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990000

City of Lakeland
Ten Year Site Plan

B&V Project 60812.0040
April 1, 1999

Mr. Joseph D. Jenkins
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: City of Lakeland 1999 Ten-Year Site Plans

Dear Joe:

Please find enclosed twenty-five (25) copies of the City of Lakeland's 1999 Ten-Year Site Plan as required by 25.22.071 Florida Administrative Code. The information contained in the 1999 Ten-Year Site Plan was taken from the recent McIntosh Unit 5 Need for Power Application submitted in January of this year. If you or your staff have any questions, please give me a call at 913-458-7432 or Paul Elwing at 941-499-6531.

Sincerely yours,

BLACK & VEATCH

Myron Rollins

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MR/jlw
Enclosures

cc: Roy Young
Paul Elwing

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1999 Ten-Year Site Plan

LAKELAND ELECTRIC

1999 Ten-Year Site Plan
For Electrical Generating Facilities and Associated Transmission Lines

Submitted to
Florida Public Service Commission

April 1999

BLACK & VEATCH
Holding Company
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Executive Summary

This report documents the 1999 City of Lakeland Ten-Year Site Plan pursuant to 186.801 Florida Statutes and 25-17.0852 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule. The Plan is divided into an introduction and eight main sections: General Description of Utility, 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 Appendices contain details of Lakeland's load forecast and fuel forecast.

Power for the City of Lakeland is supplied by City of Lakeland wholly and jointly owned generation and power purchases. The City of Lakeland is also a member of the Florida Municipal Power Pool (FMPP). The total installed generating capacity based on Lakeland's ownership share is 649 MW winter and 614 MW summer as of January 1, 1999. 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 planning 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, purchase power contracts, and reserve margin indicates a need for additional capacity in 2002.

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 as well as additional energy savings and efficiency promotion programs.

Numerous 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. The alternatives that passed the screening analysis were modeled in Black & Veatch's POWROPT and POWRPRO optimal generation expansion and chronological production cost programs to rank the expansion plan according to total cumulative present worth costs over a 20-year planning period. Several sensitivity analyses were performed to determine the impact on the 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's 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
Base Case Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	1998 Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW)	110,129	366,978
2004	McIntosh 4 PCFB (238 MW)	124,516	437,264
2005	McIntosh 2 retired (103 MW)	130,019	503,984
2006		135,595	567,240
2007		142,106	627,507
2008		145,849	683,738
2009		152,890	737,325
2010	LM6000 SC (43 MW)	161,333	788,731
2011		152,663	832,952
2012		159,034	874,831
2013		165,849	914,533
2014		172,878	952,157
2015		180,885	987,944
2016		188,938	1,021,926
2017	LM6000 SC (43 MW)	200,299	1,054,676
2018		209,297	1,085,787

(1)Capacity is stated in winter ratings.

1.0 Introduction

This report documents the 1999 City of Lakeland (Lakeland) Ten-Year Site Plan (TYSP) pursuant to Florida Statutes. The City of Lakeland TYSP provides the information required by Rule 25-17.0852 as adopted by Order No. PSC-97-1373-FOF-EU on October 30, 1997. The filing is divided into eight main sections: General Description of Utility, 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 TYSP Schedules.

1.1 General Description of the Utility

Section 2.0 of the TYSP details existing generation 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 649 MW in the winter and 614 MW in the summer.

1.2 Forecast of Electrical Power Demand and Energy Consumption

Section 3.0 of the TYSP provides a 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 2.40 and 1.85 percent, respectively, for 1999 through 2018.

Net energy for load is projected to grow at an average annual rate of 2.19 percent over the next 20 years compared to 2.82 percent over the last 10 historical 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 are on file with the PSC.

Lakeland's current conservation and demand-side 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 outlines the forecasting methods for the TYSP and summarizes the assumptions applied for system planning.

Assumptions for the economic parameters and evaluation criteria applied in the TYSP are 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 least-cost cumulative present worth revenue requirement (CPWRR) as the selection criteria for generating unit alternatives.

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.

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 Lakeland's 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 exhibited 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 TYSP. 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 integrates 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 TYSP.

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 the 500 kW unit 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 MW 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 5.0.

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 ratepayers. 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 124 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 placed Larsen Unit No. 6 in cold shutdown. Larsen Unit No. 6 is a 25 MW oil fired unit that was reaching the end of its economic life. Lakeland's existing units are summarized in Tables 2-1, 2-2, and 2-3.

In 1998, Lakeland regained 9 MW (represents Lakeland's 60 percent share) from the McIntosh 3 unit after performing non-routine maintenance activities to upgrade the turbine steam path. This capacity is reflected in the unit's performance and summer capacity.

Also in 1998, Lakeland had two long-term power purchase contracts terminated by the suppliers. The first contract was with Enron for 20 MW through 12/31/2001. The second contract for 10 MW of baseload power was with TECO through 9/30/2006. The termination of the contracts was under terms that were agreeable to Lakeland. As a result of the termination of the two contracts, Lakeland brought Larsen Unit 6 out of cold shutdown to meet reliability requirements.

Additionally in 1998, the construction of McIntosh Unit 5 Simple Cycle combustion turbine was initiated. The Unit is currently under construction with the first fire of the combustion turbine scheduled for the second quarter of 1999 and release to Lakeland for commercial operation on July 10, 1999.

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, 20 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. By 1998, 29 sections of 69 kV lines were in service feeding 20 distribution substations.

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

Plant	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (kW)	Net Capability(1) Summer (MW)	Net Capability(1) Winter (MW)	Fuel Transportation Primary	Fuel Transportation Alternate
Charles Larsen Memorial	1	16-17/28S/24E Polk County	GT	NG	F02	10/62	Sold, 5/98	*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
	6		ST	NG	F06	12/59	07/99	25,000	25.0	27.0	PL	TK
	7		ST	NG	F06	02/66	02/01	50,000	50.0(2)	50.0(2)	PL	TK
	8		CT	NG	F02	07/92	Unknown	101,520	73.0	93.0	PL	TK
	5		CW	WH		04/56	Unknown	26,000	29.0	31.0		
Plant Total									197.0	229.0		
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	--
	1GT		GT	NG	F02	05/73	Unknown	26,640	17.0	20.0	PL	TK
	1		ST	NG	F06	02/71	10/02	103,000	87.0	87.0	PL	TK
	2		ST	NG	F06	06/76	7/04	126,000	103.0	103.0	PL	TK
	3		ST	BIT	NG	09/82	Unknown	363,870	205.0(3)	205.0(3)	RR	TK
Plant Total									417.0	420.0		
System Total									614.0	649.0		

(1)Net normal.
(2)Capacity after Boiler Repairs (Capacity Before the TEA sale).
(3)Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.

Source: Lakeland Power Production Unit Rating Group 7/30/98

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 Acres	In-Use Acres	Land	Site Improvements	Buildings and Equipment	Total
Charles Larsen Memorial	18	8.7	18	0	85,256	85,274
C. D. McIntosh, Jr.*	513	300	2,815	0	331,006	333,821

*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		Cooling
			SO_x	NO_x	
Charles Larsen Memorial	6	None	None	None	OTF
	7	None	None	None	OTF
	8ST	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

As the Lakeland system continued to grow, the need for additional and larger transmission facilities grew as well. In 1981, Lakeland's first 230 kV facilities went into service to accommodate Lakeland's McIntosh Unit 3 and to tie Lakeland into the State Transmission Grid at the 230 kV level. A 230 kV line was also built from McIntosh Plant to Lakeland's West substation. A 230/69 kV autotransformer was installed at each of those substations to tie the 69 kV and 230 kV transmission systems together. In 1988, a second 230 kV line was constructed from McIntosh Plant to Lakeland's Eaton Park substation along with a 230/69 kV autotransformer at Eaton Park. That line was the next phase of the long-range goal to electrically circle the Lakeland service territory with 230 kV transmission to serve as the primary backbone of the system.

Early transmission interconnections with the outside world included a 69 kV tie at Larsen Plant with Tampa Electric Company (TECO). This tie was established sometime in the mid 1960s. A second tie with TECO was later established at Lakeland's Highland City substation. A 115 kV tie was established in the 1970s with Florida Power Corporation (FPC) and Lakeland's west substation and was subsequently upgraded and replaced with the current two 230 kV lines to FPC in 1981. At the same time, Lakeland interconnected with Orlando Utilities Commission (OUC) at Lakeland's McIntosh Power Plant. In August 1987, the 69 kV TECO tie at Larsen Power Plant was taken out of service and a new 69 kV TECO tie was put in service connecting Lakeland's Orangedale substation to TECO's Polk City substation. In mid-1994, a new 69 kV line was energized connecting Larsen Plant to the Ridge Generating Station, an independent power producer. Lakeland has a 30-year firm power-wheeling contract with Ridge to wheel up to 40 MW of their power to FPC. In early 1996, a new substation, East, was inserted in the Larsen Plant to Ridge 69 kV transmission line. Later in 1996, the third tie line to TECO was built from East to TECO's Gapway substation. The multiple 230 kV interconnection configuration of Lakeland is also tied into the bulk transmission grid and provides access to the 500 kV transmission network via FPC. This ultimately provides for greater reliability. Lakeland's system has sufficient internal generation to supply its requirements in a peak period independent of its ties. At the present time, Lakeland has approximately 104.7 miles of the 69 kV transmission and 16.9 miles of the 230 kV transmission lines in service along with three 150 MVA 230/69 kV autotransformers.

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

2.2.1 Existing Generating Units

Lakeland's existing generating units are located at the two existing plant sites: Charles Larsen Memorial (Larsen) and C.D. McIntosh Jr. (McIntosh). Both plant sites are located in Polk County, Florida on Lake Parker. The two plants have multiple units with different technologies and fuel types. The following paragraphs provide a summary of the existing generating units for Lakeland.

The Larsen site is located on the southeast shore of Lake Parker in Lakeland. The site has six existing units with a total winter and summer capacity of 229.0 MW and 197 MW, respectively. Unit 1 was an 11.5 MW gas turbine that was physically removed from the plant in 1998 for economic reasons and sold to General Electric. Units 2 and 3 are identical units to Unit 1, with a nameplate rating of 11.5 MW that burn natural gas as the primary fuel with diesel backup. Unit 5 was a steam power plant that had a boiler for steam generation and steam turbine to convert the steam to electrical power. The boiler began to show signs of degradation beyond repair so a gas turbine with a heat recovery steam generator, Unit 8 was added to the facility. This allowed the gas turbine to generate electricity and the waste steam from the turbine was injected to the Unit 5 steam turbine for a combined cycle configuration. The Unit 8 combustion turbine has a nameplate rating of 101.5 MW. Unit 6 is a 25 MW steam turbine burning natural gas that was placed in cold shutdown but was returned to service in 1998 due to the termination of the ENRON and TECO power purchase agreements. Unit 6 is slated for re-retirement in 1999. Unit 7 has just undergone a significant boiler tube replacement to bring the total capacity of the unit back up to 50 MW. The unit has been derated for several years due to boiler tube problems. The Energy Authority (TEA) has contracted with Lakeland to purchase a 50 percent portion (25 MW) of the unit from March 1, 1999 through February 28, 2001. Table 2-1 summarizes each of the generating units.

The McIntosh site is located in the City of Lakeland along the northeastern shore of Lake Parker and encompasses 513 acres. The McIntosh site currently includes six existing units, and support facilities with a total winter and summer capacity of 420 MW and 417 MW, respectively. Unit GT1 consists of a General Electric combustion turbine with a nameplate rating of 26.6 MW. Unit 1 is a natural gas/oil fired General Electric steam turbine with a nameplate rating of 103.0 MW. Unit 2 is a natural gas/oil fired Westinghouse steam turbine with a nameplate rating of 126.0 MW. Unit 3, a pulverized coal (primary fuel) fired unit, has a nameplate rating of 363.9 MW, with Lakeland retaining 60 percent ownership and OUC retaining 40 percent. Unit 3 also fires refuse-derived fuel (RDF) and petroleum coke. Unit 3 includes a wet flue gas scrubber for SO_2 removal and uses treated sewage water for cooling water. Two small diesel units with nameplate ratings of 2.5 MW each are also installed. Lakeland's seventh unit at McIntosh (Unit 5) is currently under construction, a 249 MW Westinghouse 501G-combustion turbine. The unit is scheduled for startup by April 1999 and release to Lakeland for commercial operation by July 10, 1999. The combustion turbine unit is rated at 249 MW under ISO conditions burning natural gas as the primary fuel with a guaranteed full load heat rate of 9,684 Btu/kWh higher heating value (HHV).

At the time of this filing, Lakeland is proposing in a Need for Power Application to convert the 501G simple cycle combustion turbine to combined cycle for January 1, 2002. The proposed McIntosh Unit 5 conversion consists of adding a heat recovery steam generator (HRSG) with new stack, a steam turbine, electrical generator, cooling tower and condenser, and associated balance-of-plant equipment.

Electricity generated by McIntosh Units is stepped up in voltage by generator step-up transformers to 69 kV and 230 kV for transmission via the power grid.

2.2.2 Capacity and Power Sales Contracts

Lakeland currently has two firm power sales contracts. The first contract was negotiated with TEA for a power sale from the Larsen Unit 7 of 25 MW from January 1, 1999 to February 28, 2001. Larsen Unit 7 has undergone major maintenance to replace plugged boiler tubes that will allow Lakeland to return the unit back to its normal dispatchable capacity of 50 MW.

The second contract is with Florida Municipal Power Agency (FMPA) for capacity and energy. The contract is for 50 MW from December 15, 2000 to June 14, 2001; then 100 MW from June 15, 2001 through December 14, 2010.

Lakeland shares ownership of the C. D. McIntosh Unit 3 with OUC, with Lakeland retaining 60 percent ownership. The energy and capacity delivered to OUC from McIntosh Unit 3 is not considered a power sales contract because OUC owns 40 percent of the unit.

2.2.3 Capacity and Power Purchase Contracts

Lakeland had one contract with ENRON Power Marketing for 20 MW with a maximum annual capacity factor of 10 percent. The contract was scheduled to expire December 31, 2001, but the contract was bought out by ENRON and ended on July 1, 1998. Another contract for 10 MW of capacity and energy from TECO, scheduled through September 30, 2006, was terminated on December 1, 1997.

Lakeland has recently secured a firm power purchase contract with TEA for 20 MW of capacity and energy for the winter period of 1999. This 20 MW purchase will provide Lakeland with enough capacity over the 1999 winter season to maintain their minimum 15 percent reserve margin.

2.2.4 Planned Unit Retirements

Lakeland plans to retire older, less efficient units as new capacity additions provide more cost effective generating units. This will provide Lakeland with generating units that are more efficient, more reliable, and produce fewer emissions on a kWh basis compared to current generating units. This fulfills all of Lakeland's strategic considerations for the future. The following units will be retired over the upcoming years based upon the expansion plan identified and pending FPSC approval of capacity additions:

Unit Name	Current Age	Summer Capacity	Winter Capacity	Anticipated Retirement Date
Larsen CT1	36	10.0	14.0	Retired
Larsen 6	39	25.0	27.0	07/1999
Larsen 7	32	50.0	50.0	03/2001
McIntosh 1	27	87.0	87.0	10/2002
McIntosh 2	22	103.0	103.0	07/2004

Larsen CT1 was retired on May 4, 1998 when the combustion turbine was removed from the facility. Larsen 6 was moved from cold shutdown to active duty in 1998 to replace the lost capacity from the Enron and TECO contracts. Unit 6 is scheduled for retirement after the winter peak demand for 1999. Unit 7 recently underwent a major maintenance activity to repair boiler tubes to return the unit's capacity from 40 MW back to 50 MW. The contract with TEA for 50 percent of the unit's output and capacity will terminate on February 28, 2001. This is the date at which the unit is slated for retirement. McIntosh Unit 1 is scheduled for retirement in October of 2002 after successful demonstration of the 501G Combined Cycle (pending certification under the Florida Electrical Power Plant Siting Act). McIntosh Unit 2 is scheduled for retirement July of 2004 after completion of the DOE Clean Coal Project. The Clean Coal Project will replace the older capacity with a cleaner, more efficient method of generation.

2.2.5 Total System Resources

As described in the preceding subsections, Lakeland's generating system is very diversified and economically beneficial to its customers. Lakeland's 1999 total generating unit capacity for summer and winter is 614 MW and 649 MW, respectively. The total capacity includes the capacity from Larsen Unit 6, which is scheduled for retirement in 1999. This capacity reflects the 10 MW addition with the regained capacity of Larsen Unit 7 after the boiler modifications.

2.2.6 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 592 MW for 1999, occurring in January.

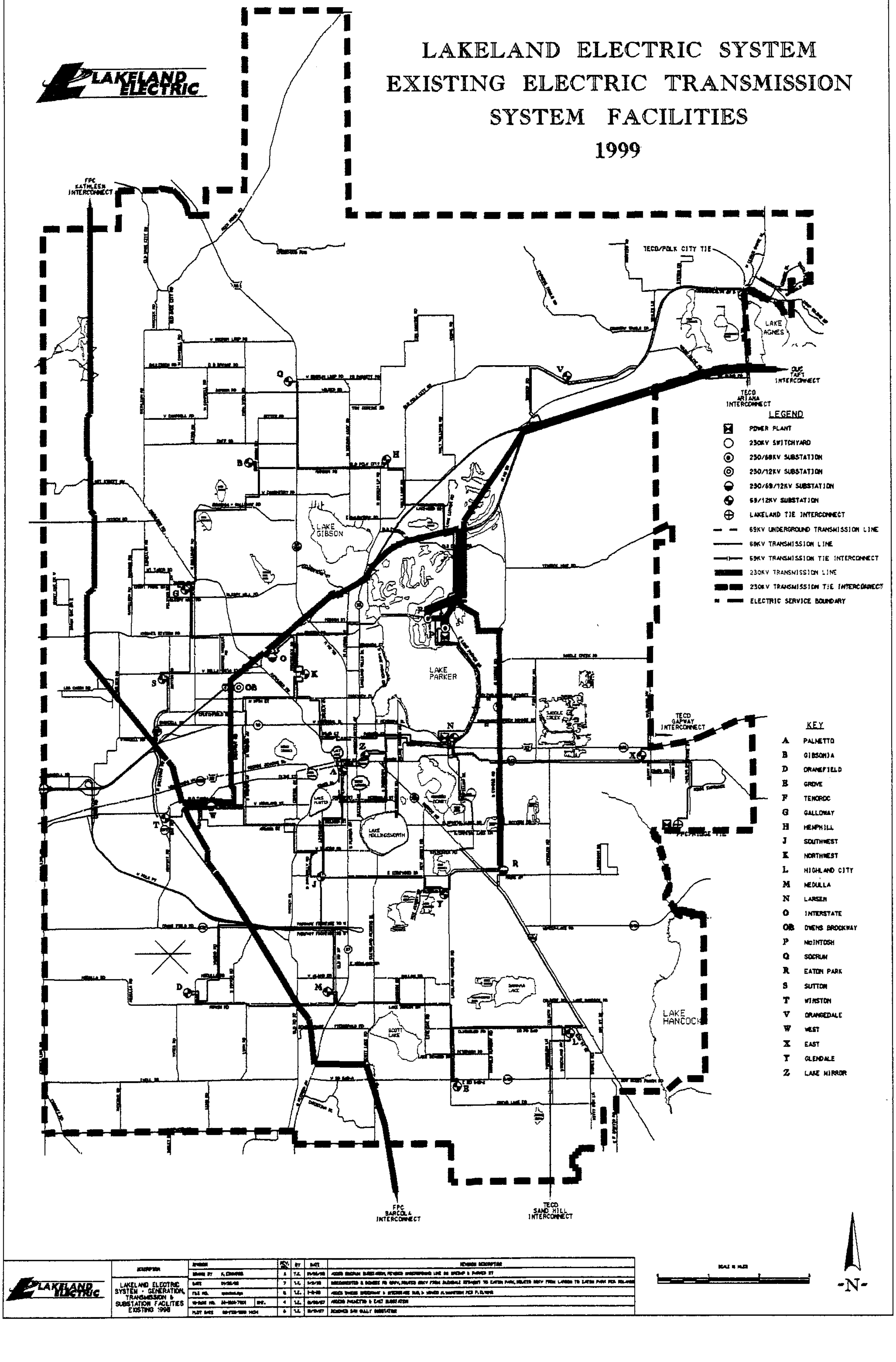
Lakeland's historical and projected summer peak demands are presented in Section 3.5 for the base, high, and low cases, respectively. Further details of Lakeland's load and electrical characteristics are contained in Appendix A, Electric Load and Energy Forecast Fiscal Year 1997-1998.

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 with all FMPP capacity from its four members committed and dispatched together. 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.

2.2.7 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

LAKELAND ELECTRIC SYSTEM EXISTING ELECTRIC TRANSMISSION SYSTEM FACILITIES 1999



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 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.

3.0 Forecast of Electrical Power Demand and Energy Consumption

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

Lakeland develops forecasts for the following areas:

- Population.
- Accounts.
- Sales.
- Net energy for load.
- Summer peak demand.
- Winter peak demand.

The preceding forecasts are developed on a fiscal and annual basis. Lakeland's fiscal year ends on September 30. 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 the Florida Reliability Coordinating Council (FRCC).

3.1 Population Forecast

Lakeland used 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 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 1.49 percent average annual growth rate (AAGR) from 1999 through 2018.

Table 3-1
Projected Population Estimates

Year	1997 BEBR Polk County Population	Historical Service Territory Population	Forecasted Service Territory Population
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	
1998		215,349	
Forecast			
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

3.2 Accounts Forecast

Lakeland forecasts the number of accounts in the following categories:

- Residential.
- Commercial and Industrial:
  - 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 the difference between the total number of residential accounts and the number of residential accounts inside the city. The projection of the total number of residential accounts was based on a regression model using heads of households as the independent variable. The projected AAGR for residential accounts is 1.36 percent for 1999 through 2018. Fiscal year 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 based on historical growth rates for the General Service account projections for inside and outside the city.

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

		Rural and Residential			Commercial		
Fiscal Year	Population	GWh	Average No. of Customers	kWh/Cust	GWh	Average No. of Customers	kWh/Cust
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
1998	215,349	1,254	86,340	14,529	634	10,127	62,644
Forecast							
1999	222,329	1,263	87,656	14,409	639	10,027	63,728
2000	226,708	1,300	89,091	14,592	655	10,122	64,711
2001	230,494	1,337	90,408	14,789	670	10,218	65,571
2002	234,280	1,374	91,727	14,979	686	10,314	66,512
2003	238,066	1,411	93,047	15,164	702	10,411	67,429
2004	241,852	1,448	94,369	15,344	717	10,508	68,234
2005	245,638	1,485	95,693	15,518	732	10,607	69,011
2006	249,298	1,523	96,997	15,702	747	10,704	69,787
2007	252,958	1,561	98,302	15,880	762	10,802	70,542
2008	256,618	1,600	99,609	16,063	778	10,902	71,363
2009	260,278	1,638	100,918	16,231	793	11,002	72,078
2010	263,937	1,676	102,229	16,395	809	11,103	72,863
2011	267,597	1,713	103,552	16,542	824	11,204	73,545
2012	271,257	1,751	104,896	16,693	840	11,307	74,290
2013	274,917	1,789	106,218	16,843	855	11,409	74,941
2014	278,577	1,826	107,541	16,980	871	11,512	75,660
2015	282,236	1,865	108,863	17,132	886	11,616	76,274
2016	285,896	1,902	110,191	17,261	902	11,720	76,962
2017	289,556	1,940	111,523	17,396	917	11,825	77,548
2018	293,216	1,978	112,858	17,526	933	11,932	78,193

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

Fiscal Year	Industrial GWh	Industrial Average No. of Cust.	Industrial kWh/Cust	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh	Utility Use and Losses GWh	NEL GWh
1989	331	41	8,073,171	11	59	1,812	148	1,960
1990	346	44	7,863,636	8	62	1,889	108	1,997
1991	344	45	7,644,444	11	61	1,905	138	2,043
1992	356	47	7,574,468	13	65	1,947	143	2,090
1993	381	51	7,470,588	13	68	2,030	155	2,185
1994	400	51	7,843,137	14	69	2,137	146	2,283
1995	427	51	8,372,549	15	74	2,279	146	2,425
1996	589	59	9,983,051	15	78	2,472	102	2,574
1997	459	61	7,524,590	16	78	2,335	115	2,450
1998	474	62	7,645,161	17	80	2,460	132	2,592
Forecast								
1999	494	65	7,600,000	17	85	2,497	140	2,637
2000	511	67	7,626,866	18	88	2,572	143	2,715
2001	527	68	7,750,000	18	91	2,644	146	2,790
2002	543	70	7,757,143	19	94	2,716	149	2,865
2003	559	72	7,763,889	19	97	2,788	152	2,940
2004	575	73	7,876,712	20	100	2,860	155	3,015
2005	591	75	7,880,000	21	103	2,932	158	3,090
2006	607	76	7,986,842	21	106	3,005	161	3,166
2007	624	78	8,000,000	22	109	3,079	164	3,243
2008	640	79	8,101,266	22	112	3,152	167	3,319
2009	657	81	8,111,111	23	115	3,227	169	3,396
2010	673	83	8,108,434	24	118	3,301	172	3,473
2011	689	84	8,202,381	24	121	3,372	175	3,547
2012	705	86	8,197,674	25	125	3,445	178	3,623
2013	722	87	8,298,851	26	128	3,518	181	3,699
2014	738	89	8,292,135	26	131	3,592	184	3,776
2015	754	90	8,377,778	27	134	3,666	186	3,852
2016	771	92	8,380,435	27	137	3,739	189	3,928
2017	787	94	8,372,340	28	140	3,812	192	4,004
2018	803	95	8,452,632	29	143	3,885	195	4,080

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 is projected to increase at an AAGR of 0.78 and 1.92 percent, respectively, from 1999 through 2018.

3.2.3 Other Accounts

The Electric account projection was based on a historical growth rate. The Electric accounts are only 0.03 percent of the total accounts. 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 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 following subsections describe each of the sales forecast categories.

3.3.1 Residential Sales

Residential sales projections inside the city were based on a regression model using year, 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 2.42 percent from 1999 through 2018 and are presented in Table 3-2.

3.3.2 *Commercial and Industrial 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 are 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 2.04 and 2.65 percent, respectively, for 1998 through 2018, 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 on a historical trend of sales and accounts.

Street and highway lighting and other sales have projected AAGRs of 3.02 and 2.88 percent, respectively, for 1999 through 2018 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 2.39 percent from 1999 through 2018. This is a lower growth rate than experienced in the past. A 3.22 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 and historical net energy for load as the independent variables. The model has an adjusted R-squared of 98 percent. Lakeland projects the total percentage of system energy 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 energy conservation programs.

The forecasted net energy for load, including conservation, for the base case is summarized in Table 3-3. The projected AAGR for the base case is 2.36 percent for 1999 through 2018. The projected AAGR represents a reduction from the historical AAGR of 2.82 percent for the last 10 years.

3.5 Peak Demand

Lakeland forecasts electric system winter and summer season peak demands for each year 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 served on the interruptible rate were developed and applied to reduce the projection of total peak demand. Projections of the effect of Lakeland's load management program were likewise developed and applied to reduce the projection of total peak demand.

Projections of the resultant summer and winter peak demand for the base case are included in Table 3-3. The projected AAGR for the summer and winter peak demand for the base case for the period 1999 through 2018 are 1.85 percent and 2.40 percent, respectively.

Table 3-3
Summer, Winter, and Net Energy for Load--Base Case

Year	Summer, MW(1)		Winter, MW(1)		Net Energy for Load, GWh
	Before(2)	After(3)	Before(2)	After(3)	
1999	515	510	593	588	2,655
2000	529	524	612	607	2,732
2001	540	535	631	626	2,807
2002	553	548	650	645	2,882
2003	565	560	668	663	2,957
2004	576	571	687	682	3,032
2005	589	584	706	701	3,108
2006	600	594	725	720	3,184
2007	613	607	744	739	3,260
2008	624	618	762	756	3,337
2009	636	630	781	775	3,413
2010	648	642	800	794	3,490
2011	660	654	819	813	3,564
2012	672	666	838	832	3,641
2013	684	678	857	851	3,717
2014	696	689	876	869	3,793
2015	708	701	895	888	3,869
2016	719	712	913	906	3,946
2017	731	724	932	925	4,022
2018	743	736	952	945	4,098

(1)Peak demand after conservation.
(2)Peak demand before interruptible.
(3)Peak demand after interruptible.

3.6 Sensitivities

Lakeland has conducted two sensitivity cases to the base case load forecast, reflecting a high load growth case and a low load growth case. These two sensitivity cases provide a bracket in which Lakeland can evaluate potential power supply planning alternatives and test the robustness of the base case against higher or lower load growth.

3.6.1 High Load Growth

The high load growth scenario assumes that load growth for the region will be higher than expected. The high load growth sensitivity assumes a growth rate that is 1.5 percent greater than the base case load forecast. The base case load forecast has an AAGR of 1.85 and 2.04 percent for summer and winter peak demand, respectively. Therefore, the high load growth case for winter peak demand has an AAGR of 1.50 + 2.04 = 3.54. The 1.5 percent was determined to be an upper limit based on a review of historical forecasts and actual growth rates. Table 3-4 displays the summer and winter peak demand forecast and net energy for load for the planning horizon for the high load growth sensitivity.

3.6.2 Low Load Growth

The low load growth scenario assumes that load growth for the region will be lower than expected. The low load growth sensitivity assumes a growth rate that is 1.5 percent less than the base case load forecast. The base case load forecast has an AAGR of 1.85 and 2.04 percent for summer and winter peak demand, therefore the low load growth case for winter peak demand has an AAGR of 2.04 – 1.50 = 0.54. The 1.5 percent was determined to be a lower limit based on a review of historical forecasts and actual growth rates. Table 3-5 displays the summer and winter peak demand forecasts and net energy for load for the planning horizon for the low load growth sensitivity.

Table 3-4
Summer, Winter, and Net Energy for Load--High Load Growth

Year	Summer, MW(1), (2)	Winter, MW(1), (2)	Net Energy for Load, GWh
1999	517	596	2,677
2000	539	625	2,796
2001	559	653	2,915
2002	581	683	3,037
2003	601	712	3,162
2004	623	743	3,290
2005	646	775	3,421
2006	668	807	3,557
2007	692	841	3,696
2008	715	874	3,839
2009	740	909	3,985
2010	764	944	4,136
2011	790	981	4,285
2012	816	1,019	4,442
2013	844	1,057	4,602
2014	870	1,096	4,766
2015	899	1,137	4,934
2016	927	1,177	5,106
2017	956	1,219	5,281
2018	986	1,262	5,461

(1)Peak demand after conservation.
(2)Peak demand after interruptible exercised.

Table 3-5
Summer, Winter, and Net Energy for Load--Low Load Growth

Year	Summer, $MW^{(1), (2)}$	Winter, $MW^{(1), (2)}$	Net Energy for Load, GWh
1999	502	579	2,598
2000	508	589	2,635
2001	512	598	2,668
2002	516	607	2,700
2003	519	615	2,731
2004	522	623	2,759
2005	526	631	2,786
2006	528	639	2,814
2007	531	646	2,839
2008	533	652	2,863
2009	535	659	2,887
2010	537	665	2,909
2011	539	671	2,927
2012	541	676	2,946
2013	542	681	2,963
2014	543	686	2,981
2015	545	691	2,996
2016	546	695	3,011
2017	546	699	3,024
2018	547	702	3,036

(1) Peak demand after conservation.
(2) Peak demand after interruptible exercised.

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 and the description of additional programs. Further details can be found in Lakeland's Demand Side Management Plan Docket No. 930556-EG, 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 demand by 1 kW per account from each water heater control and 1.2 kW per account from control of HVAC systems.

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. This program is projected to save 795 kWh per account 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 that 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 of lighting.

Currently, all streetlights 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. In Lakeland's opinion, an informed public is the greatest conservation resource. 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 cost-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 to offer the program. It is the hope of Lakeland that time-of-day rates will draw more attention combined with TES systems discussed earlier.

4.2 Additional Conservation and Demand-side Management Programs Under Consideration

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:

- Distributed Generation Energy using Solar-Thermal Collectors.
- Utility-Interactive Residential Photovoltaic Systems.
- Utility-Interactive Photovoltaic Systems on Polk County Schools
- Integrated Photovoltaics for Florida Residences.

4.2.1 Solar Powered Distributed Generation Energy

4.2.1.1 Solar Powered Street Lights. 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 environmental degradation, and other objections to central station generation.

Solar powered streetlights offer reliable, cost-effective solutions to remote lighting needs. As shown in Figure 4-1, they are completely self-contained, with the ability to generate DC power from photovoltaic modules and batteries. During daylight hours solar energy is stored in the battery bank used to power the lights at night.

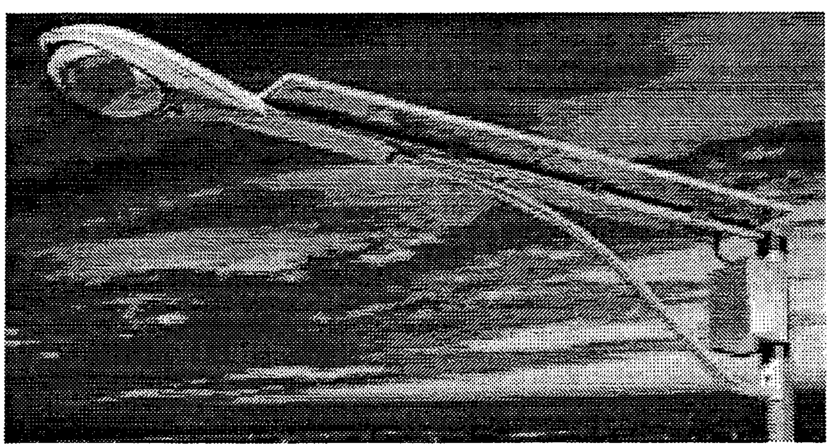


Figure 4-1
Solar Powered Streetlight

Lakeland currently has twenty solar powered streetlights that are in service. Lakeland installed these twenty lights in mid 1994 in a grant program with the cooperation of the Florida Solar Energy Center (FSEC). Lakeland is continuing to collect operational and maintenance data to further assess the long term cost-effectiveness, maintenance needs and reliability of this type of lighting.

4.2.1.2 Solar Thermal Collectors for Water Heating. Water heating provides the most efficient, waste-free, 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. By selling the service rather than selling the system, Lakeland residents are relieved of investment and obligation. The long life unit would not place risk on the consumer in the form of installation, maintenance, mobility or disassembly. The system will have minimal impact on customer's structure, be modular, and easily removed or relocated. The only obligation of the customer is the use of space on the premises.

Since the customer is paying for the service and not the asset, the standard system is designed for a family of four with the future possibility of smaller units for retired adults. By choosing a family of four, the household should purchase enough power to offset the cost of the unit and provide a reasonable return.

4.2.2 Utility-Interactive Residential Photovoltaic Systems

This project is a collaborative effort between the Florida Energy Office (FEO), FSEC, 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.

Lakeland will own, operate, and maintain the systems for at least five years. FSEC will conduct periodic site visits for testing and evaluation purposes. System performance data will be collected via telephone modem line for at least two years. Lakeland and FSEC will analyze the results of utility and systems simulation tests and prepare recommendations for appropriate interconnection requirements for residential PV systems. FSEC will prepare technical reports on system performance evaluation, on site utilization, coincidence of PV generation with demand profiles, and utilization of PV generated electricity as a demand side management option.

4.2.3 Utility-Interactive Photovoltaic Systems on Polk County Schools

This program is entitled "Portable Power" because the focus of the program is to install Photovoltaic Systems on portable classrooms in the Polk County School District. This program is a partnership including the City of Lakeland, Polk County School District, Siemens Solar Industries, Hutton Communications, Trace Engineering, Florida Solar Energy Center and Utility Photovoltaic Group which will allow eighteen of these portable classrooms to be enrolled in President Clinton's Million Solar Roofs Initiative. With the installation of the photovoltaic systems 80 percent of the electricity requirements for these classrooms will be met.

Along with the photovoltaic systems, there will also be a specially designed curriculum on solar energy appropriate to various grade levels.

The "Portable Power" in the schools will consist of installing 2kWp photovoltaics systems on eighteen portable classrooms. In addition to the philosophic "goodness" of associating photovoltaics with schools, there are several practical reasons why portable classrooms are most appropriate as the platforms for photovoltaics. They have nearly flat roofs, and are installed in open spaces, so final orientation is of little consequence. Another reason is the primary electric load of the portable is air conditioning, which is reduced by the shading effect of the panels on their short stand-off mounts. Most important, the total electric load on the portable has high coincidence with the output from the PV system. The hot, sunny day which results in the highest cooling requirements also produces the maximum PV output. Very few portable classrooms are used at night.

The City of Lakeland will own, operate and maintain the systems that are installed on these classrooms. The City of Lakeland will monitor the performance and FSEC will conduct periodic testing of the equipment. Through the cooperative effort of the partnership, we will be evaluating different ways to use photovoltaics efficiently and effectively in today's society.

4.2.4 Integrated Photovoltaics for Florida Residences

This program provides research on the integrated photovoltaics in newly constructed homes. The two new homes are of the same design and construction except one unit contains a 4 kW PV system. The units are being measured for performance under two conditions: unoccupied and occupied. Data is being collected for end use load, and

PV system interface.

Under President Clinton's 'Million Solar Roofs Initiative,' the Department of Energy granted five million dollars, in addition to the existing privately funded twenty-seven million dollars, for a total of thirty-two million dollars for solar electric businesses. Through the Utility Photo Voltaic Group, the investment will support 1,000 PV systems in 12 states and Puerto Rico hoping to bring photovoltaics to the main market. The 1,000 systems are part of the 500,000 commitments received for the initiative to date. The goal is to have installed one million roofs by the year 2010.

The first solar home was unveiled May 28, 1998, in Lakeland, Florida. The home construction includes a 4kW photovoltaic system, white tiled roof, argon filled windows, exterior wall insulation, improved interior duct system, high performance air conditioner and high efficiency appliances. An identical home with strictly conventional construction features was also built to use as a control home. The homes are 1 block apart and oriented in the same direction as shown in Figure 4-2. For the month of July 1998, the occupied solar home air conditioning consumption was 72 percent lower than the unoccupied control house. With regards to total power, the solar home used 50 percent less electricity than the air conditioning consumption of the control home.

The solar home was designed to provide enough power during the utility peak that it would not place a net demand on the grid. If the solar home produces more energy than what is consumed, the photovoltaic cells are connected to an inverter sending the excess electricity to the grid. The objective of the solar house design was to be as efficient as possible, not cost effective. The next objective will be to make the model cost effective.

4.3 Evaluation of Additional Conservation and Demand-Side Management Programs

In order to ensure that no cost-effective demand-side management (DSM) programs existed as alternatives to the least cost supply-side alternative, Lakeland evaluated 66 DSM programs using the Florida Integrated Resource Evaluator (FIRE) model. Florida Power Corporation originally developed the FIRE model and several utilities in Florida have applied this model. The results of the analysis are included in Section 6.4, Economic Evaluation of DSM Programs.

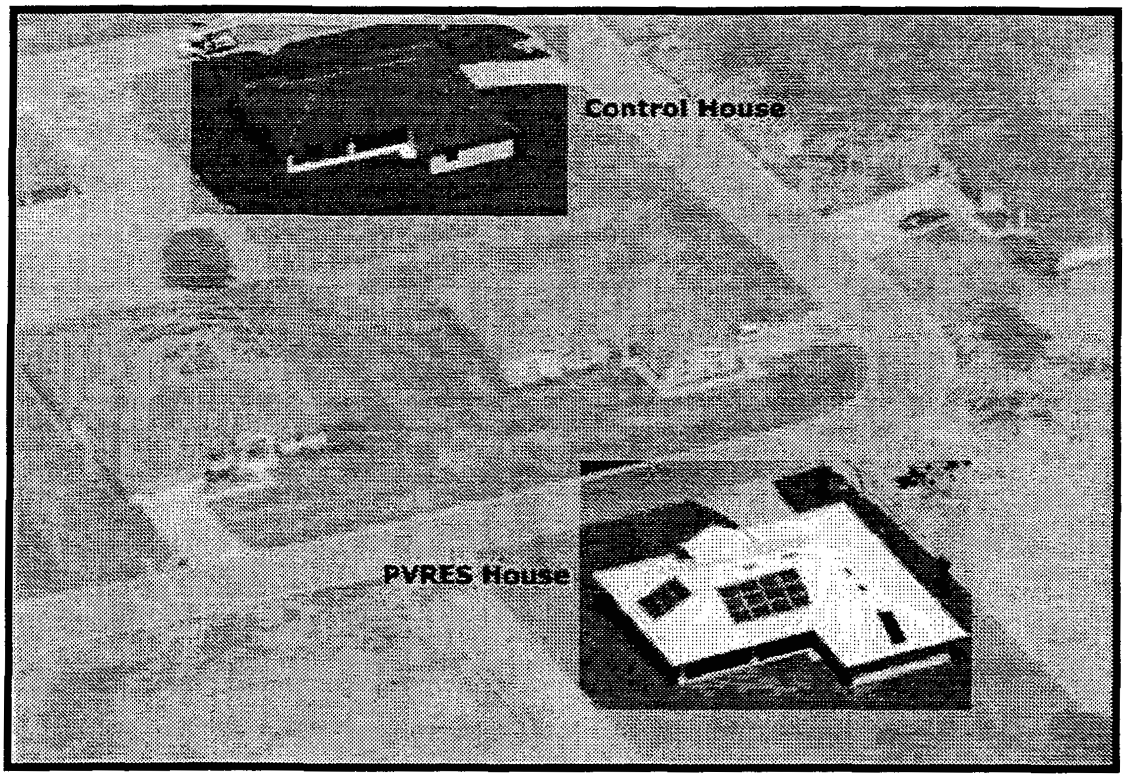


Figure 4-2
Solar House and Control House

Synergic Resources Corporation (SRC) compiled the DSM residential and commercial program data used in the FIRE model. SRC compiled this data as a first step to refine statewide energy policies and better position Florida in an energy efficient economy. The program data includes only technologies that are currently available and based on the use of current data including equipment costs, installation costs, and lifetime estimates. The DSM program code designations are classified by Residential, Commercial, and Other Technology Descriptions:

Code	Description
	Residential Technology Descriptions
RSC	HVAC Technologies
WH	Water Heating
LT	Lighting Technologies
PP	Pool Pumps

	Commercial Technology Descriptions
SC-D	Space Conditioning and Envelope Measures
V-D	Ventilation
L-D	Lighting
	Other Technology Descriptions
R-D	Refrigeration Technologies
W-D	Hot Water Technologies
C-D	Cooking Technologies

The information contained in the next section is designed to identify and describe the range of the analyzed measures. The information has been divided between two categories, new and existing technologies. While Lakeland did not model all DSM programs that SRC compiled, they focused on alternatives that have potential in Florida and have historically been analyzed by other utilities.

4.3.1 New Construction DSM Measures and DSM Codes

4.3.1.1 RSC-1: High Efficiency Air Source Heat Pump. This DSM program assumes a high efficiency air source heat pump with a Standard Energy Efficiency Ratio (SEER) of 13.0 and a Heat Source Performance Factor (HSPF) of 8.1 replaces a standard efficiency heat pump with a SEER of 10.0 and an HSPF of 6.8 in new and existing construction. The standard unit has a cooling Coefficient of Performance (COP) of 2.570 and heating COP of 2.978. The high efficiency unit has a cooling COP of 3.437 and heating COP of 3.540.

4.3.1.2 RSC-8A/B: Load Control for Residential Electric Heat. This measure involves the use of remote transmitters to control residential space heating systems to reduce peak load by load shedding (turning units off at the time of the utility peak) or cycling (periodically turning units off). This measure is based on having an existing load control program.

4.3.1.3 RSC-21A: High Efficiency Central Air Conditioner. A high efficiency unit with an SEER of 13.0 and a COP of 3.437 replaces a standard unit with an SEER of 10.0 and a COP of 2.570.

4.3.1.4 RSC 26A/B: Direct Load Control of Central Air Conditioner. This measure involves the use of remote transmitters to control residential space cooling systems to reduce peak load by load shedding (turning units off at the time of the utility peak) or cycling (periodically turning units off). This measure is based on having an existing load control program.

4.3.1.5 WH-10: DLC of Electric Water Heater. Utility controlled radio switches would be installed on residential electric water heaters, which would be controlled by the utility during times of system peak demand. One hundred percent of participating water heaters would be entirely shut off during system peak periods.

4.3.1.6 PP-3: Direct Load Control of Pool Pumps. Utility controlled radio switches would be installed on residential pool pumps, which would be controlled by the utility during times of system peak demand. One hundred percent of participating pool pumps would be shut off during system peak periods.

4.3.1.7 SC-D-1: High Efficiency Chiller. This measure consists of comparing standard efficiency [Compressor COP = 4.0] reciprocating chillers to high efficiency [Compressor COP = 4.75] screw chillers for all buildings but hospitals and warehouses. For hospitals, standard efficiency [Compressor COP = 5.0] centrifugal chillers are replaced with high efficiency [Compressor COP = 5.76] centrifugal chillers. This option does not apply to warehouses.

4.3.1.8 SC-D-2: High Efficiency Chiller With ASD. This option consists of retrofitting an adjustable speed drive (ASD) controller onto high efficiency centrifugal chillers. The same assumptions apply here as in the high efficiency chiller option. Technical feasibility is assumed to be 0 percent for restaurant and warehouse, 80 percent for hospitals, and 10 percent for the remaining buildings.

4.3.1.9 V-D-8/9: High Efficiency Ventilation Motors. This measure assumes high efficiency motors in place of standard efficiency motors, resulting in an average demand and energy savings of 5.9 percent. Technical feasibility is assumed to be 85 percent.

4.3.1.10 L-D-25: Compact Fluorescent Lamps (15/18/27W). This measure considers replacing a weighted mix of 60W, 75W, and 100W incandescent lamps with the same mix of 15W, 18W and 27W compact fluorescent lamps in both new and existing buildings. The percentage breakdown of the mix varies by building type. Weighted average lighting energy and demand savings is 70.7 percent, while maintaining the original lumen output. Technical feasibility is assumed to be 85 percent and 90 percent for new and existing buildings.

4.3.1.11 L-D-26: Two Lamp Compact Fluorescent (18W). This measure consists of two 18W compact fluorescent tubes within a single fixture which replaces one 150W incandescent lamp in both new and existing buildings. Estimated lighting energy and demand savings is 76.0 percent. Technical feasibility is assumed to be 85 percent and 90 percent for new and existing buildings.

4.3.1.12 W-D-13: Heat Recovery Water Heater. This measure consists of an electric water heater which utilizes a supplemental heat source from the cooling system waste heat recovered from a double bundle chiller or condenser heat exchanger. There is an assumed 25 percent energy savings based on the WAPA Guidebook of Commercial DSM Technologies, while assuming a summer and winter demand savings of 35 percent and 15 percent. The current penetration is assumed to be zero.

4.3.1.13 C-D-19: Energy Efficient Electric Fryers. This technology was modeled as a replacement technology applicable to restaurants, grocery, school, hospitals, and lodging. Energy and demand savings were estimated to be 10 percent.

4.3.2 Existing Construction DSM Measures and DSM Codes

4.3.2.1 RSC-1: High Efficiency Air Source Heat Pump. A high efficiency air source heat pump with an SEER of 13.0 and an HSPF of 8.1 replaces a standard efficiency heat pump with an SEER of 10.0 and an HSPF of 6.8 in new and existing construction. The standard unit has a cooling COP of 2.570 and heating COP of 2.978. The high efficiency unit has a cooling COP of 3.437 and heating COP of 3.540.

4.3.2.2 RSC-5A/B: Reduced Duct Leakage. This measure involves the sealing of space conditioning ducts to eliminate the loss of conditioned air and/or the introduction of attic air into the duct system.

4.3.2.3 RSC-8A/B: Load Control for Residential Electric Heat. This measure involves the use of remote transmitters to control residential space heating systems to reduce peak load by load shedding (turning units off at the time of the utility peak) or cycling (periodically turning units off). This measure is based on having an existing load control program.

4.3.2.4 RSC-10A/B: Ceiling Insulation (R-0 to R-19). This measure only applies to existing dwellings with no ceiling insulation as identified from the 1990 Florida Residential Survey and involves the addition of insulation with an R-value of R-19.

4.3.2.5 RSC-11A/B: Ceiling Insulation (R-11 to R-30). This measure only applies to existing dwellings with R-11 ceiling insulation as identified from the 1990 Florida Residential Survey and involves the addition of insulation with an R-value of R-19 to achieve a total R-value of R-30.

4.3.2.6 RSC-17A: Low Emissivity Glass. For this measure, double pane glass with an argon gas fill and a low emissivity coating on the inner surface of the outer pane replaces single and double pane clear glass windows. This measure reduces heat transmission through the windows.

4.3.2.7 RSC-21A: High Efficiency Central Air Conditioner. A high efficiency unit with an SEER of 13.0 and a COP of 3.437 replaces a standard unit with an SEER of 10.0 and a COP of 2.570.

4.3.2.8 RSC 24A: High Efficiency Room Air Conditioner. A high efficiency unit with an EER of 11.0 replaces a standard unit with an EER of 8.8.

4.3.2.9 RSC 26A/B: Direct Load Control of Central Air Conditioner. This measure involves the use of remote transmitters to control residential space cooling systems to reduce peak load by load shedding (turning units off at the time of the utility peak) or cycling (periodically turning units off). This measure is based on having an existing load control program.

4.3.2.10 WH-7: DHW Pipe Insulation. This option includes the installation of pipe insulation to all accessible domestic hot water piping (assumed to be 70 feet of pipe in new homes, but only 20 feet in existing homes).

4.3.2.11 WH-10: DLC of Electric Water Heater. Utility controlled radio switches would be installed on residential electric water heaters, which would be controlled by the utility during times of system peak demand. One hundred percent of participating water heaters would be entirely shut off during system peak periods.

4.3.2.12 PP-1: High Efficiency Pool Pumps. Standard efficiency pool pump motors are replaced with more efficient motors.

4.3.2.13 PP-3: Direct Load Control of Pool Pumps. Utility controlled radio switches would be installed on residential pool pumps, which would be controlled by the utility during times of system peak demand. One hundred percent of participating pool pumps would be shut off during system peak periods.

4.3.2.14 SC-D-1: High Efficiency Chiller. This measure consists of comparing standard efficiency [Compressor COP = 4.0] reciprocating chillers to high efficiency [Compressor COP = 4.75] screw chillers for all buildings but hospitals and warehouses. For hospitals, standard efficiency [Compressor COP = 5.0] centrifugal chillers are replaced with high efficiency [Compressor COP = 5.76] centrifugal chillers. This option does not apply to warehouses and maintenance.

4.3.2.15 SC-D-2: High Efficiency Chiller With ASD. This option consists of retrofitting an adjustable speed drive (ASD) controller onto high efficiency centrifugal chillers. The same assumptions apply here as in the high efficiency chiller option. Technical feasibility is assumed to be 0 percent for restaurant and warehouses, 80 percent for hospitals, and 10 percent for the remaining buildings.

4.3.2.16 SC-D-4: High Efficiency Room AC Units. The Florida Energy Efficiency Code for Building Construction shows the following standards for 1992:

Cooling Capacity (Btu/h)	EER
< 8,000	8.9
≥ 8,000 <13,000	8.3
≤ 13,000	7.9

An average baseline EER = 8.3 (1.45 kW/ton) is assumed. The DSM EER is 10.9 based on data provided by Bosek, Gibson & Assoc. This measure applies to all building types.

4.3.2.17 SC-D-8: Two-Speed Motor for Cooling Tower. This option consists of replacing the single speed motors in the cooling tower with a two-speed motor. This applies only to chiller systems. The energy savings are estimated to be 80 percent of the Speed Control for Cooling Tower option (SC-D-9).

4.3.2.18 SC-D-9: Speed Control for Cooling Tower. This includes retrofitting an ASD (or VFD) to an existing cooling tower fan. This applies only to chiller systems.

4.3.2.19 SC-D-19: Roof Insulation. Additional insulation is installed raising the R-value from 2.53 to 10.53 in existing buildings and from 10 to 20 in new buildings.

4.3.2.20 SC-D-22/23: Window Film. This option consists of installing window film on existing and new construction. For existing buildings, the shading coefficient was reduced from 0.85 to 0.23 and the U-value from 1.06 to 0.69. For new buildings, the shading coefficient was not changed but the U-value is reduced from 1.06 to 0.69.

4.3.2.21 V-D-1: Leak Free Ducts. This measure primarily consists of sealing all exterior ductwork for rooftop DX AC equipment. Cooling and ventilation demand and energy savings of 7 percent for existing buildings and 3 percent for new buildings was estimated.

4.3.2.22 V-D-8/9: High Efficiency Ventilation Motors. This measure assumes high efficiency motors in place of standard efficiency motors, resulting in an average demand and energy savings of 5.9 percent. Technical feasibility is assumed to be 85 percent.

4.3.2.23 V-D-10/11: Separate Makeup Air/Exhaust Hoods. This technology is typically installed in commercial kitchen areas to reduce the energy wasted in pre-conditioned supply air via exhaust hoods. Cooling energy and demand savings of 80 percent is estimated within the kitchen areas. This measure is applied to the restaurant, school, college, hospital, and lodging market segments. It was assumed the kitchen areas with hoods are approximately 3 percent of school, college, and hospital, 10 percent of restaurant, and 2 percent of lodging total floor space. It is assumed the current penetration is 30 percent for each of these market segments.

4.3.2.24 L-D-1: 4'-34W Fluorescent Lamps/Hybrid Ballasts (No. 1). This measure compares four 4'-34W fluorescent lamps and two hybrid ballasts with 4'-40W lamps and two EE ballasts in existing buildings only. The estimated lighting energy and demand savings is 30.2 percent. Technical feasibility is assumed to be 90 percent.

4.3.2.25 L-D-3: 4'-34W Fluorescent Lamps/Electronic Ballasts (No. 1). This measure considers the following:

- Compares 4'-34W fluorescent lamps and two electronic ballast with 4'-40W fluorescent lamps and two EE ballasts in existing buildings only. Estimated lighting energy and demand savings is 30.2 percent.
- Compares three 4'-34W fluorescent lamps and one electronic ballasts with three 4'-40W fluorescent lamps and one EE ballast in new buildings only. Estimated lighting energy and demand savings is 31.6 percent.

4.3.2.26 L-D-5: 8'-60W Fluorescent Lamps/Electronic Ballasts (No. 1). This measure compares two 8'-60W fluorescent lamps and one electronic ballast with two 8'-75W lamps and one EE ballast in both new and existing buildings. The estimated lighting energy and demand savings is 31.0 percent. Technical feasibility is assumed to be 90 percent.

4.3.2.27 L-D-7: T8 Lamps/Electronic Ballasts (No. 1). This measure considers the following:

- Compares 4'-T8 lamps and two electronic ballasts with four 4'-40W lamps and two EE ballasts in existing buildings only. Estimated lighting energy and demand savings is 27.9 percent.
- Compares three 4'-T8 lamps and one electronic ballast with three 4'-40W lamps and one EE ballast in new buildings only. Estimated lighting energy and demand savings of 34.6 percent.

4.3.2.28 L-D-9: Reflector/Delamped No. 1: Install 4'-40W Fluorescent Lamps/EE Ballast. This measure consists of the installation of an efficient reflector along with a two 4'-40W lamp/one EE ballast fixture in existing buildings only. This is compared to a four 4'-40W lamp/two EE ballast base case fixture. Estimated lighting energy and demand savings of 50 percent. Technical feasibility is assumed to be 67 percent.

4.3.2.29 L-D-10: Reflector/Delamped No. 2: Install 4'-34W and 40W Fluorescent Lamps/EE Ballast. This measure consists of the installation of an efficient reflector and a 20 percent/80 percent mix of two 4'-40W lamps/one EE ballast fixture and two 4'-34W lamps/one EE ballast fixture in existing buildings only. This is compared to a four 4'-34W lamps/two EE ballast base case fixture. The estimated combined lighting energy and demand savings is 47.7 percent. Technical feasibility is assumed to be 67 percent.

4.3.2.30 L-D-11: Reflector/Delamping No. 3: Install 8'-75W Fluorescent Lamps/EE Ballast. This measure consists of the installation of an efficient reflector along with one 8'-75W fluorescent lamp/one EE ballast fixture, in both new and existing buildings (it is assumed one ballast serves two single lamp fixtures). This is compared to a two 8'-75W fluorescent lamp/one EE ballast base case fixture. Estimated lighting energy and demand savings of 50 percent. Technical feasibility is assumed to be 60 percent and 40 percent in new and existing buildings.

4.3.2.31 L-D-12: Reflector/Delamping No. 4: Install 8'-60W Fluorescent Lamps/EE Ballast. This measure consists of the installation of an efficient reflector along with a one 8'-60W fluorescent lamp/one EE ballast fixture for both new and existing buildings (it is assumed one ballast serves two single lamp fixtures). This is compared to a two 8'-60W fluorescent lamp/one EE ballast base case fixture. Estimated lighting energy and demand savings is 50 percent. Technical feasibility is assumed to be 60 percent and 40 percent in new and existing buildings.

4.3.2.32 L-D-21: High-Pressure Sodium (70/100/150/250W). This measure considers a weighted mix of 70W, 100W, 150W, and 250W high-pressure sodium lamps/fixtures replacing the same mix of 100W, 175W, 250W, and 400W mercury vapor lamps/fixtures. Estimated lighting energy and demand savings range from 28.6 percent to 35.8 percent while maintaining or increasing original lumen output. Technical feasibility is assumed to be 90 percent (SRC). The analysis of this mixture does not include heating and cooling interactive effects since the location may be in an unconditional space.

4.3.2.33 L-D-23: High-Pressure Sodium (35W). This measure considers replacing one 150W incandescent lamp with one 35W HPS fixture in both new and existing buildings. Estimated lighting energy and demand savings is 72 percent. Annual maintenance costs of replacing both incandescent and HPS lamps during the lifetime of the HPS ballast is considered. The technical feasibility is assumed to be 90 percent.

4.3.2.34 L-D-25: Compact Fluorescent Lamps (15/18/27W). This measure considers replacing a weighted mix of 60W, 75W, and 100W incandescent lamps with the same mix of 15W, 18W, and 27W compact fluorescent lamps in both new and existing buildings. The percentage breakdown of the mix varies by building type. Weighted average lighting energy and demand savings is 70.7 percent while maintaining the original lumen output. Technical feasibility is assumed to be 85 percent and 90 percent for new and existing buildings.

4.3.2.35 L-D-26: Two Lamp Compact Fluorescent (18W). This measure consists of two 18W compact fluorescent tubes within a single fixture which replaces one 150W incandescent lamp in both new and existing buildings. Estimated lighting energy and demand savings is 76.0 percent. Technical feasibility is assumed to be 85 percent and 90 percent for new and existing buildings.

4.3.2.36 R-D-4/5: Multiplex and Open Drive Refrigeration Systems. These measures consist of various air-cooled refrigeration systems which are compared to a stand-alone compressor system. Includes a multiplex system with or without ambient or mechanical subcooling, external liquid suction heat exchanger, in addition to an open drive (ASD) refrigeration system. Assumed applicable to restaurant, grocery, warehouse, and hospital market segments.

4.3.2.37 W-D-13: Heat Recovery Water Heater. This measure consists of an electric water heater which utilizes a supplemental heat source from the cooling system waste heat from a double bundle chiller or condenser heat exchanger. There is an assumed 25 percent energy savings based on the WAPA Guidebook of Commercial DSM Technologies, while assuming a summer and winter demand savings of 35 percent and 15 percent. The current penetration is assumed to be zero.

4.3.2.38 W-D-14: DHW Heating Insulation. This is a retrofit measure consisting of wrapping an existing water tank with additional insulation. Energy and demand savings of 5 percent is assumed. The technical feasibility and current penetration are assumed to be 50 percent and 20 percent.

4.3.2.39 W-D-15: DHW Heat Trap. This retrofit measure reduces hot water energy due to backflow through the pipes from natural convection. It is analyzed for all existing market segments and is not analyzed in the new market since the technology is a Florida Energy Efficiency Code for Building Construction – 1991 requirement. Energy savings is 10 percent based on the WAPA Guidebook of Commercial DSM Technologies, while demand savings is expected to be 2 percent. The technical feasibility and current penetration is assumed to be 80 percent and 15 percent.

4.3.2.40 W-D-16: Low Flow/Variable Flow Showerhead. This retrofit measure can easily be installed in place of existing showers and faucets to reduce the flow of hot water. It is assumed there are approximately two showerheads and four faucets per water heater. Estimated energy and demand energy savings is 15 percent. This measure was only analyzed in the existing market segment, and excluded new buildings since the Florida Energy Efficiency Code for Building Construction – 1991 includes this measure. Technical feasibility varies by building type based on the following assumed percentage of hot water dedicated to showers and faucets:

- 80 percent office, retail, school, college, and lodging.
- 50 percent grocery, hospital, and miscellaneous.
- 20 percent restaurant.

Penetration of this measure is assumed to be 10 percent.

4.3.2.41 C-D-19: Energy Efficient Electric Fryers. This technology was modeled as a replacement technology applicable to restaurants, grocery, school, hospitals, and lodging. Energy and demand savings were estimated to be 10 percent.

4.4 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 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), in 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 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 5.3.1 outlines the basic economic assumptions while Subsection 5.3.2 discusses the evaluation criteria.

5.3.1 Economic Parameters

5.3.1.1 Escalation Rates. The general inflation rate applied is 2.5 percent annually, which is based upon the US Consumer Price Index (CPI). A 2.0 percent annual escalation rate is applied to capital costs. Operations and maintenance (O&M) expenses are assumed to escalate at a 3.0 percent rate.

5.3.1.2 Present Worth Discount Rate. The present worth discount rate assumed is 10.0 percent.

5.3.1.3 Lakeland Municipal Bond Interest Rate. Lakeland's current municipal long-term bond interest rate is assumed to be 5.5 percent. This is based upon the historical bond rate for Lakeland and current bond ratings.

5.3.1.4 Interest During Construction Interest Rate. The interest rate applied for interest during construction is assumed to be 5.5 percent.

5.3.1.5 Fixed Charge Rate. Based upon a 2.0 percent issuance fee, a 1.0 percent insurance annual cost, the bond interest rate of 5.5 percent, and the economic life of the unit additions amortized over 25 years, the fixed charge rate for Lakeland in the base case is 8.41 percent.

5.3.1.6 Present Worth Discount Rate Sensitivity. Sensitivity analysis is performed in Section 8.2 to test the expansion plan if the present worth discount rate is raised or lowered. The higher sensitivity assumes a discount rate of 15.0 percent. The low sensitivity case assumes that the discount rate would be equal to the assumed municipal bond interest rate for Lakeland of 5.5 percent.

5.4 Economic Evaluation Methodology

Economic evaluation is conducted over a 20 year period from 1999 through 2018. The economic evaluations are based on the cumulative present worth of annual costs for capital costs, nonfuel O&M costs, fuel costs, and purchase power demand, and energy 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.

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.

5.5 Fuel Price Forecast and Availability

5.5.1 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 nominal delivered fuel are presented in Table 5-1. 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 Table 5-1 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 5-2 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 2 additional years. The contract with Consol Coal is a 1-year term agreement.

5.5.1.1 Coal Price Forecast. The coal price forecast encompasses several underlying assumptions of the market structure and environmental regulations that will affect coal burning plants. The coal industry is currently going through two major changes. The first change will be the fluidity of the market with the NYMEX futures contracts in place. This will cause the market to be driven by not only supply and demand, but by speculation. The second major change is environmental regulations that may occur in the years 2000 to 2005. The federal government has considered more stringent clean air act amendments and potential carbon taxes for power plants burning coal. The carbon tax was not approved under President Clinton's first administration but may possibly be pursued under a new administration. If more stringent amendments are passed this will require many utilities to burn coal that has low sulfur properties, many of which are not doing so at this time. This will increase the demand for low sulfur coals, thus driving up the price.

Based on the above characterization, Lakeland is forecasting a 3.65 percent average annual increase including general inflation for coal prices over the planning period.

Table 5-1: Base Case Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Pet. Coke	RDF
1999	$1.85	$3.07	$3.25	$4.55	$4.76	$1.15	($2.42)
2000	$1.92	$3.15	$3.38	$4.74	$4.99	$1.24	($2.54)
2001	$1.99	$3.23	$3.52	$4.93	$5.22	$1.29	($2.67)
2002	$2.06	$3.32	$3.67	$5.14	$5.45	$1.35	($2.79)
2003	$2.13	$3.42	$3.83	$5.37	$5.71	$1.40	($2.93)
2004	$2.21	$3.54	$4.01	$5.61	$5.96	$1.46	($3.07)
2005	$2.29	$3.66	$4.19	$5.87	$6.25	$1.52	($3.22)
2006	$2.37	$3.81	$4.40	$6.16	$6.56	$1.59	($3.37)
2007	$2.46	$3.97	$4.61	$6.46	$6.98	$1.65	($3.53)
2008	$2.56	$4.13	$4.85	$6.80	$7.41	$1.73	($3.70)
2009	$2.65	$4.29	$5.11	$7.17	$7.83	$1.80	($3.88)
2010	$2.74	$4.48	$5.39	$7.57	$8.26	$1.87	($4.06)
2011	$2.84	$4.62	$5.59	$7.84	$8.56	$1.94	($4.21)
2012	$2.95	$4.77	$5.79	$8.13	$8.87	$2.01	($4.37)
2013	$3.05	$4.92	$6.00	$8.43	$9.20	$2.09	($4.53)
2014	$3.17	$5.07	$6.22	$8.74	$9.53	$2.16	($4.69)
2015	$3.28	$5.24	$6.45	$9.06	$9.88	$2.24	($4.86)
2016	$3.40	$5.40	$6.68	$9.39	$10.24	$2.33	($5.04)
2017	$3.53	$5.58	$6.93	$9.73	$10.61	$2.41	($5.22)
2018	$3.66	$5.76	$7.18	$10.08	$11.00	$2.50	($5.42)
AAI	**3.65%**	**3.37%**	**4.27%**	**4.28%**	**4.51%**	**4.19%**	**4.34%**

AAI = Average Annual Increase

Table 5-2
McIntosh Units 3 and 4 Fuel Price Forecast

Year	McIntosh 3 nominal prices	McIntosh 4 nominal prices
1999	$1.66	
2001	$1.79	
2002	$1.86	
2003	$1.93	
2004	$2.00	$1.64
2005	$2.07	$1.71
2006	$2.14	$1.77
2007	$2.21	$1.86
2008	$2.30	$1.73
2009	$2.39	$1.80
2010	$2.48	$1.87
2011	$2.57	$1.94
2012	$2.68	$2.01
2013	$2.78	$2.09
2014	$2.88	$2.16
2015	$2.99	$2.24
2016	$3.10	$2.33
2017	$3.21	$2.41
2018	$3.34	$2.50

5.5.1.2 High and Low Sulfur No. 6 Oil and Diesel Price Forecasts. While Lakeland is not a large consumer of No. 6 oil or diesel fuel, a small percentage is consumed during operations for backup fuel and diesel unit operations. The forecasted average annual increase for high and low sulfur No. 6 oil and diesel fuel are 4.27, 4.28, and 4.51 percent, respectively.

5.5.1.3 Natural Gas Price Forecast. The base case natural gas commodity price forecast was developed from current market conditions and speculation of the future supply of natural gas in the U.S. While it is no longer feasible to forecast natural gas prices in the short term based on supply and demand, over the long term, U.S. gas supplies are predicted to be adequate. Therefore, gas commodity prices are assumed to escalate at a 4.02 percent average annual increase over the forecast horizon.

Florida Gas Transmission Company (FGT) supplies natural gas transportation in Florida. Details of FGT's system are presented in Subsection 5.7.3.1. Natural Gas transportation from FGT is currently supplied under two tariffs, FTS-1 and FTS-2. Rates for FTS-2 are based on FGT's Phase III expansion while rates for FTS-1 are based on the Phase II expansion. As discussed in Subsection 5.7.3.1, the Phase III expansion was extensive and rates for FTS-2 transportation are significantly higher than FTS-1. The Phase IV expansion will be less extensive and thus, transportation rates should be lower. While it is anticipated that Phase IV rates may be lower, the cost for the Phase IV expansion may be rolled in with the Phase III costs, and the resultant rate may not be significantly less than the current Phase III rates.

For purposes of projecting delivered gas prices, an average transportation charge of $0.65/MBtu is assumed. The transportation charge is based upon Lakeland's current transportation charges including the effects of relinquished firm transportation and purchases of transportation on the secondary market, and projections that FGT will keep transportation rates at or below the current rates for the near future. Table 5-3 presents the delivered natural gas price forecast based on commodity and transportation rates. The delivered price is applied in the Ten-Year Site Plan for all natural gas burning generating units.

Lakeland has entered into a 10 year fixed rate contract with Natural Gas Clearinghouse to supply 50 percent of Lakeland's Phase II firm transportation natural gas entitlements. Lakeland plans to enter into long-term contracts that will provide between 50 and 60 percent of its natural gas requirements and into 1 year (spot market) contracts for the balance of its requirements. The mixture of contracts should give Lakeland stability of pricing while allowing enough flexibility for Lakeland to respond to changing market conditions.

5.5.1.4 Nuclear Fuel Price Forecast. Lakeland utilized KUA's and FMPA's recent need for power application for Cane Island Unit 3 forecast for nuclear fuel prices. Lakeland historically does not forecast nuclear fuel prices since Lakeland does not have an ownership interest in nuclear units. After a review of this forecast, the forecast seems reasonable for analysis purposes. The forecast assumes a 1999 nuclear fuel price of $0.56/MBtu with an average annual increase of 2.5 percent.

5.5.1.5 Petroleum Coke Forecast. The petroleum coke price forecast is based upon current contracts and anticipated growth of this fuel's usage for Florida. While the domestic market is a price taker instead of a price setter, it is envisioned that usage of this

Table 5-3
Delivered Natural Gas Price Forecast

Year	Commodity Price $/Mbtu	Transportation Charge $/Mbtu	Total Delivered Price $/Mbtu
1999	$2.42	$0.65	$3.07
2000	$2.50	$0.65	$3.15
2001	$2.58	$0.65	$3.23
2002	$2.67	$0.65	$3.32
2003	$2.77	$0.65	$3.42
2004	$2.89	$0.65	$3.54
2005	$3.01	$0.65	$3.66
2006	$3.16	$0.65	$3.81
2007	$3.32	$0.65	$3.97
2008	$3.48	$0.65	$4.13
2009	$3.64	$0.65	$4.29
2010	$3.83	$0.65	$4.48
2011	$3.97	$0.65	$4.62
2012	$4.12	$0.65	$4.77
2013	$4.27	$0.65	$4.92
2014	$4.42	$0.65	$5.07
2015	$4.59	$0.65	$5.24
2016	$4.75	$0.65	$5.40
2017	$4.93	$0.65	$5.58
2018	$5.11	$0.65	$5.76

fuel will increase in the future. Therefore, petroleum coke prices are forecasted to rise at an average annual increase of 4.19 percent.

5.5.1.6 Refuse Derived Fuel. The refuse derived fuel price forecast is based upon current contracts with the city for fuel delivery and quality. Lakeland does not consume a large portion of this fuel annually and is not considered a primary fuel for McIntosh Unit 3. The price indicated is negative because the city pays Lakeland to burn the refuse instead of placing it in a landfill. The forecast assumes the price will escalate at 4.34 percent.

5.5.1.7 McIntosh 3 and McIntosh 4 Forecast. McIntosh 3 and the proposed PCFB unit, McIntosh 4, burn a combination of fuels during operation. McIntosh 3 burns coal, petroleum coke, and refuse derived fuel. McIntosh 4 is proposed to burn four types of high sulfur coal for a 4 year demonstration period and then burn petroleum coke thereafter. The high sulfur coal is projected to be lower in cost than the coal for McIntosh 3. Table 5-2 displays fuel price projections for McIntosh Unit 3 and Unit 4 for the fuels associated with these generators.

5.5.1.8 Review of Industry Forecasts. Lakeland conducted a thorough review of industry recognized fuel price forecasts for comparison with their forecast. The review analyzed the year 2000 price forecast and the year 2015 price. The comparison forecasts were developed on a real basis (1997 dollars). Lakeland's fuel price forecast was placed in real terms to compare the fuel price projections. Details of the fuel price forecasts in real terms are provided in Appendix B.

The intent of the review of industry forecasts was to provide a check to ensure Lakeland's view of the future prices of fuel is similar to industry recognized forecasts. Lakeland selected the following industry forecasts for comparison to their internal forecast:

- 1998 Gas Research Institute.
- 1998 Annual Energy Outlook (U.S. Dept. of Energy, Energy Information Administration).
- 1998 American Gas Association Forecast.

Lakeland's price for fuels are compared against the industry forecast for the years 2000 and 2015 below:

	2000 Price(1)			2015 Price(1)		
Forecast	Gas	Oil	Coal	Gas	Oil	Coal
1997 Lakeland	2.32	3.14	1.78	2.94	4.13	2.10
1998 AGA	2.25	2.74	NA	2.35	3.72	1.05
1998 GRI	2.24	2.71	NA	2.40	2.71	1.15
1998 AEO	2.54	3.03	1.20	3.04	3.41	1.03

(1) Forecast prices are in 1997 dollars (real basis).

5.6 Fuel Forecast Sensitivities

Lakeland attempts to carefully forecast fuel prices based upon information available at the time of the forecast. With the uncertainty of the future conditions, Lakeland recognizes that the actual fuel prices may vary from the forecasted values. In attempt to bracket the variance of the projected fuel prices, Lakeland utilizes a high and low fuel price forecast. Lakeland also presents a case where a constant price differential is maintained over the planning horizon between coal and natural gas/oil.

5.6.1 High Fuel Price Forecast

The high fuel price forecast assumes that higher than expected fuel price escalation occurs over the planning horizon. Lakeland has assumed that a high fuel price bracket of 2.5 percent above the base case forecast is a reasonable upper limit. The forecast is provided in Table 5-4.

5.6.2 Low Fuel Price Forecast

The low fuel price forecast assumes that lower than expected fuel price escalation occurs over the planning horizon. Lakeland has assumed that a low fuel price bracket of 2.5 percent below the base case forecast is a reasonable lower limit. The forecast is provided in Table 5-5.

5.6.3 Constant Differential Between Coal Versus Natural Gas/Oil

Lakeland also conducts a sensitivity analysis that assumes a constant differential between coal and natural gas/oil over the planning horizon. This case uses the 1999 fuel cost differential between the fuels and maintains that same dollar value differential throughout the planning horizon. Table 5-6 displays the fuel price forecast for this sensitivity analysis.

5.7 Fuel Availability

5.7.1 Coal Availability

Lakeland projects that McIntosh Unit No. 3 will burn approximately 850,000 to 900,000 tons of coal per year. Normally a 30 to 35 day coal supply reserve (90,000 to 110,000 tons) is maintained at the McIntosh plant. Lakeland has a 1 year coal supply agreement with Shamrock Coal Company, Inc. for 500,000 tons. The coal sources are located in eastern Kentucky, which affords Lakeland a single rail line haul via CSX Transportation (CSX). Lakeland still has the capacity to purchase additional spot market coal for its additional needs. Lakeland continually reviews its coal purchasing strategy and currently plans to purchase coal based on 1 year contracts.

Table 5-4: High Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Pet. Coke	RDF
1999	$1.90	$3.13	$3.33	$4.66	$4.88	$1.17	($2.36)
2000	$2.01	$3.27	$3.55	$4.98	$5.24	$1.30	($2.42)
2001	$2.14	$3.43	$3.79	$5.31	$5.62	$1.39	($2.48)
2002	$2.27	$3.60	$4.04	$5.66	$6.01	$1.48	($2.53)
2003	$2.41	$3.78	$4.32	$6.07	$6.44	$1.58	($2.59)
2004	$2.56	$4.00	$4.64	$6.49	$6.89	$1.69	($2.64)
2005	$2.72	$4.22	$4.97	$6.96	$7.41	$1.80	($2.70)
2006	$2.89	$4.49	$5.34	$7.48	$7.96	$1.93	($2.76)
2007	$3.06	$4.78	$5.73	$8.04	$8.67	$2.05	($2.83)
2008	$3.27	$5.09	$6.19	$8.66	$9.44	$2.21	($2.89)
2009	$3.47	$5.41	$6.67	$9.36	$10.21	$2.35	($2.95)
2010	$3.68	$5.78	$7.21	$10.12	$11.03	$2.51	($3.02)
2011	$3.91	$6.10	$7.66	$10.75	$11.72	$2.66	($3.05)
2012	$4.15	$6.44	$8.13	$11.42	$12.44	$2.83	($3.08)
2013	$4.41	$6.80	$8.64	$12.13	$13.22	$3.01	($3.12)
2014	$4.68	$7.18	$9.17	$12.88	$14.04	$3.19	($3.15)
2015	$4.97	$7.59	$9.74	$13.68	$14.91	$3.39	($3.19)
2016	$5.28	$8.02	$10.35	$14.53	$15.84	$3.60	($3.22)
2017	$5.61	$8.47	$10.99	$15.43	$16.82	$3.83	($3.26)
2018	$5.89	$8.87	$11.55	$16.22	$17.68	$4.02	($3.25)
AAI	**6.15%**	**5.64%**	**6.77%**	**6.78%**	**7.01%**	**6.69%**	**1.71%**

AAI = Average Annual Increase

Table 5-5: Low Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Pet. Coke	RDF
1999	$1.80	$3.01	$3.17	$4.44	$4.64	$1.12	($2.48)
2000	$1.82	$3.03	$3.22	$4.51	$4.74	$1.18	($2.67)
2001	$1.84	$3.05	$3.27	$4.58	$4.84	$1.20	($2.87)
2002	$1.86	$3.06	$3.32	$4.65	$4.94	$1.22	($3.08)
2003	$1.88	$3.09	$3.38	$4.74	$5.04	$1.24	($3.31)
2004	$1.90	$3.13	$3.45	$4.83	$5.13	$1.26	($3.55)
2005	$1.92	$3.18	$3.52	$4.93	$5.25	$1.28	($3.81)
2006	$1.94	$3.24	$3.60	$5.04	$5.37	$1.30	($4.09)
2007	$1.96	$3.30	$3.68	$5.17	$5.58	$1.32	($4.39)
2008	$1.99	$3.36	$3.79	$5.30	$5.79	$1.35	($4.72)
2009	$2.01	$3.42	$3.89	$5.45	$5.96	$1.37	($5.06)
2010	$2.03	$3.49	$4.00	$5.62	$6.14	$1.39	($5.43)
2011	$2.05	$3.52	$4.05	$5.68	$6.20	$1.41	($5.77)
2012	$2.08	$3.55	$4.09	$5.74	$6.27	$1.42	($6.13)
2013	$2.10	$3.59	$4.13	$5.80	$6.34	$1.44	($6.51)
2014	$2.12	$3.62	$4.18	$5.87	$6.41	$1.45	($6.92)
2015	$2.14	$3.65	$4.22	$5.93	$6.48	$1.47	($7.34)
2016	$2.17	$3.68	$4.27	$6.00	$6.55	$1.48	($7.80)
2017	$2.19	$3.72	$4.32	$6.06	$6.62	$1.50	($8.29)
2018	$2.19	$3.71	$4.31	$6.06	$6.62	$1.50	($8.71)
AAI	**1.03%**	**1.12%**	**1.64%**	**1.65%**	**1.89%**	**1.57%**	**6.84%**

AAI = Average Annual

Table 5-6: Constant Differential Fuel Price Forecast Summary (Delivered Price $/MBtu)

Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Pet. Coke	RDF
1999	$1.85	$3.07	$3.24	$4.53	$4.69	$1.13	($2.34)
2000	$1.92	$3.13	$3.30	$4.60	$4.75	$1.20	($2.28)
2001	$1.99	$3.20	$3.37	$4.67	$4.82	$1.27	($2.21)
2002	$2.06	$3.28	$3.45	$4.74	$4.90	$1.34	($2.13)
2003	$2.13	$3.35	$3.52	$4.81	$4.97	$1.42	($2.06)
2004	$2.21	$3.43	$3.60	$4.89	$5.05	$1.50	($1.98)
2005	$2.29	$3.51	$3.68	$4.97	$5.13	$1.58	($1.90)
2006	$2.37	$3.59	$3.76	$5.05	$5.21	$1.66	($1.82)
2007	$2.46	$3.68	$3.84	$5.14	$5.29	$1.74	($1.73)
2008	$2.56	$3.78	$3.95	$5.24	$5.40	$1.84	($1.63)
2009	$2.65	$3.87	$4.04	$5.33	$5.49	$1.94	($1.54)
2010	$2.74	$3.96	$4.13	$5.42	$5.58	$2.03	($1.45)
2011	$2.84	$4.06	$4.23	$5.52	$5.68	$2.13	($1.35)
2012	$2.95	$4.16	$4.33	$5.63	$5.78	$2.23	($1.24)
2013	$3.05	$4.27	$4.44	$5.73	$5.89	$2.34	($1.14)
2014	$3.17	$4.38	$4.55	$5.85	$6.00	$2.45	($1.03)
2015	$3.28	$4.50	$4.67	$5.96	$6.12	$2.57	($0.91)
2016	$3.40	$4.62	$4.79	$6.08	$6.24	$2.69	($0.79)
2017	$3.53	$4.74	$4.91	$6.21	$6.36	$2.81	($0.67)
2018	$3.66	$4.87	$5.04	$6.33	$6.49	$2.94	($0.54)
AAI	**3.65%**	**2.47%**	**2.36%**	**1.78%**	**1.73%**	**5.14%**	**-7.46%**

AAI = Average Annual Increase

5.7.2 No. 2 Oil, No. 6 Oil, and Diesel Fuel Availability

Lakeland currently obtains all of its fuel oil and diesel fuel through purchases via the spot market, and has no long-term contracts. This strategy provides the lowest cost for fuel oil consistent with usage, current price stabilization, and onsite storage. Lakeland's Fuels Section continually monitors the cost-effectiveness of spot market purchasing.

5.7.3 Natural Gas Availability

5.7.3.1 Florida Gas Transmission Company. Florida Gas Transmission Company (FGT) is an open access interstate pipeline company transporting natural gas for third parties through its 5,000 mile pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation, which in turn, is jointly owned by Enron Corporation, the largest integrated natural gas company in America, and Sonat, Inc., one of the largest independent producers of natural gas in the United States.

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

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

FGT's total receipt point capacity is in excess of 3.0 billion cubic feet per day and includes connections with 10 interstate and 10 intrastate pipelines to facilitate transfers of natural gas into its pipeline system. FGT reports a current delivery capability to Peninsular Florida in excess of 1.4 billion cubic feet per day.

5.7.3.2 Florida Gas Transmission Market Area Pipeline System. The FGT multiple pipeline system corridor enters the Florida Panhandle in northern Escambia County and runs easterly to a point in southwestern Clay County, where the pipeline corridor turns southerly to pass west of the Orlando area. The mainline corridor then turns to the southeast to a point in southern Brevard County, where it turns south generally paralleling Interstate Highway 95 to the Miami area. A major lateral line (the St. Petersburg Lateral) extends from a junction point in southern Orange County westerly to terminate in the Tampa, St. Petersburg, Sarasota area. A major loop corridor (the West Leg Pipeline) branches from the mainline corridor in southeastern Suwannee County to run southward through western Peninsular Florida to connect to the St. Petersburg Lateral system in northeastern Hillsborough County. Each of the above major corridors includes stretches of multiple pipelines (loops) to provide flow redundancy and transport capability. Numerous lateral pipelines extend from the major corridors to serve major local distribution systems and industrial/utility customers.

5.7.3.3 Florida Gas Transmission Phase IV Expansion. On August 15, 1997, FGT initiated an “open season” for a proposed expansion of mainline transmission capability to serve new and existing markets. This initiative was structured to gauge the potential demand for the prospective FGT Phase IV expansion project with an estimated in-service date of mid-year 2000.

FGT filed for Federal Energy Regulatory Commission (FERC) approvals of the Phase IV expansion program December 2, 1998. The filing consists of expanding services to southwest Florida with 205 miles of underground pipelines. Additionally, FGT proposes to add 48,570 hp of compression to its system. The proposed additions will add 272,000 MBtu per day of incremental firm transportation service to peninsular Florida. The estimated cost of the expansion is $350 million. FGT anticipates construction of this project will begin in March of 2000, and is scheduled for completion and placed in service by May 2001. The Phase IV expansion of the FGT system should therefore be capable of implementation at a relatively low incremental cost impact to existing and prospective customers. Phase V expansion discussions are currently under way.

5.7.3.4 Alternative Natural Gas Supply Pipelines for Peninsular Florida. Over the years, a number of alternatives for pipeline delivery of natural gas to peninsular Florida have been proposed to provide competition to the existing FGT system. The most notable of these initiatives was the "SunShine System" pipeline, proposed in 1993 by SunShine Pipeline Partners, a subsidiary of the Coastal Corporation, to provide natural gas from an interconnection to existing pipelines from Texas-Louisiana Gulf Coast production regions and from onshore gas processing plants located in the Mobile Bay production region. The interstate portion of the proposed system comprised approximately 143 miles of new pipeline extending from near Pascagoula, Mississippi, to delivery points in Escambia and Okaloosa Counties, Florida. A separate proposed intrastate pipeline extended from the Okaloosa delivery point eastward and then southward for a distance of about 502 miles to terminate at the Florida Power Corporation's Hines Energy Complex site northwest of Fort Meade (Polk County), Florida. The project included a 27 mile lateral line to enable deliveries to customers in the Pensacola (Escambia County) area.

Florida Power Corporation (FPC) was the intended primary customer of the project, and acquired equity position and firm transport conditional commitment in the pipeline (January and February 1993). The project subsequently received preliminary (nonenvironmental) approvals for the intrastate and interstate pipelines from the Florida Public Service Commission and FERC, respectively.

The competitive threat to the established pipeline system was countered by FGT, which reached agreement with FPC for gas transmission via the expanded FGT system. FPC subsequently withdrew as an equity partner in the SunShine Project (September 1994) and terminated the agreements for firm transmission service (February 1995). The project was canceled in April 1995.

The successor to the SunShine pipeline is the "Gulf Stream" pipeline, which is also being promoted by the Coastal Corporation and ANR Pipeline. This pipeline would also originate in the Mobile Bay region, cross the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay) to service existing and prospective electric generation and industrial projects in south Florida. This project is in the development stage with the prognosis for ultimate completion uncertain. In any case, the proposed routing of the pipeline across peninsular Florida would appear to be too far to the south to provide economic service to the McIntosh site. Another proposal by Williams-Transco is also in the initial stage of development.

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 most often used deterministic method is the reserve margin method, which is calculated as follows:

$$\frac{\text{system net capacity - system net peak demand}}{\text{system net peak demand}}$$

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

6.1.3 Additional Capacity Requirements

Lakeland's requirements for additional capacity are presented in Tables 6-2 to 6-5 showing projected reliability levels for winter and summer base cases, and winter high and low load demands respectively. 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 (649 MW compared to 614 MW), the winter peak demand is also higher making the winter peak the governing load for capacity requirements.

Table 6-1
Summary of Load Forecast

	Winter Peak Demand[1]			Summer Peak Demand[1]		
Year	Base	High	Low	Base	High	Low
1999	588	596	579	510	517	502
2000	607	625	589	524	539	508
2001	626	653	598	535	559	512
2002	645	683	607	548	581	516
2003	663	712	615	560	601	519
2004	682	743	623	571	623	522
2005	701	775	631	584	646	526
2006	720	807	639	594	668	528
2007	739	841	646	607	692	531
2008	756	874	652	618	715	533
2009	775	909	659	630	740	535
2010	794	944	665	642	764	537
2011	813	981	671	654	790	539
2012	832	1,019	676	666	816	541
2013	851	1,057	681	678	844	542
2014	869	1,096	686	689	870	543
2015	888	1,137	691	701	899	545
2016	906	1,177	695	712	927	546
2017	925	1,219	699	724	956	546
2018	945	1,262	702	736	986	547

[1]Includes conservation and interruptible load reductions.

Table 6-2
Projected Reliability Levels - Winter / Base Case

Year	Net Generating Capacity	Net System Purchases	Net System Sales	Net System Capacity	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15%	
					Before Interruptible and Load Management	After Interruptible and Load Management	Before Interruptible and Load Management	After Interruptible and Load Management	Before Interruptible and Load Management	After Interruptible and Load Management
1998/99	649	20	25 (1)	669	593	588	12.82	13.78	(13)	(7)
1999/00	886	0	25	861	612	607	40.69	41.85	157	163
2000/01	886	0	75	811	631	626	28.53	29.55	85	91
2001/02	836	0	100	736	650	645	13.23	14.11	(11)	(6)
2002/03	749	0	100	649	668	663	(2.84)	(2.11)	(119)	(113)
2003/04	749	0	100	649	687	682	(5.53)	(4.84)	(141)	(135)
2004/05	646	0	100	546	706	701	(22.66)	(22.11)	(266)	(260)
2005/06	646	0	100	546	725	720	(24.69)	(24.17)	(288)	(282)
2006/07	646	0	100	546	744	739	(26.61)	(26.12)	(310)	(304)
2007/08	646	0	100	546	761	756	(28.25)	(27.78)	(329)	(323)
2008/09	646	0	100	546	780	775	(30.00)	(29.55)	(351)	(345)
2009/10	646	0	100	546	799	794	(31.66)	(31.23)	(373)	(367)
2010/11	646	0	0	646	818	813	(21.03)	(20.54)	(295)	(289)
2011/12	646	0	0	646	837	832	(22.82)	(22.36)	(317)	(311)
2012/13	646	0	0	646	856	851	(24.53)	(24.09)	(338)	(333)
2013/14	646	0	0	646	875	870	(26.17)	(25.75)	(360)	(355)
2014/15	646	0	0	646	894	889	(27.74)	(27.33)	(382)	(376)
2015/16	646	0	0	646	912	907	(29.17)	(28.78)	(403)	(397)
2016/17	646	0	0	646	931	926	(30.61)	(30.24)	(425)	(419)
2017/18	646	0	0	646	951	946	(32.07)	(31.71)	(448)	(442)

(1) Sale of 25MW to TEA occurs during the winter period but is after the peak demand for the season.

Table 6-3
Projected Reliability Levels - Summer / Base Case

Year	Net Generating Capacity	Net System Purchases	Net System Sales	Net System Capacity	System Peak Demand Before Interruptible and Load Management	System Peak Demand After Interruptible and Load Management	Reserve Margin Before Interruptible and Load Management	Reserve Margin After Interruptible and Load Management	Excess/ (Deficit) to Maintain 15% Before Interruptible and Load Management	Excess/ (Deficit) to Maintain 15% After Interruptible and Load Management
1999	797	0	25	772	515	510	49.90	51.37	180	186
2000	797	0	25	772	529	524	45.94	47.33	164	169
2001	747	0	100	647	540	535	19.81	20.93	26	32
2002	747	0	100	647	553	548	17.00	18.07	11	17
2003	660	0	100	560	565	560	(0.88)	0.00	(90)	(84)
2004	557	0	100	457	576	571	(20.66)	(19.96)	(205)	(200)
2005	557	0	100	457	589	584	(22.41)	(21.75)	(220)	(215)
2006	557	0	100	457	600	594	(23.83)	(23.06)	(233)	(226)
2007	557	0	100	457	613	607	(25.45)	(24.71)	(248)	(241)
2008	557	0	100	457	624	618	(26.76)	(26.05)	(261)	(254)
2009	557	0	100	457	636	630	(28.14)	(27.46)	(274)	(268)
2010	557	0	100	457	648	642	(29.48)	(28.82)	(288)	(281)
2011	557	0	0	557	660	654	(15.61)	(14.83)	(202)	(195)
2012	557	0	0	557	672	666	(17.11)	(16.37)	(216)	(209)
2013	557	0	0	557	684	678	(18.57)	(17.85)	(230)	(223)
2014	557	0	0	557	696	689	(19.97)	(19.16)	(243)	(235)
2015	557	0	0	557	708	701	(21.33)	(20.54)	(257)	(249)
2016	557	0	0	557	719	712	(22.53)	(21.77)	(270)	(262)
2017	557	0	0	557	731	724	(23.80)	(23.07)	(284)	(276)
2018	557	0	0	557	743	736	(25.03)	(24.32)	(297)	(289)

Table 6-4
Projected Reliability Levels - Winter / High Load

Year	Net Generating Capacity	Net System Purchases	Net System Sales	Net System Capacity	System Peak Demand: Before Interruptible & Load Management	System Peak Demand: After Interruptible & Load Management	Reserve Margin: Before Interruptible & Load Management	Reserve Margin: After Interruptible & Load Management	Excess/ (Deficit) to Maintain 15%: Before Interruptible & Load Management	Excess/ (Deficit) to Maintain 15%: After Interruptible & Load Management
1998/99	649	20	25 (1)	669	601	596	11.31	12.25	(22)	(16)
1999/00	886	0	25	861	630	625	36.67	37.76	137	142
2000/01	886	0	75	811	658	653	23.25	24.20	54	60
2001/02	836	0	100	736	688	683	6.98	7.76	(55)	(49)
2002/03	836	0	100	736	717	712	2.65	3.37	(89)	(83)
2003/04	646	0	100	546	748	743	(27.01)	(26.51)	(314)	(308)
2004/05	646	0	100	546	780	775	(30.00)	(29.55)	(351)	(345)
2005/06	646	0	100	546	812	807	(32.76)	(32.34)	(388)	(382)
2006/07	646	0	100	546	846	841	(35.46)	(35.08)	(427)	(421)
2007/08	646	0	100	546	879	874	(37.88)	(37.53)	(465)	(459)
2008/09	646	0	100	546	914	909	(40.26)	(39.93)	(505)	(499)
2009/10	646	0	100	546	949	944	(42.47)	(42.16)	(545)	(540)
2010/11	646	0	0	646	986	981	(34.48)	(34.15)	(488)	(482)
2011/12	646	0	0	646	1,024	1019	(36.91)	(36.60)	(532)	(526)
2012/13	646	0	0	646	1,062	1057	(39.17)	(38.88)	(575)	(570)
2013/14	646	0	0	646	1,101	1096	(41.33)	(41.06)	(620)	(614)
2014/15	646	0	0	646	1,143	1137	(43.48)	(43.18)	(668)	(662)
2015/16	646	0	0	646	1,183	1177	(45.39)	(45.11)	(714)	(708)
2016/17	646	0	0	646	1,225	1219	(47.27)	(47.01)	(763)	(756)
2017/18	646	0	0	646	1,267	1262	(49.01)	(48.81)	(811)	(805)

(1) Sale of 25MW to TEA occurs during the winter period but is after the peak demand for the season.

Table 6-5
Projected Reliability Levels - Winter / Low Load

Year	Net Generating Capacity	Net System Purchases	Net System Sales	Net System Capacity	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15%	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
1998/99	649	20	25(1)	669	584	579	14.55	15.54	(3)	3
1999/00	886	0	25	861	594	589	44.95	46.18	178	184
2000/01	886	0	75	811	603	598	34.49	35.62	118	123
2001/02	836	0	100	736	612	607	20.26	21.25	32	38
2002/03	836	0	100	736	620	615	18.71	19.67	23	29
2003/04	646	0	100	546	628	623	(13.06)	(12.36)	(176)	(170)
2004/05	646	0	100	546	636	631	(14.15)	(13.47)	(185)	(180)
2005/06	646	0	100	546	644	639	(15.22)	(14.55)	(195)	(189)
2006/07	646	0	100	546	652	646	(16.26)	(15.48)	(204)	(197)
2007/08	646	0	100	546	658	652	(17.02)	(16.26)	(211)	(204)
2008/09	646	0	100	546	665	659	(17.89)	(17.15)	(219)	(212)
2009/10	646	0	100	546	671	665	(18.63)	(17.89)	(226)	(219)
2010/11	646	0	0	646	677	671	(4.58)	(3.73)	(133)	(126)
2011/12	646	0	0	646	682	676	(5.28)	(4.44)	(138)	(131)
2012/13	646	0	0	646	687	681	(5.97)	(5.14)	(144)	(137)
2013/14	646	0	0	646	692	686	(6.65)	(5.83)	(150)	(143)
2014/15	646	0	0	646	697	691	(7.32)	(6.51)	(156)	(149)
2015/16	646	0	0	646	702	695	(7.98)	(7.05)	(161)	(153)
2016/17	646	0	0	646	706	699	(8.50)	(7.58)	(166)	(158)
2017/18	646	0	0	646	709	702	(8.89)	(7.98)	(169)	(161)

(1) Sale of 25MW to TEA occurs during the winter period but is after the peak demand for the

Applying the base case forecast for peak electrical demand, Lakeland will need additional capacity by the year 2002 to maintain a 15 percent annual reserve margin. Table 6-2 presents the projected reserve margins and system deficit for Lakeland's system for the winter period. Table 6-3 presents the projected reserve margins and system deficit for Lakeland's system for the summer period. The winter period is the driver for system capacity planning on Lakeland's system. As Tables 6-2 and 6-3 indicate, capacity is clearly needed in the year 2002 to maintain reserve margins.

6.2 Supply-Side Alternatives

6.2.1 Screening Process

Several supply-side alternatives were selected as potential expansion options for Lakeland's capacity deficits. The numerous supply-side alternatives identified require a screening process to arrive at an acceptable number of alternatives to model in detail. The supply-side alternatives considered include conventional, advanced, and renewable energy sources. The supply-side alternatives reviewed are included in Appendix C. The supply-side alternatives described in detail in Subsection 6.2.2 were selected from a screening analysis conducted in two phases. The first phase consisted of screening out alternatives that were still under development or were not technically feasible with Lakeland's resources. The second phase eliminated alternatives that would not provide cost-effective generation under any operating strategy. The alternatives that passed both phases of the screening analysis are included in Section 6.2.2.

6.2.2 Conventional Alternatives

Several conventional capacity addition alternatives were selected for consideration. The size of the alternatives selected considered the need for capacity and the suitability of the McIntosh site for installation of the alternatives. The alternatives considered include specific alternatives that Lakeland has studied in the past as well as generic alternatives. Conventional generating unit alternatives considered for capacity expansion included the following:

- Pulverized coal.
- Fluidized bed.
- Combined cycle.
- Simple cycle combustion turbine.

Combustion turbine based alternatives were based on the size and performance of specific machines, but were 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. The pulverized coal and fluidized bed units are assumed to be located at the McIntosh site. Combined cycle and simple cycle combustion turbines were assumed to be installed on the McIntosh site and to take advantage of existing infrastructure.

Performance and O&M cost estimates have been compiled for each capacity addition alternative. The estimates provide representative values for each generation alternative and show expected trends in performance and costs within a given technology as well as between technologies. Degradation is also included. Actual unit performance and availability will vary based on site conditions, regulatory requirements, and operation practices. Capital costs for conventional technology alternatives are in 1998 dollars.

6.2.2.1 Performance Estimates.

6.2.2.1.1 Net Plant Output. Net plant output (NPO) is equal to the net turbine output less auxiliary power.

6.2.2.1.2 Equivalent Availability (EA). Equivalent availability is a measure of the capacity of a generating unit to produce power considering limitations such as equipment failures, repairs, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

6.2.2.1.3 Equivalent Forced Outage Rate (EFOR). Equivalent forced outage rate is a reliability index, which reflects the probability that a unit will be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours plus equivalent forced outage hours by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

6.2.2.1.4 Planned Maintenance Outage. Estimates are provided for the time required each year to perform scheduled maintenance.

6.2.2.1.5 Startup Fuel. Estimates for startup energy, where applicable, in millions of Btu, are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operation conditions.

6.2.2.1.6 Net Plant Heat Rate. Estimates for net plant heat rates are based on the higher heating value of the fuel. Heat rate estimates are provided for summer (97° F ambient) and winter (30° F ambient) conditions for combustion turbines and combined cycle units. Heat rates may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, and local site conditions.

6.2.2.2 Cost Estimates.

6.2.2.2.1 Capital Costs. Capital costs were developed on the basis of the current competitive generation market. Indirect costs include the typical items of engineering, construction management, general indirect costs, and contingency. In addition, other indirect costs included were SCADA interface costs, spares, owner's engineer, permitting, training, and substation costs to integrate the unit into the McIntosh substation in order to place the costs on a comparable basis with costs resulting from purchase power bids. Direct costs for the combined cycle alternatives include bypass stacks with dampers, along with continuous emissions monitoring equipment. Direct costs for natural gas alternatives include a fuel oil storage tank. Costs for the coal units to be located at McIntosh site include costs for substation integration. Total capital cost is the summation of direct and indirect cost and interest during construction for commercial operation. The construction period is the time from start of construction to commercial operation. The construction period was used to estimate costs for interest during construction (IDC).

6.2.2.2.2 O&M Costs. O&M estimates are based on a unit life of 25 years for combustion turbines and combined cycles, variable and fixed contingency of 20 percent, and baseload capacity factor of 92 percent (except simple cycle units which assumed a capacity factor of 30 percent for the 501G, 20 percent for the 501F, and 5 percent for all others). Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage related overheads for the permanent plant staff. Fuel costs typically are determined separately and are not included in either fixed or variable O&M costs. The O&M costs presented in this application are typically referred to as nonfuel O&M costs. Variable O&M costs include disposal of combustion wastes and consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation.

6.2.2.2.3 Coal Fueled O&M. O&M and performance estimates for the coal fueled alternatives were based on the following assumptions.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Variable operations costs include an assumed lime cost of $95/ton for flue gas desulfurization (FGD); limestone cost of $22/ton for the CFB; waste disposal, which includes trucking to an onsite landfill, dozing and flattening (mobile reclaim equipment); and startup fuel oil. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs. Staffing estimates provided are based on recent utility experience with modern facilities.

An additional variable O&M cost of 0.73 $/MWh is included for the selective catalytic reduction (SCR), which includes NH_3 costs and catalyst replacement costs. For the selective noncatalytic reduction (SNCR), the additional variable O&M cost is approximately 0.52 $/MWh for NH_3 costs. The pulverized coal unit is assumed to require SCR, while the fluidized bed unit is assumed to require SNCR. The PCFB unit is assumed to require an SCR.

McIntosh 4, a proposed pressurized circulating fluidized bed unit, is currently in the design stages. It has not been determined if a scrubber will be required for this unit. For the economic analysis, the O&M cost for the scrubber has been included.

6.2.2.2.4 Combined and Simple Cycle O&M. O&M and performance estimates for the combined cycle and simple cycle units were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors.
- Capacity and heat rate degradation of 4 and 2 percent, respectively, has been included in the performance estimates.
- Combustion turbine generator (CTG) maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at $38/man-hour for Westinghouse and $35/man-hour for General Electric (provided by manufacturers).
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost. These costs are included in the capital cost.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralizer cycle makeup water and cooling tower raw water are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle 501G is based on a 30 percent capacity factor.

- O&M costs for the simple cycle 501F is based on 20 percent capacity factor.
- O&M costs for all other simple cycle alternatives are based on a 5 percent capacity factor.

6.2.2.3 Pulverized Coal. A 250 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and SCR was selected as a solid fueled alternative. The unit is assumed to be located at the existing McIntosh site. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 6-6 presents the estimated cost and performance of the 250 MW pulverized coal unit.

6.2.2.4 Fluidized Bed. A 250 MW atmospheric circulating fluidized bed unit (CFB) with SNCR was selected as another solid fuel alternative. The CFB is capable of burning a wide range of fuels. For expansion planning purposes, the CFB is assumed to burn coal. Like the pulverized coal unit, the CFB is assumed to be located at the existing McIntosh site. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 6-7 presents the estimated cost and performance of the 250 MW CFB unit.

6.2.2.5 Pressurized Circulating 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 Pressurized Circulating Fluidized Bed (PCFB) 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 Department of Energy (DOE) PCFB project that will provide baseload capacity for Lakeland. 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 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.

Table 6-6
Estimated Cost and Performance of 250 MW Pulverized Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 1998 $1,000	186,577
Indirect Capital Cost, 1998 $1,000	81,658(1)
Total Capital Cost, 1998 $1,000	268,235
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	23.18
Variable O&M Cost, 1998 $/MWh	2.46
Equivalent Availability, percent	85
Equivalent Forced Outage Rate, percent	7
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,000
Construction Period, months	30
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	250,000/10,141
75 Percent of Full Load	187,000/10,317
50 Percent of Full Load	125,000/10,878
25 Percent of Full Load	62,500/13,062

(1)Includes interest during construction.

Table 6-7
Estimated Cost and Performance of 250 MW Fluidized Bed Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 1998 $1,000	173,409
Indirect Capital Cost, 1998 $1,000	78,537(1)
Total Capital Cost, 1998 $1,000	251,946
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	18.75
Variable O&M Cost, 1998 $/MWh	1.77
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	7
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	4,200
Construction Period, months	30
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	250,000/10,543
75 Percent of Full Load	187,500/10,803
50 Percent of Full Load	125,000/11,593
25 Percent of Full Load	62,500/14,516

(1)Includes interest during construction.

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 adds the topped cycle.

The 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. The DOE funding also covers 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 after the conversion of McIntosh 5. Table 6-8 presents the estimated cost and performance for the DOE PCFB project. The unit will be capable of burning both coal and petroleum coke.

6.2.2.6 Combined Cycle. Four combined cycle units were selected as generating unit alternatives:

- 1 x 1 General Electric 7EA--(Table 6-9).
- 2 x 1 General Electric 7EA--(Table 6-10).
- 1 x 1 Westinghouse 501F--(Table 6-11).
- 1 x 1 Westinghouse 501G--(Table 6-12).

The combined cycles all utilize conventional, heavy-duty, industrial type combustion turbines. Several other vendors were analyzed and demonstrated similar performance characteristics. The combined cycles would be dual fueled with natural gas as the primary fuel. Specifications for performance and operating costs are based on natural gas fuel and baseload operation. The combined cycles assume that emission requirements will be met with dry low NO_x combustors.

Table 6-8
Generating Unit Characteristics
DOE Pressurized Fluidized Bed Unit – Phase I

Item	
Steam Pressure, psia	2,400
Steam Temperature, °F	1,050
Reheat Steam Temperature, °F	1,050
Direct Capital Cost, 1998 $1,000	119,383
Indirect Capital Cost, 1998 $1,000	23,877(1)
Total Capital Cost, 1998 $1,000(2), (3)	143,260
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	27.65
Variable O&M Cost, 1998 $/MWh	1.73
Equivalent Availability, percent	74.2
Equivalent Forced Outage Rate, percent	12
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,200
Construction Period, months	28
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	238,000/8,776
75 Percent of Full Load	173,000/9,031
50 Percent of Full Load	122,000/9,961
25 Percent of Full Load	83,000/11,687

(1)Includes interest during construction.

(2)Total capital cost is reduced by DOE funding including 4 years of O&M contributions applied to the total capital cost.

(3)This estimate is not finalized and may be lowered if the scrubber is not required and contingency costs can be lowered.

Table 6-9
Generating Unit Characteristics
General Electric 7EA 1 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	53,695	
Indirect Capital Cost, 1998 $1,000	11,085[1]	
Total Capital Cost, 1998 $1,000	64,780	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	3.29	
Variable O&M Cost, 1998 $/MWh	2.37	
Equivalent Availability, percent	92.1	
Equivalent Forced Outage Rate, percent	3.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	59	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	109,939/8,114	127,538/7,642
79 Percent of Full Load	86,852/8,454	100,755/7,928
59 Percent of Full Load	64,864/9,219	75,248/8,507
35 Percent of Full Load	38,479/11,288	44,638/10,201

[1]Includes interest during construction.

Table 6-10
Generating Unit Characteristics
General Electric 7EA 2 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	89,586	
Indirect Capital Cost, 1998 $1,000	20,779(1)	
Total Capital Cost, 1998 $1,000	110,365	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.24	
Variable O&M Cost, 1998 $/MWh	2.16	
Equivalent Availability, percent	92.5	
Equivalent Forced Outage Rate, percent	3.0	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	119	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	222,096/7,938	257,217/7,585
75 Percent of Full Load	166,572/8,258	192,912/7,812
50 Percent of Full Load	111,048/8,178	128,609/7,661
25 Percent of Full Load	55,524/9,865	64,304/9,063

(1)Includes interest during construction.

Table 6-11
Generating Unit Characteristics
Westinghouse 1 x 1 501F Combined Cycle

Item		
Steam Pressure, psia	1,800	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 1998 $1,000	95,370	
Indirect Capital Cost, 1998 $1,000	22,799(1)	
Total Capital Cost, 1998 $1,000	118,169	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.40	
Variable O&M Cost, 1998 $/MWh	2.30	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	85	
Construction Period, months	25	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	236,630/6,945	268,902/6,635
75 Percent of Full Load	175,106/7,483	201,677/6,952
52 Percent of Full Load	123,048/8,011	142,519/7,495
27 Percent of Full Load	63,890/10,474	75,293/9,632

(1)Includes interest during construction.

Table 6-12
Generating Unit Characteristics
Westinghouse 1 x 1 501G Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 1998 $1,000	135,500	
Indirect Capital Cost, 1998 $1,000	33,185[(1)]	
Total Capital Cost, 1998 $1,000	165,685	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	1.133	
Variable O&M Cost, 1998 $/MWh	1.266	
Equivalent Availability, percent	91.6	
Equivalent Forced Outage Rate, percent	4.5	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	27	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	337,507/6,699	384,380/6,249
75 Percent of Full Load	253,130/6,877	288,285/6,415
50 Percent of Full Load	168,754/7,603	192,190/7,091
25 Percent of Full Load	118,127/8,922	134,533/8,321

[(1)]Includes interest during construction.

The units would be located at the McIntosh site and would utilize existing common facilities to the extent possible. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate.

6.2.2.7 Simple Cycle Combustion Turbine. Three simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric LM6000--(Table 6-13).
- General Electric 7EA--(Table 6-14).
- Westinghouse 501F--(Table 6-15).

The 7EA and 501F combustion turbines are heavy-duty, industrial combustion turbines. The LM6000 is an aeroderivative combustion turbine. The combustion turbines are dual fueled with specifications for performance and operating costs based on natural gas operation.

6.2.2.8 Conversion of McIntosh Unit 5 to Combined Cycle. The conversion of McIntosh Unit 5 from simple cycle to combined cycle is described in detail in Lakeland's recent Need for Power Application. Table 6-16 provides the costs and performance estimates for the unit after conversion.

Table 6-13
Generating Unit Characteristics
General Electric LM6000 Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	15,275	
Indirect Capital Cost, 1998 $1,000	3,224[1]	
Total Capital Cost, 1998 $1,000	18,499	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	5.45	
Variable O&M Cost, 1998 $/MWh	6.92	
Equivalent Availability, percent	95.8	
Equivalent Forced Outage Rate, percent	2.3	
Planned Maintenance Outage, weeks/y	1	
Startup Fuel (cold start), MBtu	6	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	33,360/10,684	42,796/10,051
75 Percent of Full Load	25,020/11,472	32,097/10,462
50 Percent of Full Load	16,680/13,359	21,398/11,783
25 Percent of Full Load	8,340/19,292	10,699/16,297

[1]Includes interest during construction.

Table 6-14
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	21,228	
Indirect Capital Cost, 1998 $1,000	4,917[1]	
Total Capital Cost, 1998 $1,000	26,145	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	3.32	
Variable O&M Cost, 1998 $/MWh	23.56	
Equivalent Availability, percent	95.6	
Equivalent Forced Outage Rate, percent	2.1	
Planned Maintenance Outage, weeks/y	1.25	
Startup Fuel (cold start), MBtu	12	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	72,432/12,335	83,767/11,643
75 Percent of Full Load	54,324/13,504	62,825/12,705
50 Percent of Full Load	36,216/15,844	41,884/14,895
25 Percent of Full Load	18,108/23,515	20,942/21,513

[1]Includes interest during construction.

Table 6-15
Generating Unit Characteristics
Westinghouse 501F Simple Cycle Combustion Turbine

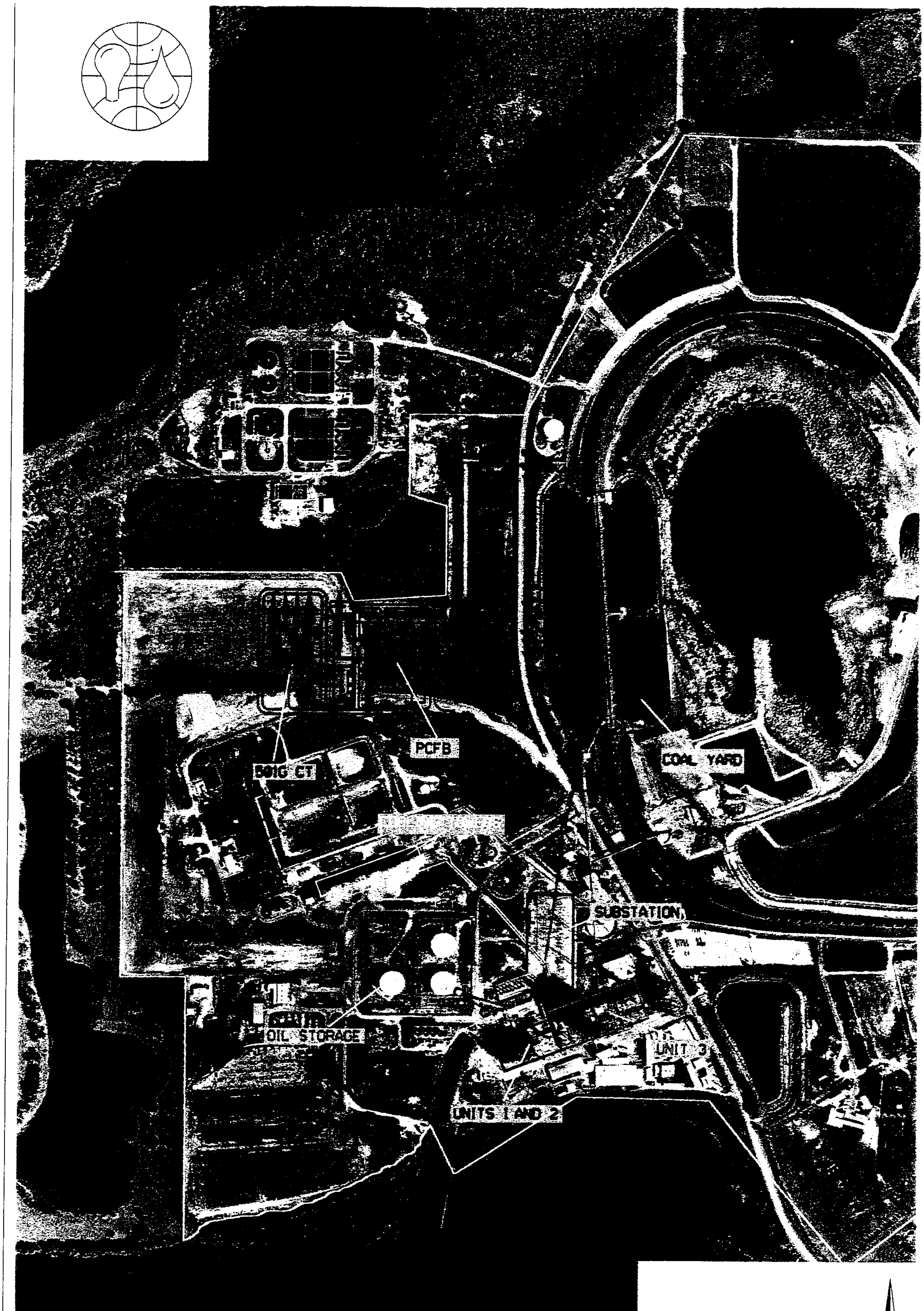
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	42,585	
Indirect Capital Cost, 1998 $1,000	9,962[(1)]	
Total Capital Cost, 1998 $1,000	52,547	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	5.50	
Variable O&M Cost, 1998 $/MWh	2.00	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	85	
Construction Period, months	14	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	156,100/11,216	186,500/10,243
75 Percent of Full Load	117,075/12,142	139,875/11,089
50 Percent of Full Load	78,050/13,843	93,250/12,642
25 Percent of Full Load	39,025/17,276	46,625/15,778

(1)Includes interest during construction.

Table 6-16
Generating Unit Characteristics
McIntosh Unit 5 after Conversion to Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 1998 $1,000	64,400(2)	
Indirect Capital Cost, 1998 $1,000	16,100(1)(2)	
Total Capital Cost, 1998 $1,000	80,500(2)	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	1.133	
Variable O&M Cost, 1998 $/MWh	1.266	
Equivalent Availability, percent	91.6	
Equivalent Forced Outage Rate, percent	4.5	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	18	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	337,507/6,699	384,380/6,249
75 Percent of Full Load	253,130/6,877	288,285/6,415
50 Percent of Full Load	168,754/7,603	192,190/7,091
25 Percent of Full Load	118,127/8,922	134,533/8,321

(1)Includes interest during construction.
(2)Includes only the cost for conversion.



CITY OF LAKELAND
DEPARTMENT
OF ELECTRIC
& WATER
UTILITIES

McINTOSH
PLANT GENERAL
ARRANGEMENT

7.0 Environmental and Land Use Information

The environmental and land use impacts were studied closely to determine resource addition effects on the system. From the least-cost expansion plan identified in the Need for Power Application the environmental and land use information is provided herein.

7.1 Status of Site Certification

Lakeland has filed a Need for Power application on January 6, 1999 for the site certification to convert McIntosh Unit 5 to combined cycle operation. The project would initially operate as a simple cycle combustion turbine and will be converted to a combined cycle unit with the addition of a heat recovery steam generator (HRSG) and steam turbine in the year 2002. Lakeland has obtained the permits for simple cycle operation. The hearing for the Need for Power is scheduled for April 1, 1999. Lakeland anticipates filing the Site Certification Application for McIntosh Unit 5 in April of 1999. The DOE PCFB Need for Power and Site Certification Applications have not been submitted.

7.2 Land and Environmental Features

Emissions will be minimized through the use of the highly efficient combined cycle generation and the pressurized circulating fluidized bed clean coal technology. The use of treated sewage effluent will conserve valuable water resources and the return of wastewater to the City Wastewater Treatment Facility eliminates 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 proposed site layout with McIntosh Unit 5 and McIntosh Unit 4 is also provided in Figure 7-1.

7.3 Air and Noise Emissions

Florida DEP has approved a NO_X emission rate of 25ppm for the McIntosh Unit 5 simple cycle until May 1, 2002. After May 1, 2002 NO_X emissions are permitted to be 9 ppm using Ultra Low NO_X combusters, 7.5 with conventional SCR, or 9 ppm using a hot SCR. Lakeland has filed a Need for Power and Site Certification Application for the conversion of McIntosh Unit 5 from a simple cycle unit to a combined cycle unit. The proposed commercial operating date for the combined cycle unit is January of 2002. Permitted and estimated emissions for McIntosh 4 and 5 are as follows.

McIntosh Unit 5 Westinghouse 501G Simple Cycle burning Natural Gas (Permitted)[1]

SO_2 -- 1 ppm
NO_x -- 25 ppm
CO -- 10 ppm
VOC - 4 ppm
PM/Visibility - 10 percent opacity

McIntosh Unit 5 Westinghouse 501G Combined Cycle (Permitted)[2]

SO_2 - 1 ppm
NO_x -- 9 ppm
CO -- 10 ppm
VOC - 4 ppm
PM/Visibility - 10 percent opacity

McIntosh Unit 4 DOE PCFB Clean Coal Project (Planned)

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.

7.4 Analysis of 1990 Clean Air Act Amendments

The City of Lakeland considers the impacts to its community and Peninsular Florida a vital portion of its strategic planning. While the Florida Electrical Power Plant Siting Act carefully bifurcates the need for the power plant from the environmental impacts of the facility, the Clean Air Act requirements have a great impact on the power plant's cost and performance. The conversion of McIntosh Unit 5 to combined cycle would lower emissions on a kilowatt hour basis from the current simple cycle machine and improve fuel utilization.

7.4.1 Authority to Construct

McIntosh Unit 5 is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. Lakeland's Authority to

[1] Permitted until May 1, 2002.
[2] Must be met by McIntosh Unit 5 after May 1, 2002.

Construct (ATC) permit has been obtained for McIntosh 5. One aspect of the ATC permit is the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are NO_x, VOC, CO, and PM/PM10. McIntosh 5 will achieve BACT for NO_x through the use of Dry Low NO_x combustors initially at a level of 25 ppm. Before May 1, 2002, Lakeland will retrofit the Dry Low NO_x combustors with Ultra Low NO_x combustors. If the Ultra Low NO_x combustors perform at or below a NO_x emission level of 9 ppm, Lakeland will continue to operate with only the Ultra Low NO_x combustors. If the Ultra Low NO_x combustors do not perform at or below 9 ppm, Lakeland will use other technologies to reduce the NO_x emissions. If a conventional SCR is installed, the permitted NO_x emission level is 7.5 ppm.

When firing fuel oil the unit is limited to 42 ppm with steam injection and 15 ppm with the installation of either a hot or conventional SCR. The installation of an SCR is the most costly option. The cost of the SCR has been included in the capital cost for conversion for evaluation purposes.

7.4.2 Title V Operating Permit

Along with the ATC, the unit will be required to obtain an operating permit under Title V of the Clean Air Act. All units at the McIntosh and Larsen sites will be ultimately included in a single Title V permit. Requirements under the Title V permit for McIntosh 5 will require similar emissions control and operations to those required under the ATC and BACT determination.

7.4.3 Title IV Acid Rain Permit

In addition to the construction and operating permit requirements of the Unit, the regulations implementing the Acid Rain provisions of the Clean Air Act Amendments require that electric utility units obtain acid rain permits.

7.4.4 Compliance Strategy

McIntosh 5 will emit very small amounts of sulfur dioxide while running on either natural gas or fuel oil. As an affected unit, McIntosh 5 must have allowances available for emission of sulfur dioxide to comply with its Title IV Acid Rain permit. Lakeland's ATC permit requires a limit of sulfur dioxide emissions from McIntosh 5 of 40 tons per year. The 40-ton per year maximum emissions level minimized permitting requirements for a McIntosh 5. The current operating plan for the McIntosh 5 specifies operation on fuel oil only during emergency situations. Lakeland has identified two different sulfur dioxide emissions compliance strategies. The first and preferred compliance strategy involves re-allocation of excess allowances currently maintained by the City of Lakeland to cover the McIntosh and Larsen plants emissions. Current operation of the McIntosh and Larsen Units result in a combined sulfur dioxide emission rate of approximately 3,358 tons per year, leaving enough allowances to cover operation of McIntosh 5 at baseload. Lakeland currently has 12,809 allowances available. The second possible compliance strategy involves purchasing allowances. Purchasing allowances will be the compliance strategy utilized if, for any reason, re-allocation proves to supply insufficient quantities of allowances.

8.0 Analysis Results and Conclusions

8.1 Economic Evaluation

A four phase economic analysis was conducted to determine Lakeland's optimum capacity expansion plan. The four phases included supply-side evaluations, demand-side evaluations, proposal evaluations, and sensitivity analyses. The results of the supply-side, demand-side, and proposal evaluations analyses are included in this Subsection and discussed in detail. The sensitivity analyses are discussed in Subsection 8.2.

8.1.1 Supply-Side Economic Analysis

8.1.1.1 Methodology. The supply-side evaluations of generating unit alternatives were performed using POWROPT, an optimal generation expansion model. Black & Veatch developed POWROPT as an alternative to other optimization programs. POWROPT has been benchmarked against other optimization programs and has proven to be an effective modeling program. The program operates on an hourly chronological basis and is used to determine a set of optimal capacity expansion plans, simulate the operation of each of these plans, and select the most desirable plan based on cumulative present worth revenue requirements. POWROPT evaluates all combinations of generating unit alternatives and purchase power options while maintaining user-defined reliability criteria. The reserve criterion utilized was a minimum reserve margin of 15 percent. All capacity expansion plans were analyzed over a 20-year period from 1999 to 2018.

After the optimal generation expansion plan was selected using POWROPT, Black & Veatch's POWRPRO detailed chronological production costing program was used to obtain the annual production cost for the expansion plan.

8.1.1.2 Expansion Candidates The expansion candidates for the POWROPT evaluation were taken directly from the screening analysis in Subsection 6.2.1. Table 8-1 summarizes the expansion alternatives considered in the optimization study for supply-side alternatives.

8.1.1.3 Results of the Supply-Side Economic Analysis The economic evaluation was first conducted for a base case scenario of the future, which assumed the base case load forecast, base case fuel price forecast, and minimum reserve margin of 15 percent. The evaluations were based upon the cost and performance characteristics described in detail in Section 6.2 and summarized in Table 8-1. The expansion plan outlined in Table 8-2 represents the least-cost capacity addition plan for Lakeland under

Table 8-1
Summary of Generation Alternatives (1998 $)

Description	Capital Costs	Capacity		O&M Costs		Fuel Type	Full Load Heat Rate[1]	Forced Outage Rate	Planned Maintenance	First Year Available
		Summer	Winter	Variable	Fixed					
	$1,000	kW	kW	$/MWh	$kW-Yr		Btu/kWh	percent	weeks	
Pulverized Coal	268,235	250,000	250,000	2.46	23.18	Coal	10,141	7.0	4.00	2003
Fluidized Bed	251,946	250,000	250,000	1.77	18.75	Coal	10,543	7.0	4.00	2003
PCFB	143,260	238,000	238,000	1.73	27.65	Coal/Pet Coke	8,776	12.0	4.00	2004
7EA 1x1 CC	64,780	109,939	127,538	2.37	3.29	Nat. Gas	7,642	3.7	2.25	2002
7EA 2x1 CC	110,365	222,096	257,217	2.16	2.24	Nat. Gas	7,585	3.0	2.25	2002
501F 1x1 CC	118,169	236,630	268,902	2.30	2.40	Nat. Gas	6,635	4.1	2.25	2002
501G 1x1 CC	165,685	337,507	384,380	1.27	1.13	Nat. Gas	6,249	4.5	2.25	2002
501G conversion[2]	80,500[3]	337,507	384,380	1.27	1.13	Nat. Gas	6,249	4.5	2.25	2002
LM6000 SC	18,499	33,360	42,796	26.92	5.45	Nat. Gas	10,051	2.3	1.00	2001
7EA SC	26,145	72,432	83,767	23.56	3.32	Nat. Gas	11,643	2.1	1.25	2001
501F SC	52,547	156,100	186,500	2.00	5.50	Nat. Gas	10,243	4.1	2.25	2001

(1)At winter conditions.

(2)Performance is provided for combined cycle operation.

(3)Capital cost is for steam side of combined cycle.

Table 8-2
Base Case Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW)	110,129	366,978
2004	McIntosh 4 PCFB (238 MW)	124,516	437,264
2005	McIntosh 2 retired (103 MW)	130,019	503,984
2006		135,595	567,240
2007		142,106	627,507
2008		145,849	683,738
2009		152,890	737,325
2010	LM6000 SC (43 MW)	161,333	788,731
2011		152,663	832,952
2012		159,034	874,831
2013		165,849	914,533
2014		172,878	952,157
2015		180,885	987,944
2016		188,938	1,021,926
2017	LM6000 SC (43 MW)	200,299	1,054,676
2018		209,297	1,085,787

[1]Capacity is stated in winter ratings.

the base case scenario. The expansion plan units are listed in the table according to the first year in which they will serve to meet the winter peak demand. For example: McIntosh 5 simple cycle is listed in the expansion plan for the year 2000, but actually is scheduled for commercial operation on July 10, 1999. Figure 8-1 displays the expansion plan and peak demand with reserves for the planning period.

All units were modeled using the summer and winter capacity ratings in the respective seasons, but are listed in winter ratings because winter capacities and winter peak demand drive Lakeland's reserve margin requirements. Table 8-3 displays the reserve margins for the base case after the construction of the resources identified.

Tables 8-4 through 8-6 provide the top three expansion plans that were runner-ups to the top plan. The plans were ranked based upon the cumulative present worth revenue requirements. These plans were very similar to the base case plan with only minor changes after the conversion of McIntosh 5 from simple cycle to combined cycle. All of the top plans selected the construction of the combined cycle conversion in the year 2002.

8.1.2 Demand-Side Economic Analysis

Lakeland has performed an extensive analysis of demand-side alternatives to determine if any measures are available to delay or mitigate the need for the capacity addition. In the following subsections, the methodology of the analysis and the results of the DSM analysis are discussed.

8.1.2.1 Methodology The City of Lakeland utilized the Florida Integrated Resource Evaluator (FIRE) model to analyze the cost-effectiveness of 66 potential demand-side programs. The FIRE model was originally developed by Florida Power Corporation in 1991, and has been adopted by the Florida Public Service Commission as an effective tool in measuring DSM programs cost-effectiveness. If a DSM program was a cost-effective alternative to the supply-side alternative identified in Section 8.1.2, Lakeland would include the DSM program in the generation plan and reevaluate the supply-side alternatives. As the analysis in the next subsection will indicate, this was not necessary since none of the DSM programs were cost-effective.

8.1.2.2 Florida Integrated Resource Evaluator (FIRE) Results The Florida Integrated Resource Evaluator uses avoided unit costs, DSM program costs, operations and maintenance costs, rebates/incentives, and other input variables to calculate the incremental benefits of a DSM program. These incremental costs are used to perform three cost-effectiveness tests: the Rate Impact Test, the Total Resources Test, and the Participant Test. The DSM programs reviewed are listed in Table 8-7, along with the results of the FIRE analysis. Details of the programs are provided in Section 4.3.

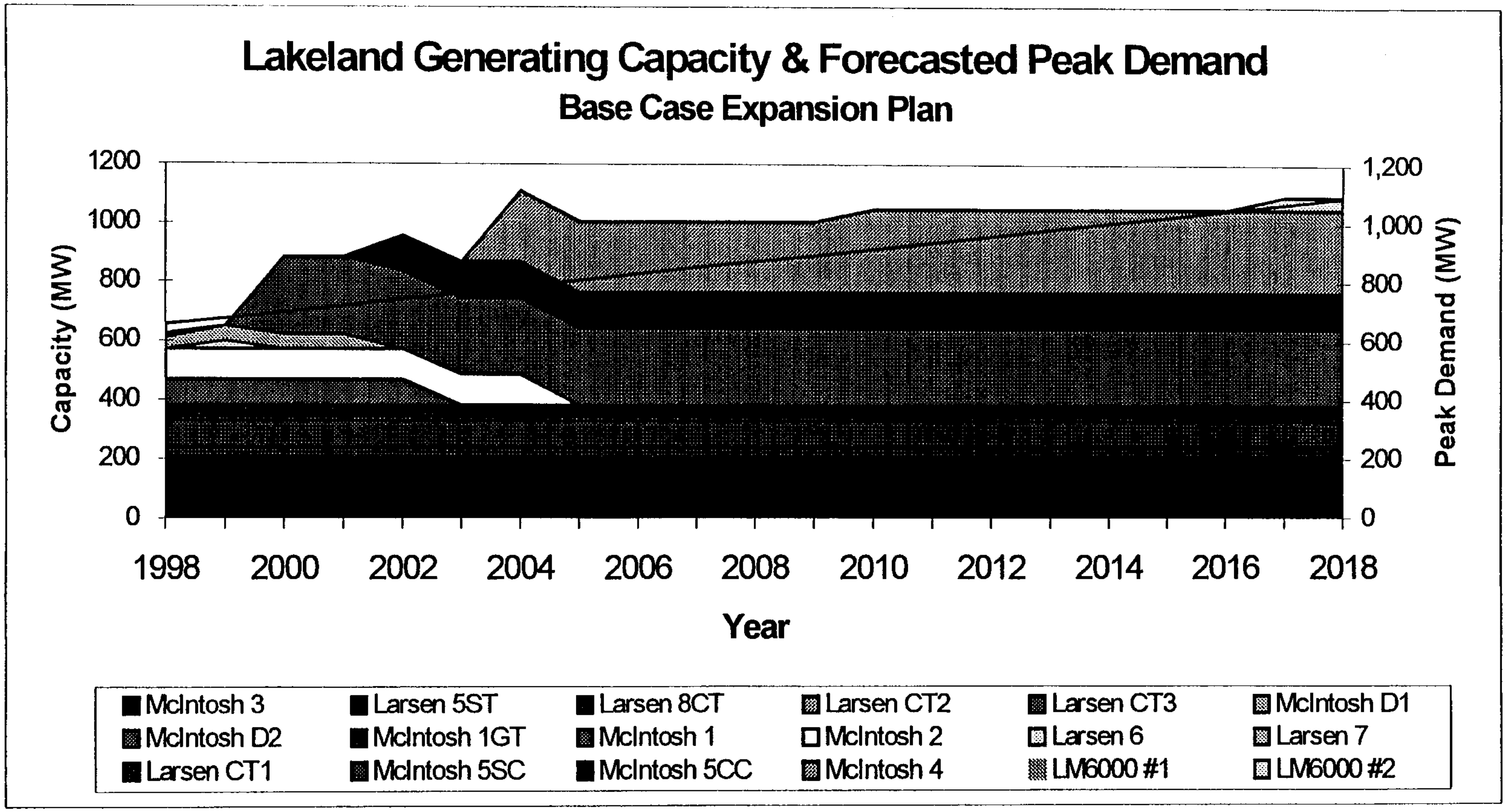

Lakeland Generating Capacity & Forecasted Peak Demand
Base Case Expansion Plan
Capacity (MW)
0
200
400
600
800
1000
1200
Peak Demand (MW)
0
200
400
600
800
1,000
1,200
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
Year
McIntosh 3
Larsen 5ST
Larsen 8CT
Larsen CT2
Larsen CT3
McIntosh D1
McIntosh D2
McIntosh 1GT
McIntosh 1
McIntosh 2
Larsen 6
Larsen 7
Larsen CT1
McIntosh 5SC
McIntosh 5CC
McIntosh 4
LM6000 #1
LM6000 #2

Table 8-3
Projected Reliability Levels - Winter / Base Case with Expansion Plan Identified in Table 8-2

Year	Net Generating Capacity	Net System Purchases	Net System Sales	Net System Capacity	System Peak Demand: Before Interruptible & Load Management	System Peak Demand: After Interruptible & Load Management	Reserve Margin: Before Interruptible & Load Management	Reserve Margin: After Interruptible & Load Management	Excess/ (Deficit) to Maintain 15%: Before Interruptible & Load Management	Excess/ (Deficit) to Maintain 15%: After Interruptible & Load Management
1998/99	649	20	25 (1)	669	593	588	12.82	13.78	(13)	(7)
1999/00	886	0	25	861	612	607	40.69	41.85	157	163
2000/01	886	0	75	811	631	626	28.53	29.55	85	91
2001/02	956	0	100	856	650	645	31.69	32.71	109	114
2002/03	869	0	100	769	668	663	15.12	15.99	1	7
2003/04	1107	0	100	1007	687	682	46.58	47.65	217	223
2004/05	1004	0	100	904	706	701	28.05	28.96	92	98
2005/06	1004	0	100	904	725	720	24.69	25.56	70	76
2006/07	1004	0	100	904	744	739	21.51	22.33	48	54
2007/08	1004	0	100	904	761	756	18.79	19.58	29	35
2008/09	1004	0	100	904	780	775	15.90	16.65	7	13
2009/10	1047	0	100	947	799	794	18.52	19.27	28	34
2010/11	1047	0	0	1047	818	813	28.00	28.78	106	112
2011/12	1047	0	0	1047	837	832	25.09	25.84	84	90
2012/13	1047	0	0	1047	856	851	22.31	23.03	63	68
2013/14	1047	0	0	1047	875	870	19.66	20.34	41	47
2014/15	1047	0	0	1047	894	889	17.11	17.77	19	25
2015/16	1090	0	0	1090	912	907	19.52	20.18	41	47
2016/17	1090	0	0	1090	931	926	17.08	17.71	19	25
2017/18	1133	0	0	1133	951	946	19.14	19.77	39	45

(1) Sale of 25MW to TEA occurs during the winter period but is after the peak demand for the winter season.

Table 8-4
Base Case Expansion Plan – Runner Up #1

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW)	110,129	366,978
2004	McIntosh 4 PCFB (238 MW)	124,516	437,264
2005	McIntosh 2 retired (103 MW)	130,019	503,984
2006		135,595	567,240
2007		142,106	627,507
2008		145,849	683,738
2009		152,890	737,325
2010	LM6000 SC (43 MW)	161,333	788,731
2011		152,663	832,952
2012		159,034	874,831
2013		165,849	914,533
2014		172,878	952,157
2015		180,885	987,944
2016		188,938	1,021,926
2017	GE 7EA SC (84 MW)	202,619	1,055,056
2018		212,157	1,086,592

Table 8-5 Base Case Expansion Plan – Runner Up #2			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW)	110,129	366,978
2004	McIntosh 4 PCFB (238 MW)	124,516	437,264
2005	McIntosh 2 retired (103 MW)	130,019	503,984
2006		135,595	567,240
2007		142,106	627,507
2008		145,849	683,738
2009		152,890	737,325
2010	LM6000 SC (43 MW)	161,333	788,731
2011		152,663	832,952
2012		159,034	874,831
2013		165,849	914,533
2014		172,878	952,157
2015		180,885	987,944
2016		188,938	1,021,926
2017	GE 7EA 1x1 CC (128 MW)	206,782	1,055,736
2018		215,653	1,087,792

Table 8-6 Base Case Expansion Plan – Runner Up #3			
Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW)	110,129	366,978
2004	McIntosh 4 PCFB (238 MW)	124,516	437,264
2005	McIntosh 2 retired (103 MW)	130,019	503,984
2006		135,595	567,240
2007		142,106	627,507
2008		145,849	683,738
2009		152,890	737,325
2010	LM6000 SC (43 MW)	161,333	788,731
2011		152,663	832,952
2012		159,034	874,831
2013		165,849	914,533
2014		172,878	952,157
2015		180,885	987,944
2016		188,938	1,021,926
2017	West. 501F SC (186 MW)	207,005	1,055,773
2018		216,123	1,087,898

Table 8-7
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
New Construction				
RSC-1	High Efficiency Air Source Heat Pump	0.37	0.22	0.49
RSC-8A	Load Control for Residential Heat	0.00	0.01	7.13
RSC-8B	Load Control for Residential Heat	0.01	0.01	7.18
RSC-21A	High Efficiency Central AC	0.26	0.17	0.52
RSC-26A	DLC of Central AC	-0.30	-0.65	1.00
RSC-26B	DLC of Central AC	-0.30	-0.65	1.00
WH-10	DLC of Electric Water Heater	-0.23	-0.48	1.00
PP-3	DLC of Pool Pumps	-0.70	-0.71	1.00
SC-D-1	High Efficiency Chiller	0.71	10.67	23.72
SC-D-2	High Efficiency Chiller w/ASD	0.73	1.73	2.45
V-D-8	High Efficiency Motors - Chiller	0.43	1.57	7.64
V-D-9	High Efficiency Motors - DX AC	0.43	1.57	7.68
L-D-25	Compact Fluorescent Lamps (15/18/27W)	0.71	0.57	0.00
L-D-26	Two Lamp Compact Fluorescent (18W)	0.71	0.57	0.00
W-D-13	Heat Recovery Water Heater	0.59	1.36	2.83
C-D-19	Energy Efficient Electric Fryers	-0.07	-0.10	3.63
Existing Construction				
RSC-1	High Efficiency Air Source Heat Pump	0.37	0.22	0.48
RSC-5A	Reduced Duct Leakage	0.40	0.57	1.86

Table 8-7 (Continued)
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
RSC-5B	Reduced Duct Leakage	0.40	0.57	1.86
RSC-8A	Load Control for Residential Heat	0.01	0.01	7.14
RSC-8B	Load Control for Residential Heat	0.01	0.01	7.14
RSC-10A	Ceiling Insulation (R0-R19)	0.44	0.50	1.20
RSC-10B	Ceiling Insulation (R0-R19)	0.42	0.45	1.11
RSC-11A	Ceiling Insulation (R11-R30)	0.34	0.25	0.57
RSC-11B	Ceiling Insulation (R11-R30)	0.26	0.17	0.43
RSC-17A	Low Emissivity	0.06	0.02	0.26
RSC-21A	High Efficiency Central AC	0.32	0.24	0.63
RSC-24A	High Efficiency Room AC	-0.06	-0.05	0.77
RSC-26A	DLC of Central AC	-0.38	-1.35	1.00
RSC-26B	DLC of Central AC	-0.11	-0.26	1.00
WH-7	DHW Pipe Insulation	0.05	0.06	1.00
WH-10	DLC of Electric Water Heater	-0.23	-0.48	1.00
PP-1	High Efficiency Pool Pumps	0.27	0.37	3.92
PP-3	DLC of Pool Pumps	-0.67	-0.68	1.00
SC-D-1	High Efficiency Chiller	0.74	10.57	22.78
SC-D-2	High Efficiency Chiller w/ASD	0.74	1.71	2.39
SC-D-4	High Efficiency Room AC Units	0.84	9.89	13.17
SC-D-8	2-Speed Motor for Cooling Tower	0.01	0.11	44.70
SC-D-9	Speed Control for Cooling Tower	0.74	2.23	4.38
SC-D-19	Roof Insulation - DX AC	0.18	0.54	4.00
SC-D-22	Window Film - Chiller	0.63	2.38	4.34
SC-D-23	Window Film - DX AC	0.49	1.36	3.16
V-D-1	Leak Free Ducts - DX AC	0.57	1.73	3.84

Table 8-7 (Continued)
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
V-D-8	High Efficiency Motors - Chillers	0.60	1.59	5.22
V-D-9	High Efficiency Motors - DX AC	0.60	1.58	5.24
V-D-10	Separate Makeup Air/Exhaust Hoods - Chiller	0.55	0.03	0.05
V-D-11	Separate Makeup Air/Exhaust Hoods - DX AC	0.43	0.02	0.03
L-D-1	4' - 34W Flour. Lamps/Hybrid Ballasts (#1)	0.70	3.00	0.02
L-D-3	4' - 34W Flour. Lamps/Electronic Ballasts (#1)	0.70	2.42	0.02
L-D-5	8' - 60W Flour. Lamps/Electronic Ballasts (#1)	0.71	2.32	0.01
L-D-7	T8 Lamps/Electronic Ballasts (#1)	0.69	1.77	0.01
L-D-9	Refl/Delamp: Install 4' - 40W Flour. Lamps/ EE Ball	0.71	4.21	0.07
L-D-10	Refl/Delamp: Install 4' - 34 and 40W Flour. Lamps/EE	0.71	4.02	0.05
L-D-11	Refl/Delamp: Install 8' - 75W Flour. Lamps/EE Ball	0.71	3.42	0.04
L-D-12	Refl/Delamp: Install 8' - 60W Flour. Lamps/ EE Ball	0.71	3.29	0.03
L-D-21	High Pressure Sodium (70/100/150/250W)	0.71	0.95	0.00
L-D-23	High Pressure Sodium (35W)	0.71	0.35	0.00
L-D-25	Compact Fluorescent Lamps (15/18/27W)	0.71	0.53	0.00
L-D-26	Two Lamp Compact Fluorescent (18W)	0.73	0.26	0.00

Table 8-7 (Continued)
FIRE Results

DSM Program SRC Code	DSM Program Description	Test		
		Rate Impact	Total Resource Cost	Participant Costs
R-D-4	Multiplex: Air-Cooled/Ambient and Mechanical Sub	0.81	1.42	0.00
R-D-5	Multiplex: Air-Cooled/External Liquid Suction HX	0.76	1.64	0.00
W-D-13	Heat Recovery Water Heater	0.59	1.36	2.84
W-D-14	DHW Heater Insulation	0.43	0.96	25.67
W-D-15	DHW Heat Trap	0.53	1.8	102.69
W-D-16	Low Flow Variable Flow Showerhead	0.51	2.52	212.84
C-D-19	Energy Efficient Electric Fryers	-0.08	-0.11	3.63

The DSM measures correlate to the SRC codes in Table 8-7 are based on the Electricity Conservation and Energy Efficiency in Florida study prepared by Synergic Resources Corporation for the Florida Energy Office.

Based on the FIRE results, there are no DSM measures that are cost-effective alternatives based upon the Rate Impact Measure (RIM) to the self-build option identified in the supply-side economic analysis. The RIM method provides a measure by which Lakeland can see the total impact a DSM alternative might have on rates for their system. This allows Lakeland to view the overall effect of DSM alternative.

8.1.3 Power Supply Bid Economic Evaluations

The IFP proposals identified from the Need for Power Application were evaluated against the least-cost expansion plan identified through the economic analysis in Sections 8.1.2 and 8.1.3. The evaluation consisted of a detailed 20-year cumulative present worth production cost evaluation using the POWROPT optimization model and POWRPRO production model for each proposal. The proposals were then compared against the self-build alternative on a 20-year cumulative present worth basis. The bids received were considered confidential and proprietary, thus details of the economics are not provided, but Table 8-8 provides a summary of the results of the economic analysis.

Table 8-8 Rank of the Power Supply Proposals versus Self-Build Option		
Rank	Bidder Name	Cumulative Present Worth Difference ($1,000)
1	Lakeland Self-Build Option	--
2	Tenaska Energy Partners	21,073
3	Enron Energy	21,600
4	Progress Energy Corporation	30,891
5	Tarpon Power Partners	31,903
6	Panda Energy International	38,220
7	Constellation Power Development	38,926
8	Florida Power Corporation	45,355
9	CRSS Inc.	49,848
10	Enpower Incorporated	52,536
11	LG&E Power	74,031
12	Southern Wholesale Energy	106,735
13	Duke Energy	145,580
14	PECO Energy Company	NA – proposal did not meet requirements of IFP.

8.1.3.1 Evaluation Methodology Evaluations of the power supply bids received from IFP # 7083 were performed using the POWOPT and POWRPRO production cost models. POWOPT was used to determine the optimal expansion plan using generating unit alternatives from the screening analysis in Subsection 6.2.1 where the bids did not provide adequate capacity for Lakeland's system throughout the 20 year planning period. Detailed annual costs for the expansion plans were obtained using the POWRPRO chronological production cost model.

8.1.3.2 Power Supply Proposals All proposals received were modeled in the POWRPRO production cost model, except for the proposal from PECO Energy Company which called for Lakeland to build a unit and PECO Energy Company would buy the excess power. The PECO Energy Company proposal did not provide any pricing and therefore could not be modeled. Furthermore, it represented a self-build alternative, which was counter to the purpose of the IFP. While several bids did not meet certain criteria of the IFP, they were considered in the economic evaluation.

8.1.3.3 Results of the Power Supply Bid. Bids were modeled based upon Lakeland's existing generating units, base case load forecast, 15 percent minimum reserve margin, and the bidders proposal. The proposals are ranked in Table 8-8 in ascending order based on projected cumulative present worth revenue requirements over the 20-year period.

8.2 Sensitivity Analysis

Lakeland performed several sensitivity analyses to measure the impact of important assumptions on the least cost plan identified in Section 8.1. The sensitivity analyses are presented in Subsections 8.2.1 through 8.2.10, which include the following:

- High load and energy growth.
- Low load and energy growth.
- Minimum reserve margin increased to 20 percent.
- High fuel price escalation.
- Low fuel price escalation.
- Constant differential between oil/gas and coal prices over the planning horizon.
- Higher discount rate sensitivity.
- Lower discount rate sensitivity.
- Capital cost of the McIntosh combined cycle conversion is increased until it is not cost-effective.
- Two sensitivity cases in which a Westinghouse 501F 1x1 combined cycle unit or a Westinghouse 501F simple cycle unit is installed instead of converting McIntosh Unit 5 to combined cycle in 2002.

For each sensitivity analysis, the least cost plan over the planning horizon is identified. The sensitivity analyses were performed over the 20-year planning period used in the base case economic evaluation, with a projection of annual costs and cumulative present worth costs. All capacities listed in the expansion plan summary tables are the winter ratings of the units. The winter capacity is listed because reserve margins are driven by the winter peak demand. The modeling of the units applied both summer and winter ratings of the units in their respective seasons. As demonstrated in the sensitivity analyses, and the base expansion plans, the conversion of McIntosh 5 from simple cycle to combined cycle is the best resource addition for Lakeland customers.

8.2.1 High Load and Energy Growth

The high load and energy growth sensitivity provides insight into the effect of resource decisions made in an environment where load and energy growth is greater than the expected forecast. The high load and energy growth requires more generation to cover higher energy and demand levels, thus the increase in supply costs and greater cumulative present worth revenue requirements. The high load and energy growth sensitivity is based upon the high load and energy growth forecast presented in Subsection 3.6.1. Table 6-4 indicates the need for capacity based upon the high load and energy forecast.

As indicated in Table 6-4, the need for capacity to maintain a 15 percent reserve margin occurs in 1998/99. The generating alternatives would not be available to meet this construction time frame, therefore a purchase was assumed to fulfill load until the alternatives were available in 2001. Table 8-9 displays the results of the economic evaluation for the least cost expansion plan for the high load and energy growth sensitivity.

8.2.2 Low Load and Energy Growth

The low load and energy growth sensitivity provides analysis insight into the effect of resource decisions made in an environment where load and energy growth is less than the expected forecast. The low load and energy growth requires less generation, thus the reduced cumulative present worth revenue requirements and resource additions. Table 6-5 indicates the need for capacity based upon the low load and energy forecast. Table 8-10 displays the results of the economic evaluation for the least cost expansion plan for the low load and energy growth sensitivity. With the lower load and energy projections, capacity is not required until 2003/04. The conversion of McIntosh 5 to combined cycle in 2002 results in lower costs than delaying the conversion until 2004.

8.2.3 Minimum Reserve Margin Increased to 20 Percent

With the growing concern for reliable electric service for Peninsular Florida and ongoing discussion if the reserve margin should be increased, Lakeland conducted a sensitivity analysis to determine what the least cost expansion plan is if a 20 percent reserve margin was applied to Lakeland's projected load demands. Table 8-11 indicates the need for capacity based upon the 20 percent reserve margin and Table 8-12 displays the results for the least cost expansion plan for the 20 percent reserve margin.

Table 8-9
High Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	110,301	100,274
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	108,265	189,749
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA, LM6000 (43 MW)	116,452	277,241
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	109,804	352,239
2003	McIntosh 1 retired (87MW), GE 7EA SC (87MW)	129,271	432,506
2004	McIntosh 4 PCFB (238 MW)	148,536	516,351
2005	McIntosh 2 retired (103 MW)	155,140	595,962
2006		161,831	671,457
2007		169,644	743,403
2008	Westinghouse 501G CC (384 MW)	193,956	818,181
2009		202,405	889,123
2010		209,751	955,956
2011		199,346	1,013,700
2012		206,992	1,068,207
2013		215,170	1,119,717
2014		223,604	1,168,380
2015		233,213	1,214,520
2016		242,877	1,258,204
2017		253,310	1,299,622
2018		264,108	1,338,880

Capacity listed is for winter ratings.

Table 8-10
Low Load and Energy Growth Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	89,757	81,597
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	86,039	152,704
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	90,990	221,066
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	88,136	281,264
2003	McIntosh 1 retired (87MW)	101,648	344,379
2004		105,962	404,192
2005	McIntosh 2 retired (103 MW), McIntosh 4 PCFB (238 MW)	119,747	465,641
2006		123,703	523,349
2007		128,536	577,861
2008		130,035	627,995
2009		134,576	675,163
2010		138,726	719,366
2011		126,813	756,099
2012		131,190	790,645
2013		135,591	823,105
2014		139,173	853,393
2015		143,989	881,880
2016		148,626	908,612
2017		152,409	933,532
2018		157,131	956,889

Table 8-11
Projected Reliability Levels for 20 Percent Reserve Margin

Year	Net Generating Capacity	Net System Purchases	Net System Sales	Net System Capacity	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 20%	
					Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management	Before Interruptible & Load Management	After Interruptible & Load Management
1998/99	649	20	25 (1)	669	593	588	12.82	13.78	(43)	(37)
1999/00	886	0	25	861	612	607	40.69	41.85	127	133
2000/01	886	0	75	811	631	626	28.53	29.55	54	60
2001/02	836	0	100	736	650	645	13.23	14.11	(44)	(38)
2002/03	749	0	100	649	668	663	(2.84)	(2.11)	(153)	(147)
2003/04	749	0	100	649	687	682	(5.53)	(4.84)	(175)	(169)
2004/05	646	0	100	546	706	701	(22.66)	(22.11)	(301)	(295)
2005/06	646	0	100	546	725	720	(24.69)	(24.17)	(324)	(318)
2006/07	646	0	100	546	744	739	(26.61)	(26.12)	(347)	(341)
2007/08	646	0	100	546	761	756	(28.25)	(27.78)	(367)	(361)
2008/09	646	0	100	546	780	775	(30.00)	(29.55)	(390)	(384)
2009/10	646	0	100	546	799	794	(31.66)	(31.23)	(413)	(407)
2010/11	646	0	0	646	818	813	(21.03)	(20.54)	(336)	(330)
2011/12	646	0	0	646	837	832	(22.82)	(22.36)	(358)	(352)
2012/13	646	0	0	646	856	851	(24.53)	(24.09)	(381)	(375)
2013/14	646	0	0	646	875	870	(26.17)	(25.75)	(404)	(398)
2014/15	646	0	0	646	894	889	(27.74)	(27.33)	(427)	(421)
2015/16	646	0	0	646	912	907	(29.17)	(28.78)	(448)	(442)
2016/17	646	0	0	646	931	926	(30.61)	(30.24)	(471)	(465)
2017/18	646	0	0	646	951	946	(32.07)	(31.71)	(495)	(489)

(1) Sale of 25MW to TEA occurs during the winter period but is after the peak demand for the season.

Table 8-12
20 Percent Reserve Margin Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	111,314	367,714
2004	McIntosh 4 PCFB (238 MW)	126,198	438,950
2005	McIntosh 2 retired (103 MW)	131,649	506,506
2006		137,315	570,565
2007		143,730	631,520
2008		147,360	688,334
2009		154,305	742,417
2010	LM6000 SC (43 MW)	163,029	794,363
2011		154,496	839,115
2012		161,209	881,566
2013		167,927	921,767
2014		174,930	959,837
2015		182,936	996,029
2016		190,817	1,030,350
2017	LM6000 SC (43 MW)	202,320	1,063,430
2018	LM6000 SC (43 MW)	214,037	1,095,246

8.2.4 High Fuel Price Escalation

The high fuel price scenario applies the high fuel price forecast to the generation planning assumptions. The high fuel price forecast is provided in Section 5.4 and detailed in Appendix B. Table 8-13 displays the results of the economic evaluation for the least cost expansion plan for the high fuel price escalation sensitivity.

8.2.5 Low Fuel Price Escalation

The low fuel price scenario applies the low fuel price forecast to the generation planning assumptions. The low fuel price forecast is provided in Section 5.4 and detailed in Appendix B. Table 8-14 displays the results of the economic evaluation for the least cost expansion plan for the low fuel price escalation sensitivity.

8.2.6 Constant Differential Between Coal Versus Natural Gas/Oil

This sensitivity case assumes the differential price between natural gas/oil and coal remains constant over the planning horizon based on the differential in the base year for the fuel forecasts. Table 5-4 displays the constant differential fuel price forecast. The economic evaluation results of the analysis are included in Table 8-15.

8.2.7 Higher Discount Rate (15.0 Percent)

Lakeland looked at a sensitivity case in which the discount rate is increase to 15 percent. Table 8-16 summarizes the economic evaluation for the sensitivity case in which the higher discount rate is assumed.

8.2.8 Lower Discount Rate (5.5 percent)

Lakeland looked at a sensitivity case in which the discount rate was reduced to 5.5 percent, equal to Lakeland's assumed municipal bond rate. Table 8-17 summarizes the economic evaluation for the sensitivity case in which the lower discount rate is assumed.

8.2.9 Capital Cost Increase of Least Cost Alternative

Lakeland analyzed a scenario in which the capital cost of the McIntosh 5 conversion to combined cycle was increased until this alternative was not the least cost alternative. The analysis predicts that the capital cost of the unit could be increased by less than or equal to $35.260 million and still be the most cost-effective option for the Lakeland.

Table 8-13
High Fuel Price Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	95,222	86,566
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	93,717	164,017
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	102,389	240,944
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	98,994	308,558
2003	McIntosh 1 retired (87MW)	118,017	381,838
2004	McIntosh 4 PCFB (238 MW)	131,181	455,886
2005	McIntosh 2 retired (103 MW)	138,471	526,943
2006		147,054	595,545
2007		156,712	662,006
2008		167,154	726,451
2009		178,094	788,872
2010	LM6000 SC (43 MW)	191,580	849,915
2011		182,466	902,769
2012		194,000	953,855
2013		205,671	1,003,091
2014		218,363	1,050,613
2015		233,217	1,096,754
2016		249,142	1,141,564
2017	LM6000 SC (43 MW)	268,240	1,185,424
2018		283,897	1,227,623

Table 8-14
Low Fuel Price Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	93,013	84,558
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	88,580	157,764
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	93,788	228,229
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	89,360	289,263
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	102,999	353,218
2004	McIntosh 4 PCFB (238 MW)	118,185	419,930
2005	McIntosh 2 retired (103 MW)	121,720	482,392
2006		125,320	540,854
2007		129,491	595,771
2008		129,069	645,533
2009		133,358	692,274
2010	LM6000 SC (43 MW)	138,807	736,502
2011		130,133	774,197
2012		133,941	809,468
2013		138,113	842,531
2014		141,922	873,418
2015		145,308	902,166
2016		149,416	929,040
2017	LM6000 SC (43 MW)	156,396	954,612
2018		160,239	978,431

Table 8-15
Constant Differential Between Coal Versus Natural Gas/Oil

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,098	85,543
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	93,235	162,597
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	99,879	237,637
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	97,614	304,309
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	113,904	375,034
2004	McIntosh 4 PCFB (238 MW)	131,797	449,430
2005	McIntosh 2 retired (103 MW)	136,603	519,529
2006		141,872	585,713
2007		148,184	648,558
2008		145,538	704,669
2009		151,699	757,839
2010	LM6000 SC (43 MW)	158,451	808,326
2011		150,304	851,864
2012		156,455	893,063
2013		162,626	931,995
2014		169,054	968,786
2015		176,200	1,003,646
2016		183,253	1,036,606
2017	LM6000 SC (43 MW)	156,396	1,062,178
2018		160,239	1,085,996

Table 8-16
High Discount Rate Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	81,815
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	150,731
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	215,143
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	268,834
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	110,129	323,587
2004	McIntosh 4 PCFB (238 MW)	124,516	377,419
2005	McIntosh 2 retired (103 MW)	130,019	426,297
2006		135,595	470,624
2007		142,106	511,019
2008		145,849	547,071
2009		152,890	579,934
2010	LM6000 SC (43 MW)	161,333	610,088
2011		152,663	634,900
2012		159,034	657,376
2013		165,849	677,758
2014		172,878	696,232
2015		180,885	713,041
2016		188,938	728,308
2017	LM6000 SC (43 MW)	200,299	742,383
2018		209,297	755,171

Table 8-17
Low Discount Rate Sensitivity

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	89,182
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	171,068
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	254,495
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	330,297
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	110,129	414,560
2004	McIntosh 4 PCFB (238 MW)	124,516	504,864
2005	McIntosh 2 retired (103 MW)	130,019	594,244
2006		135,595	682,598
2007		142,106	770,366
2008		145,849	855,751
2009		152,890	940,591
2010	LM6000 SC (43 MW)	161,333	1,025,450
2011		152,663	1,101,561
2012		159,034	1,176,716
2013		165,849	1,251,005
2014		172,878	1,324,406
2015		180,885	1,397,202
2016		188,938	1,469,276
2017	LM6000 SC (43 MW)	200,299	1,541,700
2018		209,297	1,613,432

8.2.10 Conversion Not an Option

Lakeland analyzed scenarios in which the conversion to combined cycle was not an option and they were forced to choose from the other alternatives to meet capacity requirements in the year 2002. Lakeland analyzed two other alternatives to meet the capacity requirements in 2002. The Westinghouse alternatives selected were the 501F simple cycle and the 501F 1x1 combined cycle. The alternatives were selected based on their ability to be in place by 2002 as indicated in Table 8-1. The expansion plan installing the Westinghouse 501F 1x1 combined cycle in 2002 results in $27.7 million in additional costs as indicated in Table 8-18 compared to the base case expansion plan which converts McIntosh 5 to combined cycle. The expansion plan installing the Westinghouse 501F simple cycle in 2002 results in $71.9 million in additional costs as indicated in Table 8-19 compared to the base case expansion plan.

8.3 Transmission

The generating units evaluated can generally be installed at the McIntosh site. 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 10 year planning horizon to meet local load growth needs.

8.4 Strategic Concerns

In selecting a power supply alternative, a utility must consider certain strategic factors, which reflect the utility's long-term ability to provide economical and reliable electric capacity and energy to its consumers. A number of strategic considerations favor the conversion of McIntosh Unit 5 to combined cycle. These include exceptional efficiency, low installation cost on a $/kW basis, low operating costs, domestically produced fuel, existing site which can support the project capacity, electric industry deregulation, and environmental benefits and risks.

Table 8-18
Westinghouse 501F 1x1 Combined Cycle Unit in 2002

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Westinghouse 501F 1x1 CC (269 MW), Larsen 7 retired (50 MW)	102,569	304,514
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	119,772	378,883
2004		113,504	442,954
2005	McIntosh 4 PCFB (238 MW), McIntosh 2 retired (103 MW)	135,392	512,431
2006		141,357	578,375
2007		148,081	641,176
2008		152,040	699,794
2009		159,335	755,640
2010		166,304	808,629
2011		155,624	853,708
2012		163,089	896,655
2013		170,594	937,494
2014		178,089	976,251
2015		186,464	1,013,142
2016		195,340	1,048,275
2017		204,086	1,081,645
2018		214,563	1,113,538

Table 8-19
Westinghouse 501F Simple Cycle Unit in 2002

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	95,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Westinghouse 501F SC (187 MW), Larsen 7 retired (50 MW)	111,905	310,891
2003	McIntosh 1 retired (87MW), LM6000 SC (43 MW)	133,435	393,743
2004		115,791	459,104
2005	McIntosh 4 PCFB (238 MW), McIntosh 2 retired (103 MW)	138,523	530,188
2006		145,396	598,017
2007		153,302	663,032
2008		158,233	724,037
2009		166,518	782,401
2010		174,677	838,059
2011		161,136	884,734
2012		169,506	929,370
2013		178,153	972,018
2014		186,639	1,012,636
2015		196,043	1,051,422
2016		206,249	1,088,518
2017		216,217	1,123,871
2018	LM6000 SC (43 MW)	227,887	1,157,745

8.4.1 Efficiency

Lakeland strives to provide its customers with the lowest rates they can achieve while maintaining sound operating principles and environmentally clean units. The new "G" class combustion turbines represent the best technology available to achieve this goal. With the conversion of the McIntosh Unit 5 from simple cycle to combined cycle, the unit will boast the highest efficiency in the country and provide a very clean burning solution to meet Lakeland load growth. The efficiency of the "G" technology ensures that McIntosh 5 will produce competitively priced generation for many years.

8.4.2 Reliability Need

Lakeland will not be able to maintain the minimum reserve margin if they do not install generation or purchase power for the 2002 time frame. The McIntosh 5 conversion to combined cycle offers the least cost solution for meeting Lakeland's expected load growth and reserve margin requirement of 15 percent.

Lakeland has analyzed millions of potential expansion plans using POWROPT and the conversion of McIntosh 5 from simple cycle to combined cycle proves to be the most cost-effective alternative available to Lakeland. Westinghouse is confident that the unit will be a reliable unit and has provided Lakeland an equivalent availability guarantee of 92 percent.

8.4.3 Least Cost Supply Plan

The complete McIntosh 5 project is the least cost alternative for Lakeland to add new generation. The conversion of the combustion turbine to combined cycle is slightly more costly on a $/kW basis in comparison to other resources additions because the steam portion of a combined cycle unit has a higher $/kW cost than the CT portion. All alternate resource additions that were evaluated were either complete integrated units or purchase arrangements. In a conversion of this type, the steam side of the project requires no fuel to operate the steam unit. With no expenses for fuel, the slightly higher incremental cost of the capital to convert the unit from simple cycle to combined cycle is more than made up for in operational savings.

8.4.4 Deregulation

In a deregulated environment, the 501G combined cycle will be one of the most economical units in the state due to its high efficiency, high availability, and low heat rate. This will ensure competitive generation for Lakeland customers and Florida residents. This will also ensure Lakeland remains a competitive and conscious provider of electric generation for the future and provides low risk of McIntosh 5 becoming a stranded asset if retail access occurs in the state.

8.4.5 Timing

If McIntosh 5 is converted now, Lakeland will experience lower energy costs in the next 5 to 6 years than they would by installing a completely new unit. The better operating characteristics of the converted McIntosh 5 will displace older, more expensive base loaded generation and those savings can be passed along to the consumers. The timing also allows the installation for the ultra low NO_x burners. In the event the ultra low NO_x burners do not provide an effective option to meet environmental compliance, another method of environmental compliance will be used.

8.4.6 Personnel Required

The ability to utilize the existing McIntosh site offers many strategic advantages. The utilization of existing personnel for the operation and maintenance of the converted McIntosh unit, which will result in very low fixed O&M costs. McIntosh Unit 5 will also have the advantage of skilled and trained staff for operation and maintenance.

8.4.7 Fuel Risk

McIntosh Unit 5 will utilize domestic natural gas, which minimizes risks from imported fuels. The unit is also capable of burning both natural gas and No. 2 oil for generation, thus providing Lakeland with fuel diversity in situations in which natural gas supply may be interrupted.

8.4.8 Emission Impacts

The use of the existing site minimizes environmental impacts and reduces the time and effort required for licensing. The low level of emissions with the McIntosh 5 conversion provides assurance from risk of future environmental regulations while reducing emissions within the state through displacement and retirement of other less efficient units. The conversion will also produce capacity and energy for Lakeland and the state while reducing emissions statewide.

8.5 Conclusions and Recommendations

The least-cost expansion plan identified in the Need for Power Application for McIntosh Units and the 1999 Ten-Year Site Plan proves to be a robust method of meeting Lakeland's continued load growth and system requirements. Numerous alternatives, both supply-side and demand-side alternatives were evaluated under numerous forecasts. The least-cost expansion plans under each scenario identify the conversion of McIntosh Unit 5 from simple cycle to combined cycle. Therefore, it is recommended Lakeland pursue the expansion plan identified in Table 8-20.

Table 8-20
Recommended Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
1999	25MW sale to TEA, Larsen 6 retired (27 MW)	94,088	85,534
2000	McIntosh 5 SC (264 MW), 25 MW sale to TEA, 50 MW sale to FMPA	91,141	160,857
2001	100 MW sale to FMPA until 12/15/2010, 25 MW sale to TEA	97,963	234,458
2002	Convert McIntosh 5 to CC (120 MW), Larsen 7 retired (50 MW)	93,905	298,597
2003	McIntosh 1 retired (87MW)	110,129	366,978
2004	McIntosh 4 PCFB (238 MW)	124,516	437,264
2005	McIntosh 2 retired (103 MW)	130,019	503,984
2006		135,595	567,240
2007		142,106	627,507
2008		145,849	683,738
2009		152,890	737,325
2010	LM6000 SC (43 MW)	161,333	788,731
2011		152,663	832,952
2012		159,034	874,831
2013		165,849	914,533
2014		172,878	952,157
2015		180,885	987,944
2016		188,938	1,021,926
2017	LM6000 SC (43 MW)	200,299	1,054,676
2018		209,297	1,085,787

[1]Capacity is stated in winter ratings.

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.

Table 9-1
Schedule 1: Lakeland Electric and Water Utilities Existing Generating Facilities

Plant	Unit No.	Location	Type	Fuel Primary	Fuel Alternate	Commercial In-Service (Month/Year)	Expected Retirement (Month/Year)	Generator Maximum Nameplate (kW)	Net Capability(1) Summer (MW)	Net Capability(1) Winter (MW)	Fuel Transportation Primary	Fuel Transportation Alternate
Charles Larsen	1	16-17/28S/24E	GT	NG	F02	10/62	Sold, 5/98	*11,500*	*10.0*	*14.0*	PL	TK
Memorial	2	Polk County	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
	6		ST	NG	F06	12/59	07/99	25,000	25.0	27.0	PL	TK
	7		ST	NG	F06	02/66	02/01	50,000	50.0(2)	50.0(2)	PL	TK
	8		CT	NG	F02	07/92	Unknown	101,520	73.0	93.0	PL	TK
	5		CW	WH		04/56	Unknown	26,000	29.0	31.0		
Plant Total									197.0	229.0		
C.D. McIntosh,	IC1	4-5/28S/24E	IC	F02	NA	01/70	Unknown	2,500	2.5	2.5	TK	--
Jr.	IC2	Polk County	IC	F02	NA	01/70	Unknown	2,500	2.5	2.5	TK	--
	1GT		GT	NG	F02	05/73	Unknown	26,640	17.0	20.0	PL	TK
	1		ST	NG	F06	02/71	10/02	103,000	87.0	87.0	PL	TK
	2		ST	NG	F06	06/76	7/04	126,000	103.0	103.0	PL	TK
	3		ST	BIT	NG	09/82	Unknown	363,870	205.0(2)	205.0(2)	RR	TK
Plant Total									417.0	420.0		
System Total									614.0	649.0		

(1)Net normal.
(2)Capacity after Boiler Repairs (Capacity Before the TEA sale).
(3)Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.

Source: Lakeland Power Production Unit Rating Group 7/30/98

Table 9-2
Schedule 2.0: Forecast of Total Accounts and Sales For Lakeland

		Rural and Residential			Commercial		
Fiscal Year	Population	GWh	Average No. of Customers	kWh/Cust	GWh	Average No. of Customers	kWh/Cust
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
1998	215,349	1,266	87,099	14,535	660	10,576	62,405
Forecast							
1999	222,329	1,263	87,656	14,409	639	10,027	63,728
2000	226,708	1,300	89,091	14,592	655	10,122	64,711
2001	230,494	1,337	90,408	14,789	670	10,218	65,571
2002	234,280	1,374	91,727	14,979	686	10,314	66,512
2003	238,066	1,411	93,047	15,164	702	10,411	67,429
2004	241,852	1,448	94,369	15,344	717	10,508	68,234
2005	245,638	1,485	95,693	15,518	732	10,607	69,011
2006	249,298	1,523	96,997	15,702	747	10,704	69,787
2007	252,958	1,561	98,302	15,880	762	10,802	70,542
2008	256,618	1,600	99,609	16,063	778	10,902	71,363

Table 9-2 (Continued)
Schedule 2.0: Forecast of Total Accounts and Sales for Lakeland

Fiscal Year	Industrial GWh	Industrial Average No. of Cust.	Industrial kWh/Cust	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh	Utility Use and Losses GWh	NEL GWh
1989	331	41	8,073,171	11	59	1,812	148	1,960
1990	346	44	7,863,636	8	62	1,889	108	1,997
1991	344	45	7,644,444	11	61	1,905	138	2,043
1992	356	47	7,574,468	13	65	1,947	143	2,090
1993	381	51	7,470,588	13	68	2,030	155	2,185
1994	400	51	7,843,137	14	69	2,137	146	2,283
1995	427	51	8,372,549	15	74	2,279	146	2,425
1996	589	59	9,983,051	15	78	2,472	102	2,574
1997	459	61	7,524,590	16	78	2,335	115	2,450
1998	497	68	7,308,824	17	32	2,472	120	2,592
Forecast								
1999	494	65	7,600,000	17	85	2,497	140	2,637
2000	511	67	7,626,866	18	88	2,572	143	2,715
2001	527	68	7,750,000	18	91	2,644	146	2,790
2002	543	70	7,757,143	19	94	2,716	149	2,865
2003	559	72	7,763,889	19	97	2,788	152	2,940
2004	575	73	7,876,712	20	100	2,860	155	3,015
2005	591	75	7,880,000	21	103	2,932	158	3,090
2006	607	76	7,986,842	21	106	3,005	161	3,166
2007	624	78	8,000,000	22	109	3,079	164	3,243
2008	640	79	8,101,266	22	112	3,152	167	3,319

Table 9-3
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
1989	406	0	406	0	0	Included in (4)	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
1998	535	0	535	0	0		535
Forecast							
1999	537	0	515	5	22	Included in (4)	510
2000	551	0	529	5	22		524
2001	563	0	540	5	23		535
2002	576	0	552	5	23		548
2003	589	0	565	5	24		560
2004	601	0	576	5	25		571
2005	614	0	589	5	25		584
2006	626	0	600	6	26		594
2007	639	0	613	6	26		607
2008	645	0	624	6	27		618

Table 9-4
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
1989	530	0	530	0	22	Included in (4)	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	40		578
1996	655	0	655	0	45		610
1997	552	0	552	0	0		552
1998	611	0	611	0	0		611
Forecast							
1999	645	0	588	5	52	Included in (4)	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
2008	825	0	762	6	63		756

Table 9-5
Schedule 3.3: History and Forecast of Net Energy for Load – Base Case (GWh)

(1)	(2)	(3)	(5)	(6)	(7)	(8)	(9)
Year	Total	Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load factor %
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
1998	2,713	1	2,712	0	120	2,592	48.4
Forecast							
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
2008	3,506	2	3,504	0	167	3,337	50.4

Table 9-6
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 1998		Forecast 1999		Forecast 2000	
Month	Peak Demand [1] (MW)	Net Energy For load (GWh)	Peak Demand[2] (MW)	Net Energy For load (GWh)	Peak Demand[2] (MW)	Net Energy For load (GWh)
January	420	190	593	226	612	232
February	454	175	554	194	571	200
March	476	193	476	198	491	203
April	406	185	416	190	428	196
May	483	222	471	224	483	230
June	535	264	506	243	520	250
July	519	258	512	255	526	262
August	526	267	515	259	529	267
September	482	232	506	243	519	250
October	485	225	436	215	446	221
November	384	185	451	194	466	199
December	413	194	546	216	564	222
Total		2,592		2,655		2,732

(1) 1998 Actual Demand served all Interruptible Load.
(2) Forecasted Peak Demands are shown before Interruptible Load.

Table 9-7
Schedule 5: Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel Requirements	Type	Units	1998 - Actual	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Nuclear		1000 MBtu	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal (*)		1000 Ton	385	564	445	565	446	330	767	1111	1060	1018	1218
(3)	Residual	Total	1000 BBL	184	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	184	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)	Distillate	Total	1000 BBL	5	1	1	2	2	2	2	1	1	2	2
(8)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	1000 BBL	3	0	0	0	0	0	0	0	0	0	0
(10)		CT	1000 BBL	2	1	1	2	2	2	2	1	1	2	2
(12)	Natural Gas	Total	1000 MCF	5,090	11,333	15,313	16,691	19,960	17,283	14,839	12,906	13,759	14,157	12,779
(13)		Steam	1000 MCF	2,042	3,508	4,304	4,811	4,066	1,060	715	487	594	262	0
(14)		CC	1000 MCF	2,962	5,573	5,993	5,786	15,799	16,133	14,054	12,386	13,106	13,821	12,655
(15)		CT	1000 MCF	86	2252	5016	6094	95	90	70	33	59	74	124
(16)	Other		1000 MBtu	0	0	0	0	0	0	0	0	0	0	0

(*) Includes petroleum coke and RDF.

Table 9-8
Schedule 6.1: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	Fuel	Type	Units	1998 - Actual	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		GWh	731	18	12	-341	-412	-397	-407	-452	-436	-411	-400
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal (*)		GWh	1,126	1,445	1,142	1,448	1,123	796	1,311	1,754	1,678	1,635	1,910
(4)	Residual	Total	GWh	106	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWh	106	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)	Distillate	Total	GWh	2	0	0	0	0	0	0	0	0	0	0
(9)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	GWh	1	0	0	0	0	0	0	0	0	0	0
(11)		CT	GWh	1	0	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Total	GWh	627	1,192	1,578	1,699	2,170	2,557	2,127	1,806	1,941	2,035	1,826
(13)		Steam	GWh	321	344	419	474	393	104	66	45	56	25	0
(14)		CC	GWh	301	633	682	660	1,770	2,447	2,056	1,759	1,881	2,005	1,818
(15)		CT	GWh	5	215	477	565	7	6	5	2	4	5	8
(16)	Other	Total	GWh	0	0	0	0	0	0	0	0	0	0	0
(17)	Net Energy For Load		GWh	2,592	2,655	2,732	2,807	2,882	2,957	3,032	3,108	3,184	3,260	3,337

(*) Includes petroleum coke and RDF.

Table 9-9
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	1998 - Actual	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
(1)	Annual Firm Interchange		GWh	28%	1%	0%	-12%	-14%	-13%	-13%	-15%	-14%	-13%	-12%
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal (*)		GWh	43%	54%	42%	52%	39%	27%	43%	56%	53%	50%	57%
(4)	Residual	Total	GWh	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(5)		Steam	GWh	4%	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)	Distillate	Total	GWh	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)		Steam	GWh	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(10)		CC	GWh	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		CT	GWh	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(12)	Natural Gas	Total	GWh	24%	45%	58%	61%	75%	86%	70%	58%	61%	62%	55%
(13)		Steam	GWh	12%	13%	15%	17%	14%	4%	2%	1%	2%	1%	0%
(14)		CC	GWh	12%	24%	25%	24%	61%	83%	68%	57%	59%	62%	54%
(15)		CT	GWh	0%	8%	17%	20%	0%	0%	0%	0%	0%	0%	0%
(16)	Other	Total	GWh	0	0	0	0	0	0	0	0	0	0	0
(17)	Net Energy For Load		GWh	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

(*) Includes petroleum coke and RDF.

Table 9-10
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	%
1999	797	0	25	0	772	493	279	57%	0	279	57%
2000	797	0	25	0	772	507	265	52%	0	265	52%
2001	747	0	100	0	647	517	130	25%	0	130	25%
2002	867	0	100	0	767	530	237	45%	0	237	45%
2003	780	0	100	0	680	541	139	26%	0	139	26%
2004	915	0	100	0	815	551	264	48%	0	264	48%
2005	915	0	100	0	815	564	251	45%	0	251	45%
2006	915	0	100	0	815	574	241	42%	0	241	42%
2007	915	0	100	0	815	587	228	39%	0	228	39%
2008	915	0	100	0	815	597	218	37%	0	218	37%

Table 9-11

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	%
1999	649	20	25 (1)	0	669	588	81	14%	0	81	14%
2000	886	0	25	0	861	607	254	42%	0	254	42%
2001	886	0	75	0	811	626	185	30%	0	185	30%
2002	956	0	100	0	856	645	211	33%	0	211	33%
2003	869	0	100	0	769	663	106	16%	0	106	16%
2004	1107	0	100	0	1007	682	325	48%	0	325	48%
2005	1004	0	100	0	904	701	203	29%	0	203	29%
2006	1004	0	100	0	904	720	184	26%	0	184	26%
2007	1004	0	100	0	904	739	165	22%	0	165	22%
2008	1004	0	100	0	904	756	148	20%	0	148	20%

(1) Sale of 25MW to TEA occurs during the winter period but is after the peak demand for the season.

Table 9-12
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			Sold, 06/98	11,500	(10.0)	(14.0)	Retired
	6	Polk County	ST	NG	FO6	PL	TK			07/99	25,000	(25.0)	(27.0)	Planned
	7	Polk County	ST	NG	FO6	PL	TK			03/01	50,000	(50.0)	(50.0)	Planned
C.D. McIntosh	1	Polk County	ST	NG	FO6	PL	TK			10/02	103,000	(87.0)	(87.0)	Planned
	2	Polk County	ST	NG	FO6	PL	TK			07/04	126,000	(113.0)	(113.0)	Planned
C.D. McIntosh	501G	Polk County	CT	NG	FO6	PL	TK	6/98	07/99		249,000	217	264	Under Construction, more than 50% completed
	501G	Polk County	ST	WH				6/00	01/02		120,000	120	120	Planned
	DOE PCFB	Polk County	ST	Coal	PC	RR	TK		01/04		238,000	238	238	Planned

Table 9-13
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	217
(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:	07/1999
(9)	Fuel	
(10)	Primary	Natural Gas
(11)	Alternate	FO2
(12)	Air Pollution Control Strategy:	Low NOx burners
(13)	Cooling Method:	N/A
(14)	Total Site Area:	3.5 acres
(15)	Construction Status:	Under Construction
(16)	Certification Status:	N/A
(17)	Status with Federal Agencies:	Permits Obtained
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	4.38 percent
(20)	Forced Outage Factor (FOF):	4.5 percent
(21)	Equivalent Availability Factor (EAF):	91.2 percent
(22)	Resulting Capacity Factor (%):	30.0 percent
(23)	Average Net Operating Heat Rate (ANOHR):	9,805 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25
(26)	Total Installed Cost (In-Service year $/kW):	212.9
(27)	Direct Construction Cost ($/kW):	212.9
(28)	AFUDC Amount ($/kW):	0
(29)	Escalation ($/kW):	-
(30)	Fixed O&M ($/kW-yr):	1.004
(31)	Variable O&M ($/MWh):	3.438

Table 9-14
Schedule 9.2: Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Westinghouse 501G, McIntosh Unit 5 ST
(2)	Capacity:	
(3)	Summer MW	120
(4)	Winter MW	120
(5)	Technology Type:	Combined Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	06/2000
(8)	Commercial In-Service date:	01/2002
(9)	Fuel	
(10)	Primary	Waste Heat
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Ultra Low NO_x burners
(13)	Cooling Method:	Mechanical Cooling Tower
(14)	Total Site Area:	9.5 acres
(15)	Construction Status:	Planned
(16)	Certification Status:	Need for Power Application Pending, Site Certification Application to be field in April
(17)	Status with Federal Agencies:	Permits Pending
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	4.38 percent
(20)	Forced Outage Factor (FOF):	4.5 percent
(21)	Equivalent Availability Factor (EAF):	91.2 percent
(22)	Resulting Capacity Factor (%):	91.6 percent
(23)	Average Net Operating Heat Rate (ANOHR):	6,523 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25
(26)	Total Installed Cost (In-Service year $/kW):	670.83
(27)	Direct Construction Cost ($/kW):	670.83
(28)	AFUDC Amount ($/kW):	0
(29)	Escalation ($/kW):	-
(30)	Fixed O&M ($/kW-yr):	1.133
(31)	Variable O&M ($/MWh):	1.266

Table 9-15
Schedule 9.3: Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	McIntosh Unit 4 PCFB
(2)	Capacity:	
(3)	Summer MW	238
(4)	Winter MW	238
(5)	Technology Type:	Pulverized Circulating Fluidized Bed (PCFB)
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	09/2001
(8)	Commercial In-Service date:	01/2004
(9)	Fuel	
(10)	Primary	Coal
(11)	Alternate	Pet. Coke
(12)	Air Pollution Control Strategy:	Unknown
(13)	Cooling Method:	Mechanical Cooling Tower
(14)	Total Site Area:	
(15)	Construction Status:	Planned
(16)	Certification Status:	Planned
(17)	Status with Federal Agencies:	Planned
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	7.69 percent
(20)	Forced Outage Factor (FOF):	12.0 percent
(21)	Equivalent Availability Factor (EAF):	74.2 percent
(22)	Resulting Capacity Factor (%):	74.2 percent
(23)	Average Net Operating Heat Rate (ANOHR):	8,776 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25
(26)	Total Installed Cost (In-Service year $/kW):	664
(27)	Direct Construction Cost ($/kW):	664
(28)	AFUDC Amount ($/kW):	-
(29)	Escalation ($/kW):	62.65
(30)	Fixed O&M ($/kW-yr):	22.61
(31)	Variable O&M ($/MWh):	1.73

Table 9-16
Schedule 10: Status Report and Specifications of Proposed Directly Associated Transmission

(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. Transmission changes limited to interconnecting new units into existing substation facilities and transmission upgrades to support load growth and system reliability.

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

TABLE OF CONTENTS

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).

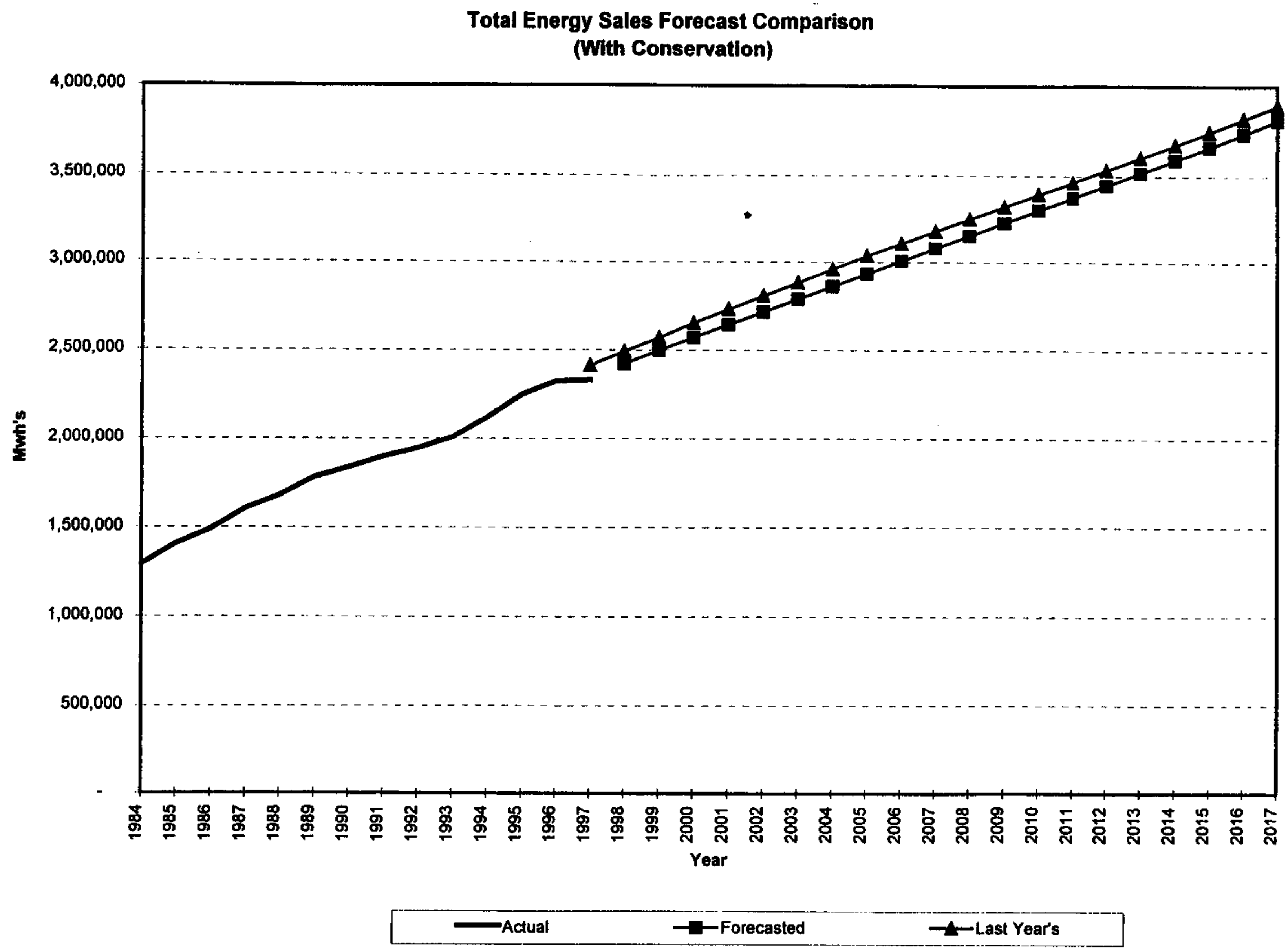
The remainder of this document will explain the methodology used for each individual model (both inside and outside city limits) used to generate the forecast. The supporting statistics, tables, and graphs can be found on the network under Z:\Forecast|1997L&E.xls

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)
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2,000,000
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Mwh's
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Year
Actual
Forecasted
Last Year's

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%**	

Total Account Forecast Comparison

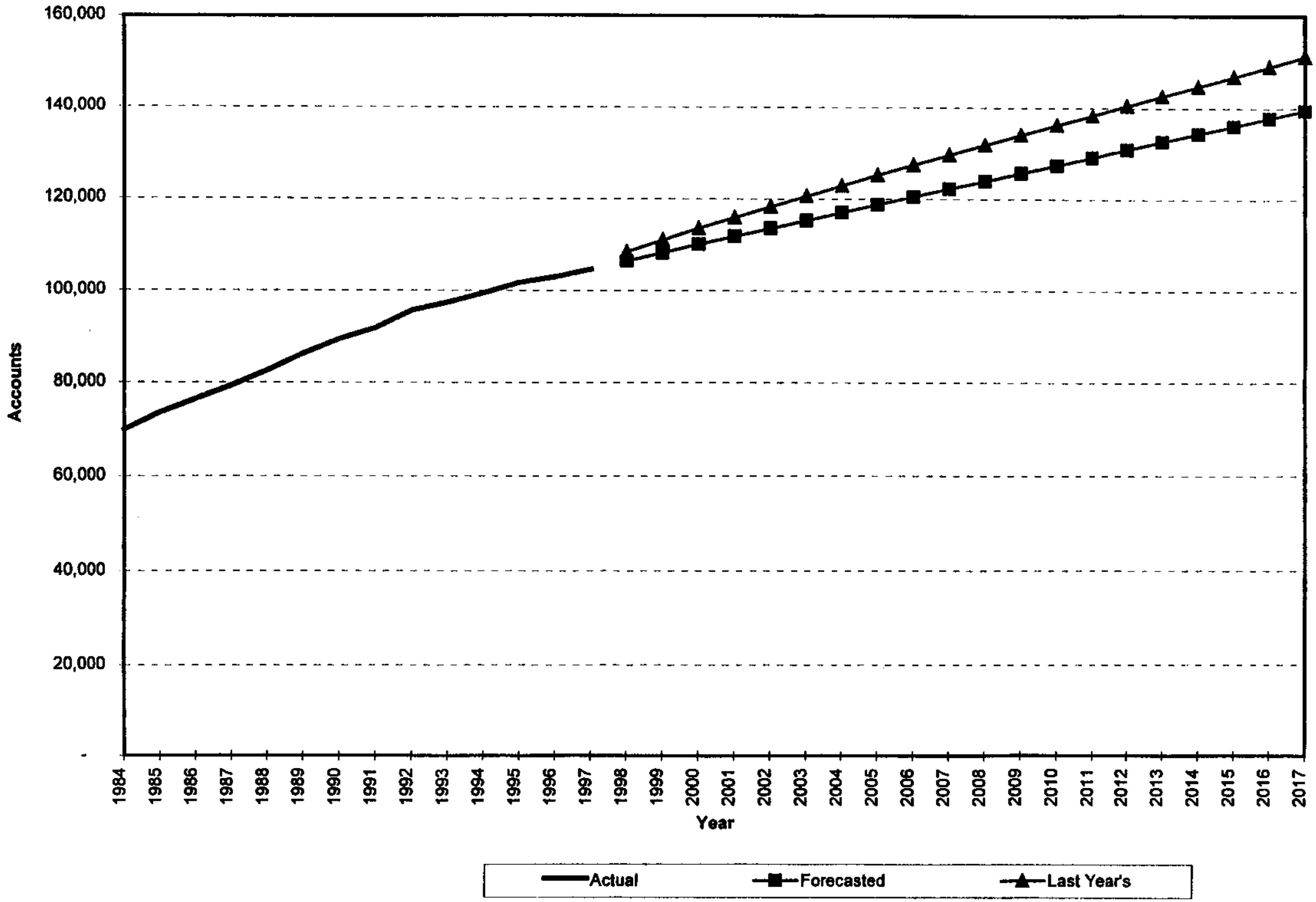


Table ES-3

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%	(175,375)
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		4,004,147	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)

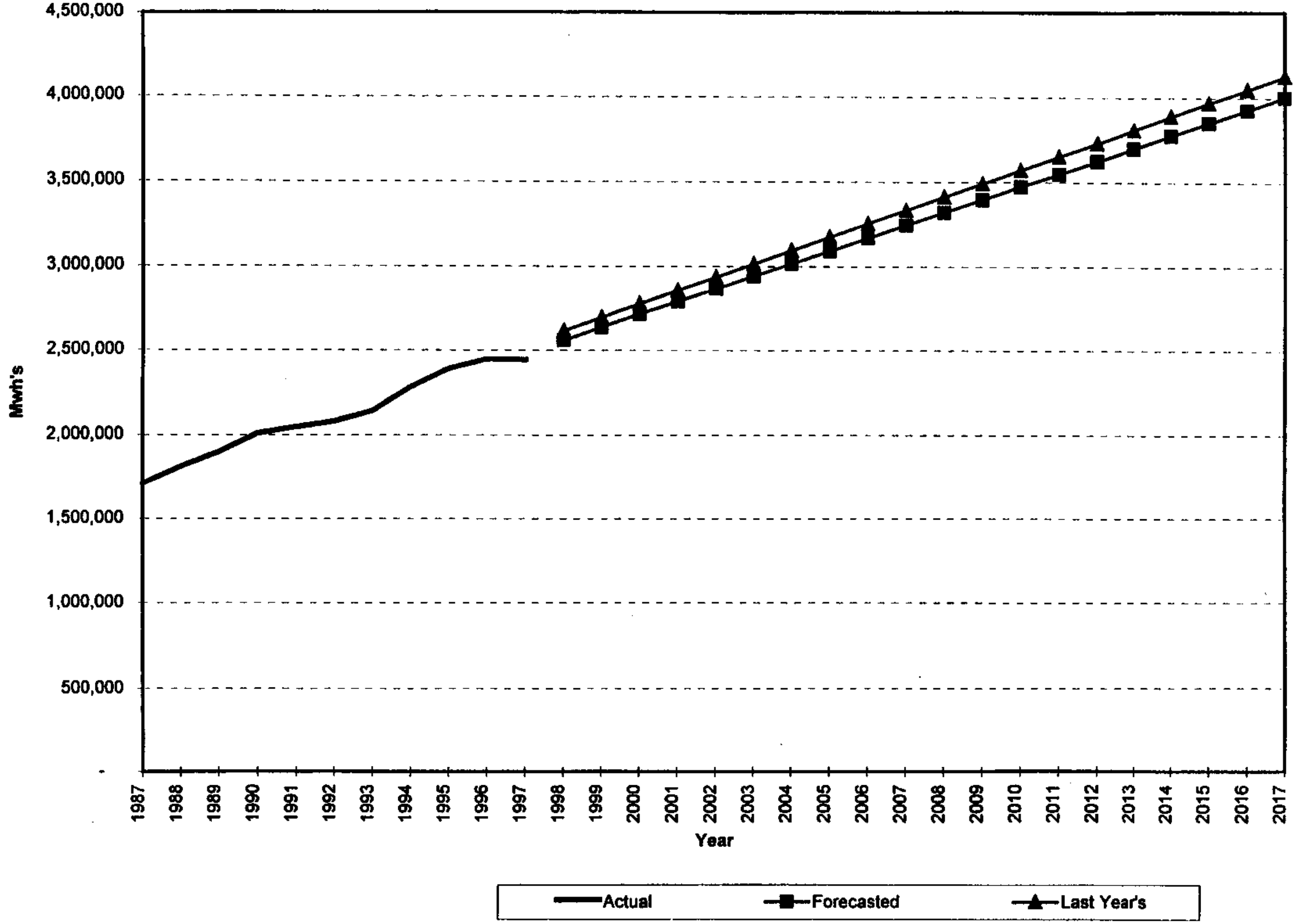
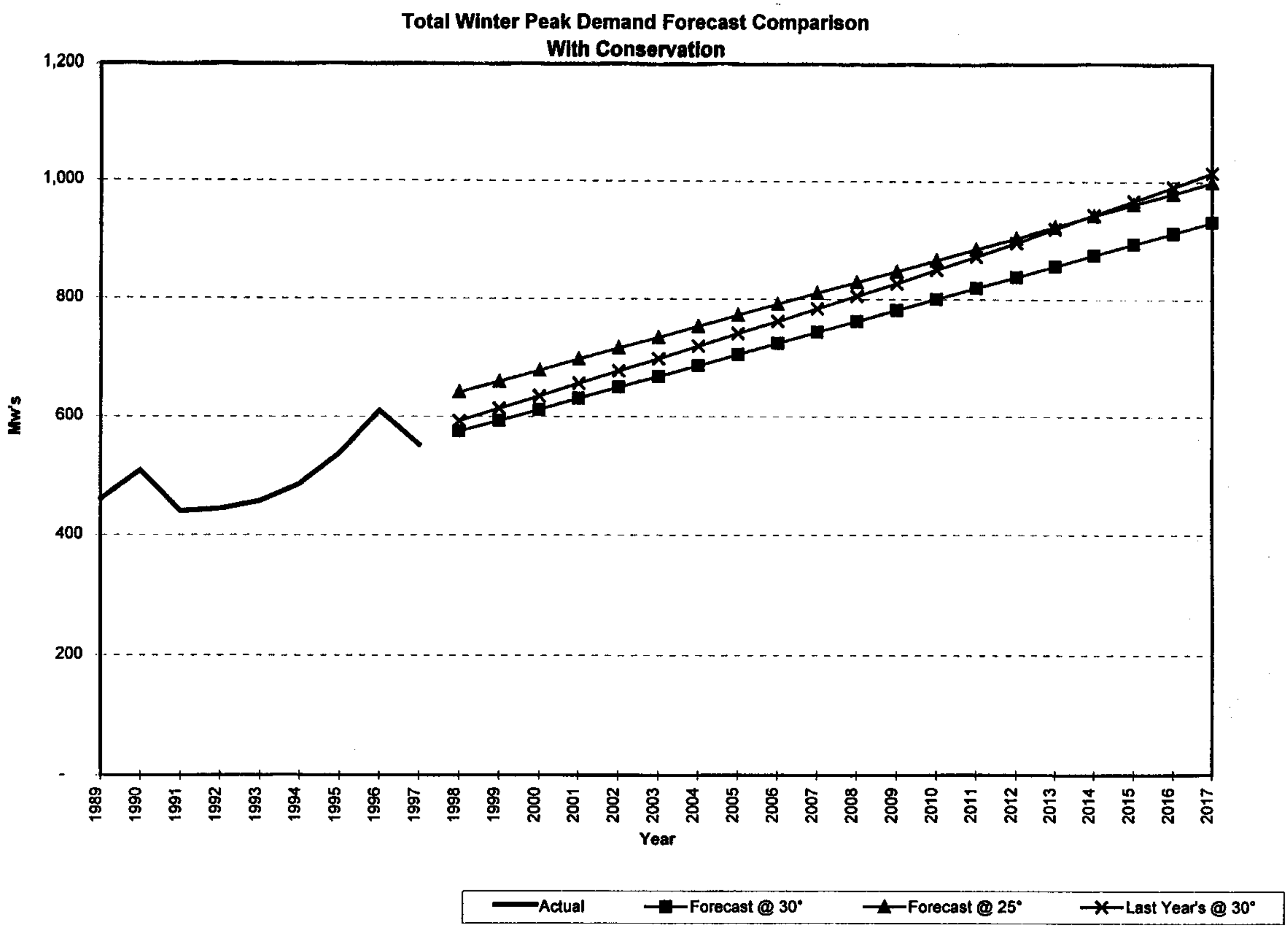


Table ES-4

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.**



*The 1996 Winter Peak Occurred @ 25°.

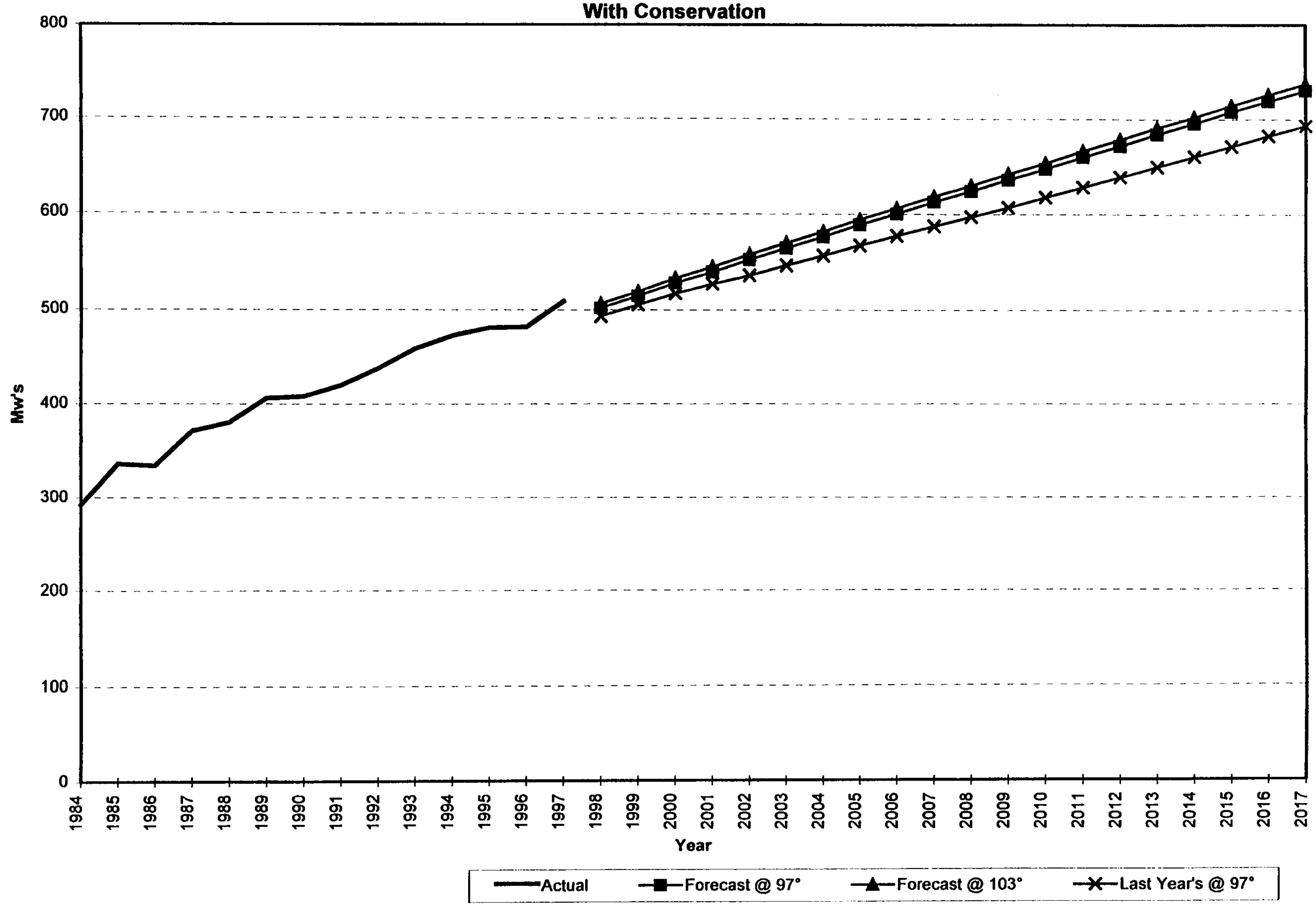
Table ES-5

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°.

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	0.08%
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	-0.09%

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	3,301,158	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	126,178
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%**

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	57,694	6,327	417	6,744	322	47,782	36	-	-	5,199	26	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	89,430
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	83,656	8,557	1,190	9,747	588	60,344	57	-	-	9,072	37	16		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 INDUSTRIAL 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 Sales	Contract Sales Water Plant	Municipal Sales	Privaate Area Lights Sales	Unmetered Sales	Actual Energy Sales	Total Energy Forecast (Less Conservation)
1984	686,367	138,385	183,859	322	230,972			2,455	16,029		19,655	8,695	8,246	1,294,663	
1985	740,898	153,136	207,312	360	247,657			2,682	17,716		20,407	8,644	8,140	1,406,592	
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	296,854	430	278,682			2,872	22,524		23,038	9,748	7,889	1,605,364	
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	346,960	495	327,165			3,468	17,099		30,623	11,323	7,986	1,781,241	
1990	915,600	150,200	359,000	509	336,000			5,215	18,712		31,055	12,057	7,689	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	382,695	529	348,961			5,181	17,619		33,781	12,704	8,201	1,943,899	
1993	1,011,768	152,445	383,756	536	377,424			5,700	16,495		35,881	13,161	8,969	2,005,599	
1994	1,084,651	159,428	403,382	563	387,053			5,864	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	167,696	439,343	607	459,090			6,357	17,581		44,947	15,854	9,555	2,330,534	
Forecast				-											
1998	1,225,186	170,841	452,176	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	119,519	39,923	334,197	6,732	2,988	15,190	49,755	17,003	9,872		2,497,062
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	498,645	686	151,138	41,138	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	21,248	10,890		3,005,279
2007	1,561,640	206,334	556,013	762	211,867	43,253	368,669	8,120	5,602	16,448	67,914	21,857	11,031		3,078,748
2008	1,599,848	209,958	567,746	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	579,479	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	248,874	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	259,889	45,005	383,643	8,814	6,833	17,115	77,107	24,295	11,595		3,371,089
2012	1,750,546	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%	1.15%	2.15%	6.35%	1.00%	3.43%	2.81%	1.30%		2.39%

**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		1026	59	6	1020	74	946	19

Table D-2

City of Lakeland
Electric & Water Utiliites
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	267							
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	97		768	62	6	762	32	730	12

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%.

<u>Forecast Comparison:</u>

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.

<u>Changes to Forecast Model</u>

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

LAKELAND ELECTRIC & WATER

Excellence Is Our Goal, Service Is Our Job

FUEL PRICE FORECAST

1998

PREPARED BY:
FUELS DIVISION

JANUARY, 1998

City of Lakeland • Department of Electric and Water Utilities

TABLE OF CONTENTS

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 proportions 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.

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

Fiscal Year	Coal	Natural Gas	High Sulfur Oil	Low Sulfur Oil	Diesel	Petroleum Coke
1998	$ 1.74	$ 2.28	$ 3.06	$ 4.29	$ 4.44	$ 1.06
1999	$ 1.76	$ 2.30	$ 3.09	$ 4.33	$ 4.53	$ 1.09
2000	$ 1.78	$ 2.32	$ 3.14	$ 4.40	$ 4.63	$ 1.15
2001	$ 1.80	$ 2.34	$ 3.19	$ 4.47	$ 4.73	$ 1.17
2002	$ 1.82	$ 2.36	$ 3.24	$ 4.54	$ 4.82	$ 1.19
2003	$ 1.84	$ 2.39	$ 3.30	$ 4.63	$ 4.92	$ 1.21
2004	$ 1.86	$ 2.43	$ 3.37	$ 4.72	$ 5.01	$ 1.23
2005	$ 1.88	$ 2.47	$ 3.44	$ 4.82	$ 5.13	$ 1.25
2006	$ 1.90	$ 2.53	$ 3.52	$ 4.93	$ 5.25	$ 1.27
2007	$ 1.92	$ 2.59	$ 3.60	$ 5.05	$ 5.45	$ 1.29
2008	$ 1.95	$ 2.65	$ 3.70	$ 5.18	$ 5.65	$ 1.32
2009	$ 1.97	$ 2.71	$ 3.80	$ 5.33	$ 5.82	$ 1.34
2010	$ 1.99	$ 2.78	$ 3.91	$ 5.49	$ 5.99	$ 1.36
AAGR	**1.13%**	**1.66%**	**2.22%**	**2.08%**	**2.53%**	**2.10%**

AAGR = Average Annual Growth Rate

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

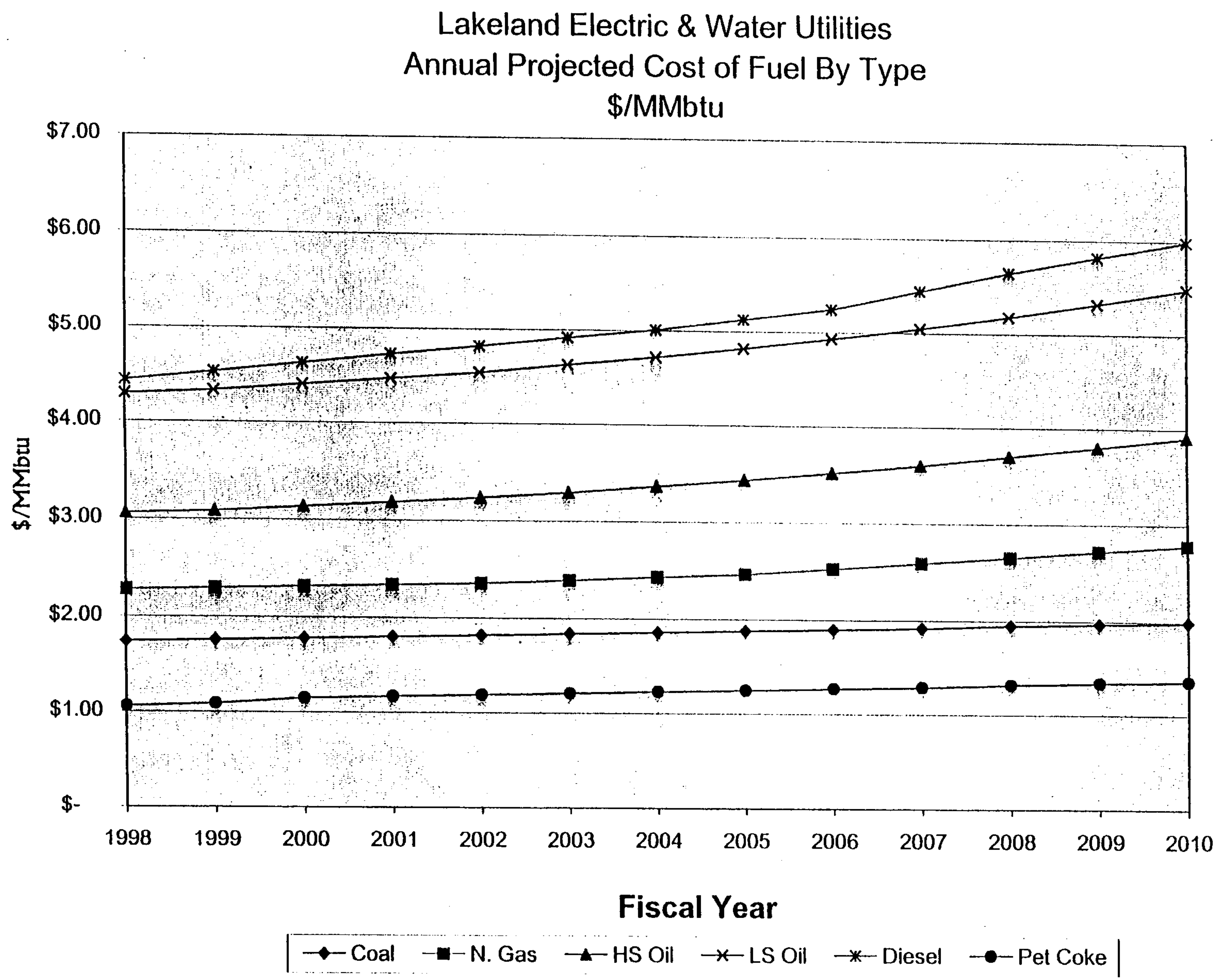
At this point in time, the City of Lakeland does not have any long term contracts or intermediate contracts for the purchase of oil since the purchase is minimal.

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.


Lakeland Electric & Water Utilities
Annual Projected Cost of Fuel By Type
$/MMbtu
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$-
$/MMbtu
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year
Coal
N. Gas
HS Oil
LS Oil
Diesel
Pet Coke

III. COAL

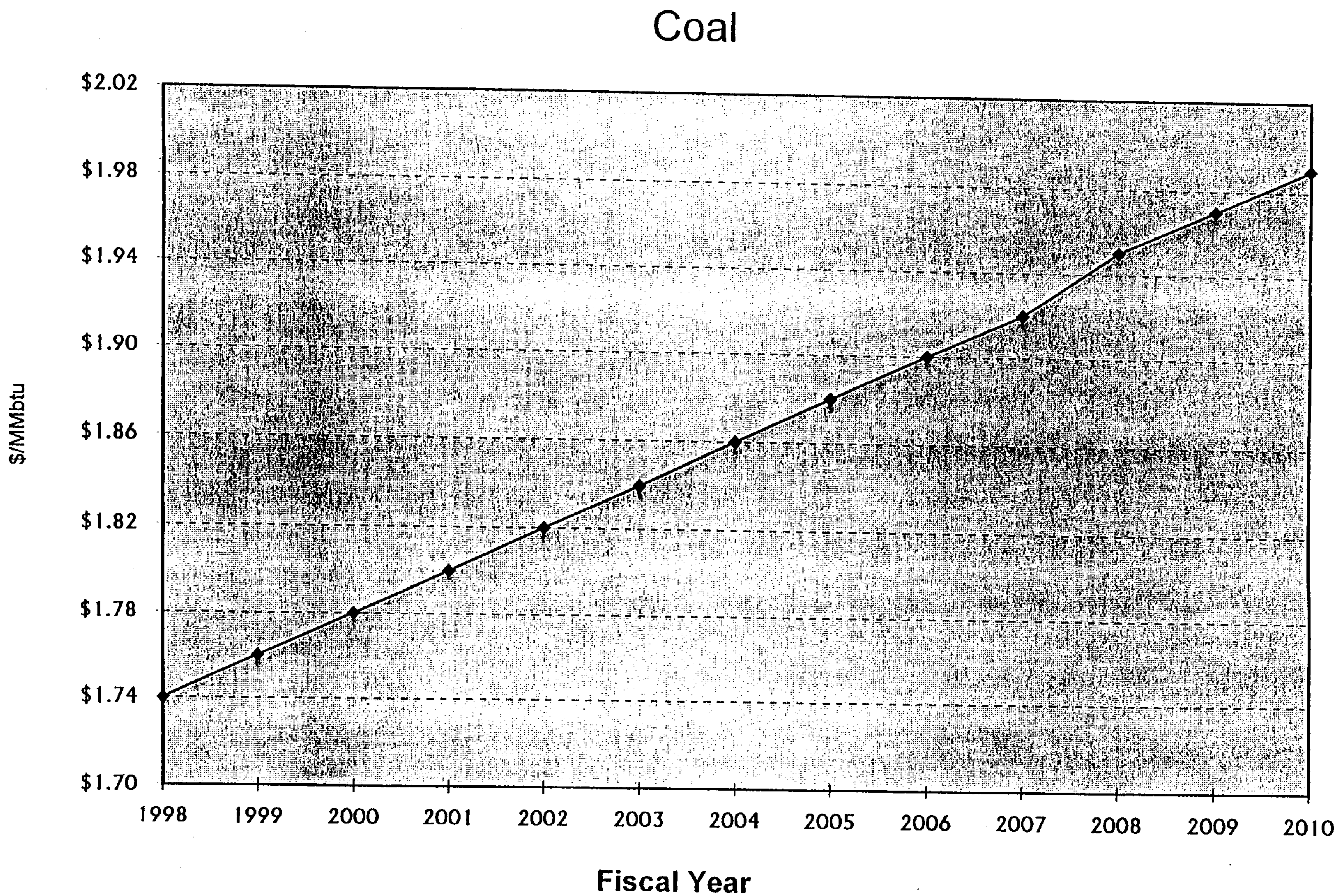
The coal market has been very stable. Over the past few years, little increase or decrease has occurred and in real terms (without inflation) the price has been decreasing. The NYMEX Board is expecting to add a new futures contract in the second quarter of 1998. This will cause the market to be more 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.


Coal
$/MMbtu
$2.02
$1.98
$1.94
$1.90
$1.86
$1.82
$1.78
$1.74
$1.70
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year

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.

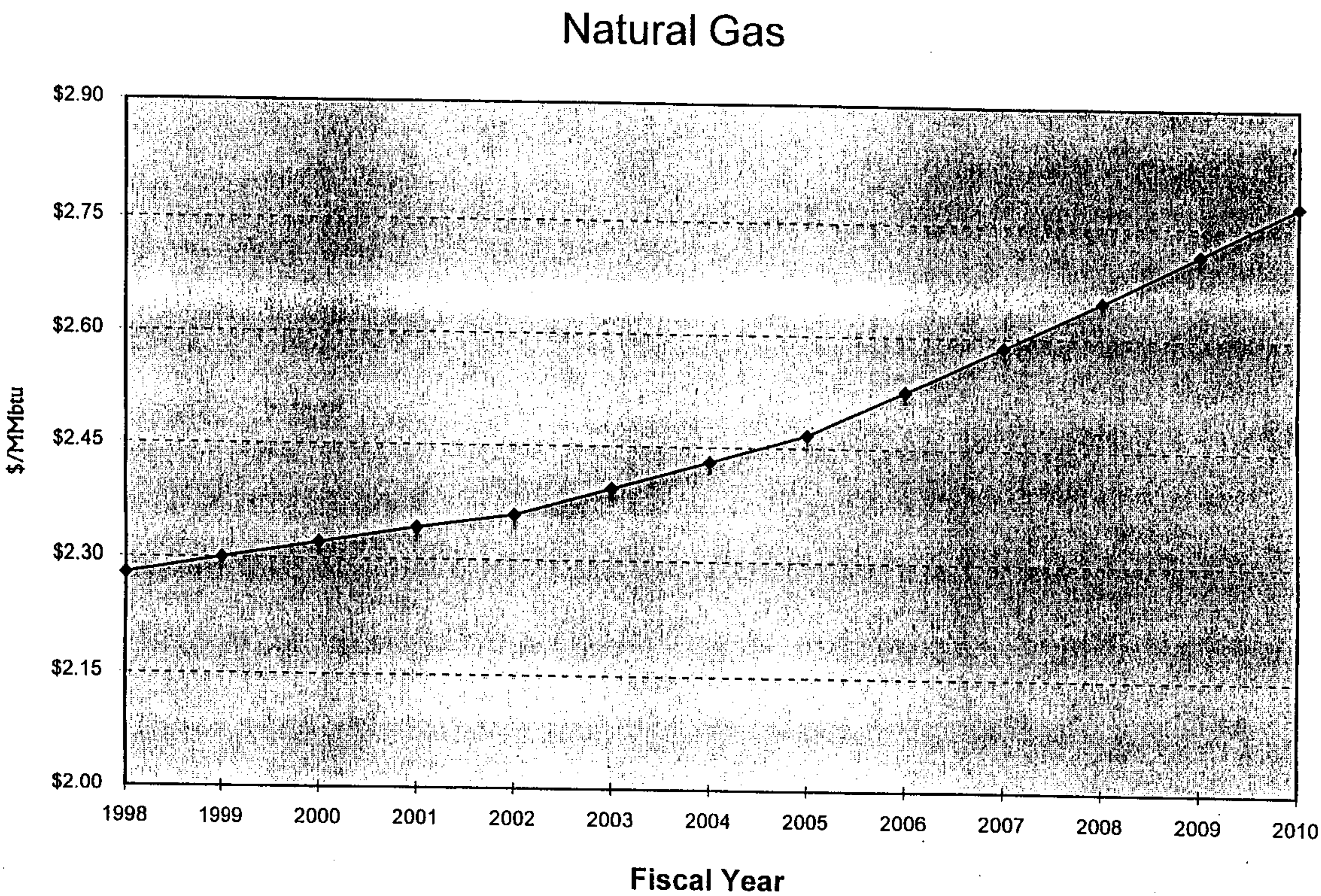
Because the gas market has become more fluid, the gas market trades on an hourly and a daily basis without much consideration to long term production or demand.

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.

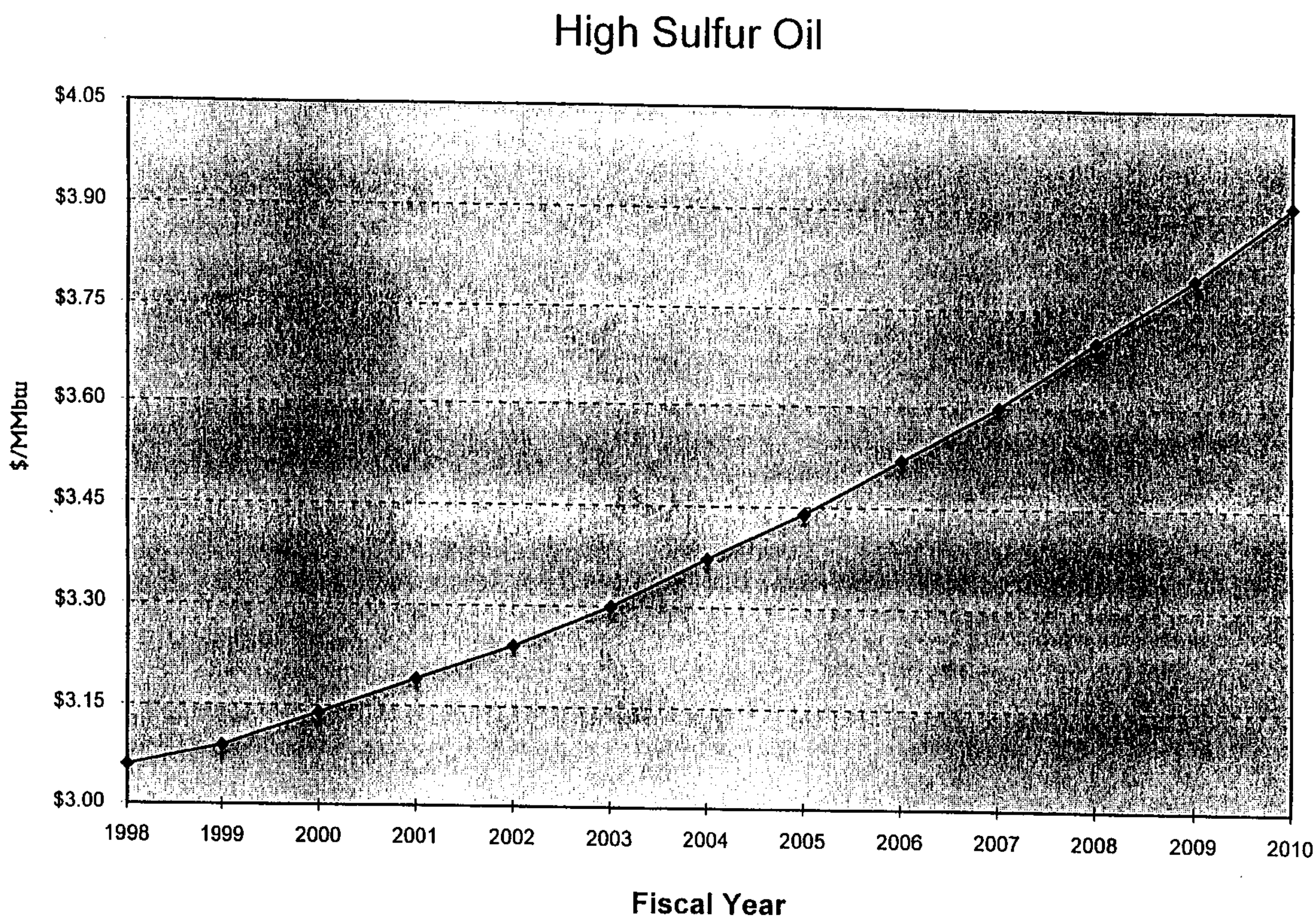
There is a new project proposed that involves a second natural gas pipeline in the state. The project is known as Gulf Stream. The proposal has in it an additional 500,000 mmbtus per day and is expected to be on-line in 2001. Although the likelihood of this pipeline is, at this point, unknown, it is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


Natural Gas
$2.90
$2.75
$2.60
$2.45
$2.30
$2.15
$2.00
$/MMbtu
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year

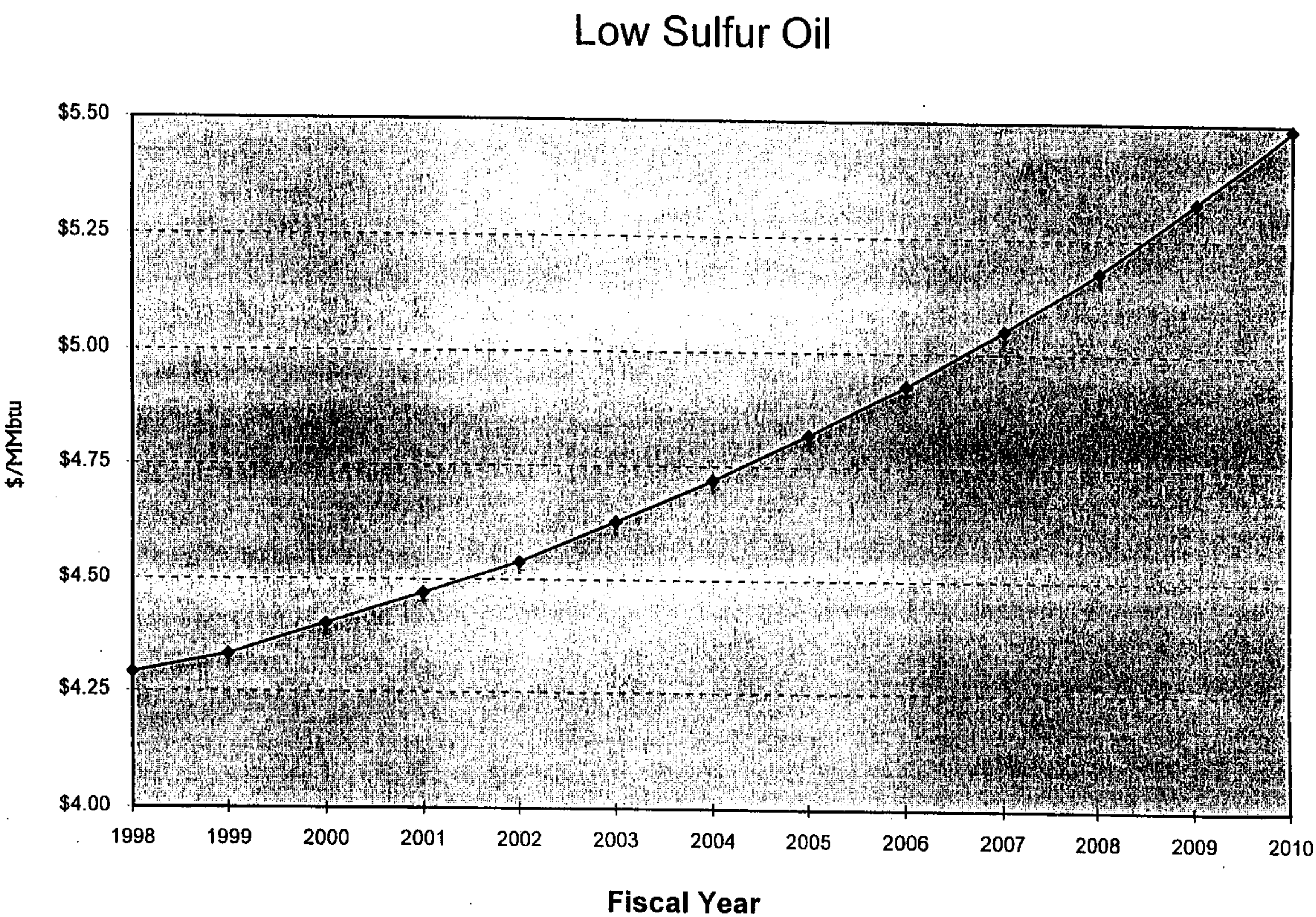
V. OIL

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.



High Sulfur Oil
$4.05
$3.90
$3.75
$3.60
$3.45
$3.30
$3.15
$3.00
$/MMbtu
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year


Low Sulfur Oil
$5.50
$5.25
$5.00
$4.75
$4.50
$4.25
$4.00
$/MMbtu
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year

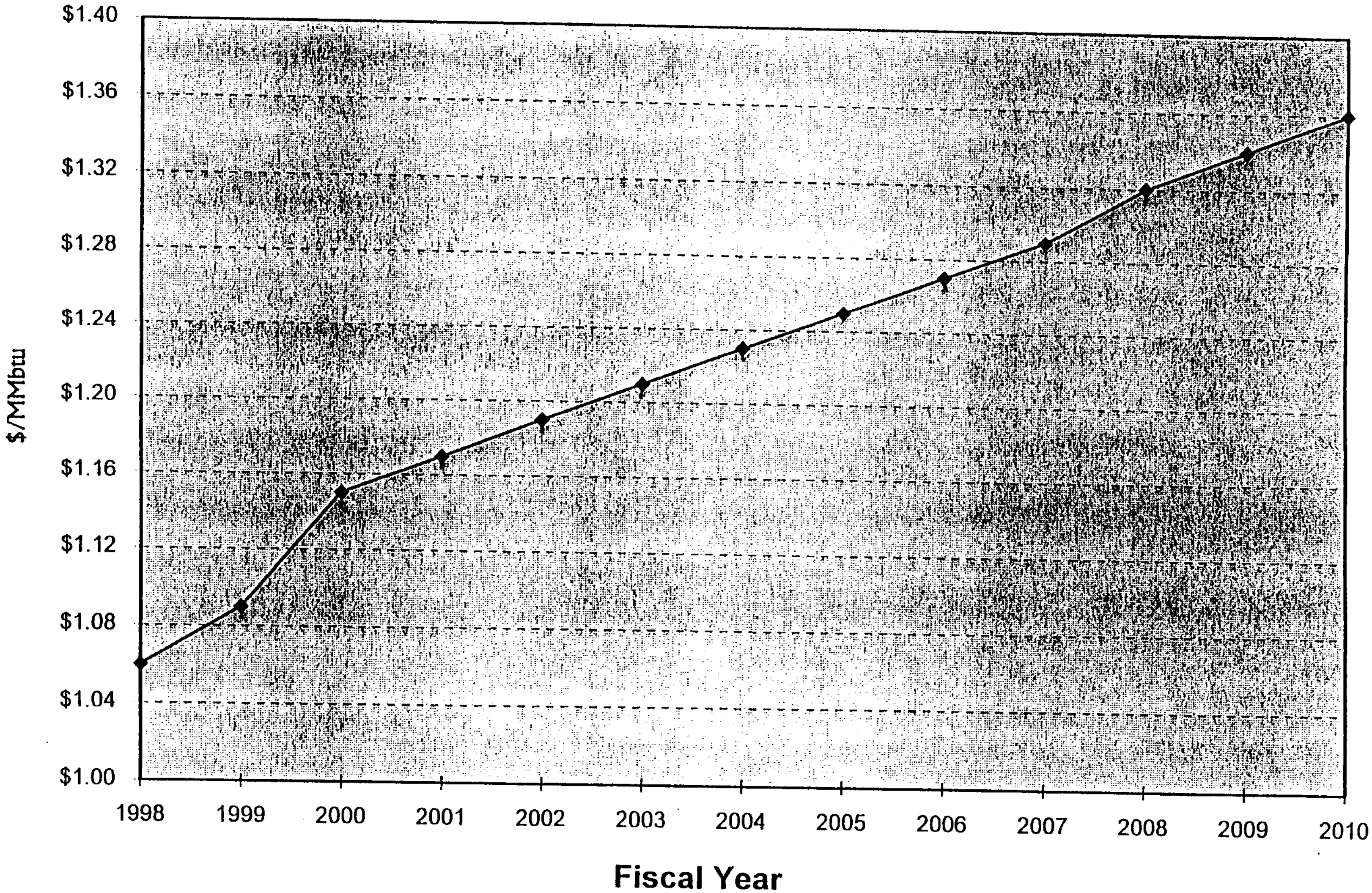
VI. PETROLEUM COKE

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.

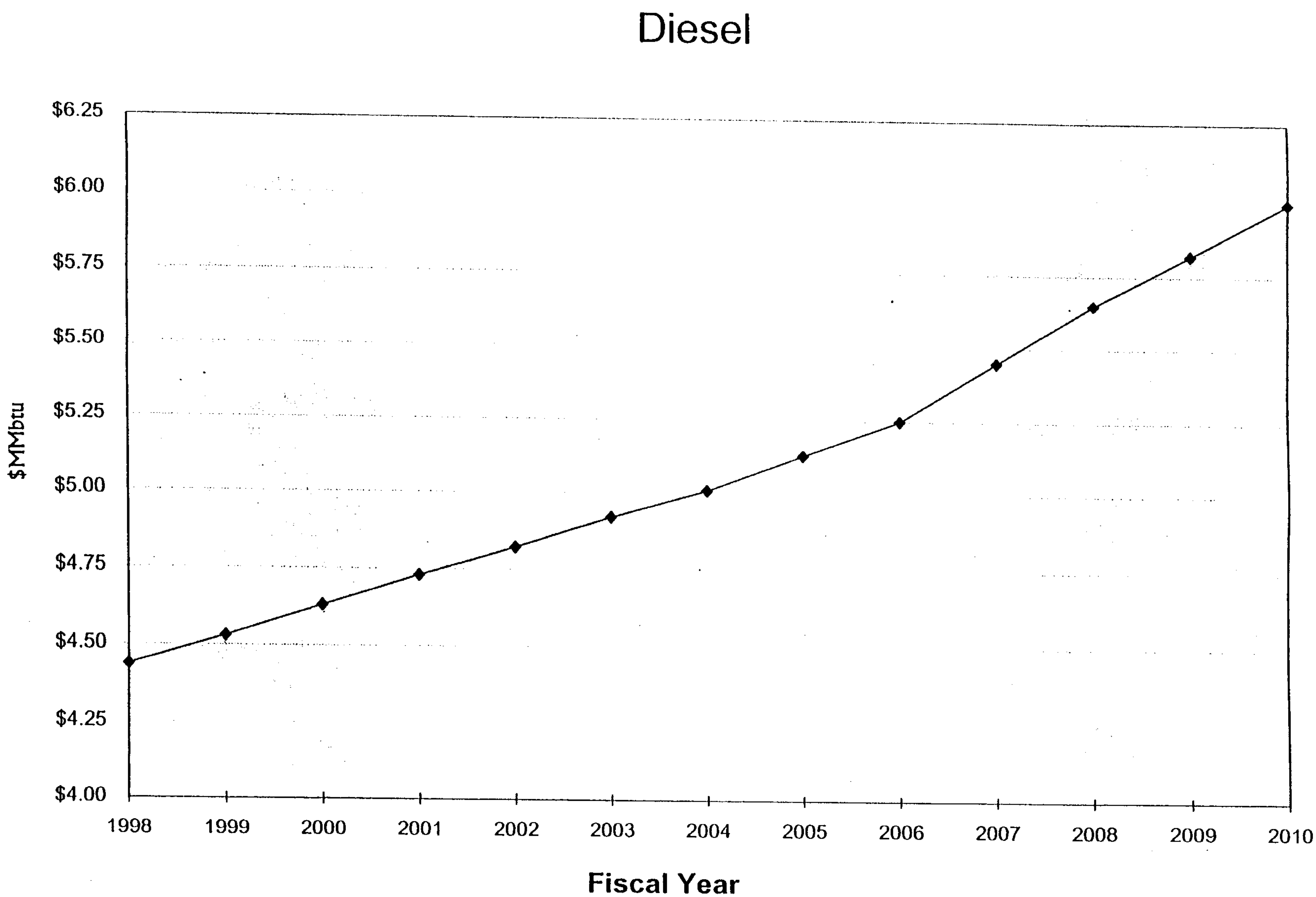
Since the Mobil refinery is the City of Lakeland's only source, further developments will enhance our opportunity to purchase a longer term contract after year 2000. The forecast shows an increase after year 2000 to show Lakeland's prices becoming closer to what the market will be at that point in time.

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.

Pet Coke



$/MMbtu
$1.40
$1.36
$1.32
$1.28
$1.24
$1.20
$1.16
$1.12
$1.08
$1.04
$1.00
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year


Diesel
$6.25
$6.00
$5.75
$5.50
$5.25
$5.00
$4.75
$4.50
$4.25
$4.00
$MMbtu
1998
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2003
2004
2005
2006
2007
2008
2009
2010
Fiscal Year

11.0 Supply-Side Alternatives

This section presents a review of the conventional, advanced, and renewable energy resources evaluated by Lakeland as potential capacity addition alternatives. Although many technologies are not commercially viable at this time, cost and performance data were developed in as much detail as possible to provide the most accurate resource planning evaluation. In addition, due to the nature of some technologies dependence on site characteristics and resources, it is difficult to accurately estimate performance and costing information. For this reason, some of the options have been presented with a typical range for performance and cost. For most technologies, the performance and costs are based on a specified size. In addition, an overall levelized cost range for the general technology type is provided. This levelized cost of energy production accounts for capital, fuel, operations, and maintenance costs over the typical life expectancy of the unit, assuming municipal ownership and financing. Costs for the alternatives are escalated to 2001 dollars assuming the escalation rates stated in Section 5.1. The following alternative categories are addressed in the following subsections:

- Renewable Technologies.
- Waste Technologies.
- Advanced Technologies.
- Energy Storage Systems.
- Nuclear (Fission).
- Conventional Alternatives.
  - Coal Fueled.
  - Combined Cycle.
  - Simple Cycle Combustion Turbine.

11.1 Renewable Technologies

11.1.1 Wind Energy Conversion

Wind power is growing significantly in the international market, but domestic growth in the United States has been slow. Worldwide installed wind power is over 5,000 MW, with around 1,700 MW in the U.S. Germany and India accounted for almost two-thirds of all new installations in 1996--nearly 900 MW. The U.S., on the other hand, lagged behind, adding only 41 MW of new wind capacity. In the last 10 years, the U.S.

share of total world wind energy capacity has dropped from about 90 percent to 30 percent. Stagnation in the U.S. market can be attributed to the pending restructuring of the electric utility industry, which has made utility power planners hesitant to plan new capacity additions.

Utility scale wind energy systems consist of multiple wind turbines that range in size from 100 kW to 1,000 kW. Multiple turbines are used to supply the desired megawatt output. Reasonably sized installations may be 5 to 50 megawatts in size. Wind energy provides supplemental power when operating as a stand-alone resource with typical capacity factors of 15 to 40 percent, depending on wind regime in the area and energy capture characteristics of the wind turbine. To provide a peaking resource, wind energy systems may be coupled with battery energy storage to provide power when required. Table 11-1 provides wind energy characteristics for a 10 MW wind farm with average yearly wind speed of 20 miles per hour.

Table 11-1
Wind Energy Conversion
Performance and Costs

Commercial Status	Commercial
Average Wind Speed (mph)	20
Performance:	
Power Capacity (MW_{rated})	10
Power Capacity ($MW_{average}$)	3.5
Energy Production (MWh/yr)	29,127
Capacity Factor (percent)	35
Costs:	
Capital Cost ($\$/kW_{rated}$)	1,130
Capital Cost ($\$/kW_{average}$)	3,220
O&M Costs:	
Fixed O&M ($\$/kW\text{-}yr_{average}$)	31
Variable O&M ($\$/MWh_{average}$)	5.0
Levelized Cost (cents/kWh)	4.22[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.1.2 Solar

Solar energy consists of capturing the sun's energy and converting it to either thermal energy (solar thermal) or electrical energy (photovoltaics). Numerous options and techniques are used for this purpose.

11.1.2.1 Solar Thermal. Solar thermal systems convert solar insolation to high temperature thermal energy, usually steam, which is then used to drive heat engines, turbine/generators, or other devices for electricity generation. Commercial solar thermal plants in the U.S currently generate more than 350 MW. Solar thermal technologies are appropriate for a wide range of intermediate and peak load applications including central power station power plants and modular power stations in both remote and grid-connected areas.

In order to achieve the high temperature needed for solar thermal systems, the sunlight is usually concentrated with mirrors or lenses. Three concentrating solar thermal collector technologies have been developed. The shape of the mirrored surface on which the sunlight is concentrated characterizes each. They are parabolic trough, parabolic dish, and central receiver.

A measure of solar thermal plant efficiency is the ratio of net electric output to annual solar energy received by the collector field. The amount of solar energy received is a product of annual direct normal solar radiation, in kWh/m^2, multiplied by the total collector area. An 80 MW parabolic trough solar thermal plant is represented in Table 11-2.

11.1.2.2 Photovoltaics. Photovoltaic cells convert sunlight directly into electricity by the interaction of photons and electrons within the semiconductor material. To create a photovoltaic cell, a material such as silicon is doped with atoms from an element with one more or less electron than occurs in its matching substrate (e.g., silicon). A thin layer of each material is joined to form a junction. Photons, striking the cell, cause this mismatched electron to be dislodged, creating a current as it moves across the junction. Through a grid of physical connections, the current is gathered. Various currents and voltages can be supplied through series and parallel arrays of cells.

The DC current produced depends on the material involved and the intensity of the solar radiation incident on the cell. Most widely used today, is the single crystal silicon cell. The source silicon is highly purified and sliced into wafers from single-crystal ingots or is grown as thin crystalline sheets or ribbons. Polycrystalline cells are

Table 11-2 Solar Thermal - Parabolic Trough Performance and Costs	
Commercial Status	Commercial
Duty Cycle	Supplemental
Performance:	
Power Capacity (MW)	80
Energy Production (MWh/yr)	252,288
Capacity Factor (percent)	36
Costs:	
Capital Cost ($/kW)	2,870 - 3,600
O&M Costs:	
Fixed O&M ($/kW-yr)	47
Variable O&M ($/MWh)	4.1
Levelized Cost (cents/kWh)	9.8 - 14.6[1]
(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.	

another alternative, which are inherently less efficient than single crystal solar cells, but also cheaper to produce. Gallium arsenide cells are among the most efficient solar cells today, with many other advantages, but are also expensive.

Another approach to producing solar cells that shows great promise is thin films. Commercial thin films today are principally made from amorphous silicon; however, copper indium diselenide and cadmium telluride also show promise as low-cost solar cells. Thin film solar cells require very little material and can be easily manufactured on a large scale. Manufacturing lends itself to automation and the fabricated cells can be flexibly sized and incorporated into building components.

Current utility grid connected photovoltaic systems are generally below 1 megawatt in size, however, several larger projects ranging from 1 megawatt to 50 megawatts have been proposed. Recently, Greece funded 5 megawatts of photovoltaic power of a 50 MW proposed plant on the island of Crete.

Numerous variations in photovoltaic cells are available such as single crystalline silicon, polycrystalline, thin film silicon, etc. and several structure concepts are available (fixed-tilt, one-axis tracking, two-axis tracking). For representative purposes a fixed-tilt, single crystalline photovoltaic system is characterized in Table 11-3.

Table 11-3
Utility-Scale Photovoltaics
Performance and Costs

Commercial Status	Commercial
Module Type	Single Crystalline
Array Type	Fixed-tilt
Duty Cycle	Supplemental
Performance:	
Module Efficiency (%)	12.0
Power Capacity (MW)	10
Energy Production (MWh/yr)	17,520
Capacity Factor (percent)	20
Costs:	
Capital Cost ($\$/kW_{rated}$)	2,000
Capital Cost ($\$/kW_{average}$)	10,000
O&M Costs:	
Fixed O&M ($\$/kW\text{-}yr_{average}$)	14
Variable O&M ($\$/MWh_{average}$)	2.0
Levelized Cost (cents/kWh)	8.4 - 13.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.1.3 Wood Chip

Direct wood chip combustion power plants in operation today essentially use the same steam-Rankine cycle introduced into commercial use 100 years ago. Pressurized steam is produced in a boiler and then expanded through a turbine to produce electricity. Prior to combustion in the boiler, the wood chip fuel may require some processing to improve the physical and chemical properties of the feedstock. Furnaces used in the combustion of wood chips include spreader stoker-fired, suspension-fired, fluidized bed, cyclone and pile burners.

The capacity of wood chip plants is usually less than 50 MW because of the large quantities and dispersed nature of the feedstock required. The stoker-fired grate is limited to the amount of fuel that can be handled. Wood chip plants will commonly have lower efficiencies as compared to modern coal plants. The low efficiency is due to the lower heating value and higher moisture content of the wood chip fuel compared to coal. Also, finding sufficient sources of fuel within a 100-mile radius may also limit the size of the plant because of the transportation costs associated with low-density wood chip fuel.

There are around 1,000 wood-fired plants in the country, with a typical size ranging from 10 to 25 MW. Only a third are operated to sell electricity, with the rest being owned and operated by the forest-products industry for self-generation. Table 11-4 provides typical characteristics of a 50 MW wood-fired combustion plant assuming spreader-stoker furnace technology using wet wood chips as fuel.

Table 11-4
Wood Chip Combustion
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	50
Net Plant HHV Heat Rate (Btu/kWh)	12,500 to 17,500
Energy Capacity (MWh)	260,000
Capacity Factor (percent)	60
Costs:	
Capital Cost ($/kW)	1,450 - 1,850
O&M Costs:	
Fixed O&M ($/kW-yr)	24 - 48
Variable O&M ($/MWh)	4.0 - 5.0
Levelized Cost (cents/kWh)	5.8 - 11.1[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.1.4 Geothermal

The production of geothermal energy in the U.S. currently ranks third in renewable energy sources, following hydroelectric power and biomass energy. In the United States, the electrical-generation industry has an installed capacity of 2,900 megawatts of electricity (MWe) from geothermal energy, and direct applications have an installed capacity in excess of 2,100 thermal megawatts (MWt). Approximately 5,700 MWe are currently being generated in some 20 countries from geothermal energy, and there are 11,300 MWt of installed capacity worldwide for direct-heat applications at inlet temperatures above 95°F.

Geothermal power is limited to locations where geothermal pressure reserves are found. In the United States, most of these reserves can be found in the western portion of the country. Four types of geothermal power conversion systems are in common use. They are dry steam, single-flash, double-flash, and binary cycle power plants. No known geothermal sources are located in the state of Florida. For representative purposes a 25 MW binary-cycle power plant is characterized in Table 11-5. Capital costs of geothermal facilities can vary widely as the drilling of wells can cost as much as four million dollars and the number of wells drilled depends on success of finding the resource. Variable O&M cost will also include the replacement of production wells.

Table 11-5
Geothermal
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25
Energy Capacity (MWh)	175,200
Capacity Factor (percent)	80
Costs:	
Capital Cost ($/kW)	2,000 - 4,000
O&M Costs:	
Fixed O&M ($/kW-yr)	105
Variable O&M ($/MWh)	7.2
Levelized Cost (cents/kWh)	3.4 - 12.1[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.1.5 Hydroelectric

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. Turbine efficiency and costs have remained somewhat stable; however, construction techniques and cost have and are changing. Capital costs are highly dependent on site characteristics and may vary widely. To be able to predict performance and cost, site and river resource data would be required. Table 11-6 has typical ranges for performance and cost estimates.

Table 11-6
Hydroelectric
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	10 to 1,500+
Energy Capacity (MWh)	Resource dependent
Capacity Factor (percent)	Resource dependent
Costs:	
Capital Cost ($/kW)	1,300 - 5,200
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 30
Variable O&M ($/MWh)	1.5 - 4.0
Levelized Cost (cents/kWh)	3.3 - 6.3[1]
(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.	

11.2 Waste Technologies

11.2.1 Refuse to Energy Conversion

A wide variety of refuse types have the potential to produce energy. The use of municipal solids waste, used tires, and sewage sludge will be addressed in this section. Economic feasibility of refuse to energy facilities is difficult to assess in general. Costs are highly dependent on transportation, processing, and tipping fees associated with a particular location.

11.2.1.1 MSW to Energy Conversion. Converting refuse or municipal solids waste (MSW) to energy can be accomplished by a variety of technologies. These technologies have been developed and implemented as a means of reducing the quantity of municipal and agricultural solid waste. The avoided cost of disposal is primarily what will determine whether a waste to energy facility is economically feasible.

The degree of refuse processing determines the method used to convert municipal solids waste to energy. Unprocessed refuse is typically combusted in a water wall furnace (mass burning). After only limited processing to remove non-combustible and oversized items, the MSW is fed on to a reciprocating grate in the boiler. The combustion generates steam in the walls of the furnace, which is converted to electrical energy via a steam turbine generator system. Other furnaces used in mass burning applications are refractory furnaces and rotary kiln furnaces, which use other means to transfer the heat to the steam cycle or add a mixing process to the combustion. For smaller modular units, controlled air furnaces, which utilize two stage burning for more efficient combustion, can be used in mass burning applications. Table 11-7 has typical ranges for performance and costs.

Table 11-7
Waste to Energy - Mass Burn Unit Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	15,500
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,000 - 3,000
O&M Costs:	
Fixed O&M ($/kW-yr)	100 - 150
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	7.0 - 12.0[1,2]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.
(2) Excludes tipping fee credit.

11.2.1.2 RDF to Energy Conversion. Refuse Derived Fuel (RDF) is preferred in many refuse to energy applications because it can be combusted in coal fired technologies. Spreader stoker-fired boilers, suspension fired boilers, fluidized bed boilers, and cyclone furnace units have all been utilized to generate steam from RDF.

Fluidized bed combustors are often preferred to energy applications for RDF due to their high combustion efficiency, capability to handle RDF with minimal processing, and inherent ability to effectively reduce nitrous oxides and sulfur dioxide emissions. In all boiler types the combustion temperature for MSW or RDF must be kept at a temperature less than 800°F in order to minimize boiler tube degradation due to chlorine compounds in the flue gas. Table 11-8 has typical ranges for performance and costs.

Table 11-8
Waste to Energy - RDF Unit
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	50
Net Plant Heat Rate (Btu/kWh)	17,000
MSW Tons per Day	2,000
Capacity Factor (percent)	60 - 75
Availability (percent)	82
Costs:	
Capital Cost ($/kW)	2,500 - 3,500
O&M Costs:	
Fixed O&M ($/kW-yr)	150 - 200
Variable O&M ($/MWh)	25 - 50
Levelized Cost (cents/kWh)	8.0 - 13.0[1,2]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.
(2) Excludes tipping fee credit.

11.2.1.3 Landfill Gas Energy Conversion. Landfilled waste can be converted to energy by collecting the gases generated by the decomposition of waste in landfills. To reduce smog production and the risk of explosion, many landfills are currently required to collect the landfill gas and either flare or generate energy with the gas. The major constituents released from landfill gas wells are carbon dioxide and methane. The methane concentration is typically around 50 percent. To convert this clean burning low

Btu gas to electricity, the gas is piped from wells, filtered, compressed, and used in internal combustion engine generation sets. Depending on the scale of the gas collection facility, it may be feasible to blend this gas with natural gas and generate power via a combustion turbine generator.

In general, landfills that have over one million tons of waste in place, a waste depth greater than 40 feet, more than 30 acres available for gas recovery, and the equivalent of 25+ inches of annual precipitation are sites at which landfill gas recovery is economically feasible. In many cases the payback period of landfill gas energy facilities is between 2 and 5 years. The capital costs will be highly dependent on the conversion technology and landfill characteristics. Table 11-9 has typical ranges for performance and costs.

Table 11-9
Landfill Gas - IC Engine Unit
(Gas Collection/Processing Not Included)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	10
Net Plant Heat Rate (Btu/kWh)	8,500
Capacity Factor (percent)	60 - 75
Availability (percent)	93
Costs:	
Capital Cost ($/kW)	825
O&M Costs:	
Fixed O&M ($/kW-yr)	0.9[1]
Variable O&M ($/MWh)	6.7
Levelized Cost (cents/kWh)	2.0 - 4.0[2]

(1) Unstaffed site.
(2) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.2.1.4 Sewage Sludge to Energy Conversion. The disposal of sewage sludge is a significant environmental problem. The combustion of these materials in order to convert them into energy is one solution that has been proposed. Dewatered sewage sludge has a heating value of up to 7,000 Btu/lb. Typically the sludge has been co-fired with coal in a fluidized bed combustor. Some problems of fluidized bed agglomeration have been realized when utilizing large amounts of sludge. In addition to this performance problem, the low heating value of this waste has impeded the development of sludge combustion. Other wastes to energy methods are currently being investigated that involve either digestion or fermentation of the sludge to produce a higher grade fuel or gas for energy conversion. Also, a number of sewage recycling methods convert sludge to soil, fertilizer, or building materials. These applications compete with energy conversion methods.

11.2.1.5 Used Tire to Energy Conversion. The conversion of used tires to energy via combustion is attractive due to the high heating value (15,000 - 17,000 Btu/lb) of tire derived fuel (TDF). The co-firing of TDF with coal can be done in either a cyclone or conventional stoker boiler without system modification. TDF at co-firing percentages of 2 to 10 percent has been utilized by eight utilities in the U.S. on a regular basis. In cyclone plants, the NO_x emissions and trace metal emissions have actually been reduced when burning TDF. Sulfur dioxide emissions did not change with the co-firing of TDF. On an energy basis, the cost of TDF (processed to 1 inch mesh) can be almost half that of coal. A new facility designed to co-fire TDF with coal would likely be a fluidized bed unit. Fluidized bed systems provide multi-fuel capability, in situ sulfur removal, high combustion efficiencies, and low NO_x emissions. The estimated cost and performance of a 100 MW multi-fuel (10 percent TDF co-fire) circulating fluidized bed system are shown in Table 11-10. This plant has the flexibility to process MSW to RDF and co-fire up to 40 percent RDF with coal.

11.3 Advanced Technologies

11.3.1 Brayton Cycles

The Brayton cycle is based on an all gas cycle that uses air and combustion gases as the working fluid, as opposed to the Rankine cycle that is a vapor cycle. Three of the Brayton cycles that are showing promise for advanced technologies and discussed below include Humid Air cycle, Kalina cycle, and Cheng cycle.

Table 11-10
Multi-Fuel CFB
(~10 Percent TDF Co-Fire)
Performance and Costs

Commercial Status	Commercial
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	11,000
TDF Tons per Day	100
Capacity Factor (percent)	60 - 75
Availability (percent)	85
Costs:	
Capital Cost ($/kW)	1,650
O&M Costs:	
Fixed O&M ($/kW-yr)	40
Variable O&M ($/MWh)	3.0
Levelized Cost (cents/kWh)	4.0 - 8.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.3.1.1 Humid Air. The humid air turbine (HAT) cycle is an intercooled, regenerative cycle burning natural gas with a saturator that adds considerable moisture to the compressor discharge air so that the combustor inlet flow contains 20 to 40 percent water vapor. The warm humidified air from the saturator is then further heated by the turbine exhaust in a recuperator before being sent to the combustor. The water vapor adds to the turbine output while intercooling reduces the compressor work requirement. The heat addition in the recuperator reduces the amount of fuel heat input required. Table 11-11 presents typical performance and cost characteristics.

11.3.1.2 Kalina Cycle. The Kalina cycle is a combined cycle plant configuration that injects ammonia into the vapor side of the cycle. The ammonia/water working fluid provides thermodynamic advantages based on the non-isothermal boiling and condensing behavior of the working fluid's two-component mixture, coupled with the ability to alter

Table 11-11 Humid Air Turbine Power Plant Performance and Costs	
Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	410
O&M Costs:	
Fixed O&M ($/kW-yr)	7 - 9
Variable O&M ($/MWh)	0.10 - 0.60
Levelized Cost (cents/kWh)	3.3 - 4.8[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

the ammonia concentration at various points in the cycle. This capability allows more effective heat acquisition, regenerative heat transfer, and heat rejection.

The cycle is similar in nature to the combined cycle process except exhaust gas from the combustion turbine enters the heat recovery vapor generator (HRVG). Fluid (70 percent ammonia, 30 percent water) from the distillation condensation subsystem (DCSS) enters the HRVG to be heated. A portion of the mixture is removed at an intermediate point from the HRVG and is sent to a heat exchanger where it is heated with vapor turbine exhaust from the intermediate-pressure vapor turbine. The moisture returns to the HRVG where it is mixed with the balance of flow, superheated, and expanded in the vapor turbine generator (VTG). Additional vapor enters the HRVG from the high-pressure vapor turbine where it is reheated and supplied to the inlet of the intermediate-pressure vapor turbine. The vapor exhausts from the vapor turbine and condenses in the DCSS. Table 11-12 presents typical performance and cost characteristics.

11.3.1.3 Cheng Cycle. The Cheng cycle, also known as the steam-injected gas turbine, increases efficiency over the gas turbine cycle by injecting large volumes of steam into the combustor and/or turbine section. The basic Cheng cycle is composed of a

Table 11-12
Kalina Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 500
Net Plant Heat Rate (Btu/kWh)	6,700
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 12
Variable O&M ($/MWh)	0.1 - 0.5
Levelized Cost (cents/kWh)	4.2 - 6.3[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

compressor, combustor, turbine, generator, and heat recovery steam generator (HRSG). The HRSG provides injection steam to the combustor as well as process steam. The amount of steam injection is limited to the allowable loading of the turbine blades.

The typical application of the Cheng cycle is in a cogeneration plant where increased power can be produced during low cogeneration demand and/or peak demand periods. Since 1984, several small cogeneration plants have applied the Cheng cycle in California, Japan, Australia, and Europe. Table 11-13 presents typical performance and cost characteristics.

11.3.2 Advanced Coal Technologies

Coal continues to supply a large portion of the energy demand in the U.S. Current research is focused on making the conversion of energy from coal more clean and efficient. Supercritical pulverized coal boilers and pressurized fluidized bed systems are two systems that have been developed to improve coal conversion efficiency.

Table 11-13
Cheng Cycle Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	250 - 650
Net Plant Heat Rate (Btu/kWh)	6,500
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,025
O&M Costs:	
Fixed O&M ($/kW-yr)	12
Variable O&M ($/MWh)	0.6
Levelized Cost (cents/kWh)	5.6 - 12.4[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.3.2.1 Supercritical Pulverized Coal Boilers. New generation pulverized coal boilers can be designed at supercritical steam pressures of 3,000 to 4,500 psig, compared to the conventional 2,400 psig subcritical boilers. This increase in pressure can bring the overall efficiency of the unit from below 40 percent to nearly 45 percent. This efficiency increase coupled with the latest in emissions control technologies is expected to keep pulverized coal systems environmentally and economically competitive with other generation technologies. Table 11-14 presents typical performance and cost characteristics.

11.3.2.2 Pressurized Fluidized Bed Combustion. Pressurized fluidized bed combustion (PFBC) is a variation of fluid bed technology in which combustion occurs in a pressure vessel at 10 to 15 atm. The PFBC process involves burning crushed coal in a limestone or dolomite bed. High combustion efficiency and excellent sulfur capture are advantages of this technology. In combined cycle configurations PFBC exhaust is expanded to drive both the compressor and gas turbine generator. Heat recovery steam generators transfer heat from this exhaust to generate steam in addition to the steam generated from the PFBC boiler. Overall thermal efficiencies of PFBC combined cycle configurations are 45 to 47 percent. These second-generation PFBC systems are in the development stage. Table 11-15 presents typical performance and cost characteristics. Lakeland is currently pursuing a PCFB project with Foster Wheeler for the year 2004. This project has more defined costs than the generic alternative listed in Table 11-15.

Table 11-14
Supercritical Pulverized Coal Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	350 - 1,300
Net Plant Heat Rate (Btu/kWh)	9,300
Capacity Factor (percent)	60 - 75
Availability (percent)	78
Costs:	
Capital Cost ($/kW)	1,230
O&M Costs:	
Fixed O&M ($/kW-yr)	19 - 23
Variable O&M ($/MWh)	3.3
Levelized Cost (cents/kWh)	3.7 - 4.7[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

Table 11-15
PCFB Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	80 - 350
Net Plant Heat Rate (Btu/kWh)	8,600 (6,700 2nd generation)
Capacity Factor (percent)	60 - 75
Costs:	
Capital Cost ($/kW)	1,330 - 2,050
O&M Costs:	
Fixed O&M ($/kW-yr)	40 - 80
Variable O&M ($/MWh)	3.5
Levelized Cost (cents/kWh)	3.5 - 5.8[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.3.3 Magnetohydrodynamics

Magnetohydrodynamic (MHD) power generation converts the thermal energy of a high velocity ionized gas to electricity. Current prototypes and conceptual designs typically use the high temperature combustion of coal to produce a partially ionized flue gas, which can be passed through a magnetic field. When this highly conductive plasma-like flue gas is accelerated in a nozzle and then passed through a channel perpendicular to a magnetic field an electric field is induced. To successfully ionize the flue gas the combustion temperatures must be around 5,000°F. A seed material such as potassium is added to the flue gas flow to increase gas conductivity.

An MHD system in simple cycle configuration only converts a portion of the flue gas energy to electricity. To optimize the performance of an MHD system, the energy in the hot flue gases exiting the MHD generator can be utilized to generate steam for additional power generation. This combined cycle configuration can result in an efficiency increase of 15 to 30 percent over conventional steam plant efficiencies. The overall thermal efficiency could potentially be as high as 60 percent.

Emission levels can be effectively controlled in MHD systems. NO_x levels are controlled by designing time-temperature profiles within the radiant boiler that promote the decomposition of NO_x formed in the combustion process. The potassium seed in the flue gas reacts with the sulfur compounds to produce a solid potassium sulfate. The spent seed is regenerated and converted to non-sulfur containing potassium species. Particulate emissions can be controlled by electrostatic precipitator.

Currently, MHD power generation technology is still in the development stage. Estimates on operation, performance, costs, and availability are based primarily on conceptual designs. Although a variety of the individual subcomponents of this technology have been developed and tested, the operation of a fully integrated system has not been demonstrated. The driving force behind MHD combined cycle technology is improved performance. Currently, no commercial application of MHD technology demonstrates that this improved performance is feasible. Table 11-16 summarizes the characteristics of a conceptual 100 MW MHD plant. MHD plant sizes are expected to be 500 MW or greater for optimal economic feasibility.

Table 11-16
Magnetohydrodynamic Combined Cycle Plant
Conceptual Performance and Costs

Commercial Status	Development/Conceptual
Performance:	
Plant Capacity (MW)	100
Net Plant Heat Rate (Btu/kWh)	10,300
Capacity Factor (percent)	60 – 75
Costs:	
Capital Cost ($/kW)	1,300 - 2,500
O&M Costs:	
Fixed O&M ($/kW-yr)	20 – 35
Variable O&M ($/MWh)	1.0 - 3.1
Levelized Cost (cents/kWh)	6.7 - 13.5

11.3.4 Fuel Cells

Fuel cells are devices that can convert a hydrogen rich fuel directly to electricity through an electrochemical reaction. Fuel cell power systems have the capability of high efficiencies because they are not limited by the Carnot efficiency that limits thermal power systems. Commercial stationary fuel cell plants are fueled by natural gas. The most developed fuel cell technology for stationary power is the phosphoric acid fuel cell (PAFC). Currently PAFC plants have efficiencies on the order of 40 percent. Fuel cells can sustain high efficiency operation even under part load conditions and they have a rapid response to load changes. The construction of fuel cells is inherently modular, making it easy to size plants according to power requirements. Current PAFC plants range from around 200 kW to 10 MW in size. PAFC cogeneration facilities can attain efficiencies approaching 85 percent when the thermal energy from the fuel cell is utilized. Also, the potential development of fuel cell/gas turbine combined cycles could reach efficiencies of 60 to 70 percent.

In addition to the potential for low heat rates and low O&M costs, the environmental benefits of fuel cells remains one of the primary reasons for commercialization. With natural gas as the fuel source, carbon dioxide and water are the only emissions. High capital costs are the primary disadvantage of fuel cell systems. These costs are expected to drop significantly in the future as development efforts continue. Fuel cell plants are typically less than 10 MW in size. The performance and costs of a 200 kW unit are shown in Table 11-17.

11.3.5 Ocean Wave Energy

Wave energy systems convert the kinetic and potential energy contained in the natural oscillations of ocean waves into electricity. A variety of proposed mechanisms for the utilization of this energy source exist; however, most of which are still in the demonstration or prototype testing stage. The optimal regions for wave power applications typically occur between 40 and 60 degrees latitude, although seas that consistently experience trade winds can also produce sufficient wave energy for power applications. The potential for the utilization of wave energy is the greatest for offshore/deep wave plants, but the technical barriers and associated costs are also considerably higher. Surge devices and oscillating water column devices are the primary technologies for converting wave energy. Both types of systems convert the oscillatory flow of air or water (driven by the waves) to power via a turbine.

Table 11-17 Fuel Cell Power Plant Performance and Costs	
Commercial Status	Commercially Available
Performance:	
Plant Capacity (MW)	0.2
Net Plant Heat Rate (Btu/kWh)	9,980
Capacity Factor (percent)	85
Costs:	
Capital Cost ($/kW)	4,100
O&M Costs:	
Fixed O&M ($/kW-yr)	330
Variable O&M ($/MWh)	0.84
Levelized Cost (cents/kWh)	7.0 - 9.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

The technical problems of dealing with adverse sea conditions, complexity and difficulty of electricity interconnection and transmission, and low reliability have kept wave energy systems from being developed commercially. The high capital costs of such systems have deterred the implementation of wave energy systems. Table 11-18 presents typical performance and cost characteristics.

11.3.6 Nuclear (Fusion)

Theoretically, the potential for fusion power is great. Energy is released when two light nuclei such as deuterium and tritium undergo fusion to form heavier nuclei such as helium. This new nuclei has less mass than the total of the two original nuclei, resulting in a release of energy. Large amounts of energy are released if this fusion reaction can be sustained, but fusion also has high initiation energy requirements. A temperature greater than 50 million K is required to sustain a deuterium-tritium reaction.

Table 11-18
Ocean Wave Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	0.1 - 1.0
Net Plant Heat Rate (Btu/kWh)	N/A
Capacity Factor (percent)	25
Costs:	
Capital Cost ($/kW)	2,450
O&M Costs:	
Fixed O&M ($/kW-yr)	50 - 103
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	6.2 - 38.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

The concept of a fusion power plant is appealing not only because huge amounts of energy can be produced from relatively small amounts of readily available resources (water and lithium), but also because the fusion process has only a very limited impact on the environment. In contrast to fission, the fusion power plant is not likely to undergo a uncontrolled melt-down situation. The minimal amount of radioactive fusion waste does not emit strong radiation during its moderate half-life of approximately 12 years.

Despite the attractive possibilities of fusion, it has yet to yield a net energy output. At the current level of development, the energy required to sustain the fusion reaction is still over twice the amount produced. Recently, fusion research funding has been cut dramatically in the U.S. The Princeton Tokamak Fusion Test Reactor has been decommissioned in the spring of 1997 due to cuts in federal funding of the program. Alternative basic research on various aspects of fusion continues and the international effort to develop a viable fusion power facility is still significant. Nonetheless, it is likely to be well into the next century before fusion develops to the point of commercial viability.

11.3.7 Ocean Tidal Energy

The conversion of ocean tidal cycle energy to electricity can be done through the creation of a dam and tidal basin. By opening a sluice gate in the dam, the rising tidal waters are allowed to fill the tidal basin. At high tide these gates are closed and the tidal basin behind the dam is filled to capacity. After the ocean waters have receded, the tidal basin is released through a turbogenerator in the dam. The capacity factor of such a facility is around 24 percent. Times and amplitudes of high and low tide are predictable, although these characteristics will vary considerably from region to region. As a rule of thumb, a 16 foot tidal amplitude is considered the minimum amplitude for an energy conversion system to be considered economically feasible. In North America, the Northeast and Northwest coasts of Canada are generally considered the only regions where tidal energy plants would be economically feasible. Tidal amplitudes as high as 50 feet are experienced on the East Coast of Canada in the Bay of Fundy.

Utilization of tidal energy for power generation has the environmental advantage of a zero emissions technology. At the same time, the environmental impact that the facility has on the coastline must be carefully evaluated. As with many developing technologies for energy utilization and conversion, high capital costs are the primary obstacle for widespread application. The economic viability of this option is highly dependent on the location chosen for application. Table 11-19 presents typical performance and cost characteristics.

11.3.8 Ocean Thermal Energy

The temperature of the ocean may differ up to 40 degrees from the surface to a depth of 3000 ft. The idea of utilizing this difference for energy production has existed for over a century. Ocean Thermal Energy Cycle (OTEC) concepts have been developed using two basic types of cycles. Closed cycle plants use a low boiling point working fluid such as ammonia. The working fluid is heated and vaporized by the warm surface water, expanded in a turbine generator, and condensed by the deep cold water. Open cycle plants use seawater as the working fluid. The warm surface water is flashed to low-pressure steam, expanded in the turbine generator, and condensed by the deep cold water.

Table 11-19
Ocean Tidal Power Plant
Performance and Costs

Commercial Status	Development
Performance:	
Typical Plant Capacity (MW)	18 - 240
Annual Energy Capacity (GWh)	35 - 500
Capacity Factor (percent)	20 - 25
Costs:	
Capital Cost ($/kW)	1,030 - 4,120
O&M Costs:	
Fixed O&M ($/kW-yr)	10 - 52
Variable O&M ($/MWh)	1.5 - 5.2
Levelized Cost (cents/kWh)	13.0 - 23.0

In OTEC systems, the relatively small temperature difference between the warm and cold thermal reservoirs and the large pumping power required combine for a very low overall system efficiency. The best potentials for OTEC sites are in tropical and sub-tropical areas because of the higher temperature difference between the surface and the deep water. Although the potential of utilizing this zero emissions conversion technology is attractive, the high capital costs are expected to delay implementation. Also, some environmental questions remain regarding the effect of high pumping flow rates and local temperature changes on the surrounding aquatic environment.

OTEC systems are still in the development stage. A few 50-200 kW demonstration systems are being designed or tested in Hawaii. Due in part to the low cost of fossil fuels, which makes OTEC implementation less competitive, funding for OTEC research has been limited. Currently, new heat exchanger configurations are being tested for closed cycle OTEC systems, which could potentially improve performance and efficiency of OTEC systems.

11.4 Energy Storage Systems

11.4.1 Pumped Storage

A pumped storage hydroelectric facility requires a reservoir/dam system similar to a conventional hydroelectric facility. Excess energy is used to pump water from a lower reservoir to an upper reservoir above a dam. When this energy is required, the potential energy of the water in the upper reservoir is converted to electricity as the water flows through a turbine to the lower reservoir. Capital cost is the primary consideration in implementing this storage technology. With careful planning and construction, the environmental impact of this technology will be negligible. For this study, estimates of the cost and performance of a 30 MW pumped storage system has been provided. Table 11-20 presents typical performance and cost estimates.

Table 11-20
Pumped Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Power Capacity (MW)	30 (5 hour duration)
Energy Capacity (MWh)	150
Capacity Factor (percent)	20
Costs:	
Capital Cost ($/kW)	2,050
O&M Costs:	
Fixed O&M ($/kW-yr)	28
Variable O&M ($/MWh)	N/A
Levelized Cost (cents/kWh)	9.4 - 12.5[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.4.2 Battery Storage

A battery energy storage system consists of the battery, dc switchgear, dc/ac converter/charger, transformer, ac switchgear, and a building to house these components. During the utility peak periods, the battery system can discharge ac power to the utility system for around 4 to 5 hours. The batteries are then recharged during nonpeak hours.

In addition to the high initial cost, a battery system will require replacement every 8 to 10 years. Currently, the only commercially available battery systems are lead-acid based systems. Research to develop better performing batteries such as sodium-sulfur and zinc-bromine batteries is currently underway. Commercially available lead-acid systems have currently been installed with capacities of up to 21 MW, 140 MWh. The overall efficiency of battery systems is on average 72 percent from charge to discharge. The cost and performance of a 5 MW (15 MWh) system is provided in Table 11-21.

Table 11-21
Battery Energy Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Power Capacity (MW)	5 (3 hour duration)
Energy Capacity (MWh)	15
Capacity Factor (percent)	20
Costs:	
Capital Cost ($/kW)	2,500
O&M Costs:	
Fixed O&M ($/kW-yr)	13.5
Variable O&M ($/MWh)	310 (includes replacement)
Levelized Cost (cents/kWh)	12.0 - 14.0[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.4.3 Compressed Air Energy Storage

Compressed air energy storage (CAES) systems store energy in the form of compressed air in an underground cavern. Air is compressed during off-peak hours, stored in an underground cavern and then used when needed by expanding the compressed gas through a turbogeneration system. In combustion technology applications, over half the energy produced by the turbine generator is required to drive the compressors. The ability to compress the working fluid during the off-peak hours is the advantage of the CAES system. During peak hours the compressed air from the cavern is extracted and preheated in the recuperator. Once heated, the air is combusted with oil or gas and the hot exhaust is expanded through the combustion turbine. The location of a CAES plant must be suitable for cavern construction. To utilize this storage method, a new plant will typically be designed around the CAES system requirements.

The first commercial scale CAES plant in the world is a 290 MW plant in Huntorf, Germany. This plant has been operated since 1978, providing 2 hours of generation with 8 hours of charging. In 1991, a 110 MW CAES facility in McIntosh, Alabama began operation. CAES units have a reputation for achieving good availability. Table 11-22 shows the performance and cost characteristics of the compressed air energy storage.

Table 11-22
Compressed Air Energy Storage
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	25 - 300 MW
Availability (percent)	86
Costs:	
Capital Cost ($/kW)	1,230
O&M Costs:	
Fixed O&M ($/kW-yr)	8 - 20
Variable O&M ($/MWh)	6.0 - 12.0
Levelized Cost (cents/kWh)	6.0 - 6.5[1]

(1) California Energy Commission, 1996 Energy Technology Status Report, adjusted to 1998 dollars.

11.4.4 Fly Wheel Energy Storage

The flywheel provides a means to store energy in the form of rotational inertia. Flywheels have a number of advantages as an energy storage device. First, compared to other storage technologies, such as lead-acid batteries or pumped storage hydro systems, they are very compact due to a high energy density (Wh/kg). They have a very long life cycle with low operating and maintenance costs. They also can transfer large amounts of energy quickly. These advantages make flywheel systems particularly advantageous to the transportation industry, where weight reduction and quick energy transfer (fast acceleration) are important parameters. Although high tech prototype flywheels can exceed 80 percent efficiency from storage to release, they are still in the research and development stage. In order for a flywheel to be economically viable for general purpose energy storage, the capital cost must be reduced, the performance must be enhanced with new materials and low friction bearings, and the motor/generator controls need to be enhanced to better utilize flywheel energy under the always changing flywheel speed. Current research is focusing on the development of magnetic bearings utilizing high temperature superconductor technology. At this point in flywheel development, the price per stored energy is significantly lower for conventional battery systems. Flywheels currently cannot compete against battery systems, particularly in the power industry.

11.4.5 Super Conducting Magnetic Energy Storage

A superconducting magnetic energy storage (SMES) unit stores energy by allowing a current to pass through a "zero resistance" toriodal winding, storing the energy in a magnetic field. SMES systems for power industry storage applications are still in the research and development stage. The cost of these high tech systems must be reduced significantly before they will become commercially viable for large energy storage. Commercial SMES systems are available for eliminating power surges and dips in certain industries where elimination of these brief discontinuities is essential.

11.5 Nuclear (Fission)

The environmental and safety issues (and associated costs) involved with producing power from nuclear reactors has kept new nuclear plants from being constructed in the U.S. Table 11-23 provides a rough estimate of nuclear power plant costs.

11.6 Conventional Alternatives

Several conventional capacity addition alternatives were selected for consideration. The size of the alternatives selected considered the need for capacity and the suitability of the McIntosh site for installation of the alternatives. The alternatives considered include specific alternatives that Lakeland has studied in the past as well as generic alternatives. Conventional generating unit alternatives considered for capacity expansion included the following:

- Pulverized coal.
- Fluidized bed.
- Combined cycle.

- Simple cycle combustion turbine.

Table 11-23
Nuclear Power Plant
Performance and Costs

Commercial Status	Commercial
Performance:	
Typical Plant Capacity (MW)	>600 MW
Net Plant Heat Rate	10,500
Capacity Factor (percent)	65 - 80
Costs:	
Capital Cost ($/kW)	3,300
O&M Costs:	
Fixed O&M ($/kW-yr)	95
Variable O&M ($/MWh)	13.0
Levelized Cost (cents/kWh)	5.8 - 15.0

Combustion turbine based alternatives were based on the size and performance of specific machines, but were 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. The pulverized coal and fluidized bed units are assumed to be located at the McIntosh site. Combined cycle and simple cycle combustion turbines were assumed to be installed on the McIntosh site and to take advantage of existing infrastructure.

Performance and O&M cost estimates have been compiled for each capacity addition alternative. The estimates provide representative values for each generation alternative and show expected trends in performance and costs within a given technology as well as between technologies. Degradation is also included. Actual unit performance and availability will vary based on site conditions, regulatory requirements, and operation practices. Capital costs for conventional technology alternatives are in 1998 dollars.

11.6.1 Performance Estimates

11.6.1.1 Net Plant Output. Net plant output (NPO) is equal to the net turbine output less auxiliary power.

11.6.1.2 Equivalent Availability (EA). Equivalent availability is a measure of the capacity of a generating unit to produce power considering limitations such as equipment failures, repairs, and maintenance activities. The equivalent availability is equal to the maximum possible capacity factor for a unit as limited by forced, scheduled, and maintenance outages and deratings. The equivalent availability is the capacity factor that a unit would achieve if the unit were to generate every megawatt-hour it was available to generate.

11.6.1.3 Equivalent Forced Outage Rate (EFOR). Equivalent forced outage rate is a reliability index, which reflects the probability that a unit will be capable of providing power when called upon. It is determined by dividing the sum of forced outage hours plus equivalent forced outage hours, by the sum of forced outage hours plus service hours. Equivalent forced outage hours take into account the effect of partial outages and are equal to the number of full forced outage hours that would result in the same lost generation as actually experienced during partial outage hours.

11.6.1.4 Planned Maintenance Outage. Estimates are provided for the time required each year to perform scheduled maintenance.

11.6.1.5 Startup Fuel. Estimates for startup energy, where applicable, in millions of Btu, are based on the fuel required to bring the unit from a cold condition to the speed at which synchronization is first achievable under normal operation conditions.

11.6.1.6 Net Plant Heat Rate. Estimates for net plant heat rates are based on the higher heating value of the fuel. Heat rate estimates are provided for summer (97° F ambient) and winter (30° F ambient) conditions for combustion turbines and combined cycle units. Allowance for heat rate degradation over time because of aging has been included. Heat rates may vary as a result of factors such as turbine selection, fuel properties, plant cooling method, auxiliary power consumption, air quality control system, and local site conditions.

11.6.1.7 Degradation. For steam plants, performance degrades with time due to erosion, corrosion, and increased leakage. Similarly, performance of simple cycle combustion turbines and combined cycle plants will degrade with time. Periodic maintenance and overhauls can recover part of the degraded performance. However, some performance cannot be recovered. Approximations for performance degradation, which were applied to the new clean performance estimates of the combined cycle and simple cycle alternatives, included a 2.0 percent heat rate and 4 percent output degradation. A 2.0 percent heat rate degradation was assumed for the pulverized coal and fluidized bed alternatives with no capacity degradation assumed.

11.6.2 Cost Estimates

11.6.2.1 Capital Costs. Capital costs were developed on the basis of the current competitive generation market. Indirect costs include the typical items of engineering, construction management, general indirect costs, and contingency. In addition, other indirect costs included were SCADA interface costs, spares, owner's engineer, permitting, training, and substation costs to integrate the unit into the McIntosh substation in order to place the costs on a comparable basis with costs resulting from purchase power bids. Direct costs for the combined cycle alternatives include bypass stacks with dampers, along with continuous emissions monitoring equipment. Direct costs for natural gas alternatives include a fuel oil storage tank. Costs for the coal units to be located at McIntosh site include costs for substation integration. Total capital cost is the summation of direct and indirect cost and interest during construction for commercial operation. The construction period is the time from start of construction to commercial operation. The construction period was used to estimate costs for interest during construction (IDC).

11.6.2.2 O&M Costs. O&M estimates are based on a unit life of 25 years for combustion turbines and combined cycles, variable and fixed contingency of 20 percent, and baseload capacity factor of 92 percent (except simple cycle units which assumed a capacity factor of 30 percent for the 501G, 20 percent for the 501F, and 5 percent for all others). Fixed O&M costs are those that are independent of plant electrical production. The largest fixed costs are wages and wage-related overheads for the permanent plant staff. Fuel costs typically are determined separately and are not included in either fixed or variable O&M costs. The O&M costs presented in this application are typically referred to as nonfuel O&M costs. Variable O&M costs include disposal of combustion wastes and consumables such as scrubber additives, chemicals, lubricants, water, and maintenance repair parts. Variable O&M costs vary as a function of plant generation.

11.6.2.3 Coal-Fueled O&M. O&M and performance estimates for the coal-fueled alternatives were based on the following assumptions.

Fixed O&M costs include operating staff salary costs, basic plant supplies, and administrative costs. Variable operations costs include an assumed lime cost of \$95/ton for flue gas desulfurization (FGD); limestone cost of \$22/ton for the CFB; waste disposal, which includes trucking to an onsite landfill, dozing and flattening (mobile reclaim equipment); and startup fuel oil. Variable maintenance costs are the costs associated with the inspection/maintenance of plant components based on the operating time of the plant, such as steam turbine inspection costs. Staffing estimates provided are based on recent utility experience with modern facilities.

An additional variable O&M cost of 0.73 $/MWh is included for the SCR, which includes NH_3 costs and catalyst replacement costs. For the SNCR, the additional variable O&M cost is approximately 0.52 $/MWh for NH_3 costs. The pulverized coal unit is assumed to require SCR, while the fluidized bed unit is assumed to require SNCR. The PCFB unit is assumed to require an SCR.

McIntosh 4, a proposed Pressurized Circulating Fluidized Bed unit is currently in the design stages. It has not been determined if a scrubber will be required for this unit. For the economic analysis, the O&M cost for the scrubber has been included.

11.6.2.4 Combined and Simple Cycle O&M. O&M and performance estimates for the combined cycle and simple cycle units were based on the following assumptions:

- Primary fuel--Natural gas.
- NO_x control method--Dry low NO_x combustors.
- Capacity and heat rate degradation of 4 and 2 percent, respectively, has been included in the performance estimates.
- Combustion turbine generator (CTG) maintenance estimated costs provided by manufacturers.
- CTG specialized labor cost estimated at $38/man-hour for Westinghouse and $35/man-hour for General Electric (provided by manufacturers).
- CTG operational spares, combustion spares, and hot gas path spares are not included in the O&M cost. These costs are included in the capital cost.
- Heat recovery steam generator (HRSG) annual inspection costs are estimated based on manufacturer input and Black & Veatch data.
- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralizer cycle makeup water and cooling tower raw water are included.

- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle 501G is based on a 30 percent capacity factor.
- O&M costs for the simple cycle 501F is based on 20 percent capacity factor.
- O&M costs for all other simple cycle alternatives are based on a 5 percent capacity factor.

11.6.3 Pulverized Coal

A 250 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be located at the existing McIntosh site. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 11-24 presents the estimated cost and performance of the 250 MW pulverized coal unit.

11.6.4 Fluidized Bed

A 250 MW atmospheric circulating fluidized bed unit (CFB) with 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, the CFB is assumed to burn coal. Like the pulverized coal unit, the CFB is assumed to be located at the existing McIntosh site. Coal is assumed to be delivered by rail and cooling is achieved with mechanical draft cooling towers. Table 11-25 presents the estimated cost and performance of the 250 MW CFB unit.

Table 11-24
Estimated Cost and Performance of 250 MW Pulverized Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 1998 $1,000	186,577
Indirect Capital Cost, 1998 $1,000	81,658 [1]
Total Capital Cost, 1998 $1,000	268,235
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	23.18
Variable O&M Cost, 1998 $/MWh	2.46
Equivalent Availability, percent	85
Equivalent Forced Outage Rate, percent	7
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), Mbtu	1,000
Construction Period, months	30
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	250,000/10,141
75 Percent of Full Load	187,000/10,317
50 Percent of Full Load	125,000/10,878
25 Percent of Full Load	62,500/13,062

(1) Includes interest during construction.

Table 11-25
Estimated Cost and Performance of 250 MW Fluidized Bed Coal Unit

Item	
Steam Pressure, psia	2,535
Steam Temperature, °F	1,000
Reheat Steam Temperature, °F	1,000
Direct Capital Cost, 1998 $1,000	173,409
Indirect Capital Cost, 1998 $1,000	78,537 (1)
Total Capital Cost, 1998 $1,000	251,946
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	18.75
Variable O&M Cost, 1998 $/MWh	1.77
Equivalent Availability, percent	84
Equivalent Forced Outage Rate, percent	7
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), Mbtu	4,200
Construction Period, months	30
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	250,000/10,543
75 Percent of Full Load	187,500/10,803
50 Percent of Full Load	125,000/11,593
25 Percent of Full Load	62,500/14,516

(1) Includes interest during construction.

11.6.5 Pressurized Circulating 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 Pressurized Circulating Fluidized Bed (PCFB) 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 Department of Energy (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 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 adds the topped cycle.

The 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. The DOE funding also covers 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 after the conversion of McIntosh 5. Table 11-26 presents the estimated cost and performance for the DOE PCFB project. The unit will be capable of burning both coal and petroleum coke.

11.6.6 Combined Cycle

Four combined cycle units were selected as generating unit alternatives:

- 1 x 1 General Electric 7EA (Table 11-27)
- 2 x 1 General Electric 7EA (Table 11-28)
- 1 x 1 Westinghouse 501F (Table 11-29)
- 1 x 1 Westinghouse 501G (Table 11-30)

The combined cycles all utilize conventional, heavy-duty, industrial-type, combustion turbines. Several other vendors were analyzed and demonstrated similar performance characteristics or performances that were less efficient than the alternatives selected. The combined cycles would be dual fueled with natural gas as the primary fuel. Specifications for performance and operating costs are based on natural gas fuel and baseload operation. The combined cycles assume that emission requirements will be met with dry low NO_x combustors. The units would be located at the McIntosh site and would utilize existing common facilities to the extent possible. Natural gas compressors are not included in the cost estimates because natural gas pipeline pressure is assumed adequate.

Table 11-26
Generating Unit Characteristics
DOE Pressurized Fluidized Bed Unit – Phase I

Item	
Steam Pressure, psia	2,400
Steam Temperature, °F	1,050
Reheat Steam Temperature, °F	1,050
Direct Capital Cost, 1998 $1,000	119,383
Indirect Capital Cost, 1998 $1,000	23,877 (1)
Total Capital Cost, 1998 $1,000(2)(3)	143,260
O&M Cost-Baseload Duty	
Fixed O&M Cost, 1998 $/kW-y	27.65
Variable O&M Cost, 1998 $/MWh	1.73
Equivalent Availability, percent	74.2
Equivalent Forced Outage Rate, percent	12
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), Mbtu	1,200
Construction Period, months	28
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	238,000/8,776
75 Percent of Full Load	173,000/9,031
50 Percent of Full Load	122,000/9,961
25 Percent of Full Load	83,000/11,687

(1) Includes interest during construction.
(2) Total capital cost is reduced by DOE funding including 4 years of O&M contributions applied to the total capital cost.
(3) This estimate is not finalized and may be lowered if the scrubber is not required and contingency costs can be lowered.

Table 11-27
Generating Unit Characteristics
General Electric 7EA 1 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	53,695	
Indirect Capital Cost, 1998 $1,000	11,085 (1)	
Total Capital Cost, 1998 $1,000	64,780	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	3.29	
Variable O&M Cost, 1998 $/MWh	2.37	
Equivalent Availability, percent	92.1	
Equivalent Forced Outage Rate, percent	3.7	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	59	
Construction Period, months	20	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30°F
100 Percent of Full Load	109,939/8,114	127,538/7,642
79 Percent of Full Load	86,852/8,454	100,755/7,928
59 Percent of Full Load	64,864/9,219	75,248/8,507
35 Percent of Full Load	38,479/11,288	44,638/10,201

(1) Includes interest during construction.

Table 11-28
Generating Unit Characteristics
General Electric 7EA 2 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,250	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	89,586	
Indirect Capital Cost, 1998 $1,000	20,779 (1)	
Total Capital Cost, 1998 $1,000	110,365	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.24	
Variable O&M Cost, 1998 $/MWh	2.16	
Equivalent Availability, percent	92.5	
Equivalent Forced Outage Rate, percent	3.0	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	119	
Construction Period, months	22	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	222,096/7,938	257,217/7,585
75 Percent of Full Load	166,572/8,258	192,912/7,812
50 Percent of Full Load	111,048/8,178	128,609/7,661
25 Percent of Full Load	55,524/9,865	64,304/9,063

(1) Includes interest during construction.

Table 11-29
Generating Unit Characteristics
Westinghouse 1 x 1 501F Combined Cycle

Item		
Steam Pressure, psia	1,800	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 1998 $1,000	95,370	
Indirect Capital Cost, 1998 $1,000	22,799 (1)	
Total Capital Cost, 1998 $1,000	118,169	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	2.40	
Variable O&M Cost, 1998 $/MWh	2.30	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	85	
Construction Period, months	25	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	236,630/6,945	268,902/6,635
75 Percent of Full Load	175,106/7,483	201,677/6,952
52 Percent of Full Load	123,048/8,011	142,519/7,495
27 Percent of Full Load	63,890/10,474	75,293/9,632

(1) Includes interest during construction.

Table 11-30
Generating Unit Characteristics
Westinghouse 1 x 1 501G Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 1998 $1,000	135,500	
Indirect Capital Cost, 1998 $1,000	33,185 (1)	
Total Capital Cost, 1998 $1,000	165,685	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	1.133	
Variable O&M Cost, 1998 $/MWh	1.266	
Equivalent Availability, percent	91.6	
Equivalent Forced Outage Rate, percent	4.5	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), MBtu	92	
Construction Period, months	27	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	337,507/6,699	384,380/6,249
75 Percent of Full Load	253,130/6,877	288,285/6,415
50 Percent of Full Load	168,754/7,603	192,190/7,091
25 Percent of Full Load	118,127/8,922	134,533/8,321

(1) Includes interest during construction.

11.6.7 Simple Cycle Combustion Turbine

Three simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric LM6000 (Table 11-31)
- General Electric 7EA (Table 11-32)
- Westinghouse 501F (Table 11-33)

The 7EA and 501F combustion turbines are heavy-duty, industrial combustion turbines. The LM6000 is an aeroderivative combustion turbine. The combustion turbines are dual fueled with specifications for performance and operating costs based on natural gas operation.

Table 11-31 Generating Unit Characteristics General Electric LM6000 Simple Cycle		
Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	15,275	
Indirect Capital Cost, 1998 $1,000	3,224 (1)	
Total Capital Cost, 1998 $1,000	18,499	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	5.45	
Variable O&M Cost, 1998 $/MWh	6.92	
Equivalent Availability, percent	95.8	
Equivalent Forced Outage Rate, percent	2.3	
Planned Maintenance Outage, weeks/y	1	
Startup Fuel (cold start), MBtu	6	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	33,360/10,684	42,796/10,051
75 Percent of Full Load	25,020/11,472	32,097/10,462
50 Percent of Full Load	16,680/13,359	21,398/11,783
25 Percent of Full Load	8,340/19,292	10,699/16,297

(1) Includes interest during construction.

Table 11-32
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	21,228	
Indirect Capital Cost, 1998 $1,000	4,917 (1)	
Total Capital Cost, 1998 $1,000	26,145	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	3.32	
Variable O&M Cost, 1998 $/MWh	23.56	
Equivalent Availability, percent	95.6	
Equivalent Forced Outage Rate, percent	2.1	
Planned Maintenance Outage, weeks/y	1.25	
Startup Fuel (cold start), MBtu	12	
Construction Period, months	13	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	72,432/12,335	83,767/11,643
75 Percent of Full Load	54,324/13,504	62,825/12,705
50 Percent of Full Load	36,216/15,844	41,884/14,895
25 Percent of Full Load	18,108/23,515	20,942/21,513

(1) Includes interest during construction.

Table 11-33
Generating Unit Characteristics
Westinghouse 501F Simple Cycle Combustion Turbine

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 1998 $1,000	42,585	
Indirect Capital Cost, 1998 $1,000	9,962 (1)	
Total Capital Cost, 1998 $1,000	52,547	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 1998 $/kW-y	5.50	
Variable O&M Cost, 1998 $/MWh	2.00	
Equivalent Availability, percent	91.8	
Equivalent Forced Outage Rate, percent	4.1	
Planned Maintenance Outage, weeks/y	2.25	
Startup Fuel (cold start), Mbtu	85	
Construction Period, months	14	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	97° F	30° F
100 Percent of Full Load	156,100/11,216	186,500/10,243
75 Percent of Full Load	117,075/12,142	139,875/11,089
50 Percent of Full Load	78,050/13,843	93,250/12,642
25 Percent of Full Load	39,025/17,276	46,625/15,778

(1) Includes interest during construction.

12.0 Supply-Side Screening

Lakeland has conducted a very thorough search for supply-side alternatives that would best fit the planning needs for future demands. The numerous supply-side alternatives identified in Section 11.0 must be reduced by screening methods to arrive at an acceptable number of alternatives to model in detail. Lakeland has conducted a two-phase screening process to reduce the number of alternatives. The first phase of the screening process, Phase I, eliminates alternatives that are not technically or commercially viable for Lakeland. The second phase, Phase II, eliminates alternatives based upon a busbar analysis. Details of the screening process are outlined below.

12.1 Phase I Screening

The first phase eliminated alternatives that were not technically feasible or are still under commercial development at this time. Alternatives that were eliminated for technical feasibility were based upon Lakeland's ability to support the proposed technology. Instances where Lakeland could not support the resources necessary for the technology include: wind, hydrology, and additional refuse derived fuels. Below is a discussion of why each alternative or alternative group was eliminated from the study.

12.1.1 Renewable Technologies

The five renewable technologies identified in Section 11.1, including: wind energy, solar thermal and photovoltaics, wood chip, geothermal, and hydroelectric were reviewed to determine if Lakeland could support the technical feasibility and provide the available resources needed for these alternatives. Lakeland could not support the wind generation technologies due to the wind conditions necessary for generation. The wood generation technologies were deleted from consideration due to environmental emission concerns and lack of raw materials for baseload operation. Geothermal and hydroelectric alternatives were eliminated due to a lack of natural resources to support these technologies. Solar thermal and photovoltaics were considered for Phase II.

12.1.2 Waste Technologies

Waste technologies evaluated include mass burn units, refused derived fuel (RDF), landfill gas, sewage sludge, and used tire fueled generating units. All waste technology alternatives were eliminated based on insufficient fuel supply availability. Lakeland is currently burning all city-collected refuse and some county refuse. Lakeland currently does not have landfill sites where methane gas is being collected. The City currently uses all sewage residuals at established wetlands south of town. There are no known tire storage facilities in Polk County.

12.1.3 Advanced Technologies

Advanced technologies evaluated include humid air turbine (HAT), Kalina and Cheng cycles, advanced coal technologies, magnetohydrodynamics, fuel cells, fusion, and ocean wave and ocean tidal systems. Only fuel cell and supercritical coal technologies are considered commercially viable at this time. Therefore, the other alternatives were eliminated from further consideration.

12.1.4 Energy Storage Systems

Energy storage systems evaluated include pumped storage, battery storage, compressed air energy storage, flywheel storage, and super conducting magnetic energy storage. Pumped storage and compressed air are commercially proven resources, but Lakeland's natural resources do not provide access to these technologies. Battery storage, flywheel storage, and super conducting magnetic storage were eliminated from further consideration since the status of these alternatives is experimental.

12.1.5 Nuclear

Nuclear power was included for the next level of screening.

12.1.6 Conventional Technologies

Conventional generating unit alternatives considered for capacity expansion include pulverized coal, fluidized bed, combined cycle, and simple cycle combustion turbines. These alternatives were included in the second phase of screening analysis.

12.2 Phase II Screening

The alternatives that passed the initial screening analysis of Phase I are included in the Phase II screening analysis, which considers the capital and operating costs of the units on a busbar level. Supply-Side alternatives that pass the Phase II screening will be modeled in detail for the economic evaluation of supply-side alternatives. Figure 12-1 and 12-2 displays the busbar screening curve based upon the cost and performance estimates provided in the tables in Section 11.0. Details of the screening are provided in the following subsections.

12.2.1 Renewable Technologies

The two remaining renewable technologies, after the Phase I screening analysis, are the solar thermal and photovoltaics technologies. Lakeland reviewed these alternatives as a generating technology for supply to consumers and found that the capital and operating costs to be two to three times the costs of operating a conventional alternative. While solar technologies may fulfill a potential niche market, as Lakeland is researching, for remote generation or conservation devices, the technologies do not represent a cost-effective alternative at this juncture. Lakeland is currently promoting solar and photovoltaic technologies through their involvement in projects discussed in 8.2.1 through 8.2.3.

12.2.2 Waste Technologies

No waste technologies passed Phase I screening do to insufficient fuel supply for baseload generation. As an aside, most of the alternatives would be too costly to build and operate in comparison to conventional alternatives.

12.2.3 Advanced Technologies

Advanced technologies that passed the Phase I screening was advanced coal technologies and fuel cells. These alternatives were analyzed based on capital and operating costs and eliminated from further considerations.

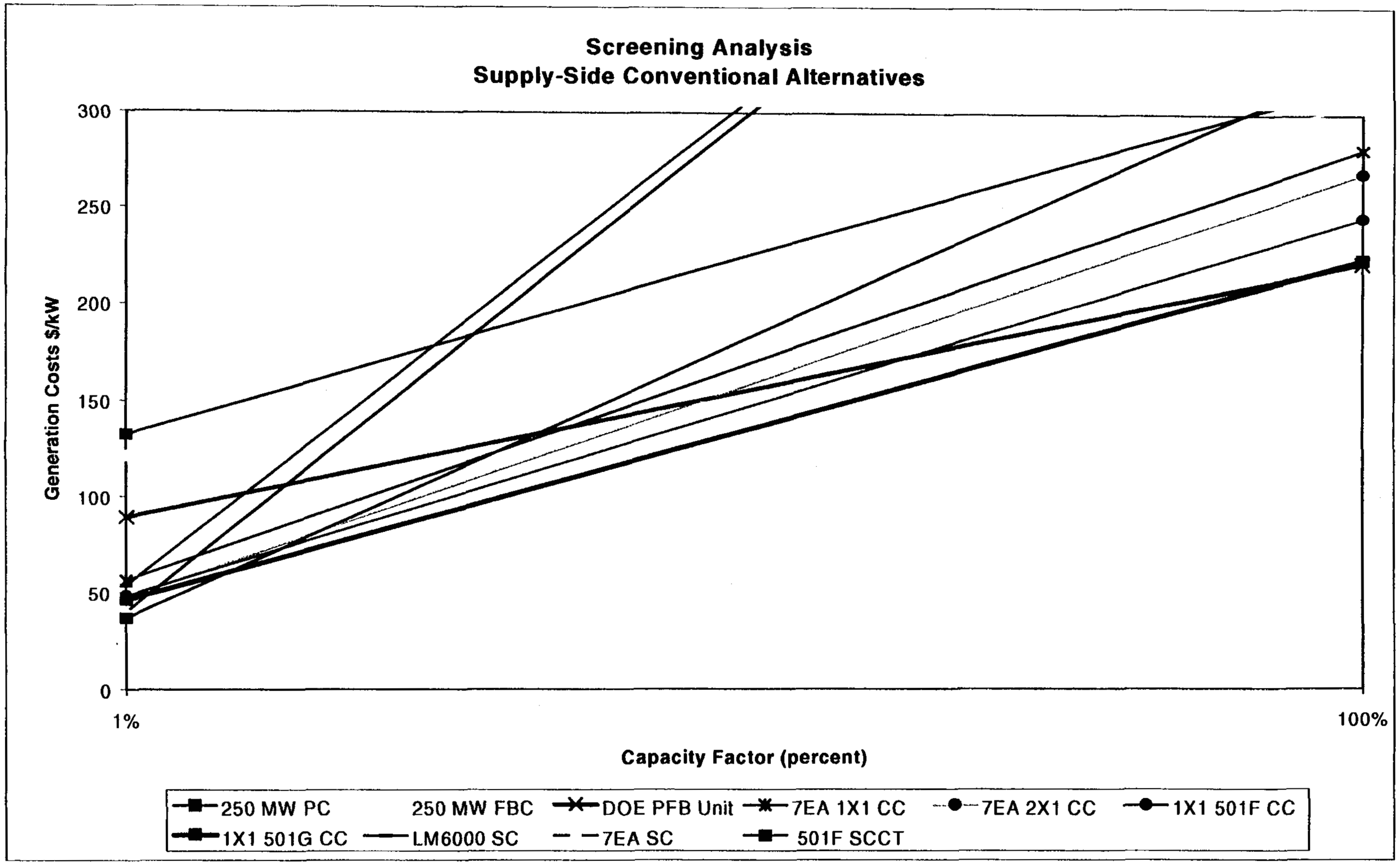

Figure 12-1: Generation Cost Screening Analysis for Conventional Alternatives

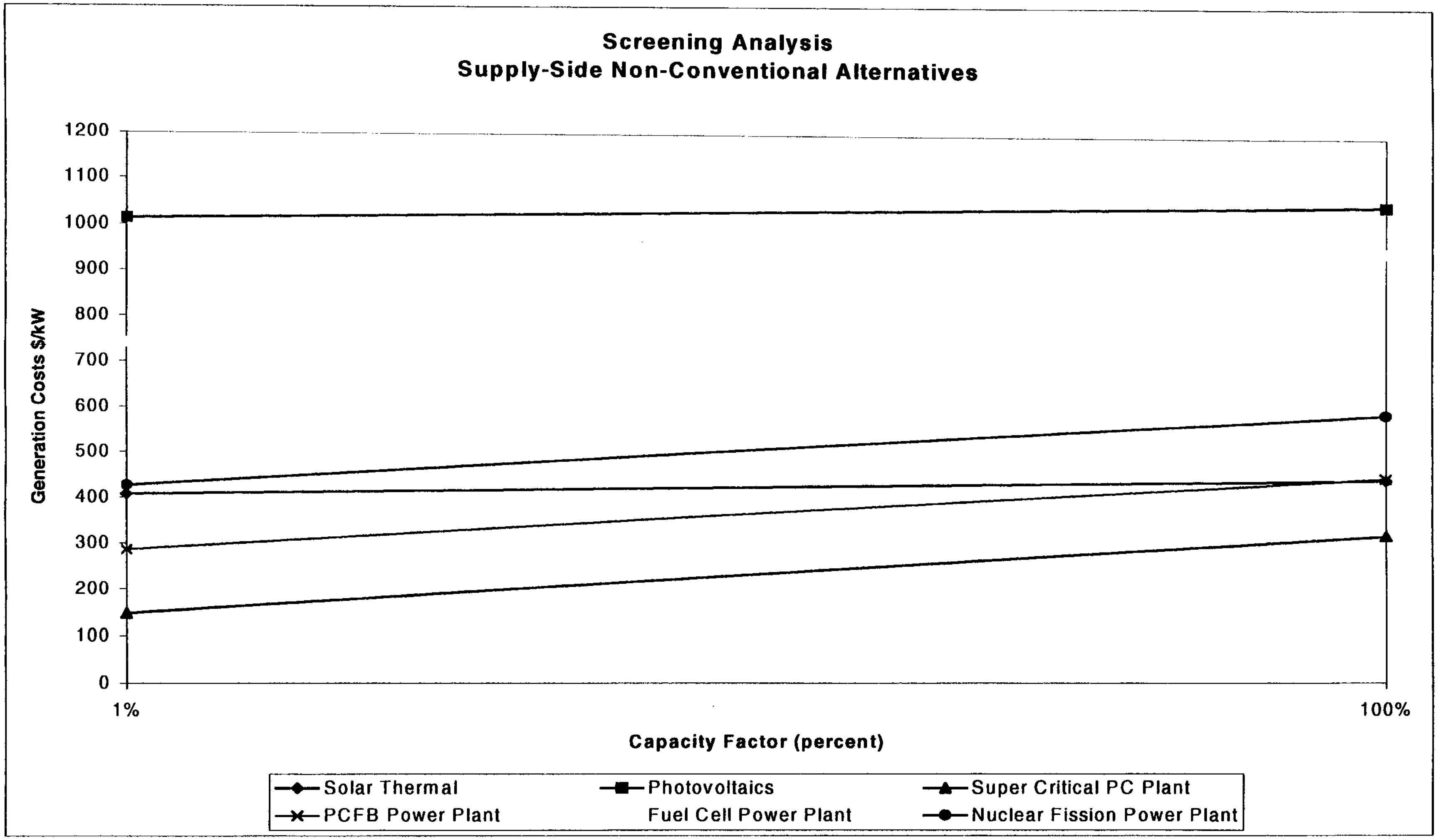

Figure 12-2: Generation Cost Screening Analysis for Conventional Alternatives

12.2.4 Energy Storage Systems

Energy storage systems were eliminated from further consideration in Phase I due to lack of resources or the status of these alternatives as experimental. Also the alternatives were very costly to build and operate at this point.

12.2.5 Nuclear

Nuclear power represents a capital-intensive technology and as demonstrated on the screening curves, it would not be a cost-effective alternative. Therefore, is eliminated from consideration because of the high capital cost and uncertain licensing requirements. The public concern and environmental aspects also factored into eliminating this alternative.

12.2.6 Conventional Technologies

Conventional generating unit alternatives all passed the Phase I screening process. The alternatives that passed the two-phase screening are included in the detailed economic analysis in Section 13.0.