fluidized Bed (PFB).
- Atmospheric Circulating Fluidized Bed (CFB).
- Pulverized Coal.
- Combined Cycle.
- Simple Cycle.
- Repowering Options.
- Advanced and Renewable.

Purchase power alternatives will be obtained through Lakeland's RFP and will be evaluated against self-build generation alternatives. The following sections describe the generating unit alternatives considered and present estimated capital cost for overnight construction in 1997 dollars and performance characteristics.

6.2.1 Pressurized Fluidized Bed

Lakeland is currently pursuing a project utilizing the pressurized circulating fluidized bed technology. The flexibility, low cost, and efficiency of this technology will provide for low cost generation for many years. The PFB process is essentially a combined cycle system burning solid fuel; wherein; the conventional gas turbine combustor is replaced by a pressurized fluidized bed combustor and the turbine section is replaced by a hot gas expander ruggedized to tolerate the dust downstream from the primary and secondary cyclones.

The project is a greenfield DOE PCFB project that will provide baseload capacity for the City. With the participation of DOE, the project will receive substantial cost savings and provide low cost energy and capacity for the City of Lakeland. The project is partially being funded under the Clean Coal Technology Program by the US Department of Energy (DOE) under two cooperative agreements. The total project is estimated to cost $390 million, including a 4 year demonstration period, with DOE will providing approximately $195 million dollars of funding for the project.

The project is demonstrating Foster Wheeler PYROFLOW PCFB technology integrated with Westinghouse's hot gas filter (HGF) and power generator technologies. The time frame for the project is approximately 8 years broken into three separate phases: 2 years of design and permitting, followed by an initial period of 2 years of fabrication and construction, and concluding with a 4 year demonstration (commercial operation) period.

The PCFB technology is a combined cycle power generation system that is based on the pressurized combustion of solid fuel to generate steam in a conventional Rankine cycle combined with the expansion of hot pressurized flue gas through a gas turbine in a Brayton cycle. The technology can be subdivided into the basic PCFB cycle and the topped PCFB cycle. In the PCFB cycle, hot pressurized flue gas is expanded through the gas turbine at a temperature of less than 1,650 F. Topped PCFB cycles include a coal carbonizer (mild gasifier) to generate a low Btu fuel gas. Char and limestone entrained in the syngas are removed by the Westinghouse hot gas filter and transferred back to the PCFB combustor for complete carbon combustion and limestone utilization. The hot clean filtered syngas is then fired in a topping combustor to raise the turbine inlet temperature to almost 2,000 F. Both versions of PCFB technology offer high cycle efficiencies and low emissions.

The project will be constructed in two phases. Phase I includes the basic cycle and will be operated for approximately 2 years before Phase II will add the topped cycle.

The $390 million project cost includes the cost estimates for the design and construction of Phases I and II, the 4 year operating demonstration period, and in-kind contributions to the project by both Lakeland and the technology providers. A final, not to exceed cost to Lakeland is currently under negotiation. For expansion planning and preliminary budgetary purposes, Lakeland's share of the capital costs are estimated to be $99 million. The DOE funding is to also cover half the operating expenses for the demonstration period. Negotiations between Lakeland and the technology providers are progressing at the time of this filing. The results of those negotiations will determine whether or not this proposed unit addition will remain the most cost effective capacity choice for Lakeland and its customers.

Table 6-3 presents estimated cost and performance for the DOE PCFB project. For expansion planning purposes, the units primary design fuel is coal; however, consideration is being given in the design phase to make the unit capable of burning lower cost petroleum coke after the initial four year DOE demonstration period.

Table 6-3
Estimated Cost and Performance of
DOE Pressurized Fluidized Bed Unit

	Phase I	**Phase II (Topping Cycle)**
Net plant output	183 MW	185 MW
Capital cost ($1,000)	$99,000	
Variable O&M, 1997	$1.73/MWh	$1.73/MWh
Fixed O&M, 1997	$22.61/kW year	$22.61/kW year
Net plant heat rate		
Full load	8,990 Btu/kWh	8,370 Btu/kWh
75 percent load	9,240 Btu/kWh	8,576 Btu/kWh
50 percent load	9,704 Btu/kWh	9,204 Btu/kWh
Equivalent forced outage rate	12 percent	12 percent
Planned maintenance outage	28 days	28 days

*Lakeland portion of costs.
**For installation in 2003.
***Lakeland only incurs half of these costs during the demonstration period.

6.2.2 Atmospheric Fluidized Bed

A 250 MW atmospheric circulating fluidized bed unit (CFB) with a dry scrubber and selective noncatalytic reduction (SNCR) was selected as another solid fuel alternative. The CFB is capable of burning a wide range of fuels. For expansion planning purposes in the base case, the CFB is assumed to burn coal. Table 6-4 presents the estimated cost and performance of the 250 MW CFB unit. The CFB differs from the PCFB in that the CFB is not a pressurized boiler.

Table 6-4
Estimated Cost and Performance of
250 MW Atmospheric Circulating Fluidized Bed

Net plant output	250 MW
Total direct capital cost ($1,000)	$250,000
Variable O&M, 1997	$1.73/MWh
Fixed O&M, 1997	$18.29/kW year
Net plant heat rate	
Full load	10,543 Btu/kWh
75 percent load	10,803 Btu/kWh
50 percent load	11,593 Btu/kWh
25 percent load	14,516 Btu/kWh
Equivalent forced outage rate	7 percent
Planned maintenance outage	28 days
Construction period	30 months

6.2.3 Pulverized Coal

A 150 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. Pulverized coal units are capable of burning a blend of up to approximately 20 percent of petroleum coke. For purposes of expansion planning for the base case, the pulverized coal unit is assumed to burn coal. Table 6-5 presents the estimated cost and performance of the 150 MW pulverized coal unit.

Table 6-5
Estimated Cost and Performance of
150 MW Pulverized Coal

Net plant output	150 MW
Total direct capital cost ($1,000)	$175,000
Variable O&M, 1997	$2.40/MWh
Fixed O&M, 1997	$22.61/kW year
Net plant heat rate	
Full load	10,236 Btu/kWh
75 percent load	10,443 Btu/kWh
50 percent load	11,150 Btu/kWh
25 percent load	13,802 Btu/kWh
Equivalent forced outage rate	7 percent
Planned maintenance outage	28 days
Construction period	30 months

6.2.4 Combined Cycle

Four combined cycle units were selected as generating unit alternatives as follows:

- 1 x 1 Siemens V64.3A (Table 6-6).
- 1 x 1 Siemens V84.3A (Table 6-7).
- 1 x 1 Westinghouse 501F (Table 6-8).
- 1 x 1 Westinghouse 501G (Table 6-9).

The Siemens V64.3A is a conventional heavy-duty industrial type combustion turbine, while the Siemens V84.3A and Westinghouse 501F and 501G are an advanced high temperature combustion turbine.

6.2.5 Simple Cycle Combustion Turbine

Six simple cycle combustion turbines were selected as generating unit alternatives as follows:

- Siemens V64.3A (Table 6-10).
- Siemens V84.3A (Table 6-11).
- Trent Aeroderivative (Table 6-12).
- Westinghouse 501DA (Table 6-13).
- Westinghouse 501F (Table 6-14).
- Westinghouse 501G (Table 6-15).

The Siemens combustion turbines are heavy-duty industrial combustion turbines. The V64.3A is a conventional combustion turbine, while the V84.3A is a high temperature advanced combustion turbine. The Trent Aeroderivative is an aeroderivative combustion turbine. The Westinghouse 501F and 501G are a state of the art high temperature heavy-duty industrial combustion turbine.

Table 6-6
Estimated Cost and Performance of
Siemens V64.3A 1 x 1 Combined Cycle

Net plant output	
30 F	108 MW
71 F	93 MW
Capital cost ($1,000)	$62,600
Variable O&M, 1997	$2.06/MWh
Fixed O&M, 1997	$15.77/kW year
Net plant heat rate, 71 F HHV	
Full load	7,401 Btu/kWh
75 percent load	7,845 Btu/kWh
50 percent load	9,200 Btu/kWh
25 percent load	12,582 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	17 months

Table 6-7
Estimated Cost and Performance of Siemens
V84.3A 1 x 1 Combined Cycle

Net plant output 30 F 71 F	256 MW 222 MW
Capital cost ($1,000)	$97,800
Variable O&M, 1997	$2.24/MWh
Fixed O&M, 1997	$8.34/kW year
Net plant heat rate, 71 F HHV Full load 75 percent load 50 percent load 25 percent load	 7,178 Btu/kWh 7,608 Btu/kWh 8,923 Btu/kWh 12,203 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	22 months

Table 6-8
Estimated Cost and Performance of Westinghouse
501F 1 x 1 Combined Cycle

Net plant output	
30 F	266 MW
71 F	245 MW
Capital cost ($1,000)	$ 93,500
Variable O&M, 1997	$ 2.24/MWh
Fixed O&M, 1997	$ 2.34/kW year
Net plant heat rate, 71 F HHV	
Full load	6,976 Btu/kWh
75 percent load	7,325 Btu/kWh
50 percent load	9,252 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	25 months

Table 6-9
Estimated Cost and Performance of Westinghouse
501G 1 x 1 Combined Cycle

Net plant output 30 F 71 F	 364 MW 322 MW
Capital cost ($1,000)	$ 128,000
Variable O&M, 1997	$ 1.30/MWh
Fixed O&M, 1997	$ 1.95/kW year
Net plant heat rate, 71 F HHV Full load 75 percent load 50 percent load	 6,596 Btu/kWh 6,872 Btu/kWh 8,000 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	27 months

Table 6-12
Estimated Cost and Performance of
Trent Aeroderivative Simple Cycle Combustion Turbine

Net plant output	
30 F	56 MW
71 F	45 MW
Capital cost ($1,0[illegible]	$23,000
Variable O&M, 1997	$1.92/MWh
Fixed O&M, 1997	$18.69/kW year
Net plant heat rate, 71 F HHV	
Full load	9,732 Btu/kWh
75 percent load	10,105 Btu/kWh
50 percent load	11,348 Btu/kWh
25 percent load	15,595 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	18 days
Construction period	12 months

Table 6-11
Estimated Cost and Performance of
Siemens V84.3A Simple Cycle Combustion Turbine

Net plant output	
30 F	176 MW
71 F	157 MW
Capital cost ($1,000)	$42,600
Variable O&M, 1997	$1.95/MWh
Fixed O&M, 1997	$5.37/kW year
Net plant heat rate, 71 F HHV	
Full load	10,241 Btu/kWh
75 percent load	11,109 Btu/kWh
50 percent load	12,648 Btu/kWh
25 percent load	14,005 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	18 days
Construction period	16 months

Table 6-10
Estimated Cost and Performance of
Siemens V64.3A Simple Cycle Combustion Turbine

Net plant output	
30 F	73 MW
71 F	63 MW
Capital cost ($1,000)	$24,200
Variable O&M, 1997	$1.56/MWh
Fixed O&M, 1997	$13.01/kW year
Net plant heat rate, 71 F HHV	
Full load	10,707 Btu/kWh
75 percent load	11,684 Btu/kWh
50 percent load	13,467 Btu/kWh
25 percent load	15,127 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	18 days
Construction period	13 months

Table 6-13 Estimated Cost and Performance of Westinghouse 501DA Combustion Turbine	
Net plant output 30 F 71 F	 119 MW 113 MW
Capital cost ($1,000)	$41,750
Variable O&M, 1997	$ 1.71/MWh
Fixed O&M, 1997	$ 2.10/kW year
Net plant heat rate, 71 F HHV Full load 75 percent load 50 percent load 25 percent load	 11,944 Btu/kWh 12,532 Btu/kWh 14,197 Btu/kWh 18,848 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	14 days
Construction period	12 months

Table 6-14
Estimated Cost and Performance of
Westinghouse 501F Combustion Turbine

Net plant output	
30 F	186.5 MW
71 F	167.5 MW
Capital cost ($1,000)	$41,750
Variable O&M, 1997	$ 1.95/MWh
Fixed O&M, 1997	$ 5.37/kW year
Net plant heat rate, 71 F HHV	
Full load	10,453 Btu/kWh
75 percent load	11,316 Btu/kWh
50 percent load	12,901 Btu/kWh
25 percent load	16,100 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	14 days
Construction period	12 months

Table 6-15
Estimated Cost and Performance of
Westinghouse 501G Combustion Turbine

Net plant output	
30 F	264 MW
71 F	226 MW
Capital cost ($1,000)	$53,000
Variable O&M, 1997	$ 0.85/MWh
Fixed O&M, 1997	$ 0.92/kW year
Net plant heat rate, 71 F HHV	
Full load	9,846 Btu/kWh
75 percent load	10,528 Btu/kWh
50 percent load	11,705 Btu/kWh
Equivalent forced outage rate	10 percent
Planned maintenance outage	14 days
Construction period	12 months

Table 6-16
Estimated Cost and Performance of Repowering
Larsen Unit No. 6 with V64.3A Siemens Combustion Turbine

Net plant output	
30 F	101 MW
71 F	88 MW
Capital cost ($1,000)	$55,200
Variable O&M, 1997	$2.06/MWh
Fixed O&M, 1997	$ 15.77/kW year
Net plant heat rate, 71 F HHV	
Full load	7,840 Btu/kWh
75 percent load	8,311 Btu/kWh
50 percent load	9,745 Btu/kWh
25 percent load	13,328 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	18 months

6.2.6 Repowering

Three repowering alternatives were developed. The repowering alternatives involve using combustion turbines to repower existing steam turbines, while the fourth repowering alternative uses two pressurized fluidized bed (PFB) units to repower a steam turbine.

The first combustion turbine repowering alternative uses a Siemens V64.3A combustion turbine and a heat recovery steam generator (HRSG) turbine to repower Larsen Unit 6. Table 6-16 presents the estimated cost and performance.

The second combustion turbine repowering alternative uses two General Electric LM6000 Combustion Turbines and an HRSG to repower Larsen Unit 6. Table 6-17 presents the estimated cost and performance for this alternative.

The third combustion turbine repowering alternative uses a Siemens V84.3A combustion turbine and a HRSG to repower Larsen Units 6 and 7. Table 6-18 presents the estimated cost and performance.

6.2.7 Natural Gas Steam Plant

A natural gas steam unit was selected as a generation alternative for the expansion plan for the City of Lakeland. The cost and performance characteristics for this unit are outlined in Table 6-19.

Table 6-17
Estimated Cost and Performance of Repowering
Larsen Unit No. 6 with Two LM6000s
General Electric Combustion Turbines

Net plant output	
30 F	117 MW
71 F	102 MW
Capital cost ($1,000)	$58,700
Variable O&M, 1997	$2.34 / MWh
Fixed O&M, 1997	$ 16.09/ kW year
Net plant heat rate, 71 F HHV	
Full load	7,283 Btu/kWh
75 percent load	7,490 Btu/kWh
50 percent load	7,345 Btu/kWh
25 percent load	8,690 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	18 months

Table 6-18
Estimated Cost and Performance of Repowering
Larsen Unit No. 6 and 7 with V84.3A
Siemens Combustion Turbine

Net plant output 30 F 71 F	 233 MW 202 MW
Capital cost ($1,000)	$92,000
Variable O&M, 1997	$2.24/MWh
Fixed O&M, 1997	$8.34/kW year
Net plant heat rate, 71 F HHV Full load 75 percent load 50 percent load 25 percent load	 7,899 Btu/kWh 8,372 Btu/kWh 9,818 Btu/kWh 13,428 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	21 days
Construction period	22 months

Table 6-19 Estimated Cost and Performance of 150 MW Natural Gas Steam Plant	
Net plant output	150 MW
Capital cost ($1,000)	$122,700
Variable O&M, 1997	$0.62/MWh
Fixed O&M, 1997	$15.50/kW year
Net plant heat rate	
Full load	10,024 Btu/kWh
75 percent load	10,193 Btu/kWh
50 percent load	10,797 Btu/kWh
25 percent load	13,080 Btu/kWh
Equivalent forced outage rate	5 percent
Planned maintenance outage	28 days
Construction period	30 months

6.3 Screening of Generating Unit Alternatives

The generating alternatives developed in Section 6.2 generally represent a robust set of alternatives. In an effort to reduce the number of alternatives to be included for detailed evaluation, the alternatives are examined to determine if any can be eliminated from further evaluation. Analysis performed on a busbar level indicates alternatives that under several capacity factors does not represent a low cost alternative. Most of the alternatives exhibit unique attributes relative to each other such as higher capital cost and lower heat rate which make it impossible to eliminate them from detailed evaluation.

The following two alternatives, however, can be eliminated from detailed evaluation:

- Repowering Larsen Unit No. 6 with V64.3A, 88 MW at 71 F.
- 150 MW Natural Gas Steam Unit.

6.4 Economic Evaluation

6.4.1 Base Case Analysis

The base case supply plan was determined from the chronological optimization production cost models and the cost and performance characteristics of the generation alternatives. The base case supply plan applies the base case demand and energy forecast outlined in Section 3, the base case fuel forecast outlined in Section 5.4., and economic evaluation criteria outlined in 5.3.

The base case plan provides a diverse source of generation for the City of Lakeland at a low cost. The plan, summarized in Table 6-20, consists of the installation of a Westinghouse 501G combustion turbine and the installation of the DOE PCFB unit. The development of this plan by Lakeland is contingent upon the successful negotiation of contracts and is also contingent upon the results of Lakeland's RFP.

The Westinghouse 501G combustion turbine will be installed in two phases. The first phase of the project is the construction and start-up of the combustion turbine for the first four months of operation starting in January of 1999. Due to the unique maintenance agreement structured with Westinghouse and the fact that this is the first 501G machine in the United States, Westinghouse will be perform extensive monitoring and analysis of the machine during the initial four months of operation. After this initial start-up period, the machine will be declared commercial.

As with most capacity additions, there is usually a period of time when the host utility has excess capacity available. Lakeland has been and will continue to explore all options to sell any excess capacity available due to the addition of this unit. Lakeland has several interested parties looking for capacity but at the time of this filing, no contracts have been signed.

Based on the delays in negotiating all the commercial terms associated with the DOE PCFB unit and the necessary lead time for permitting and construction, the earliest expected in service date will be May of 2003.

Table 6-20
Base Case Plan

Year	Expansion Plan
1998	Regain lost McIntosh Unit 3 Capacity
1999	Build McIntosh Unit 5, Westinghouse 501G Simple Cycle (Jan) Retire Larsen Units 7 & CT1 (June)
2000	
2001	
2002	
2003	Build McIntosh Unit 4, DOE PCFB (May)
2004	
2005	
2006	
2007	

6.4.2 Sensitivity Analysis

Several sensitivities were performed to ensure the supply plan resulted in a robust plan for the City of Lakeland. The sensitivities consisted of high and low demand/energy forecasts, high and low fuel price forecasts, constant differential between oil/gas and coal, and power purchase opportunities. The results of which indicate that the alternatives selected in the base case represent the least cost energy sources for many scenarios.

6.5 Transmission

The generating units evaluated can generally be installed at the McIntosh site with the exception of the repowering alternatives at Larsen. Evaluation of purchase power alternatives resulting from Lakeland's RFP will require evaluation of transmission import capability based on the nature of the individual offer.

Lakeland will continue to make transmission system upgrades as necessary to support load growth on the system. Current plans include the addition of an additional 230/69 kV autotransformer at McIntosh Plant in January 1999 and the 9.5 mile Eaton Park to Crews Lake 230 kV line in June 2000. Lakeland also plans to reconductor several 69 kV lines, in the ten year planning horizon to meet local load growth needs.

6.6 Strategic Concerns

Lakeland continues to monitor and evaluate strategic items. Lakeland has broken strategic items into several different categories for analysis. Each of the following categories is discussed below:

- Clean Air Act Compliance.
- Environmental Regulations.
- Risk Management.
- Future Firm Power Purchases Under Negotiations.
- Ability to Dispatch Non-Utility Generators,

6.6.1 Clean Air Act Compliance

Lakeland has developed a strategic plan to lower emissions by replacing units which burn high sulfur oil with generating units with lower emissions. The cold shutdown of Larsen Unit No. 6 in 1997 will reduce the emissions of Lakeland's system. Currently Lakeland is pursuing a PCFB unit and a highly efficient combined cycle unit as outlined in Table 6-20. These units provide large amounts of generation while emitting small amounts of emissions compared to smaller less efficient units.

6.6.2 Environmental Regulations

Lakeland bases current and future planning decisions on the environmental regulations that are currently in place with consideration given to possible future regulations. Lakeland maintains a close working relationship with environmental regulators to keep abreast of future regulations that will impact Lakeland. Lakeland addresses many issues with the public over the operation and future of Lakeland's generation. The areas addressed so far include EMF studies and their effect, greenhouse gases, emissions, and air toxins. The public has a large impact on the siting of new generation and its location.

6.6.3 Risk Management

The ability to reduce or hedge the risk of large swings in fuel prices is always a concern of Lakeland. Lakeland has hedged this risk by using generators that burn a wide range of fuels. The ability to dispatch coal or natural gas/oil units allows Lakeland to meet demand at the lowest cost to consumers. The City of Lakeland believes by constructing the PCFB unit, there is a large diversification of the fuels that can be burned for the system. This will provide opportunities to burn low cost fuel that other units in the region will not be able to pursue.

Another method applied by Lakeland to reduce the fuel price risk is the membership in FMPP. The pool has a broad range of generating units which can take advantage of the lowest cost fuels.

6.6.4 Future Firm Power Purchases Under Negotiations

Lakeland has negotiated a firm long term power contract with ENRON. Lakeland also secured various short term power contracts to meet near term needs. Lakeland issued an RFP for long-term purchase power in 1997 that has been used to evaluate self-build alternatives.

6.7 Procurement Process

Lakeland had issued an RFP for purchase power to ensure that the generation alternatives represent the least cost alternatives available. In Lakeland's negotiations with Foster Wheeler and Westinghouse for the PCFB Unit, Lakeland is attempting to establish appropriate guarantees for cost and performance for the project. In the event that any of these negotiations are unsuccessful, Lakeland will revise its expansion plans. The contract established with Westinghouse for the 501G combustion turbine provides for a significant price reduction for the first unit and a six year maintenance agreement. The contract is an EPC fixed price contract with Westinghouse.

7.0 Environmental and Land Use Information

The reference supply plan outlined in Section 6.10 represents the least-cost option for the City of Lakeland and provides the best overall opportunity for generation with the alternatives considered. All of the supply plans were analyzed on several levels besides cost basis to determine the overall impacts to the system. The environmental and land use impacts were studied closely to determine resource additions effect on the system and the results are outlined below.

7.1 Land and Environmental Features

Emissions will be minimized through the use of the pressurized circulating fluidized bed clean coal technology and highly efficient combined cycle generation. The use of treated sewage effluent will conserve valuable water resources and the return of wastewater to the city wastewater treatment facilities eliminates wastewater discharges. Existing fuel handling and storage facilities will be used, eliminating additional environmental impacts from these facilities. The location of the proposed site and the existing land use with adjacent areas is shown on Figure 7-1. The site for the Westinghouse 501G will be located at the McIntosh site. The DOE PCFB site will also be at the McIntosh Plant.

7.2 Air and Noise Emissions

The selected alternative Estimated emissions are as follows:

Westinghouse 501G Simple Cycle

SO_2 -- 1 ppm
NO_X -- 25 ppm
CO -- 10 ppm
Particulate -- 7.8 lb/hr.

Lakeland is currently in discussions with Florida DEP to determine mutually acceptable emissions levels for the 501G machine if converted to combined cycle operation, at a later date.

<u>DOE PCFB Clean Coal Project</u>

SO_2, lb/MBtu -- 0.25

NO_X, lb/MBtu --0.17 (includes ammonia injection).

CO -- immeasurable at full load

Particulate, lb/MBtu--0.02.

7.3 Status of Site Certification

Lakeland anticipates filing a separate application for site certification of the Westinghouse 501G Unit if a decision is made to convert that unit to combined cycle operation. The project as currently envisioned would initially operate as a simple cycle combustion turbine and could be converted to become a combined cycle unit with the addition of a Heat Recovery Steam Generator (HRSG) and steam turbine in the year 2001. Lakeland is in the process of obtaining the simple cycle air permits.

The DOE PCFB has not entered siting certification at this juncture.

DOE PCFB Clean Coal Project

SO_2, lb/MBtu -- 0.25

NO_X, lb/MBtu --0.17 (includes ammonia injection).

CO -- immeasurable at full load

Particulate, lb/MBtu--0.02.

7.3 Status of Site Certification

Lakeland anticipates filing a separate application for site certification of the Westinghouse 501G Unit if a decision is made to convert that unit to combined cycle operation. The project as currently envisioned would initially operate as a simple cycle combustion turbine and could be converted to become a combined cycle unit with the addition of a Heat Recovery Steam Generator (HRSG) and steam turbine in the year 2001. Lakeland is in the process of obtaining the simple cycle air permits.

The DOE PCFB has not entered siting certification at this juncture.

8.0 Analysis Results and Conclusions

8.1 Conclusions

Applying the Forecast of Electrical Power Demand and Energy Consumption, Conservation and Demand-Side Management, Forecasting Methods and Procedures, Forecast of Facilities Requirements, and the Environmental and Land Use Considerations; the City of Lakeland has determined the reference plan for the Ten-Year Site Plan. The Reference Plan is derived from the base case plan identified in the economic evaluation.

The reference plan was developed based on the need for power as indicated in Table 8-1. The reference plan, outlined in Table 8-2, selects units based on the economic evaluation conducted in Section 6. The plan consists of the installation of a Westinghouse 501G in simple cycle operation with the possible conversion to combined cycle operation. All projects will consider the sale of capacity and energy sales in excess of Lakeland's need.

Table 8-1
Additional Capacity Requirements

Year	Peak Demand (Winter)			Generating Capacity with Reference Plan	Reserve Margin (15%)			Existing Purchase	Excess/(Deficit)		
	Base	High	Low		Base	High	Low		Base	High	Low
1998	575	575	575	649	86	86	86	80	68	68	68
1999	593	607	578	894	89	91	87	20	232	216	249
2000	612	642	582	839	92	96	87	20	155	121	190
2001	631	678	586	839	95	102	88	20	133	79	185
2002	650	715	589	839	98	107	88	0	92	17	162
2003	668	753	591	839	100	112	89	0	71	(27)	159
2004	687	793	593	1,022	103	119	89	0	232	110	340
2005	706	835	594	1,022	106	125	89	0	210	62	339
2006	725	878	596	1,024	109	132	89	0	190	14	339
2007	744	923	596	1,024	112	138	89	0	168	(37)	339

Table 8-2 Reference Plan	
Year	**Expansion Plan**
1998	Regain lost McIntosh Unit 3 capacity
1999	Build McIntosh Unit 5, Westinghouse 501G Simple Cycle (Jan) Retire Larsen Units 7 & CT1 (June)
2000	
2001	
2002	
2003	Build McIntosh Unit 4, DOE PCFB (May)
2004	
2005	
2006	
2007	

8.2 Recommended Reference Plan

The City of Lakeland recommends the reference plan identified in Table 8-2 for the 1998 Ten-Year Site Plan. The plan has been studied under numerous sensitivities and represents the least-cost plan consistent with strategic objectives. The plan will continue to be studied while implementation is progressing.

9.0 Ten Year Site Plan Schedules

The following section presents the schedules required by the Ten Year Site Plan rules for the Florida Public Service Commission. The City of Lakeland has attempted to provide complete information for the FPSC whenever possible.

Schedule 1
Lakeland Electric and Water Utilities
Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel		Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (kW)	Net Capability **		Fuel Transportation	
				Primary	Alternate				Summer (MW)	Winter (MW)	Primary	Alternate
Charles Larsen Memorial	1	16-17/28S/24E Polk County	GT	NG	F02	10/62	06 / 99	11,500	10.0	14.0	PL	TK
	2		GT	NG	F02	11/62	Unknown	11,500	10.0	14.0	PL	TK
	3		GT	NG	F02	12/62	Unknown	11,500	10.0	14.0	PL	TK
	5		CW	WH		04/56	Unknown	25,000	29.0	31.0	PL	TK
	6		ST	NG	F06	12/59	Retired	25,000	--	--	--	--
	7		ST	NG	F06	02/66	06 / 99	50,000	41.5	41.5	PL	TK
	8		CT	NG	F02	07/92	Unknown	101,520	73.0	93.0	PL	TK
Plant Total									173.5	207.5		
C.D. McIntosh, Jr.	IC1	4-5/28S/24E Polk County	IC	F02	NA	01/70	Unknown	2,500	2.5	2.5	TK	--
	IC2		IC	F02	NA	01/70	Unknown	2,500	2.5	2.5	TK	--
	1		GT	NG	F02	05/73	Unknown	26,640	19.0	23.0	PL	TK
	1		ST	NG	F06	02/71	Unknown	103,500	92.0	92.0	PL	TK
	2		ST	NG	F06	06/76	Unknown	126,000	108.0	108.0	PL	TK
	3 *		ST	BIT	NG	09/82	Unknown	363,870	198.0	205.2	RR	TK
Plant Total									422	433.2		
System Total as of December 31, 1996									595.5	640.7		

*Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.

** Net normal.

Source: Lakeland Power Production Unit Rating Group 2/28/97

Schedule 2.0
Forecast of Total Accounts and Sales For Lakeland

		Rural & Residential			Commercial		
Fiscal Year	Population	GWh	Average # of Customers	kWh/Cust	GWh	Average # of Customers	kWh/Cust
1988	172,162	842	67,712	12,435	462	8,432	54,791
1989	178,282	913	70,696	12,914	498	8,853	56,252
1990	184,897	948	73,480	12,901	525	9,164	57,289
1991	188,609	967	76,731	12,602	522	9,517	54,849
1992	194,456	987	77,863	12,676	526	9,664	54,429
1993	200,416	1,026	79,738	12,867	542	9,768	55,487
1994	203,891	1,080	81,542	13,245	574	9,967	57,590
1995	208,586	1,169	82,616	14,150	594	9,999	59,406
1996	211,047	1,201	84,089	14,282	589	9,729	60,541
1997	213,569	1,173	84,149	13,940	609	9,816	62,042
Forecast							
1998	217,949	1,233	86,222	14,300	627	9,931	63,136
1999	222,329	1,273	87,656	14,523	644	10,027	64,227
2000	226,708	1,309	89,091	14,693	659	10,122	65,106
2001	230,494	1,346	90,408	14,888	674	10,218	65,962
2002	234,280	1,383	91,727	15,077	690	10,314	66,899
2003	238,066	1,420	93,047	15,261	706	10,411	67,813
2004	241,852	1,457	94,369	15,439	721	10,508	68,614
2005	245,638	1,494	95,693	15,612	736	10,607	69,388
2006	249,298	1,532	96,997	15,794	751	10,704	70,161
2007	252,958	1,571	98,302	15,981	766	10,802	70,913

Schedule 2.0 (Continued)
Forecast of Total Accounts and Sales For Lakeland

	Industrial			Street & Highway Lighting	Other Sales to Public Authorities	Total Sales to Ultimate Consumers	Resale	Utility Use & Losses	NEL
Fiscal Year	GWh	Average # of Customers	kWh/Cust	GWh	GWh	GWh	GWh	GWh	GWh
1988	310	39	7,948,718	11	56	1,681	0	165	1,846
1989	331	41	8,073,171	11	59	1,812	0	148	1,960
1990	346	44	7,863,636	8	62	1,889	0	108	1,997
1991	344	45	7,644,444	11	61	1,905	0	138	2,043
1992	356	47	7,574,468	13	65	1,947	0	143	2,090
1993	381	51	7,470,588	13	68	2,030	0	155	2,185
1994	400	51	7,843,137	14	69	2,137	0	146	2,283
1995	427	51	8,372,549	15	74	2,279	0	146	2,425
1996	589	59	9,983,051	15	78	2,472	0	102	2,574
1997	459	61	7,524,590	16	78	2,335	0	115	2,450
Forecast									
1998	479	63	7,603,175	16	83	2,438	0	140	2,578
1999	498	65	7,661,538	17	85	2,517	0	138	2,655
2000	514	67	7,671,642	18	89	2,589	0	143	2,732
2001	530	68	7,794,118	18	93	2,661	0	146	2,807
2002	546	70	7,800,000	19	95	2,733	0	149	2,882
2003	562	72	7,805,556	19	98	2,805	0	152	2,957
2004	578	73	7,917,808	20	101	2,877	0	155	3,032
2005	595	75	7,933,333	21	103	2,949	0	159	3,108
2006	611	76	8,039,474	21	108	3,023	0	161	3,184
2007	627	78	8,038,462	22	110	3,096	0	164	3,260

Schedule 3.1 History and Forecast of Summer Peak Demand Base Case							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total	Wholesale	Retail	Interruptible	Load Management	Conservation	Net Firm Demand
1988	380	0	380	0	0	Included in (4)	380
1989	406	0	406	0	0		406
1990	408	0	408	0	0		408
1991	424	0	424	0	0		424
1992	434	0	434	0	0		434
1993	477	0	477	0	0		477
1994	455	0	455	0	0		455
1995	481	0	481	0	0		481
1996	490	0	490	8	0		490
1997	509	0	509	0	0		509
Forecast							
1998	523	0	502	5	21	Included in (4)	502
1999	537	0	515	5	22		515
2000	551	0	529	5	22		529
2001	563	0	540	5	23		540
2002	576	0	552	5	23		552
2003	589	0	565	5	24		565
2004	601	0	576	5	25		576
2005	614	0	589	5	25		589
2006	626	0	600	6	26		600
2007	639	0	613	6	26		613

Schedule 3.2 History and Forecast of Winter Peak Demand Base Case							
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	Total	Wholesale	Retail	Interruptible	Load Management	Conservation	Net Firm Demand
1988	428	0	428	0	0	Included in (4)	428
1989	530	0	530	0	22		508
1990	365	0	365	0	0		365
1991	446	0	446	0	6		440
1992	464	0	464	0	20		444
1993	480	0	480	0	23		457
1994	485	0	485	0	0		485
1995	608	0	608	0	70		538
1996	655	0	655	0	45		610
1997	552	0	552	0	0		552
Forecast 1998	626	0	570	5	51	Included in (4)	570
1999	645	0	588	5	52		588
2000	665	0	607	5	53		607
2001	685	0	626	5	54		626
2002	705	0	645	5	55		645
2003	725	0	663	5	57		663
2004	745	0	682	5	58		682
2005	765	0	701	5	59		701
2006	785	0	720	5	60		720
2007	805	0	739	5	61		739

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

(1)	(2)	(3)	(5)	(6)	(7)	(8)	(9)
Year	Total	Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load factor %
1988	2,011	0	2,011	0	165	1,846	49.2
1989	2,108	0	2,108	0	148	1,960	44.1
1990	2,105	0	2,105	0	108	1,997	62.5
1991	2,181	0	2,181	0	138	2,043	53.1
1992	2,233	0	2,233	0	143	2,090	53.8
1993	2,340	0	2,340	0	155	2,185	54.5
1994	2,429	0	2,429	0	146	2,283	53.8
1995	2,571	0	2,571	0	146	2,425	51.5
1996	2,676	0	2,676	0	102	2,574	45.6
1997	2,566	1	2,565	0	115	2,450	50.7
Forecast							
1998	2,719	1	2,718	0	140	2,578	51.6
1999	2,794	1	2,793	0	138	2,655	51.6
2000	2,876	1	2,875	0	143	2,732	51.4
2001	2,954	1	2,953	0	146	2,807	51.1
2002	3,032	1	3,031	0	149	2,882	51.0
2003	3,111	2	3,109	0	152	2,957	50.9
2004	3,189	2	3,187	0	155	3,032	50.8
2005	3,269	2	3,267	0	159	3,108	50.8
2006	3,347	2	3,345	0	161	3,184	50.5
2007	3,426	2	3,424	0	164	3,260	50.4

Schedule 4
Previous Year Actual and Two Year Forecast of Peak Demand
And Net Energy For Load By Month
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual 1997		Forecast 1998		Forecast 1999	
Month	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)	Peak Demand (MW)	Net Energy For load (GWH)
January	552	194	575	219	593	226
February	379	167	537	188	554	194
March	396	190	461	192	476	198
April	389	175	406	184	416	190
May	464	214	459	217	471	224
June	475	226	493	236	506	243
July	469	241	499	247	512	255
August	509	251	502	252	515	259
September	466	230	493	236	506	243
October	421	203	425	209	436	215
November	359	182	435	188	451	194
December	405	204	527	210	546	216
Total		2,477		2,578		2,655

Note: 1997 Peak Demand and Net Energy For Load are projected beginning in July and March respectively.

Schedule 5 Fuel Requirements														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Type	Units	1997 - Actual	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Nuclear		1000 MBtu	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	426	495	450	458	465	466	673	767	776	786	796
(3)	Residual	Total	1000 BBL	144	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	144	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	6	4	3	3	6	7	2	2	2	2	2
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	5	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 BBL	1	4	3	3	6	7	2	2	2	2	2
(13)	Natural Gas	Total	1000 MCF											
(14)		Steam	1000 MCF	1,212	3,999	760	807	862	969	559	175	219	277	319
(15)		CC	1000 MCF	2,834	6,852	6,163	6,499	6,796	6,988	3,878	2,877	3,027	3,183	3,445
(16)		CT	1000 MCF	53	358	5,949	6,090	6,236	6,648	4,567	3,779	4,049	4,279	4,413
(17)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0
(18)	Pet Coke & RDF	Total	1000 Ton	53	58	53	54	55	55	45	43	44	45	46
(19)		Steam	1000 Ton	53	58	53	54	55	55	45	43	44	45	46
(20)		CC	1000 Ton	0	0	0	0	0	0	0	0	0	0	0
(21)		CT	1000 Ton	0	0	0	0	0	0	0	0	0	0	0
(22)		Diesel	1000 Ton	0	0	0	0	0	0	0	0	0	0	0
(23)	Other		1000 MBtu	0	0	0	0	0	0	0	0	0	0	0

Schedule 6.1 Energy Sources														
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	Type	Units	1997 - Actual	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		GWH	534	8	1	1	1	0	0	0	0	0	0
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	1,050	1,282	1,161	1,181	1,200	1,205	1,884	2,188	2,214	2,243	2,272
(4)	Residual	Total	GWH	61	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH	61	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	6	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	5	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWH	1	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	610	1,069	1,296	1,348	1,399	1,470	902	682	728	771	814
(15)		Steam	GWH	318	344	67	71	76	86	49	14	18	23	27
(16)		CC	GWH	289	706	627	663	695	716	396	287	302	317	343
(17)		CT	GWH	3	19	602	614	628	668	457	381	408	431	444
(18)		Diesel	GWH	0	0	0	0	0	0	0	0	0	0	0
(19)	Pet Coke	Total	GWH	139	162	147	149	152	153	122	117	120	123	127
(20)		Steam	GWH	139	162	147	149	152	153	122	117	120	123	127
(21)	Other	Total	GWH	55	64	50	53	56	54	49	45	46	47	47
(22)	Net Energy For Load		GWH	2,450	2,578	2,655	2,732	2,807	2,882	2,957	3,032	3,108	3,184	3,260

Schedule 6.2
Energy Sources by Percentage

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	Type	Units	1997 - Actual	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
(1)	Annual Firm Interchange		GWH	21.8	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH %	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH %	42.9	49.7	43.7	43.2	42.8	41.8	63.7	72.2	71.2	70.4	69.7
(4)	Residual	Total	GWH %	2.5	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH %	2.5	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH %	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH %	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWH %	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH %	0.2	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWH %	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH %	0.2	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH %	0	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWH %	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH %	24.9	41.5	48.8	49.3	49.8	51.0	30.5	22.5	23.4	24.2	25.0
(15)		Steam	GWH %	13.0	13.3	2.5	2.6	2.7	3.0	1.7	0.5	0.6	0.7	0.8
(16)		CC	GWH %	11.8	27.4	23.6	24.3	24.8	24.8	13.4	9.5	9.7	10.0	10.5
(17)		CT	GWH %	0.1	0.7	22.7	22.5	22.4	23.2	15.5	12.6	13.1	13.5	13.6
(18)		Diesel	GWH %	0	0	0	0	0	0	0	0	0	0	0
(19)	Pet Coke	Total	GWH %	5.7	6.3	5.5	5.5	5.4	5.3	4.1	3.9	3.9	3.9	3.9
(20)		Steam	GWH %	5.7	6.3	5.5	5.5	5.4	5.3	4.1	3.9	3.9	3.9	3.9
(21)	Other	Total	GWH %	2.2	2.5	1.9	1.9	2.0	1.9	1.7	1.5	1.5	1.5	1.4
(22)	Net Energy For Load		GWH %	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)
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin Before Maintenance	Percentage of Peak
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
1998	604	80	0	0	684	497	187	38	0	187	38
1999	846	40	0	0	886	510	376	74	0	376	74
2000	791	20	0	0	811	524	287	55	0	287	55
2001	791	20	0	0	811	535	276	52	0	276	52
2002	791	0	0	0	791	548	243	44	0	243	44
2003	1074	0	0	0	1074	560	514	92	0	514	92
2004	1074	0	0	0	1074	571	503	88	0	503	88
2005	1076	0	0	0	1076	584	492	84	0	492	84
2006	1076	0	0	0	1076	594	482	81	0	482	81
2007	1076	0	0	0	1076	607	469	77	0	469	77

Schedule 7.2 Forecast of Capacity, Demand, and Scheduled Maintenance at time of Winter Peak											
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin Before Maintenance	Percentage of Peak
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
1998	649	80	0	0	729	570	159	28	0	159	28
1999	894	40	0	0	934	588	346	59	0	346	59
2000	839	20	0	0	859	607	252	42	0	252	42
2001	839	20	0	0	859	626	233	37	0	233	37
2002	839	0	0	0	839	645	194	30	0	194	30
2003	839	0	0	0	839	663	176	27	0	176	27
2004	1,122	0	0	0	1122	682	440	65	0	440	65
2005	1,122	0	0	0	1122	701	421	60	0	421	60
2006	1,122	0	0	0	1122	720	402	56	0	402	56
2007	1,122	0	0	0	1122	739	383	52	0	383	52

Schedule 8.0
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Const Start	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	
Charles Larsen Memorial	1	Polk County	ST	FO6	NG	TK	PL			06/99	11,500	10	14	Planned
	7	Polk County	ST	NG	FO6	PL	TK			06/99	50,000	41.5	41.5	Planned
C.D. McIntosh	501G	Polk County	CT	NG	FO6	PL	TK	6/98	* 06/99		245,000	232	245	Planned
	DOE PFCB	Polk County	ST	Coal	PC	RR	TK		05/03		185,000	172	185	Planned

* This unit is expected to be available to serve load in January 1999 for the winter peak, but will not be declared commercial until June due to manufacturer requested testing period.

Schedule 9.1
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Westinghouse 501G, McIntosh Unit 5
(2)	Capacity:	
(3)	Summer MW	245
(4)	Winter MW	264
(5)	Technology Type:	Simple Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	06/1998
(8)	Commercial In-Service date:	06/1999
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	FO2
(12)	Air Polluation Control Strategy:	Low Nox burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	
(15)	Construction Status:	Planned
(16)	Certfication Status:	Planned
(17)	Status with Federal Agencies:	Permits In Progress
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	3.83 percent
(20)	Forced Outage Factor (FOF):	10.00 percent
(21)	Equivalent Availability Factor (EAF):	13.83 percent
(22)	Resulting Capacity Factor (%):	86.16 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9,486
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25
(26)	Total Installed Cost (In-Service year $/kW):	216
(27)	Direct Construction Cost ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	920
(31)	Variable O&M ($/MWh):	0.85

Schedule 9.2 Status Report and Specifications of Proposed Generating Facilities		
(1)	Plant Name and Unit Number:	DOE PCFB, McIntosh Unit 4
(2)	Capacity:	
(3)	Summer MW	184
(4)	Winter MW	185
(5)	Technology Type:	Pressurized Circulating Fluidized Bed
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	Undetermined
(8)	Commercial In-Service date:	05/2003
(9)	Fuel	
(10)	Primary	Coal
(11)	Alternate	Petroleum Coke
(12)	Air Pollution Control Strategy:	Cofire Limestone, Ammonia, ceramic air filters
(13)	Cooling Method:	Cooling Towers w/ sewage effluent makeup
(14)	Total Site Area:	
(15)	Construction Status:	Planned
(16)	Certfication Status:	Not started
(17)	Status with Federal Agencies:	Not started
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	7.67 percent
(20)	Forced Outage Factor (FOF):	13.4 percent
(21)	Equivalent Availability Factor (EAF):	21.07 percent
(22)	Resulting Capacity Factor (%):	79.03 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9,600
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25
(26)	Total Installed Cost (In-Service year $/kW):	535.14
(27)	Direct Construction Cos. ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	22.61
(31)	Variable O&M ($/MWh):	1.73

Schedule 10 Status Report and Specifications of Proposed Directly Associated Transmission Lines		
(1)	Point of Origin and Termination:	None Planned
(2)	Number of Lines:	None Planned
(3)	Right of Way:	None Planned
(4)	Line Length:	None Planned
(5)	Voltage:	None Planned
(6)	Anticipated Construction Time:	None Planned
(7)	Anticipated Capital Investment:	None Planned
(8)	Substations:	None Planned
(9)	Participation with Other Utilities:	None Planned

No new transmission lines required. Tranmsission changes limited to interconnecting new units into existing substation facilities.

ELECTRIC LOAD AND ENERGY FORECAST
FISCAL YEAR
1997-98

PREPARED BY
RATES DIVISION

Approved December 1997

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This year the forecast includes two additional rate classes. The Interruptible (IS) rate class and the Contract (GSX-6) rate class. The PXT rate class has been removed as a rate class and has migrated into the Contract rate.

The Interruptible rate class provides the customer a lower rate if the customer chooses to adapt their operations to allow for their power to be interrupted during peak usage periods. The customer must have a demand of 500 KW or greater. The accounts under the Interruptible rate class as of this forecast are:

1. Pepperidge Farms	Inside City Limits
2. Mid-Florida Freezer	Outside City Limits
3. Continental Plastics	Outside City Limits
4. Juice Bowl	Inside City Limits
5. Mutual Wholesale	Inside City Limits

The Contract rate class is for customers who choose to sign a 10-year contract for service. The customer must meet the following criteria: demand higher than 1Mw and a load factor of approximately 60% or greater. The accounts under the Contract rate class as of this forecast are:

1. Florida Juice	Outside City Limits
2. Florida Southern College	Inside City Limits
3. Breed Automotive	Inside City Limits
4. Sikes	Inside City Limits
5. Owens Brockway	Outside City Limits
6. Watson Clinic	Inside City Limits
7. Publix Industrial Center	Outside City Limits
8. Publix County Line Road	Inside City Limits
9. Publix Warehouse	Outside City Limits
10. Butterkrust Bakery	Inside City Limits
11. Lakeland Regional	Inside City Limits

As of 1994, voltage reduction will not be reflected in the forecast as a means of demand reduction or conservation. Voltage reduction can be approximately 5% of the electric distribution system load at time of winter peak. Voltage reduction is used under emergency situations only.

In an attempt to better predict the summer and winter peaks, historical (1989 - 1997) peaks were adjusted for lost capacity due to circuits out, load management (SMART), and voltage reduction. Looking at the adjusted system peak gives a truer picture of what was experienced on the system the day of the peak.

Temperature is a significant driver in projecting system demand. An evaluation was performed to determine if the minimum (30°) and the maximum (97°) temperatures used to forecast winter and summer demand accurately predict what we have seen historically. The results of the probability distribution supports our decision to use 30° for the winter peak and 97° for the summer peak. With a 95% confidence interval, the minimum temperature for winter peak should be within 28.1° and 32.9°. The summer temperature range at the 95% confidence interval is 94.5° to 97.6°.

On February 5, 1996, Lakeland experienced a record winter peak of 593 MW (579 net integrated + 14 due to circuit outages). We initialized load management during the peak which accounted for approximately 44 MW. One item that is important to note about this record peak is that the temperature three weeks prior to the peak, never reached above 60°. This is an extremely unusual occurrence which seems to have had an significant influence on the winter peak.

Forecast Summary

Total Energy Sales (With Expected Conservation - Table ES-1 and Graph ES-1)
Overall, new projections indicate that total sales will be within 3% of last year's forecast. This year's forecast was slightly lower than was expected last year. This is mainly due to the very mild weather which was experienced during 1997.

ELECTRIC LOAD AND ENERGY FORECAST
FISCAL YEAR
1997-98

PREPARED BY
RATES DIVISION

Approved December 1997

ELECTRIC LOAD AND ENERGY FORECAST

FISCAL YEAR
1997-98

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EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

The 1998 Load and Energy Forecast provides important information on future growth in the service territory and on the electric system. The forecast document is written to provide the reader with the results of the forecast, documentation supporting the results, and an explanation of the methodology and assumptions that developed the forecast.

The forecast attempts to predict how certain changes within the electric service area will affect electric power usage. This is accomplished by evaluating several variables such as: population, economic conditions, historical trends, account types, weather, usage patterns, price, and impacts of conservation (DSM). Economic conditions are measured by variables such as: Real Per Capita Income (RYPC), Labor (E), and Employment (EWS).

Econometric models, trending, and time-series decomposition were used to generate the forecasts presented in this document. The econometric models used were tested for serial correlation and heteroskedasticity. Serial correlation occurs when the errors, or residuals, of a regression are correlated or show some type of pattern. Heteroskedasticity can be encountered where there exists some relation between the error and one or more of the explanatory variables used in the model. Both occurrences will skew the results of a regression model. The Adjusted R-Squared and the *T*- Statistic is referenced throughout the document. These statistics tell us how well the model is fitting fluctuations seen in the historical data and how significant a particular independent variable is. Graphic techniques were also used to inspect the data looking closely for trends and the reliability of historical data.

This forecast document includes projections for Energy Sales, Net Energy for Load, and Demand. These forecasts are shown "With Expected Conservation" and with "No Conservation". The forecast "With Expected Conservation" assumes conservation efforts will continue throughout the twenty-year forecast horizon (1998-2018).

This year the forecast includes two additional rate classes. The Interruptible (IS) rate class and the Contract (GSX-6) rate class. The PXT rate class has been removed as a rate class and has migrated into the Contract rate.

The Interruptible rate class provides the customer a lower rate if the customer chooses to adapt their operations to allow for their power to be interrupted during peak usage periods. The customer must have a demand of 500 KW or greater. The accounts under the Interruptible rate class as of this forecast are:

1. Pepperidge Farms	Inside City Limits
2. Mid-Florida Freezer	Outside City Limits
3. Continental Plastics	Outside City Limits
4. Juice Bowl	Inside City Limits
5. Mutual Wholesale	Inside City Limits

The Contract rate class is for customers who choose to sign a 10-year contract for service. The customer must meet the following criteria: demand higher than 1Mw and a load factor of approximately 60% or greater. The accounts under the Contract rate class as of this forecast are:

1. Florida Juice	Outside City Limits
2. Florida Southern College	Inside City Limits
3. Breed Automotive	Inside City Limits
4. Sikes	Inside City Limits
5. Owens Brockway	Outside City Limits
6. Watson Clinic	Inside City Limits
7. Publix Industrial Center	Outside City Limits
8. Publix County Line Road	Inside City Limits
9. Publix Warehouse	Outside City Limits
10. Butterkrust Bakery	Inside City Limits
11. Lakeland Regional	Inside City Limits

* Water Treatment Plant - This account is assumed to be a contract account but will not show up in the Contract total. This is a water account and will be included in the Water Department's sales and accounts.

The forecast also assumes, beginning in 1998, that the following large industrial accounts which have met or are close to meeting the criteria needed to be on the Contract rate will sign a contract. The following accounts considered to be future contract accounts are:

1. Tampa Maid Food (formerly Bee Gee Shrimp)	Inside City Limits
2. Ledger	Inside City Limits
3. Alpha Chemical	Outside City Limits
4. Discount Auto Parts	Outside City Limits

The forecast has complete detail on all rate classes, including the Interruptible and Contract rate classes, by inside and outside the city limits. This segregation of data has provided a better understanding of the trends developing within each segment and rate class. The forecaster worked closely with the Account Managers in developing the list of both Interruptible and Contract customers.

The forecast also includes an extreme weather scenario forecast for "Winter Peak Demand", and "Summer Peak Demand". The minimum and maximum temperatures were the variables used to determine the high and low summer and winter peak demand scenarios.

The increase or decrease in sales or accounts due to deregulation was not factored into this forecast.

Net Energy for Load and annual Losses are also projected throughout the forecast horizon (1998-2018).

As of 1994, voltage reduction will not be reflected in the forecast as a means of demand reduction or conservation. Voltage reduction can be approximately 5% of the electric distribution system load at time of winter peak. Voltage reduction is used under emergency situations only.

In an attempt to better predict the summer and winter peaks, historical (1989 - 1997) peaks were adjusted for lost capacity due to circuits out, load management (SMART), and voltage reduction. Looking at the adjusted system peak gives a truer picture of what was experienced on the system the day of the peak.

Temperature is a significant driver in projecting system demand. An evaluation was performed to determine if the minimum (30°) and the maximum (97°) temperatures used to forecast winter and summer demand accurately predict what we have seen historically. The results of the probability distribution supports our decision to use 30° for the winter peak and 97° for the summer peak. With a 95% confidence interval, the minimum temperature for winter peak should be within 28.1° and 32.9°. The summer temperature range at the 95% confidence interval is 94.5° to 97.6°.

On February 5, 1996, Lakeland experienced a record winter peak of 593 MW (579 net integrated + 14 due to circuit outages). We initialized load management during the peak which accounted for approximately 44 MW. One item that is important to note about this record peak is that the temperature three weeks prior to the peak, never reached above 60°. This is an extremely unusual occurrence which seems to have had an significant influence on the winter peak.

Forecast Summary

Total Energy Sales (With Expected Conservation - Table ES-1 and Graph ES-1)
Overall, new projections indicate that total sales will be within 3% of last year's forecast. This year's forecast was slightly lower than was expected last year. This is mainly due to the very mild weather which was experienced during 1997.

Total energy sales (with expected conservation) for fiscal year 1998 is 2,422,081 Mwh's. Projections indicate an average increase in sales of approximately 73,000 mwh's/ year throughout the forecast.

Currently, energy sales are comprised of 50% residential, 26.0% commercial, 19.6% industrial (including Interruptible and Contract), with the remaining being in municipal sales. Customers representing 52% of total GSLD sales have now signed a 10-year contract for service.

Further detail on sales inside and outside the city and by rate class can be found in the body of this report.

Usage Per Account

Kwh usage per account is currently at 22.8 Mwh's/ account and gradually increases to approximately 27.3 Mwh's/account in the year 2018. This is an annual average growth rate (AAGR) of .97%.

Total Accounts (Table ES-2 and Graph ES-2)

The Total Account Forecast was lower than last year's projections. The forecast predicts approximately 1,738 new accounts a year. This is mainly attributable to the lower than average growth in overall accounts over the last two years.

Lakeland's customer base is currently 81% residential, 9.5% commercial and industrial with the reminder being municipal and private area lighting accounts. These percentages remain consistent throughout the forecast.

Further detail on accounts inside and outside the city and by rate class can be found in the body of this report.

Total Net Energy for Load & Losses (With Expected Conservation - Table ES-3 and Graph ES-3)

Net energy for load has changed only slightly from last year. The current forecast predicts approximately 2.5% less energy than last year's projections. The net energy for load projections for fiscal year 1998 is 2,560,037 Mwh's.

Losses are averaging approximately 5.5 to 6.0 percent of total sales throughout the twenty-year forecast horizon. System Engineering expects losses to decline within the next few years due to some changes that are expected to take place on the electric system. For instance, new substations, shorter feeders, and larger capacitors. Losses for fiscal year 1998 are projected to be 137,956 Mwh's.

Winter Peak Demand (With Expected Conservation - Table ES-4 and Graph ES-4)

The new forecast continues to indicate that the utility is winter peaking and will be throughout the forecast horizon (1998-2018). The winter peak for fiscal year 1998 is 575 MW (with expected conservation at 50 MW) at a temperature of 30°. The actual winter peak for 1997 was 552 MW's at a minimum temperature of 28°. This peak occurred on a weekend. Most winter peaks occur on weekdays, which is what assumption the forecast is based on.

Historical data prior to 1989 for information such as: circuits out during peak, and voltage reduction is limited. Therefore, the last few year's models were based only on the data that could be verified and documented (1989-1997). Adjustments to the peak for these variables provides a truer picture of what the system actually experiences at time of peak.

We are experiencing a decrease in peak demand from last year's forecast to this year's projections. The forecast indicates an annual change in demand of approximately 19 MW's a year at time of winter peak. This is with demand reduced for conservation.

Summer Peak Demand (With Expected Conservation - Table ES-5 and Graph ES-5)

The summer peak is less volatile and easier to project than the winter peak due to more predictable extreme temperatures. The forecast this year higher than last year's forecast. The summer peak projected for fiscal year 1998 (August @ 97°) is 502 MW (with expected conservation at 21 MW). The actual summer peak for 1997 was 509 MW's at a maximum temperature of 98°. Load Management was not implemented for the 1997 summer peak. The forecast indicates an annual change in demand of approximately 13 MW's a year at time of summer peak. This is with demand reduced for conservation.

Interruptible Load (Table ES-6)

This year's forecast predicts the affects of Interruptible accounts on our system at time of our summer and winter peak. For 1998, we expect approximately 5.0 MW's at time of summer peak and approximately 4.9 MW's at time of winter peak.

Conservation (Table ES-7)

It is important to note that the impacts of conservation in terms of demand reductions significantly changes the peak forecast.

Projections in conservation demand reductions for Fiscal Year 1997/98 and beyond have been revised downward due to major changes in Lakeland's SMART Load Management Program. New electric residential accounts will no longer be required to participate in the SMART Program (remains a voluntary program) and as a result the demand associated with the loss of these accounts has been reflected in the current conservation estimates.

Scenario Forecasts - With Conservation (Table ES-8)

The extreme weather scenario for the winter peak demand (modeled @ 19 degrees) indicates a demand of 721 MW (reducing for 50 MW of conservation). According to the forecast model for the winter peak demand our load should increase or decrease approximately 13 MW's for every degree deviation from the typical 30° used as the minimum temperature in the model.

The extreme weather scenario for the summer peak demand (modeled @ 103°) indicates a demand of 506 MW's (reducing for 21 MW's of conservation).

The remainder of this document will explain the methodology used for each individual model (both inside and outside city limits) used to generate the forecast. The supporting statistics, tables, and graphs can be found on the network under Z:\Forecast|1997L&E.xls

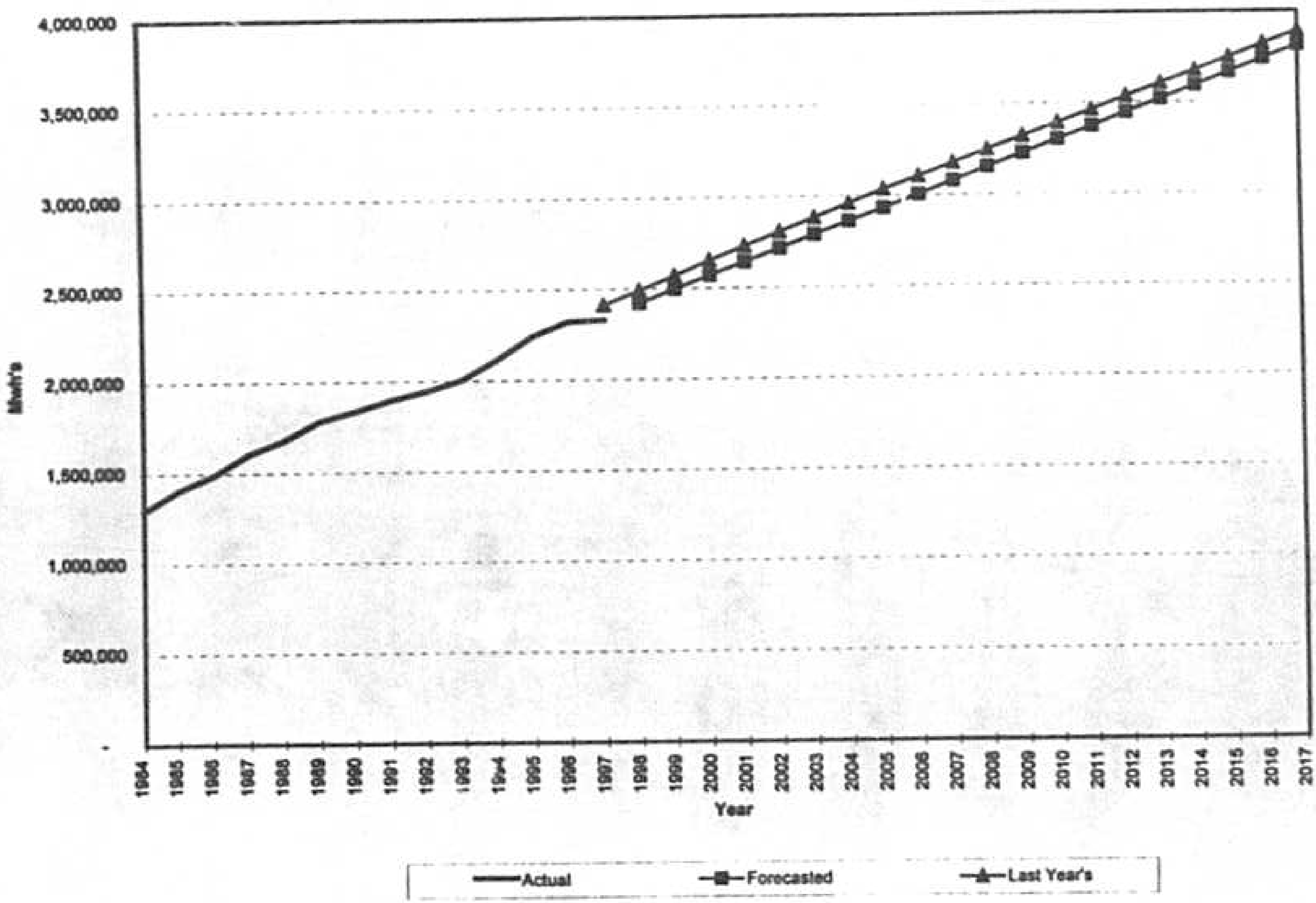
Additional monthly (by rate class) data is available for the budget year (1998/99) of the forecast. It can also be found on the network under Z:\Forecast\97monl&e.xls

Table ES-1

City of Lakeland
Electric & Water Utilities
Total Energy Sales Forecast Comparison
With Expected Conservation
(Mwh)

Fiscal Year	Historical	New Forecast	Last Year's Forecast	Percent Change Between Forecasts
1984	1,294,663			
1985	1,406,592			
1986	1,488,737			
1987	1,605,364			
1988	1,679,519			
1989	1,781,241			
1990	1,835,528			
1991	1,898,067			
1992	1,943,899			
1993	2,005,599			
1994	2,117,691			
1995	2,246,130			
1996	2,321,895			
1997	2,330,533			
Forecast				
1998		2,422,081	2,492,354	-2.82%
1999		2,497,062	2,569,579	-2.82%
2000		2,571,768	2,652,805	-3.05%
2001		2,643,617	2,729,193	-3.14%
2002		2,715,799	2,805,585	-3.20%
2003		2,787,979	2,881,529	-3.25%
2004		2,859,844	2,957,926	-3.32%
2005		2,931,477	3,034,324	-3.39%
2006		3,005,279	3,105,801	-3.24%
2007		3,078,748	3,176,826	-3.09%
2008		3,152,544	3,248,304	-2.95%
2009		3,226,354	3,319,335	-2.80%
2010		3,301,064	3,390,818	-2.65%
2011		3,371,089	3,461,851	-2.62%
2012		3,444,977	3,533,418	-2.50%
2013		3,518,508	3,604,904	-2.40%
2014		3,592,081	3,675,943	-2.28%
2015		3,665,586	3,747,429	-2.18%
2016		3,739,043	3,818,472	-2.08%
2017		3,812,194	3,889,964	-2.00%
2018		3,885,653		
AAGR		**2.39%**	**2.37%**	

Total Energy Sales Forecast Comparison
(With Conservation)



Total Account Forecast Comparison

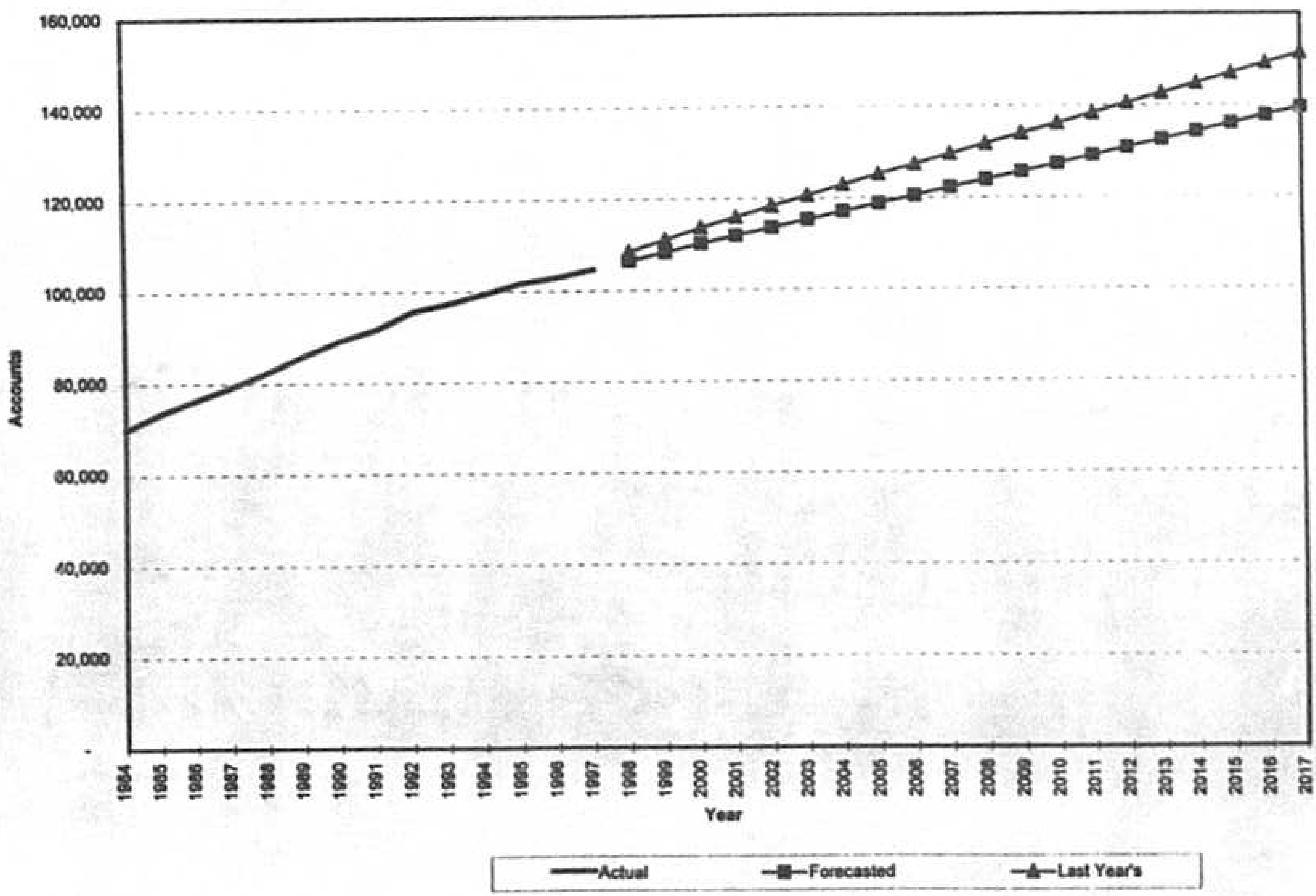


Table ES-2

City of Lakeland
Electric & Water Utilities
Total Account Forecast Comparison

Fiscal Year	Historical	New Forecast	Last Year's Forecast	Percent Change Between Forecasts
1984	69,985			
1985	73,622			
1986	76,462			
1987	79,339			
1988	82,589			
1989	86,167			
1990	89,430			
1991	91,798			
1992	95,675			
1993	97,403			
1994	99,446			
1995	101,767			
1996	103,008			
1997	104,708			
Forecast				
1998		106,454	108,491	-1.88%
1999		108,297	111,045	-2.47%
2000		110,144	113,598	-3.04%
2001		111,864	115,909	-3.49%
2002		113,587	118,219	-3.92%
2003		115,310	120,530	-4.33%
2004		117,036	122,842	-4.73%
2005		118,765	125,151	-5.10%
2006		120,471	127,333	-5.39%
2007		122,179	129,513	-5.66%
2008		123,891	131,694	-5.93%
2009		125,605	133,873	-6.18%
2010		127,324	136,057	-6.42%
2011		129,052	138,237	-6.64%
2012		130,808	140,418	-6.84%
2013		132,537	142,600	-7.06%
2014		134,268	144,783	-7.26%
2015		135,999	146,962	-7.46%
2016		137,738	149,145	-7.65%
2017		139,481	151,327	-7.83%
2018		141,229		
AAGR		**1.42%**	**1.77%**	

Table ES-3

City of Lakeland
Electric & Water Utilities
Total Net Energy For Load Forecast Comparison
With Expected Conservation

Fiscal Year	Historical Mwh's	New Forecast Mwh's	Last Year's Forecast Mwh's	Percent Change Between Forecasts	nnual Losse
1987	1,711,739				(106,375)
1988	1,812,641				(133,122)
1989	1,897,783				(116,542)
1990	2,009,391				(173,863)
1991	2,046,862				(148,795)
1992	2,078,556				(134,657)
1993	2,139,917				(134,318)
1994	2,279,203				(161,512)
1995	2,390,362				(144,232)
1996	2,447,710				(125,815)
1997	2,443,462				(112,928)
Forecast					
1998		2,560,037	2,616,229	-2.15%	(137,956)
1999		2,637,455	2,695,697	-2.16%	(140,393)
2000		2,714,659	2,775,165	-2.18%	(142,891)
2001		2,789,643	2,854,633	-2.28%	(146,026)
2002		2,864,886	2,934,101	-2.36%	(149,087)
2003		2,940,127	3,013,570	-2.44%	(152,148)
2004		3,015,124	3,093,038	-2.52%	(155,280)
2005		3,089,941	3,172,506	-2.60%	(158,464)
2006		3,166,442	3,251,974	-2.63%	(161,163)
2007		3,242,685	3,331,442	-2.66%	(163,937)
2008		3,319,182	3,410,910	-2.69%	(166,638)
2009		3,395,690	3,490,379	-2.71%	(169,336)
2010		3,472,897	3,569,847	-2.72%	(171,833)
2011		3,546,464	3,649,315	-2.82%	(175,376)
2012		3,623,032	3,728,783	-2.84%	(178,055)
2013		3,699,323	3,808,251	-2.86%	(180,815)
2014		3,775,647	3,887,719	-2.88%	(183,566)
2015		3,851,918	3,967,187	-2.91%	(186,332)
2016		3,928,151	4,046,656	-2.93%	(189,108)
2017		4,00[illegible],147	4,126,124	-2.96%	(191,953)
2018		4,080,382			(194,729)
AAGR		**2.36%**	**2.43%**		

Total Net Energy For Load Forecast Comparison
(With Conservation)

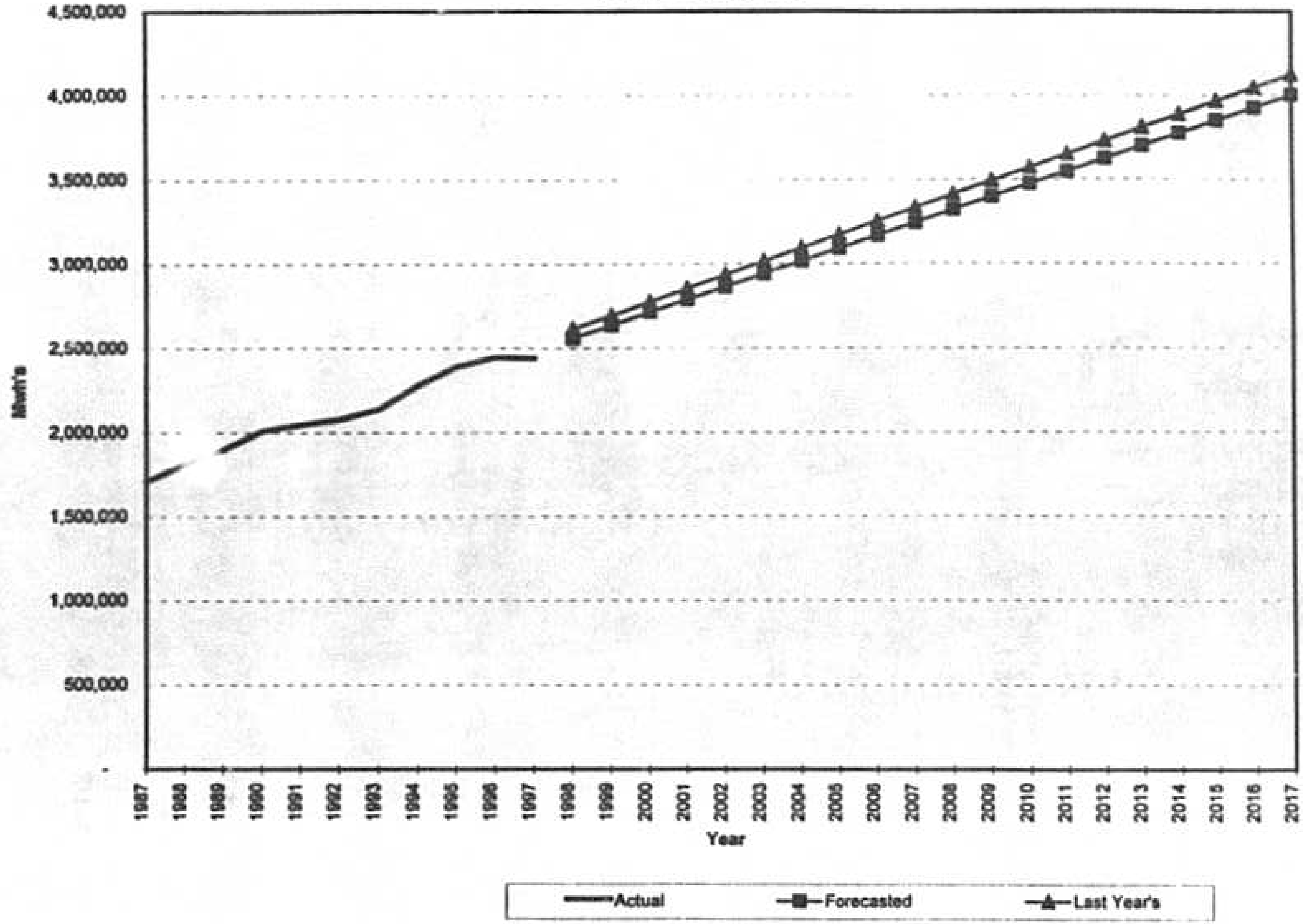


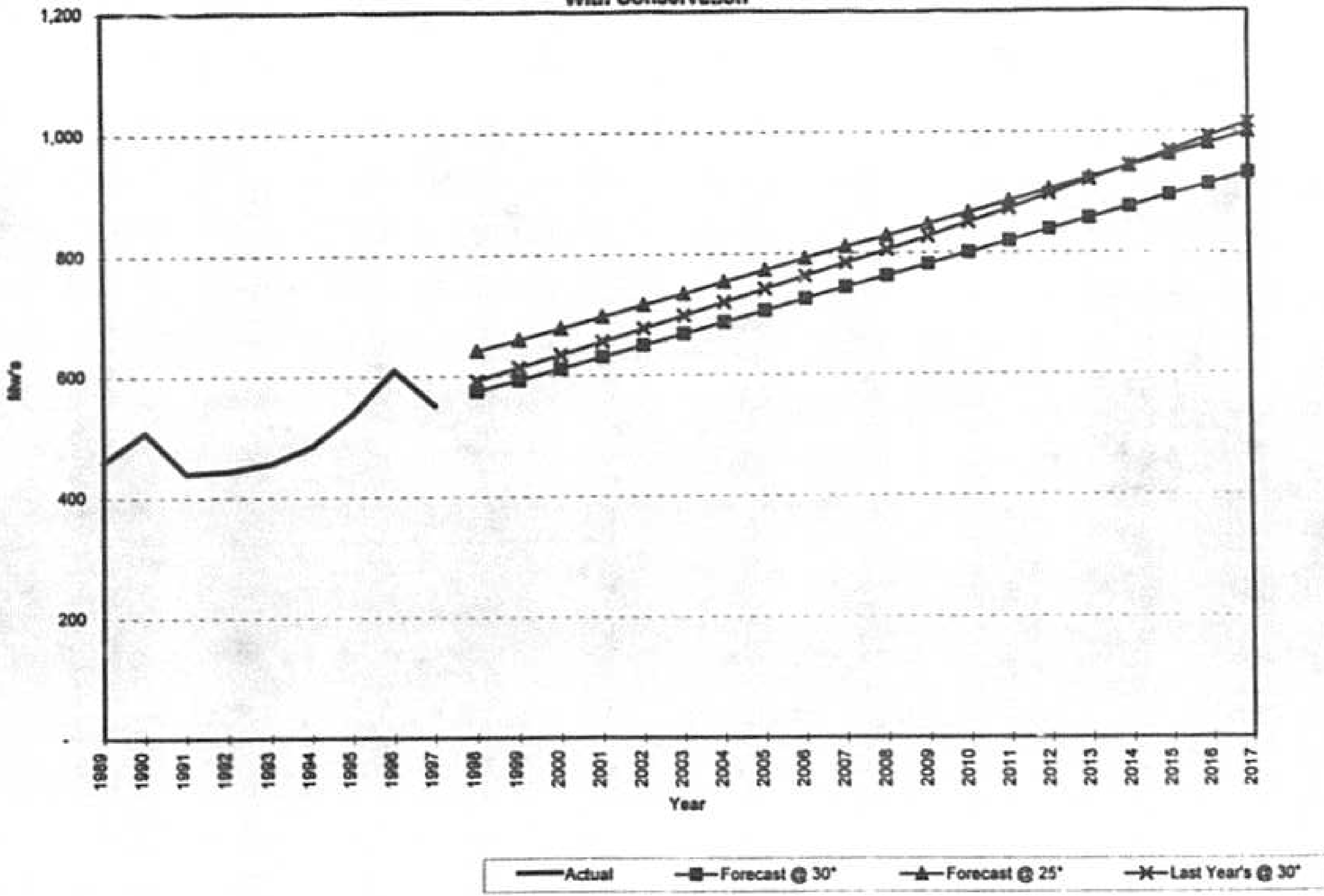
Table ES-4

City of Lakeland
Electric & Water Utilities
Total Winter Peak Demand Forecast Comparison
With Expected Conservation

Fiscal Year	Annual Minimum Temperature	Net Integrated Historical	New Forecast @ 30° *	Last Year's Forecast	Percent Change Between Forecasts
1989	27°	460			
1990	19°	508			
1991	31°	440			
1992	33°	444			
1993	32°	457			
1994	37°	485			
1995	27°	538			
1996	25°	610			
1997	28°	552			
Forecast					
1998	30°		575	592	-2.96%
1999	30°		593	614	-3.44%
2000	30°		612	634	-3.57%
2001	30°		631	656	-3.85%
2002	30°		650	678	-4.11%
2003	30°		668	698	-4.36%
2004	30°		687	720	-4.58%
2005	30°		706	741	-4.80%
2006	30°		725	762	-4.88%
2007	30°		744	784	-5.07%
2008	30°		762	805	-5.38%
2009	30°		781	827	-5.55%
2010	30°		800	851	-5.94%
2011	30°		819	873	-6.19%
2012	30°		838	897	-6.54%
2013	30°		857	921	-6.87%
2014	30°		876	944	-7.18%
2015	30°		895	968	-7.48%
2016	30°		913	991	-7.87%
2017	30°		932	1,015	-8.13%
2018	30°		952		
AAGR			2.55%	2.88%	

** This peak includes the interruptible demand at peak.*

Total Winter Peak Demand Forecast Comparison
With Conservation



*The 1996 Winter Peak Occurred @ 25°.

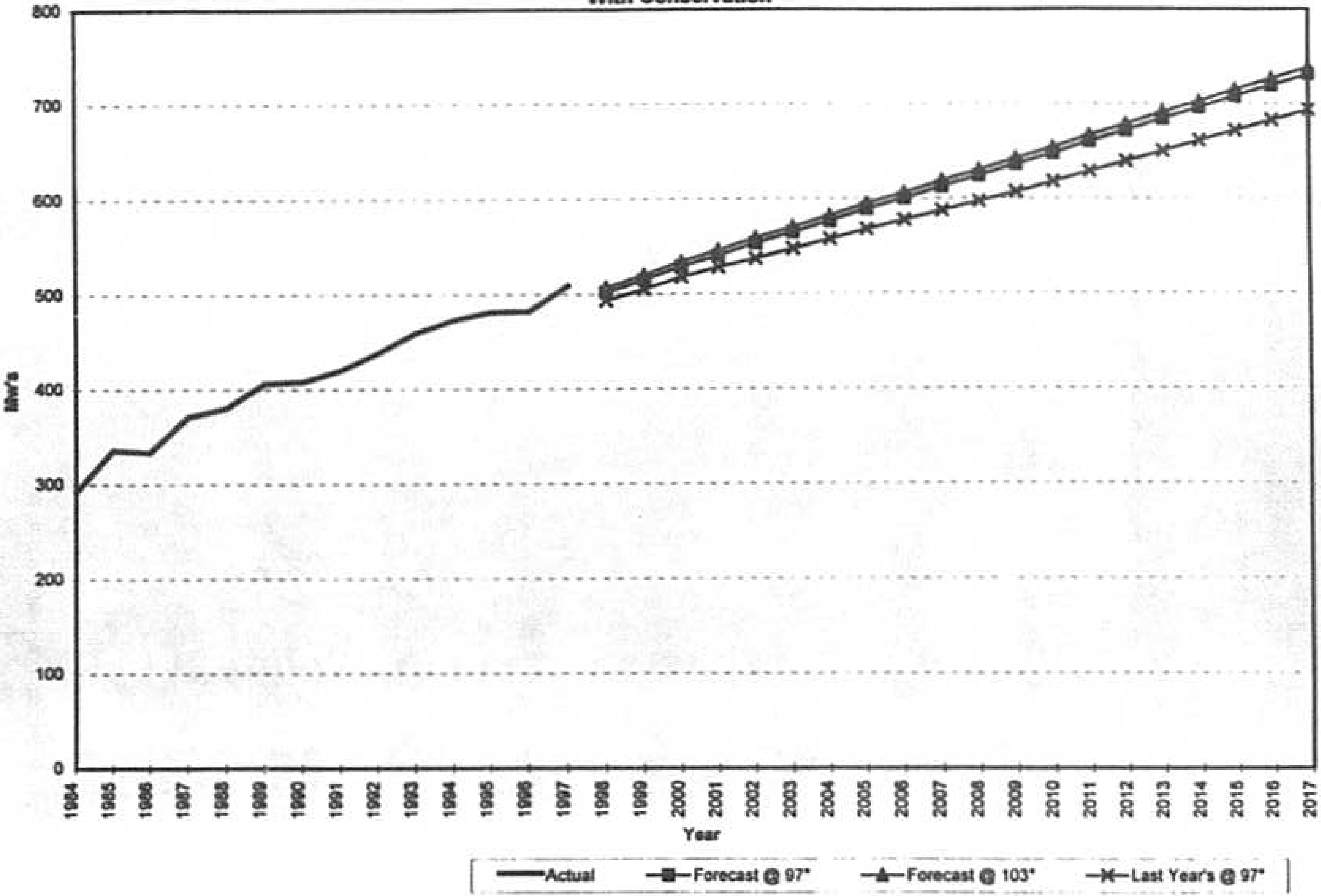
Table ES-5

City of Lakeland
Electric & Water Utilities
Total Summer Peak Demand Forecast Comparison
With Expected Conservation

Fiscal Year	Maximum Temperature	Net Integrated Historical	New Forecast @ 97° *	Last Year's Forecast	Percent Change Between Forecasts
1984	93°	292			
1985	103°	336			
1986	94°	334			
1987	97°	371			
1988	96°	380			
1989	97°	406			
1990	103°	408			
1991	99°	420			
1992	100°	438			
1993	97°	459			
1994	99°	473			
1995	97°	481			
1996	100°	482			
1997	98°	509			
Forecast					
1998	97°		502	493	1.72%
1999	97°		515	505	1.86%
2000	97°		529	517	2.18%
2001	97°		540	528	2.41%
2002	97°		553	537	3.00%
2003	97°		565	547	3.20%
2004	97°		576	557	3.39%
2005	97°		589	567	3.75%
2006	97°		600	577	3.96%
2007	97°		613	587	4.33%
2008	97°		624	597	4.52%
2009	97°		636	607	4.87%
2010	97°		648	618	4.87%
2011	97°		660	628	5.05%
2012	97°		672	639	5.11%
2013	97°		684	650	5.27%
2014	97°		696	661	5.28%
2015	97°		708	672	5.43%
2016	97°		719	682	5.44%
2017	97°		731	693	5.45%
2018	97°		743		
AAGR			1.99%	1.81%	

** This peak includes interruptible demand.*

Total Summer Peak Demand Forecast Comparison
With Conservation



*The 1996 Summer Peak Occurred at 100°.

[redacted]

Table ES-6

City of Lakeland
Electric & Water Utilities
Seasonal Interruptible Peak Demand Forecast

Fiscal Year	Winter Peak Demand (MW's)	Summer Peak Demand (MW's)
1998	4.9	5.0
1999	4.9	5.1
2000	5.0	5.1
2001	5.0	5.2
2002	5.1	5.2
2003	5.1	5.3
2004	5.2	5.3
2005	5.2	5.4
2006	5.3	5.5
2007	5.3	5.5
2008	5.4	5.6
2009	5.4	5.6
2010	5.5	5.7
2011	5.5	5.7
2012	5.6	5.8
2013	5.6	5.8
2014	5.7	5.9
2015	5.8	6.0
2016	5.8	6.0
2017	5.9	6.1
2018	5.9	6.1
AAGR	1.00%	1.00%

Table ES-7

City of Lakeland
Electric & Water Utilities
Demand and Energy Reductions
Without Voltage Reduction

Fiscal Year	Estimated Summer Demand MW	Estimated Winter Demand MW	Estimated Annual Energy MWh	Last Year's Estimated Annual Energy MWh	% Change Between Forecasts
1998	21	50	1,079	1,077	0.21%
1999	22	52	1,173	1,171	0.19%
2000	22	53	1,266	1,265	0.10%
2001	23	54	1,360	1,359	0.09%
2002	23	55	1,454	1,453	0.08%
2003	24	57	1,548	1,547	0.06%
2004	25	58	1,641	1,641	0.01%
2005	25	59	1,735	1,735	0.01%
2006	26	60	1,829	1,829	0.01%
2007	26	61	1,922	1,923	-0.04%
2008	27	63	2,016	2,017	-0.04%
2009	27	64	2,110	2,111	-0.03%
2010	28	65	2,203	2,205	-0.07%
2011	28	66	2,297	2,298	-0.06%
2012	29	67	2,306	2,308	-0.07%
2013	29	68	2,316	2,317	-0.05%
2014	30	69	2,325	2,326	-0.06%
2015	30	70	2,334	2,336	-0.08%
2016	31	72	2,343	2,345	-0.10%
2017	32	73	2,353	2,355	-0.07%
2018	32	74	2,362	2,364	-0.0[illegible]%

Table ES-8

City of Lakeland
Electric & Water Utilities
Summary of Demand and Energy Forecast
No Conservation

Fiscal Year	Total Accounts	Retail Sales (Mwh's)	Net Energy for Load (Mwh's)	Summer Demand (Mw's)	Winter Demand (Mw's)
Forecast					
1998	106,454	2,422,177	2,561,116	523	625
1999	108,297	2,497,155	2,638,628	537	645
2000	110,144	2,571,862	2,715,925	551	665
2001	111,864	2,643,711	2,791,003	563	685
2002	113,587	2,715,893	2,866,340	576	705
2003	115,310	2,788,073	2,941,675	589	725
2004	117,036	2,859,937	3,016,765	601	745
2005	118,765	2,931,571	3,091,676	614	765
2006	120,471	3,005,373	3,168,271	626	785
2007	122,179	3,078,842	3,244,607	639	805
2008	123,891	3,152,637	3,321,198	651	825
2009	125,605	3,226,447	3,397,800	663	845
2010	127,324	3,301,168	3,475,100	676	865
2011	129,052	3,371,182	3,548,761	688	885
2012	130,808	3,444,986	3,625,338	701	905
2013	132,537	3,518,517	3,701,639	713	925
2014	134,268	3,592,091	3,777,972	726	945
2015	135,999	3,665,595	3,854,252	738	965
2016	137,738	3,739,052	3,930,494	750	985
2017	139,481	3,812,203	4,006,500	763	1005
2018	141,229	3,885,662	4,082,744	775	1026
AAGR	1.42%	2.39%	2.36%	1.99%	2.51%

SECTION I - ACCOUNT FORECAST

ACCOUNT FORECAST

Results of the forecast indicate a direct correlation between the population for Polk County and the increase in residential accounts for the Lakeland area. Hence, our first step into the forecasting process is to develop a population forecast.

POPULATION FORECAST

Polk County Population (Table A-1)

Our source of information for the Polk County Population Forecast is the 1997 Annual BEBR (Bureau of Economic and Business Research) Forecast which includes projections out to 2015. Extrapolation was used to project population through the year 2026.

Electric Service Territory Population (Table A-1)

The service territory population was derived by using residential accounts inside and outside the city and multiplying them by the number of persons per household (source: 1994 Appliance Saturation Survey). The projections were based on a regression using Polk County population (POPA) as an independent variable. The model has an Adjusted R-Squared of 99.6%. The model was tested and passes all statistical tests.

RESIDENTIAL ACCOUNT FORECAST

Residential (RS) Accounts Inside, Outside and Total (Table A-2)

Inside (15 Observations: 1983 - 1997)

This year's forecast for RS accounts inside the city is based on the historical annual average growth rate (AAGR) experienced since 1991. After special review of the historical information it was determined a new trend has been developing since 1991. A definite change in growth can be seen for accounts inside the city. Therefore, this year's model is based on observations beginning in 1991. The model predicts an average increase in RS accounts inside the city limits of approximately 250 (600/yr predicted last year) accounts per year, significantly lower than what was predicted last year.

Forecast Comparison:

This forecast ranges from last years projection of -0.59% lower in 1998 to -14.83% lower in 2018.

Changes to Forecast Model

This year the number of observations used in the model was decreased. Last year the historical database used was from 1983-1996. After further evaluation, it was determined that using data from 1991-1997 was a better base of data for the forecast. This can account for some of the change seen between the two forecasts.

Outside: (6 Observations: 1991-1997)

The RS Account Forecast of those accounts outside the city was developed from a regression using Polk County population (POPA) as the explanatory variable. Forecast results estimate approximately 1,100 new RS accounts outside the city every year throughout the twenty-year forecast horizon.

Forecast Comparison:

The year's forecast for RS accounts outside indicates a -2.83% decrease in accounts for 1998, and 1.46% increase in accounts out in 2018.

Changes to Forecast Model

This year the number of observations used in the model was decreased from 1983-1996 to 1991-1997.

Total:

The forecast for total RS accounts was the sum of the individual forecasts for inside and outside the city.

Forecast Comparison:

Overall, the Total RS Account Forecast was approximately -.1.97% lower than what was projected in last year's forecast for 1998. The projections show approximately 1,350 new RS accounts a year throughout the twenty-years.

Changes to Forecast Model

The variable used in last year's model was: Heads of Households (HH). Careful evaluation of the statistical relationships between independent variables and dependent variables resulted in new independent variables being used in the models. Careful consideration was given to the sign (+ -) of the coefficients.

COMMERCIAL AND INDUSTRIAL ACCOUNT FORECAST

General Service (GS) Accounts Inside, Outside and Total (Table A-2)

Inside: (14 Observations: 1984 - 1997)

No specific variables could be proved to be significant in projecting GS accounts inside. The primary driver in the model was RS accounts inside. The relationship between RS accounts inside to GS accounts inside was used to develop the forecast.

Forecast Comparison:

This year's forecast for inside the city is -0.71% lower than last year's forecast in 1998 and approximately 14.67% lower out in the year 2018.

Changes to Forecast Model

Last year's model used RS accounts inside and Real Per Capita Income (RPCY). This model did not prove to be realistic for this year's forecast.

Outside

The projections for GS accounts outside was total developed by the difference of the individual models for inside and Total.

Forecast Comparison:

The change between this year's projections and last year's is minimal. There is a difference of less that 1.0% throughout the twenty-year forecast horizon.

Changes to Forecast Model

Last year's model used RS accounts outside, Labor (E), and Year (Y) as independent variables.

Total

The Total GS Account Forecast was based primarily on the AAGR of historical GS accounts. The projections indicate approximately 68 new GS accounts a year (significantly less than last year's forecast).

Forecast Comparison:

Overall, we see approximately -1.74% change from this year's forecast to last year's.

Changes to Forecast Model

Last year the total GS accounts forecast was the difference between the inside and outside models.

General Service Demand (GSD) Accounts Inside, Outside and Total (Table A-2)

Inside: (14 Observations: 1984 - 1997)

Variables used in the model to forecast GSD accounts inside the city include: RS accounts inside, and Year (Y). The model passes all statistical tests and has an Adjusted R-Squared of 96.9%. Results indicate approximately 20 new GSD accounts a year inside the city.

Forecast Comparison:

There is a -2.26% decrease in accounts between this year's forecast and last year's. This is primarily due to fluctuations seen in the historical data over the past two years.

Changes to Forecast Model

Last year's model used RS accounts inside and Employment (EWS) for independent variables.

Outside:

The primary driver used to develop GSD accounts outside was Polk County population (POPA). Evaluating historical relationships proves GSD accounts outside are correlated somewhat with the growth of the county's population.

Forecast Comparison:

The forecast remains lower than last year's throughout the twenty-year forecast.

Changes to Forecast Model

Last year's model used Heads of Households (HH) and Labor (E).

Total:

The Total GSD Account Forecast is the sum of the outside and inside forecasts. The model projects approximately 28 new GSD accounts a year.

Forecast Comparison:

Overall, the Total GSD Account Forecast is lower than last year's. Historical data shows that the average growth has dropped for GSD accounts over the last two years.

Changes to Forecast Model

The independent variables used in the inside and outside models differed from last year's. This change contributed to the change seen between the forecasts.

General Service Large Demand (GSLD) Accounts Inside, Outside and Total (Table A-2)

Inside:

Polk County population (POPA) was the primary driver for this forecast of GSLD accounts.

Forecast Comparison:

This year's forecast averages out to be less than last year's forecast by approximately 2.0%.

Changes to Forecast Model

Last year the independent variables that were used were: Employment (EWS) and Polk County population (POPA).

Outside: (14 Observations: 1984 - 1997)

The outside forecast for GSLD accounts is the difference between the total and inside forecasts.

Forecast Comparison:

This year's forecast is 15.50% higher than last year's forecast out in 1998. This seems high but we are looking at the difference between 25 new accounts versus 22 new accounts last year.

Total: (14 Observations: 1984 - 1997)

The total is the sum of the inside and outside models. The forecast indicates approximately 2 new GSID accounts a year throughout the twenty years.

Forecast Comparison:

This year's overall forecast averages out to be 6.69% higher than last year's forecast throughout 2018.

OTHER ACCOUNT FORECAST

Electric Accounts (Table A-2)

(14 Observations: 1984 - 1997)

This year a growth rate (developed from evaluating historical trends) was used to develop the electric account forecast. Electric accounts make up only .03% of the total account base.

Forecast Comparison:

This year's forecast is lower than last year's. This is partly due to the decrease in electric accounts which has been experienced over the last three years.

Changes to Forecast Model

Assumptions of future growth differed.

Water Accounts (Table A-2)

(13 Observations: 1985 - 1997)

Water accounts are any non-electric account including the water plant, water production, pumps, and wells. Water accounts are projected to grow at approximately one new account every six years.

Forecast Comparison:

The forecast remains higher than last year's forecast throughout the twenty years.

Changes to Forecast Model

Last year, the water service territory population was used as the basis for growth.

Municipal Accounts (Table A-2)

(22 Observations: 1976 - 1997)

This year, Labor (E) and Population (lagged POPA) were used to develop the Municipal Account Forecast. The projections indicate approximately ten new accounts a year for the next twenty years.

Forecast Comparison:

The difference between this year's forecast and last year's is minimal. Out in 2018, the difference between the forecasts is -2.77%.

Changes to Forecast Model

The same model was used for last year's and this year's model. No change in forecast assumptions.

Private Area Lighting Accounts, Inside, Outside and Total (Table A-2)

Inside : (7 Observations: 1990-1997)

A model was developed this year using a weighted average of two separate regression models. The variables used in the models include Year (Y) and percentage to RS accounts inside. They were then weighted to come up with the final forecast. Projections indicate approximately 50 new private area lighting accounts a year inside the city throughout the twenty years.

Forecast Comparison:

This is the first year private area lights accounts were forecasted for inside and outside the city limits.

Changes to Forecast Model

Last year's forecast was based on a model for total private area lights.

Outside: (7 Observations: 1990-1997)

A model was developed using Year (Y) as an independent variable. The model has an Adjusted R-Squared of 97.9%. This estimates an average new customer growth of 245 new accounts a year for outside the city.

Forecast Comparison:

This is the first year private area lights accounts were forecasted for inside and outside the city limits.

Changes to Forecast Model

Last year's forecast was based on a model for total private area lights.

Table A-1

City of Lakeland
Electric & Water Utilities
Projected Population Estimates

Fiscal Year	1997 BEBR Polk County Population	Historical Service Territory Population	Forecasted Service Territory Population
1970	231,100	91,436	87,828
1971	241,490	95,503	93,513
1972	252,404	100,876	99,486
1973	262,043	107,504	104,761
1974	274,048	113,618	111,330
1975	284,416	117,593	117,004
1976	289,558	120,572	119,818
1977	296,047	122,085	123,369
1978	301,180	125,553	128,178
1979	312,725	129,773	132,496
1980	323,635	134,101	138,466
1981	330,792	139,012	142,383
1982	336,736	143,244	145,635
1983	342,207	147,096	148,629
1984	351,008	151,851	153,446
1985	360,650	158,077	158,722
1986	370,432	162,627	164,075
1987	380,203	167,179	169,422
1988	389,720	172,162	174,630
1989	398,938	178,282	179,675
1990	407,717	184,897	184,479
1991	416,149	188,609	189,093
1992	422,729	194,456	192,694
1993	431,654	200,416	197,578
1994	438,528	203,891	201,340
1995	444,870	208,586	204,810
1996	452,873	211,047	209,190
1997	460,876		213,569
Forecast			
1998	468,880		217,949
1999	476,883		222,329
2000	484,886		226,708
2001	491,804		230,494
2002	498,723		234,280
2003	505,641		238,066
2004	512,560		241,852
2005	519,478		245,638
2006	526,166		249,298
2007	532,854		252,958
2008	539,541		256,618
2009	546,229		260,278
2010	552,917		263,937
2011	559,605		267,597
2012	566,293		271,257
2013	572,980		274,917
2014	579,668		278,577
2015	586,356		282,236
2016	593,044		285,896
2017	599,732		289,556
2018	606,419		293,216
AAGR	1.29%		1.49%

[redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted]

Table A-2

City of Lakeland
Electric & Water Utilities
Total Account Forecast Summary

Fiscal Year	Residential Accounts Total	GS Accounts Total	GSD Accounts Total				GSLD Accounts Total	GSLD Contract Accounts	Interruptible Accounts	PAL Accounts	Electric Accounts	Water Accounts	Contract Water Account	Muni Accounts	Actual/Projected Total Accounts
1984	57,894	6,327	417	6,744	322	47,782	36	-	-	5,199	28	14		272	69,985
1985	60,450	6,747	450	7,197	360	50,083	37	-	-	5,607	28	18		285	73,622
1986	62,597	6,913	604	7,517	393	52,346	35	-	-	5,970	28	17		298	76,462
1987	64,773	7,016	791	7,807	430	55,033	37	-	-	6,358	30	14		320	79,339
1988	67,146	7,468	847	8,315	459	55,233	39	-	-	6,710	33	15		331	82,589
1989	69,997	7,848	917	8,765	495	56,451	40	-	-	6,958	42	15		350	86,167
1990	73,082	8,093	991	9,084	509	56,055	42	-	-	6,815	40	13		354	89,130
1991	74,845	8,316	1,028	9,344	523	56,005	45	-	-	7,139	38	16		371	91,798
1992	77,992	8,645	1,095	9,740	529	54,310	47	-	-	7,453	39	15		389	95,675
1993	79,530	8,676	1,083	9,759	536	54,944	50	-	-	7,614	42	13		395	97,403
1994	80,909	8,764	1,123	9,887	563	56,924	51	-	-	8,144	42	11		402	99,446
1995	82,445	8,851	1,179	10,030	594	59,258	51	-	-	8,775	38	14		414	101,767
1996	83,658	8,557	1,190	9,747	588	60,344	57	-	-	9,072	37	18		423	103,008
1997	84,864	8,621	1,214	9,835	607	61,722	62	-	-	9,471	34	14		428	104,708
Forecast					-	#DIV/0!									
1998	86,222	8,689	1,242	9,931	623	62,735	41	17	5	9,752	35	14	1	436	106,454
1999	87,656	8,757	1,270	10,027	639	63,750	43	17	5	10,052	35	14	1	447	108,297
2000	89,091	8,825	1,297	10,122	655	64,724	45	17	5	10,356	36	14	1	457	110,144
2001	90,408	8,894	1,324	10,218	670	65,611	46	17	5	10,651	36	14	1	468	111,864
2002	91,727	8,963	1,351	10,314	686	66,513	48	17	5	10,946	37	14	1	478	113,587
2003	93,047	9,033	1,378	10,411	702	67,392	50	17	5	11,239	37	15	1	488	115,310
2004	94,369	9,104	1,404	10,508	717	68,224	51	17	5	11,534	38	15	1	498	117,036
2005	95,693	9,175	1,432	10,607	732	69,006	53	17	5	11,828	38	15	1	508	118,765
2006	96,997	9,246	1,458	10,704	747	69,817	54	17	5	12,121	39	15	1	518	120,471
2007	98,302	9,318	1,484	10,802	762	70,575	56	17	5	12,414	39	15	1	528	122,179
2008	99,609	9,391	1,511	10,902	778	71,336	57	17	5	12,707	40	15	1	538	123,891
2009	100,918	9,464	1,538	11,002	793	72,085	59	17	5	12,999	40	16	1	548	125,605
2010	102,229	9,538	1,565	11,103	809	72,894	61	17	5	13,292	41	16	1	559	127,324
2011	103,552	9,612	1,592	11,204	824	73,569	62	17	5	13,585	41	16	1	569	129,052
2012	104,896	9,687	1,620	11,307	840	74,269	64	17	5	13,880	42	17	1	579	130,808
2013	106,218	9,762	1,647	11,409	855	74,957	65	17	5	14,174	42	17	1	589	132,537
2014	107,541	9,838	1,674	11,512	871	75,627	67	17	5	14,466	43	17	1	599	134,268
2015	108,863	9,915	1,701	11,616	886	76,281	68	17	5	14,759	43	18	1	609	135,999
2016	110,191	9,992	1,728	11,720	902	76,929	70	17	5	15,053	44	18	1	619	137,738
2017	111,523	10,070	1,755	11,825	917	77,557	72	17	5	15,347	44	18	1	629	139,481
2018	112,858	10,148	1,784	11,932	933	78,187	73	17	5	15,640	45	18	1	640	141,229
AAGR	1.36%	0.78%	1.83%				2.93%	0.00%	0.00%	2.39%	1.26%	1.26%	0.00%	1.94%	1.42%

SECTION II - ENERGY SALES FORECAST

ENERGY SALES FORECAST

RESIDENTIAL SALES FORECAST

Residential (RS) Sales Inside, Outside and Total (Table S-1)

Inside: (18 Observations: 1980 - 1997)

Those variables that proved to be significant in this year's model include: RS accounts inside, Population (POPA), Heating and Cooling Degree Days (HDD/CDD), and Real Per Capita Income (RYPC). The primary drivers in the model were RS accounts inside and POPA.

Forecast Comparison:

Out in 2018, there is approximately a 14.0% decrease over last year's forecast. This is partly explained by the decrease in sales seen from 1996 to 1997.

Changes to Forecast Model

Last year's model used Year, Polk County population (POPA), Heating and Cooling Degree Days (HDD/CDD), and Real Per Capita Income (RPCY).

Outside:(18 Observations: 1980 - 1997)

This is the difference between the models for inside and total.

Forecast Comparison:

Minimal differences are reported for the changes between the two forecasts.

Changes to Forecast Model

No change.

Total: (18 Observations: 1980 - 1997)

A model was developed using Year (Y), Heating and Cooling Degree Days (HDD/CDD), and Real Per Capita Income (RYPC) as explanatory variables. The model has an Adjusted R-Squared of 98.1%.

Forecast Comparison:

Total RS sales was approximately 5% lower than last year's forecast. Total sales for 1997 was down 5% from the 1996 levels.

Changes to Forecast Model

No change.

COMMERCIAL AND INDU RIAL SALES FORECAST

General Service (GS) Sales Inside, Outside and Total (Table S-1)

Inside: (11 Observations: 1987 - 1997)

Variables used in the model include: Employment (EWS) and Heads of Households (HH). EWS being the primary driver for sales in this model. The model passes all statistical tests and has an Adjusted R-Squared of 98.2%.

Forecast Comparison:

Minimal differences can be seen when comparing the two forecasts. There was less than a 3% difference throughout the twenty years.

Changes to Forecast Model

Last year the independent variables that were used were: GS accounts inside, Population (POPA) and Labor (E). Labor (E) being the primary driver. The number of observations used this year was from 1992-1997 versus the 1987-1996 that was used last year.

Outside: (11 Observations: 1987 - 1997)

Those variables that proved to be significant in this model include: GS accounts outside, and Population (POPA). The Adjusted R-Squared is 97.5% for this model. Population (POPA) was the primary driver.

Forecast Comparison:

Comparing the two forecasts, we see out in year 2018 a 20.19% increase from last year. In the short-term, it 1.61% higher.

Changes to Forecast Model

Last year GS accounts outside, Heating and Cooling Degree Days (HDD/CDD) and Population (POPA) were used. The number of observations also changed. The data used this year was from 1992-1997. Last year the data range used was from 1987 - 1996.

Total: (11 Observations: 1987 - 1997)

Total sales is the sum of the inside and outside models. The overall total forecast projects GS sales to be approximately 170,841 Mwh's for Fiscal Year 1998.

General Service Demand (GSD) Sales Inside, Outside and Total (Table S-1)

Inside: (11 Observations: 1987 - 1997)

Variables used include: Employment (EWS), General Service Demand accounts inside and Employment (EWS). EWS was the primary driver in the model. The model passes all statistical tests and has an Adjusted R-Squared of 98.0%.

Forecast Comparison:

The difference between last year's and this year's forecast. This year's forecast is approximately 4-10% lower throughout the twenty-year forecast.

Changes to Forecast Model

Last year Heads of Households (HH) and Labor (E) were used.

Outside: (11 Observations: 1987 - 1997)

Real Per Capita Income (RPCY) and Population (POPA) were proved to be significant in this model. The model has an Adjusted R-Squared of 95.4%.

Forecast Comparison:

Out in the year 2018, this year's forecast is approximately 8.0% higher than last year's.

Changes to Forecast Model

A model could not be found for last year's model.

Total: (11 Observations 1987 - 1997)

The Total GSD Sales Forecast is the sum of the inside and outside models.

Forecast Comparison:

In 1998, the new forecast is -2.51% lower than last year's.

General Service Large Demand (GSLD) Sales Inside, Outside and Total (Table S-1)

Inside: (14 Observations: 1984 - 1997)

The variables that have proven to be significant in this model include: Heads of Households (HH) and Real Per Capita Income (RPCY). The primary driver is HH. The model has an Adjusted R-Squared of 96.3%.

Forecast Comparison:

In 1998, this year's forecast is 4.3% higher than last year's. In 2018, it is 1.3% higher.

Changes to Forecast Model

Year (Y) and Employment (EWS) were used as the independent variables in last year's model.

Outside: (14 Observations: 1984 - 1997)

This is the difference between the inside and total models. Projections indicate an annual change of energy of 6,498 Mwh's a year.

Forecast Comparison:

Throughout the forecast, this year's projections are slightly higher than last year's, gradually increasing to approximately 10.0% in 2018.

Changes to Forecast Model

No change.

Total: (14 Observations: 1984 - 1997)

This model used Real Per Capita Income (RPCY) and Population (POPA) as independent variables. Population (POPA) was the primary driver in the model. The model has an Adjusted R-Squared of 98.5%.

Forecast Comparison:

Overall, there is a 0.65% increase from last year's forecast in 1998, and 3.91% increase in 2018.

Changes to Forecast

Last year's model used Real Per Capita Income (RPCY) and Population (POPA) as independent variables.

OTHER SALES FORECAST

Municipal Sales (Table S-1)

(13 Observations: 1985 - 1997)

The variables used were: Year, and Real Per Capita Income (RPCY). Year being the primary driver with a *T*-Statistic of 18.72. The model has an Adjusted R-Squared of 98.9%.

Forecast Comparison:

In 1997, this year's forecast is -2.36% lower and in 2018 a change of -2.35% is evident.

Changes in Forecast Model

No change.

Private Area Lighting Sales, Inside, Outside and Total (Table S-1)

Inside: (11 Observations: 1986 - 1997)

This year the variables that were used were: Private area light accounts inside and RS accounts inside. Private area light accounts were the primary driver in the model with a *T*-Statistic of 3.89. The model has an Adjusted R-Squared of 98.7%.

Forecast Comparison:

This is the first year the forecast was segregated between inside and outside the city.

Changes to Forecast Model

The number of observations that were used this year changed significantly from last year's model. This will contribute to most of the change seen between the two forecasts. This year we used data from 1992-1997 and last year data from 1986-1996 was used.

Outside: (6 Observations: 1992 - 1997)

This year the independent variable used was Year (Y). The model has an Adjusted R-Squared on 99.8%.

Forecast Comparison:

This is the first year the forecast was segregated between inside and outside the city.

Changes to Forecast Model

The number of observations that were used this year changed significantly from last year's model. This will contribute to most of the change seen between the two forecasts. This year we used data from 1992-1997 and last year data from 1986-1996 were used.

Total:

This is the sum of the inside and outside models.

Water Sales (Table S-1)

A model using Population (POPA) was used to develop the water sales projections this year. The model has an Adjusted R-Squared of 99.2%.

Forecast Comparison:

In 1998, this year's forecast was 5.17% higher than last year's.

Changes to Forecast Model

Last year a growth rate was used to develop the water sales forecast. The number of observations was also changed to include only data from 1994-1997.

Unmetered Sales (Table S-1)

(10 Observations: 1988 - 1997)

Unmetered sales are those sales derived from municipal lighting. For this year's forecast an annual average growth rate of the Polk County population was used to develop the forecast.

Forecast Comparison:

In 1998, there is a -4.35 decrease over last year's forecast. In 2018, there was an increase of -19.87 decrease.

Changes to Forecast Model

Heads of Households (HH) and Real Per Capita Income (RPCY) were used in last year's model to project sales.

Electric Sales (Table S-1)

(5 Observations: 1992 - 1997)

This year's forecast was based on historical growth rates for sales and accounts.

Forecast Comparison:

The forecast for last year was significantly lower throughout 2018 compared to this year's forecast.

Changes to Forecast Model

Last year's model used Electric Accounts, Population (POPA) and Employment (EWS).

Table S-1

City of Lakeland
Electric & Water Utilities
Total Energy Sales Summary
With Conservation

Fiscal Year	Residential Sales	GS Sales	GSD Sales		GSLD Sales	Interruptible Sales	Contract Sales*	Electric Sales	Water Sale	Contract Sales Water Plant	Municipal Sales	Private Area Lights Sales	Unmetered Sales	Actual Energy Sales	Total Energy Forecast (Less Conservation)
1984	688,367	138,385	183,859	322	230,872			2,455	18,029		19,655	8,695	8,248	1,294,883	
1985	740,898	153,138	207,312	360	247,857			2,682	17,716		20,407	8,644	8,140	1,406,182	
1986	778,609	142,683	250,800	393	258,382			2,623	17,832		22,189	8,820	6,799	1,488,737	
1987	830,970	132,787	298,854	430	278,882			2,872	22,524		23,038	9,748	7,889	1,605,354	
1988	849,015	137,710	321,551	459	305,889			3,960	16,453		27,438	10,624	6,879	1,679,519	
1989	888,783	147,834	348,960	495	327,165			3,408	17,099		30,623	11,323	7,986	1,781,241	
1990	915,800	150,200	359,000	509	336,000			5,215	18,712		31,055	12,057	7,699	1,835,528	
1991	951,377	149,712	373,599	523	350,121			6,294	17,719		31,264	10,046	7,936	1,898,067	
1992	988,473	146,283	382,895	529	348,861			5,181	17,619		33,781	12,704	8,201	1,943,899	
1993	1,011,788	152,445	383,756	536	377,424			5,700	16,405		35,881	13,161	8,909	2,005,599	
1994	1,084,851	159,428	403,382	563	387,053			5,884	15,289		39,074	13,801	9,148	2,117,691	
1995	1,134,429	160,532	433,824	594	429,312			6,055	15,775		42,343	14,619	9,240	2,246,130	
1996	1,213,027	163,782	424,363	588	428,160			6,271	16,558		45,081	15,106	9,549	2,321,895	
1997	1,170,111	167,898	438,343	607	459,090			6,357	17,581		44,947	15,654	9,555	2,330,534	
Forecast				-											
1998	1,225,186	170,841	452,178	623	109,548	39,522	326,981	6,559	2,612	15,039	47,478	16,426	9,713		2,422,081
1999	1,262,659	175,074	464,150	639	118,519	39,923	334,197	6,732	2,988	15,190	49,755	17,003	9,872		[illegible]497,062
2000	1,300,119	179,338	475,800	655	130,743	40,326	340,158	6,906	3,365	15,341	52,032	17,608	10,032		2,571,768
2001	1,337,140	183,353	487,056	670	140,604	40,729	345,808	7,079	3,691	15,495	54,273	18,214	10,175		2,643,617
2002	1,374,162	187,367	498,845	686	151,138	41,136	350,778	7,253	4,015	15,650	56,514	18,820	10,319		2,715,799
2003	1,411,183	191,381	510,233	702	163,125	41,557	354,286	7,426	4,338	15,807	58,755	19,426	10,462		2,787,979
2004	1,448,205	195,409	521,489	717	174,828	41,977	358,076	7,600	4,660	15,965	60,996	20,033	10,606		2,859,844
2005	1,485,226	199,071	532,880	732	186,991	42,398	361,406	7,773	4,982	16,123	63,237	20,640	10,750		2,931,477
2006	1,523,433	202,703	544,613	747	199,445	42,826	365,021	7,947	5,293	16,285	65,575	21,249	10,890		3,005,279
2007	1,561,640	206,334	556,013	762	211,867	43,253	368,859	8,120	5,602	16,448	67,914	21,857	11,031		3,078,748
2008	1,599,848	209,958	567,748	778	223,986	43,684	372,616	8,294	5,911	16,612	70,252	22,466	11,171		3,152,544
2009	1,638,055	213,597	579,475	793	236,583	44,121	376,079	8,467	6,218	16,778	72,590	23,075	11,312		3,226,354
2010	1,676,262	217,810	591,535	809	248,674	44,562	379,844	8,641	6,524	16,946	74,928	23,685	11,453		3,301,064
2011	1,712,529	221,562	602,702	824	258,869	45,005	383,643	8,814	6,833	17,115	77,107	24,295	11,595		3,371,099
2012	1,750,549	225,318	614,445	840	271,986	45,449	387,745	8,988	7,147	17,286	79,423	24,905	11,739		3,444,977
2013	1,788,528	229,029	626,152	855	284,325	45,905	391,356	9,162	7,450	17,460	81,743	25,517	11,881		3,518,508
2014	1,826,527	232,754	637,867	871	296,362	46,364	395,270	9,335	7,754	17,634	84,064	26,128	12,022		3,592,081
2015	1,864,498	236,501	649,581	886	308,298	46,828	399,219	9,509	8,052	17,811	86,383	26,743	12,163		3,665,586
2016	1,902,376	240,309	661,303	902	319,884	47,302	403,494	9,682	8,352	17,988	88,694	27,355	12,304		3,739,043
2017	1,940,076	244,133	672,976	917	331,915	47,775	407,238	9,856	8,652	18,168	90,991	27,968	12,446		3,812,194
2018	1,977,767	247,952	684,977	933	343,601	48,255	411,315	10,029	8,950	18,350	93,287	28,582	12,588		3,885,653
AAGR	2.42%	1.88%	2.10%		5.88%	1.00%	1.11%	2.18%	6.35%	1.00%	3.43%	2.81%	1.30%		2.29%

*Future Contract Sales are Included.

SECTION III - SYSTEM DEMAND FORECAST

SYSTEM DEMAND FORECAST

System Demand

The winter months in the forecast are from November to March. Summer months are from April through October.

Winter Peak - With Conservation (Table D-1)

(9 Observations: 1989-1997)

The new forecast indicates the utility is winter peaking and will be throughout the forecast horizon (1998-2018). The winter peak for Fiscal Year 1998 is 575 MW (at 30°).

The variables used in this model were: Minimum Temperature (min), Day of Week (weekend vs weekday), and the Prior Day's Average Temperature. The model has an Adjusted R-Squared of 92.5% .

Forecast Comparison:

We are experiencing a change from last year's forecast to this year's projections of -2.96% lower in the first year to -8.13% out in 2018.

Changes to Forecast Model

Last year's model used the following independent variables: Minimum Temperature (min), Year (Y) and Midnight Temperature.

Summer Peak - With Conservation (Table D-2)

(18 Observations: 1980 - 1997)

This year's model includes Maximum Temperature (max), and Population (POPA) as independent variables. This model has an Adjusted R-Squared of 98.9%.

The new summer peak for Fiscal Year 1998 is 502 MW's (at 97 degrees).

Forecast Comparison:

In 1998, the new forecast is 1.72% higher than last year's, and out in 2018 it is 7.25% higher.

Changes to Forecast Model

No change.

Interruptible Demand

The amount of peak demand for 1998 that is attributable to the accounts on the Interruptible Rate is approximately 5.0 MW's for the summer peak and 4.9 MW's for the winter. The coincident peak demand of each customer was used to calculate their projected peak demand on the system.

Contract Demand

The amount of peak demand for 1998 that is attributable to the accounts on the Contract Rate is approximately 44.4 MW's for the summer peak and 42.4 MW's for the winter. The coincident peak demand of each customer was used to calculate their projected peak demand on the system.

Table D-1

City of Lakeland
Electric & Water Utilities
Winter Peak Demand Forecast, With Conservation
Normal Weather Scenario @ 30°

Fiscal Year	Minimum Temp	Prior Day's Average	Historical Net Integrated Winter Demand	New Forecast @ 30 (Including Interruptible and Contract Load)	Contract Demand @ Winter Peak	Interruptible Demand @ Winter Peak	Net System Load (Less Interruptible)	Estimated Conservation (10/23/96)	Net System Load (Less Interruptible and Conservation)	Annual Change in Demand
1989	27	39	482	480				22		
1990	19	28	508	512				0		26
1991	31	46	446	430				6		-62
1992	33	45	464	480				20		18
1993	32	40	480	497				23		16
1994	37	47	485	473				0		5
1995	27	40	608	604				70		123
1996	25	37	655	641				45		47
1997	28	40	558	571				49		-97
Forecast										
1998	30	40		625	46	5	620	50	570	
1999	30	40		645	48	5	640	52	588	18
2000	30	40		665	49	5	660	53	607	19
2001	30	40		685	50	5	680	54	626	19
2002	30	40		705	50	5	700	55	645	19
2003	30	40		725	51	5	720	57	663	18
2004	30	40		745	51	5	740	58	682	19
2005	30	40		765	52	5	760	59	701	19
2006	30	40		785	52	5	780	60	720	19
2007	30	40		805	53	5	800	61	739	19
2008	30	40		825	53	5	820	63	757	18
2009	30	40		845	54	5	840	64	776	19
2010	30	40		865	54	6	859	65	794	18
2011	30	40		885	54	6	879	66	813	19
2012	30	40		905	55	6	899	67	832	19
2013	30	40		925	55	6	919	68	851	19
2014	30	40		945	56	6	939	69	870	19
2015	30	40		965	56	6	959	70	889	19
2016	30	40		985	57	6	979	72	907	18
2017	30	40		1005	58	6	999	73	926	19
2018	30	40		1025	59	6	1020	74	946	19

Table D-2

City of Lakeland
Electric & Water Utilites
Summer Peak Demand Forecast, With Conservation
Normal Weather Scenario @ 97°

Fiscal Year	Maximum Temperature	Historical Net Integrated Summer Peak	New Forecast @ 97° (Including Interruptible and Contract Load)	Contract Demand @ Summer Peak	Interruptible Demand @ Summer Peak	Net System Load (Less Interruptible)	Estimated Conservation (10/23/96)	Net System Load (Less Interruptible and Conservation)	Annual Change In Demand
1980	102	287							
1981	102	284							17
1982	95	267							-17
1983	94	287							20
1984	93	292							5
1985	103	336							44
1986	94	334							-2
1987	97	371							37
1988	96	380							9
1989	97	406							26
1990	103	408							2
1991	99	420							12
1992	100	438					4		18
1993	97	459					0		21
1994	99	473					18		14
1995	97	481					0		8
1996	100	482					0		1
1997	98	509					0		
Forecast									
1998	97		518	49	5	513	21	492	
1999	97		532	50	5	527	22	505	13
2000	97		546	51	5	541	22	519	14
2001	97		558	52	5	553	23	530	12
2002	97		571	52	5	566	23	543	13
2003	97		583	53	5	578	24	554	12
2004	97		596	53	5	591	25	566	12
2005	97		608	54	5	603	25	578	13
2006	97		620	54	6	614	26	588	10
2007	97		633	55	6	627	26	601	12
2008	97		645	55	6	639	27	612	11
2009	97		657	56	6	651	27	624	12
2010	97		669	56	6	663	28	635	11
2011	97		682	57	6	676	28	648	12
2012	97		694	57	6	688	29	659	12
2013	97		707	59	6	701	29	672	12
2014	97		719	59	6	713	30	683	11
2015	97		731	60	6	725	30	695	12
2016	97		744	61	6	738	31	707	11
2017	97		756	61	6	750	32	718	11
2018	[illegible]		[illegible]	62	[illegible]	762	[illegible]	730	[illegible]2

SECTION IV - NET ENERGY FOR LOAD FORECAST

NET ENERGY FOR LOAD FORECAST

Net Energy for Load (With Conservation) Table E-1)

(24 Observations: 1974-1997)

Net energy for load was generated by using a regression model using Total Retail Sales. The Adjusted R-Squared is 99.7%.

Forecast Comparison:

There is a minimal difference between this year's forecast and last year's. In 1998, this year's was -2.15% lower than last year's, and in 2018 it was -2.96% lower.

Changes to Forecast Model

Last year a growth rate was used to develop the forecast. The number of observations that were used this year was changed to include data from 1974-1997.

Losses (Table E-1)

Losses are expected to remain the same in the short-term and begin decreasing slightly out into the future.

Table E-1

City of Lakeland
Electric & Water Utilities
Net Energy For Load Forecast
With Conservation

Fiscal Year	Historical	New Forecast	Last Year's Forecast	Annual Losses	Losses as a % of NEL
1987	1,711,739			(106,286)	-6.21%
1988	1,812,641			(133,123)	-7.34%
1989	1,897,783			(116,513)	-6.14%
1990	2,009,391			(139,669)	-6.95%
1991	2,046,862			(124,402)	-6.08%
1992	2,078,556			(134,657)	-6.48%
1993	2,139,917			(134,593)	-6.29%
1994	2,279,203			(161,513)	-7.09%
1995	2,390,362			(144,237)	-6.03%
1996	2,447,710			(125,753)	-5.14%
1997	2,443,462			(112,928)	-4.62%
Forecast					
1998		2,560,037	2,616,229	(137,956)	-5.39%
1999		2,637,455	2,695,697	(140,393)	-5.32%
2000		2,714,659	2,775,165	(142,891)	-5.26%
2001		2,789,643	2,854,633	(146,026)	-5.23%
2002		2,864,886	2,934,101	(149,087)	-5.20%
2003		2,940,127	3,013,570	(152,148)	-5.17%
2004		3,015,124	3,093,038	(155,280)	-5.15%
2005		3,089,941	3,172,506	(158,464)	-5.13%
2006		3,166,442	3,251,974	(161,163)	-5.09%
2007		3,242,685	3,331,442	(163,937)	-5.06%
2008		3,319,182	3,410,910	(166,638)	-5.02%
2009		3,395,690	3,490,379	(169,336)	-4.99%
2010		3,472,897	3,569,847	(171,833)	-4.95%
2011		3,546,464	3,649,315	(175,375)	-4.95%
2012		3,623,032	3,728,783	(178,055)	-4.91%
2013		3,699,323	3,808,251	(180,815)	-4.89%
2014		3,775,647	3,887,719	(183,566)	-4.86%
2015		3,851,918	3,967,187	(186,332)	-4.84%
2016		3,928,151	4,046,656	(189,108)	-4.81%
2017		4,004,147	4,126,124	(191,953)	-4.79%
2018		4,080,382		(194,729)	-4.77%
AAGR		**2.36%**	**2.43%**		

SECTION V - CONSERVATION

CONSERVATION

Demand-Side Management - Demand and Energy Reductions

Residential Direct Load Control (SMART)

The SMART Program represents cyclic control of residential heating, ventilating, and air conditioning (HVAC) systems, and continuous control of water heating to reduce weather sensitive system peak demand. Ideally, direct load control (DLC) cases a shift of demand from on-peak to off-peak periods. A winter demand reduction of approximately 1 KW per account can be expected from each water heater under continuous control. Another 1.2 KW per account can be expected from control of HVAC systems.

Low-Interest Loans

The low-interest loan program provides money to our residential accounts to make energy efficient improvements to their homes at a low interest rate. The reductions associated with the heat pump conversions are 0.8 KW demand reduction at time of winter peak. Annual energy savings of 795 Kwh per account per year can be expected for energy.

Thermal Energy Storage (TES)

Demand reductions associated with thermal energy can be estimated at an average reduction of 51 KW at time of peak. Thermal energy storage enables our commercial and industrial accounts to move most or all of their HVAC load to off-peak hours.

METHODOLOGY

ECONOMETRIC MODELS:

Econometric modeling is the statistical relationship that expresses the changes in a dependent variable as a function of a number of influencing factors or independent variables. Econometric models assume that the dependent variable will be affected by the same key factors in the future as it was in the past. In order to project future values of the dependent variable, projections of these factors must be obtained for the forecast period.

An important consideration in regression analysis is the selection of variables. Independent variables explain the changes in the dependent variable. Therefore, sufficient historical data for both dependent and independent variables must be available to produce a regression equation. Graphic techniques were also used to inspect the data, looking closely for trends and the reliability of historical data. All annual projections in this year's forecast were generated by the use of econometric models.

All of the models used were examined for heteroskedasticity & serial correlation in order to verify the statistical significance of the models. The method used to examine the models for these conditions was the Lagrange multiplier (LM) test. Multicollinearity was not considered to be a concern in our models because the forecasting ability is often not effected and has even been known to improve it.

TIME-SERIES DECOMPOSITION MODELS:

Time-series decomposition was used to forecast Fiscal Year 1997/98 monthly sales, net energy for load, system peaks and accounts for budgeting purposes based on the annual forecast. Three factors are incorporated in a time-series decomposition model: seasonal (monthly) factors, trend (annual) factor, and the cyclical factor. Monthly historical data for the variable in question is required for this form of analysis. The seasonal index was calculated by averaging the seasonal factors (the observed monthly value / centered moving average) for a given month. Normally, this would then be multiplied by the trend component. Since annual forecasts had been completed, these numbers were used as opposed to a simple trend value. Cyclical factors were determined to be insignificant based on both examined graphical data and on theoretical bases.

DATA SOURCES:

University of Florida's Bureau of Economic and Business Research (BEBR) Annual Forecast, 1997 Population Projections

Customer Statistics Report

System Planning Historical and Projected Data Book

Monthly Peak Record (Reports #50 & #53)

Monthly GSLD Report

Water Service Territory Population Estimates

1994/95 Load & Energy Forecast, 1995/96 Load & Energy Forecast

Appliance Saturation Survey , 1994

Polk Progress Report

Temperature, Load, and Humidity Files

Economic Report

Municipal Forecast, 1998/99

Historical Billing Information (CIBS Database)

Municipal Breakdown Report

Coincident Peak Information - Load Research

FUEL PRICE FORECAST

FISCAL YEAR

1997-98

I. EXECUTIVE SUMMARY

The City of Lakeland Department of Electric and Water Utilities uses many fuels. This document will explain some of the assumptions in market trends for coal, natural gas, oil, and petroleum coke. The first section of this report quickly highlights the contracts we have in place as of publication of this document. In a nutshell, we have a few contracts that are characterized in the long term over five year term that mainly deal with transportation of fuels and one natural gas contract. In the intermediate range, one through five years, we have a mix of coal, natural gas, and pet coke contracts. Lastly, in the short term, we have very few contracts since we try to optimize fuel purchases in the short term by utilizing the spot market.

The coal industry is going through some change that might be critical to the coal price obtained by the City of Lakeland. The first change is the fluidity of the market. Next year it is expected that Nymex, the New York Mercantile Exchange Commission, will set up futures contracts for coal. This is to follow the trend of the natural gas futures contracts and the electric futures contracts that the Nymex already has set up. The consequence of this will be a market that not only now is driven by demand and supply, but will also be driven by speculation.

The second major point in the coal industry is the environmental regulation that will take place in the years 2000 and 2005. If a strong environmental regulation occurs, then we will see low sulfur coals be at a much higher premium than ever in the past compared to a medium to high sulfur coal. Fortunately, because of the flexibility that the City of Lakeland has in its fuel burn, this might be more beneficial to us than many other utilities. The demand for high sulfur coal is expected to decline and based on that assumption, many producers will close their mines thereby also reducing the production of that fuel.

The natural gas market is beginning to experience the results of many years of change that have occurred in the market. Speculation has become a very important variable in the price of that fuel. It is no longer feasible to forecast natural gas prices in the short term based on supply and demand. Over the long term, the supply in the North American continent seems to be more than sufficient to cover any foreseen demand scenario in the U.S. There is plenty of supply coming down from Canada and it is expected that Mexico will begin to export its natural gas to the U.S. if production in the U.S. does not pick up.

The City of Lakeland does not consume that much oil and for that reason less importance has been given to the forecasting of such price. Overall, the oil market is driven by the OPEC nations in their inability to agree and maintain their quotas. U.S. production continues to decline regardless of the improvements in technology.

The petroleum coke market is mainly driven by foreign demand on that fuel. The domestic market mainly becomes a price taker instead of a price setter. But because producers consider petroleum coke a residual product, small changes on speculation can cause major fluctuations in that market. The City of Lakeland was able to time its purchases appropriately so it is expected that in the year 2000 (upon the expected expiration of the contract) the City of Lakeland's price would have to increase to narrow the gap between our contract price and what the market calls for.

The City of Lakeland in its forecast has changed its methodology to reflect the reality of the market more so than the market plus inflation. For that reason, this year, the reader will be able to find that there is only one forecast for each fuel type and such forecast does not include the addition to the increase in fuel price an inflation measurement. It is believed that in previous years there was some double counting of not only the increase on the fuel but also the increase on the fuel inflation that caused prices to increase in the latter proportion of the forecast. So the prices that are in this document are the prices that we expect to get for those specific years. It has been found that when applying a said number for inflation to the already increasing prices of fuel, it compounds the effect and creates unrealistic numbers at the end of the forecast.

II. CONTRACTS

The City of Lakeland characterizes three types of contracts: short term (less than a year), intermediate (a year to five year term), and long term (five years or above).

A. COAL

Based on the above characterization, in the coal area, we have two contracts of intermediate nature. One contract is with Shamrock (Sun Coal) and this contract has the possibility of continuing for two additional years. The other intermediate contract is with Consol Coal and at this point in time it is only for a one-year term. Both contracts are expected to satisfy 90% of our total need for calendar year 1998.

B. NATURAL GAS

The City of Lakeland has one long term contract with Natural Gas Clearinghouse. The expiration date of that contract will be 2002. The amount of the contract for Natural Gas Clearinghouse varies anywhere from 5,000 mmbtus a day to 9,000 mmbtus a day depending on the season. There is a possibility for another 10-year contract, a prepaid deal, participating with Florida Gas Utilities. If the prepaid deal becomes effective, it will be for 2,000 mmbtus a day for 10 years beginning in 1998. We also have an intermediate contract with Columbia Gas Services for 4,000 mmbtus a day all the way up to 5,100 mmbtus per day. All of these contracts once in effect, will account for around 50% of our 1998 needs.

C. OIL

At this point in time, the City of Lakeland does not have any long term contracts or intermediate contracts for the purchase of oil since the purchase is minimal.

D. PET COKE

We have an intermediate contract with Oxbow Carbon for the purchase of petroleum coke. This contract expires in 1998 and it is for 100% of Lakeland's needs. This contract is also for the transportation of pet coke.

E. TRANSPORTATION

Under coal we have a contract with CSX that will expire in the year 2000. We also have a contract with Florida Gas Transmission that has long term characteristics.

III. COAL

The coal market has been very stable. Over the past few years, little increase or decrease has occurred and in real terms (without inflation) the price has been decreasing. The NYMEX Board is expecting to add a new futures contract in the second quarter of 1998. This will cause the market to be more volatile. This is believed to be the case mainly based on previous commodities. The gas business, for example, used to be somewhat stable and after it began to get traded at the NYMEX, it became very volatile. So, the coal market could have a probability that it becomes more volatile and more speculative than ever. This will cause a lot of changes in the market but none of those changes are expected to (1) change too quickly (in 1998) or (2) to increase consumption.

The Clean Air Act and possible Carbon Tax by far will have the greatest affect on the coal market. Compliance coal might be the regular traded coal and those utilities that can burn higher sulfur content than compliance (less than 0.7%) will have a competitive advantage. So while the enclosed forecast is a forecast of the average coal market, which in its majority will have compliance coal, it is also believed that the price will be much lower for any utility that can burn higher sulfur coal. The higher sulfur coal, though, would be difficult to find since there are only a few utilities that can burn it. Many producers are expected to close their high sulfur coal mines because they expect low demand.

As mentioned in the contract section, our coal contracts are short term (within a year), but at least, the Shamrock Coal is expected to continue for a couple of years, if their price remains competitive.

The big impact for the City of Lakeland will be in blending different types of coals and thereby reducing the overall cost. This forecast does not assume a tremendous blend since at this point in time it is unclear what coals can be used. Some of the coals that present the greatest opportunities for the City of Lakeland are the Powder River Basin coal, the Illinois Basin coal, Indonesia coal, and South American coal.

Based on the Department of Energy's Energy Information Administration, coal production was a record 1,064 million short tons in 1996. Production is expected to grow by 1.8% in 1997 with annual output reaching 1,083 million short tons. Production will grow by an additional 3.2% in 1998. Production in the western regions should continue to rise significantly over the forecasted period while production in interior declines, and Appalachia production grows slowly.

IV. NATURAL GAS

Since full implementation of financial products in the natural gas market, the natural gas price has been less susceptive to demand and supply and more susceptive to financial derivatives and overall financial transactions. This has caused the market to behave in an erratic proportion. For example, this year we have seen October prices to be about a dollar higher than December prices. In the past, we have never seen such disparity and it is difficult to explain why such disparity has occurred.

Because the gas market has become more fluid, the gas market trades on an hourly and a daily basis without much consideration to long term production or demand.

The gas supply in the U.S., Mexico, and Canada, when combined, produce enough to satisfy any conceivable demand by the U.S. market. The dependent variables on natural gas are (1) weather in the short term, (2) some production, (3) some demand, (4) storage capabilities, and, most importantly, (5) financial speculation. Any forecasts found are normally modeled using one through four because market speculation is difficult to model. For that reason, the enclosed forecast has an average growth rate instead of trying to forecast the peaks and the valleys that will occur in the market. The short term forecast is simply based on the Nymex closing numbers for each one of the following 18 months.

A. TRANSPORTATION OF NATURAL GAS

As of today, the City of Lakeland transports 100% of its gas needs through the Florida Gas Transmission system. The Florida Gas Transmission system has two main rates for capacity. What is known as FTS-1 is for phases of the pipeline that include Phase 1 and Phase 2. FTS-2 rate is to reflect costs of Phase 3 and possibly the development of Phase 4. FTS-2 prices are higher than FTS-1 and for that reason the City of Lakeland has embarked on a mission to find as much FTS-1 as possible and relinquish some of the FTS-2 capacity. Also, it is expected that delivered gas (interruptible transportation) is available most of the time. For that reason, the City of Lakeland will not purchase all of the capacity that it needs for all of the power plants. Instead it will optimize its use to take advantage of opportunities in the market of getting cheaper short term capacity prices on FGT.

There is a new project proposed that involves a second natural gas pipeline in the state. The project is known as Gulf Stream. The proposal has in it an additional 500,000 mmbtus per day and is expected to be on-line in 2001. Although the likelihood of this pipeline is, at this point, unknown, it is believed that this will bring new competition and more opportunities for the end user.

V. OIL

As mentioned before, the City of Lakeland does not consume large percentages of oil. The use of oil, because of its expense, is usually minimized to a few percentages of the total fuel consumption for the year. Nevertheless, the City of Lakeland does have to purchase oil and oil is mainly driven by the foreign countries that have the most supply, also known as the OPEC nations. OPEC could conceivably drive the price up or down when there is perfect communication among its members. And there have been a few occasions where they have been effective in their goal. Most of the time, though, the OPEC nations have been driven by their own individual profit margin and thereby breaking their quotas and causing the oil prices to remain low.

The use of residual fuel, especially the high sulfur residual fuel is being minimized as further environmental regulations take effect. Based on a U.S. Department of Energy Energy Information Administration study, all production will continue to decrease through year 2015. Although there are numerous advances in oil discovery technologies, this is expected to be inefficient to offset declining resources. Based on this study, the share of petroleum consumption met by imports rises from 44% in 1995 to 61% in 2015.

VI. PETROLEUM COKE

The petroleum coke market is defined by what occurs in the international market. The bulk of all pet coke production goes to the international market to offset coal in the European and Asian market. Because of this, the price of pet coke will be difficult to estimate by itself. A closer look at international market has to be taken to drive the assumptions of the domestic pet coke market. In its majority, the price of coal in Africa has a direct correlation to the pet coke prices that the City of Lakeland obtains. The relationship is as follows: If the African coal price increases, the pet coke market for Europe increases as well to replace the high priced coal from Africa and this, in turn, increases the domestic market as more production is taken out of the lower 48. The reverse also has the reverse conclusion. If the South African coal market is depressed, that will have less demand on the petroleum coke and therefore lower its prices in the domestic area. Because petroleum coke is a residue of what is called cracking oil, any strong movement in the downward position stimulates a great interest from the producers of pet coke to sell off the inventory as quickly as possible. The effect causes the pet coke market to be very low when it is low and very high when it is high. Because of this, the City of Lakeland has to carefully optimize the pet coke prices when the down turn effect takes place. It is recommended to go into longer term contracts when the price is low and only a small monthly spot purchases when the price is in an upward trend. Because of this the City of Lakeland has been able to purchase pet coke between five to ten dollars per ton cheaper than what the market has required.

Since the Mobil refinery is the City of Lakeland's only source, further developments will enhance our opportunity to purchase a longer term contract after year 2000. The forecast shows an increase after year 2000 to show Lakeland's prices becoming closer to what the market will be at that point in time.

There are a few refineries in the southern part of the United States that will increase the supply of petroleum coke in the upcoming years. There is also an estimated increase in consumption by the Florida utilities and other utilities throughout the U.S. in their use of pet coke. Utilities such as Jacksonville, Tampa Electric, and Orlando Utilities are beginning to use more pet coke than before. This will have an effect on the Florida market and it is believed that it will cause pet coke to become more expensive as demand increases faster than supply can be obtained.

Lakeland Electric & Water Utilities
Annual Projected Cost of Fuel By Type
Base Case
$/MMbtu

Fiscal Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Petroleum Coke	RDF
1998	$1.74	$2.28	$3.06	$4.29	$4.44	$1.06	($2.25)
1999	$1.76	$2.30	$3.09	$4.33	$4.53	$1.09	($2.30)
2000	$1.78	$2.32	$3.14	$4.40	$4.63	$1.15	($2.36)
2001	$1.80	$2.34	$3.19	$4.47	$4.73	$1.17	($2.42)
2002	$1.82	$2.36	$3.24	$4.54	$4.82	$1.19	($2.47)
2003	$1.84	$2.39	$3.30	$4.63	$4.92	$1.21	($2.53)
2004	$1.86	$2.43	$3.37	$4.72	$5.01	$1.23	($2.58)
2005	$1.88	$2.47	$3.44	$4.82	$5.13	$1.25	($2.64)
2006	$1.90	$2.53	$3.52	$4.93	$5.25	$1.27	($2.70)
2007	$1.92	$2.59	$3.60	$5.05	$5.45	$1.29	($2.76)
2008	$1.95	$2.56	$3.70	$5.18	$5.65	$1.32	($2.82)
2009	$1.97	$2.71	$3.80	$5.33	$5.82	$1.34	($2.88)
2010	$1.99	$2.78	$3.91	$5.49	$5.99	$1.36	($2.95)
AAGR	1.13%	1.67%	2.06%	2.08%	2.53%	2.10%	2.28%

AAGR = Average Annual Growth Rate

Lakeland Electric & Water Udilities
Annual Projected Cost of Fuel By Type
High Case
$/MMbtu

Fiscal Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Petroleum Coke	RDF
1998	$1.74	$2.28	$3.06	$4.29	$4.44	$1.06	($2.25)
1999	$1.79	$2.33	$3.14	$4.39	$4.60	$1.11	($2.27)
2000	$1.83	$2.39	$3.23	$4.53	$4.77	$1.18	($2.29)
2001	$1.88	$2.45	$3.33	$4.67	$4.94	$1.22	($2.32)
2002	$1.93	$2.50	$3.44	$4.81	$5.11	$1.26	($2.33)
2003	$1.98	$2.57	$3.55	$4.98	$5.29	$1.30	($2.35)
2004	$2.03	$2.65	$3.68	$5.15	$5.47	$1.34	($2.36)
2005	$2.08	$2.74	$3.81	$5.34	$5.68	$1.38	($2.38)
2006	$2.14	$2.85	$3.96	$5.54	$5.90	$1.43	($2.40)
2007	$2.19	$2.96	$4.11	$5.76	$6.21	$1.47	($2.42)
2008	$2.26	$2.97	$4.28	$6.00	$6.53	$1.53	($2.43)
2009	$2.32	$3.18	$4.46	$6.26	$6.83	$1.57	($2.45)
2010	$2.37	$3.31	$4.66	$6.54	$7.13	$1.62	($2.47)
AAGR	**2.63%**	**3.17%**	**3.66%**	**3.58%**	**4.03%**	**3.60%**	**0.78%**

AAGR = Average Annual Growth Rate

Lakeland Electric & Water Utilities
Annual Projected Cost of Fuel By Type
Low Case
$/MMbtu

Fiscal Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Petroleum Coke	RDF
1998	$1.74	$2.28	$3.06	$4.29	$4.44	$1.06	($2.25)
1999	$1.73	$2.27	$3.04	$4.27	$4.46	$1.07	($2.33)
2000	$1.73	$2.25	$3.05	$4.27	$4.49	$1.12	($2.43)
2001	$1.72	$2.24	$3.05	$4.27	$4.52	$1.12	($2.53)
2002	$1.71	$2.22	$3.05	$4.28	$4.54	$1.12	($2.62)
2003	$1.71	$2.22	$3.06	$4.30	$4.57	$1.12	($2.72)
2004	$1.70	$2.22	$3.08	$4.32	$4.58	$1.13	($2.82)
2005	$1.69	$2.22	$3.10	$4.34	$4.63	$1.13	($2.92)
2006	$1.69	$2.25	$3.13	$4.38	$4.66	$1.13	($3.03)
2007	$1.68	$2.28	$3.15	$4.42	$4.77	$1.13	($3.15)
2008	$1.68	$2.20	$3.19	$4.47	$4.88	$1.14	($3.26)
2009	$1.67	$2.30	$3.23	$4.53	$4.95	$1.14	($3.38)
2010	$1.66	$2.33	$3.27	$4.60	$5.02	$1.14	($3.51)
AAGR	**-0.37%**	**0.17%**	**0.56%**	**0.58%**	**1.03%**	**0.60%**	**3.78%**

AAGR = Average Annual Growth Rate

BLACK & VEATCH

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