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Black & Veatch Corporation

Lakeland Electric
2000 Ten Year Site Plan

B&V Project 96592
B&V File 14.0000
April 10, 2000

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

Subject: 2000 Ten Year Site Plan

Attention: Ms. Blanca S. Bayo
Director

Dear Ms Bayo:

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

Very truly yours,

BLACK & VEATCH

Myron Rollins

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2000 Ten-Year Site Plan

LAKELAND ELECTRIC

ORIGINAL

2000 Ten-Year Site Plan For Electrical Generating Facilities and Associated Transmission Lines

Submitted to Florida Public Service Commission

April 2000

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BLACK & VEATCH
Holding Company

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Executive Summary

This report documents the 2000 Lakeland Electric (Lakeland) Ten-Year Site Plan pursuant to 186.801 Florida Statutes and 25-22.070 - 22.073 of Florida Administrative Code. The Ten-Year Site Plan provides information required by this rule. The Plan is divided into nine main sections: Introduction, General Description of Utility, Forecast of Electrical Power Demand and Energy Consumption, Conservation and Demand-Side Management, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Environmental and Land Use Information, Analysis Results and Conclusions, and Ten-Year Site Plan Schedules.

Power for the City of Lakeland is supplied by Lakeland Electric wholly and jointly owned generating units. Lakeland Electric 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, 2000. The existing supply system has a broad range of generation technology and capabilities, but is heavily dependent upon natural gas.

Lakeland Electric 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. Lakeland has reevaluated its reserve margin criteria using an uncertainty factor methodology similar to that employed by the Florida Reliability Coordinating Council (FRCC). The results of that analysis are driving Lakeland to increase its reserve margin to 20 percent in summer and 22 percent in winter. The increase is needed to account for such uncertainties as generation availability at time of peak, forecast uncertainties along with the availability of DSM and interruptible loads. This change is consistent with the Florida investor owned utilities that have agreed to increase their reserve margin criteria to 20 percent. The summer reserve requirement drives Lakeland's capacity addition requirements. 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 the summer of 2005.

Lakeland Electric 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 energy efficiency promotion programs.

Numerous self-build alternatives were developed for planning purposes and considered in the screening analysis for capacity additions. The alternatives were modeled in Black & Veatch's POWROPT and POWRPRO optimal generation expansion and chronological production cost programs to rank potential expansion plans 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 Lakeland Electric's commitment to the community.

Based on the detailed modeling of the Lakeland Electric'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.

The Base Case Expansion Plan is consistent with Lakeland's desire to lesson dependency on natural gas. To implement the Base Case Expansion Plan, Lakeland plans to issue a request for proposals (RFP) for projects to be built at McIntosh and owned by Lakeland and for purchased power. This market place test will ensure Lakeland's customers obtain power at the lowest costs consistent with full consideration given to reliability and diversity.

Table ES-1
Base Case Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	83,528	83,528
2001	Larsen 7 retired (50 MW)	94,811	172,972
2002	Convert McIntosh 5 to CC (120 MW)	79,215	243,473
2003	McIntosh 1 retired (87MW)	84,353	314,297
2004		90,706	386,145
2005	McIntosh 4 PFBC (188 MW)	103,717	463,649
2006	McIntosh 2 retired (103 MW)	116,650	545,882
2007		122,190	627,146
2008		127,268	706,995
2009	LM 6000 (32 MW)	135,113	786,968
2010		142,382	866,474
2011		139,105	939,753
2012		144,629	1,011,629
2013		151,087	1,082,464
2014		157,761	1,152,242
2015		164,533	1,220,896
2016		343,907	1,356,273
2017	LM 6000 (32 MW)	182,483	1,424,041
2018		192,166	1,491,365
2019		200,273	1,557,558

[1]Capacity is stated in summer ratings.

1.0 Introduction

This report documents the 2000 Lakeland Electric Ten-Year Site Plan (TYSP) pursuant to Florida Statutes. The Lakeland Electric TYSP provides the information required by this rule as adopted by Order No. PSC-97-1373-FOF-EU on October 30, 1997. The Plan is divided into nine main sections: Introduction, General Description of Utility, Forecast of Electrical Power Demand and Energy Consumption, Conservation and Demand-Side Management, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Environmental and Land Use Information, Analysis Results and Conclusions, and Ten-Year Site Plan Schedules.

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 the summary of the load forecast for Lakeland's system. 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 1.60 and 2.15 percent, respectively, for 2000 through 2019.

Net energy for load is projected to grow at an average annual rate of 2.12 percent over the next 10 years compared to 2.84 percent over the last 10 years. Projections are also developed for high and low load growth scenarios.

1.3 Conservation and Demand-Side Management

Section 4.0 provides descriptions of the existing conservation and demand-side management programs and additional programs that have been evaluated. Additional details regarding Lakeland's demand-side management programs are on file with the PSC.

Lakeland's current conservation and demand management programs include the following programs for which demand and energy savings can readily be demonstrated:

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

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

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

1.4 Forecasting Methods and Procedures

Section 5.0 provides the forecasting methods for the TYSP and outlines the assumptions applied for system planning. This section summarizes the integrated resource plan for Lakeland and provides planning criteria for the Florida Municipal Power Pool, in which Lakeland is a member. The integrated resource plan is fully integrated into the TYSP.

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

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

1.5 Forecast of Facilities Requirements

Section 6.0 integrates the electrical demand and energy forecast with the conservation and demand-side management forecast to determine 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 Lakeland Electric.

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 over 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 of 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 has a 40 percent undivided interest in the unit. McIntosh Unit No. 3 became commercial on September 1, 1982.

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

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

In spite of the demand and energy savings from Lakeland's conservation and demand-side management programs, additional capacity was needed. Studies indicated that conversion of one of our existing steam units with a new combustion turbine to a combined cycle unit would result in the least cost to Lakeland's 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. Both companies paid premiums to Lakeland for termination of these contracts. As a result of the two contracts expiring, Lakeland brought Larsen Unit 6 out of cold shutdown to meet reliability needs for generation capacity.

Additionally in 1999, the construction of McIntosh Unit 5 Simple Cycle combustion turbine was completed. The Unit is in the final stages of check out and testing and is scheduled to be released to Lakeland for commercial operation April 1, 2000. The unit will be converted to a combined cycle unit by the addition of a steam turbine generator with construction of the conversion to begin June 1, 2000.

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.

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 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.

In 1999 Lakeland added generation at its McIntosh Power Plant which resulted in a new 230/69/12kV substation being built and energized in March of that year. The substation, Tenoroc, replaced the switching station called North McIntosh. In addition to Tenoroc, a new 230/69/12kV substation was built. The substation, Interstate, went on line June of 1999 and is connected by what was the McIntosh – West 230 kV line. This station was built to address concerns about load growth in the areas adjacent to the I-4 corridor which were causing problems at both the 69kV and distribution levels in this area.

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 108.6 miles of the 69 kV transmission and 18.3 miles of the 230 kV transmission lines in service along with five 150 MVA 230/69 kV autotransformers.

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

Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt Fuel Days Use[3]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Net Capability[2] Summer MW	Net Capability[2] Winter MW
Charles Larsen	2	16-17/28S/24E	GT	NG	FO2	PL	TK	NR	11/62	Unknown	11,500	10.0	14.0
Memorial	3		GT	NG	FO2	PL	TK	NR	12/62	Unknown	11,500	10.0	14.0
	5		CW	WH	NA	NA	NA	NR	04/56	Unknown	25,000	29.0	31.0
	6		ST	NG	FO6	PL	TK	NR	12/59	07/00	25,000	25.0	27.0
	7		ST	NG	FO6	PL	TK	NR	02/66	03/01	50,000	50.0	50.0
	8		CT	NG	FO2	PL	TK	NR	07/92	Unknown	101,520	73.0	93.0
Plant Total												197.0	229.0
C.D.	IC1	4-5/28S/24E	IC	FO2	NA	TK	NA	NR	01/70	Unknown	2,500	2.5	2.5
McIntosh, Jr.	IC2		IC	FO2	NA	TK	NA	NR	01/70	Unknown	2,500	2.5	2.5
	1GT		GT	NG	FO2	PL	TK	NR	05/73	Unknown	26,640	17.0	20.0
	1		ST	NG	FO6	PL	TK	NR	02/71	10/02	103,000	87.0	87.0
	2		ST	NG	FO6	PL	TK	NR	06/76	10/05	126,000	103.0	103.0
	3[1]		ST	BIT	REF	RR	TK	NR	09/82	Unknown	363,870	205.0	205.0
Plant Total												417.0	420.0
System Total												614.0	649.0

[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Net Normal.
[3]Lakeland does not maintain records of the number of days that alternate fuel is used.

Source: Lakeland Power Production Unit Rating Group

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	Land Improvements	Buildings and Equipment	Total
Charles Larsen Memorial	18	8.7	28	0	86,655	86,684
C. D. McIntosh, Jr.*	513	300	2,815	0	337,385	340,200

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

Source: Lakeland Finance (CPR System).

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

Plant Name	Unit	Particulate	Flue Gas Cleaning		Type
			SO_x	NO_x	
Charles Larsen Memorial	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

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 MW and 197 MW, respectively. Unit 1 was an 11.5 MW gas turbine that was physically removed from the plant in 1998 and sold to General Electric for economic reasons. 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 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 was slated for retirement in March 1999 but due to delay of commercial operation of McIntosh Unit 5 it is now scheduled for retirement in July, 2000. Unit 7 underwent 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 January 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. Construction of Lakeland's seventh unit at McIntosh (Unit 5) is complete, as a 249 MW Westinghouse 501G combustion turbine. The unit is scheduled for commercial operation by April 1, 2000. 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). The 501G simple cycle combustion turbine will be converted to combined cycle for commercial operation in January 2002.

The McIntosh Unit 5 conversion that has been approved by the Public Service Commission 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 five 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. The Larsen Unit 7 underwent major maintenance to replace plugged boiler tubes allowing Lakeland to return the unit back to its normal dispatchable capacity of 50 MW.

The second and third contracts are with TEA and Entergy Power Marketing Corporation (EPMC) for 50 MW of summer capacity each. EPMC's contract is for April of 2000, through September of 2000 and TEA's contract begins May of 2000 ending September of 2000.

The fourth contract is with Florida Power Corporation (FPC) for 54 MW of summer capacity beginning June of 2000 and ending August 31, 2000.

The fifth 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 15, 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 currently has no power purchase contracts.

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 less 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 6	41	25.0	27.0	07/2000
Larsen 7	34	50.0	50.0	03/2001
McIntosh 1	29	87.0	87.0	10/2002
McIntosh 2	24	103.0	103.0	10/2005

Larsen 6 was removed 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 commercial operation of McIntosh 5. 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. McIntosh Unit 2 is scheduled for retirement October of 2005 after completion of McIntosh 4. The McIntosh 4 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, but is significantly dependent on natural gas. Lakeland's 2000 total 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 July of 2000.

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 in 1999 was 610 MW occurring in January. The summer peak was 535 MW occurring in August 1999. The summer peak demand actually dictates the addition of new units due to the decreased output of generating units in warmer temperature.

Lakeland's historical and projected summer and winter peak demands are presented in Section 3.5 for the base, high, and low cases, respectively.

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). The 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.

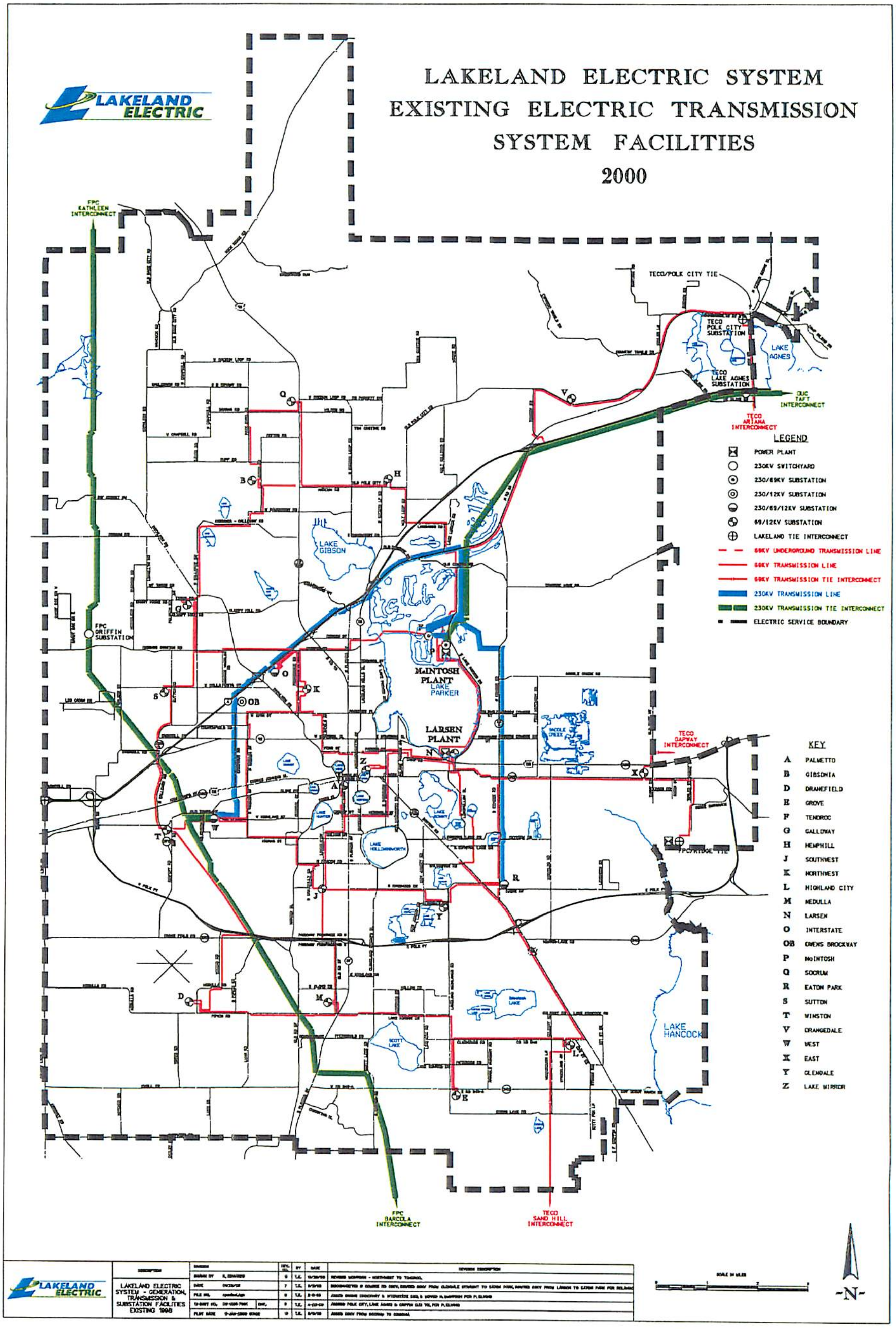
2.2.7 Transmission and Interconnections

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 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 one 69/12 kV substations, feeding more than 90 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 Tenoroc 230 kV switchyard which also has a 230/69 kV autotransformer. A fifth 230/69 kV autotransformer is located at the Interstate substation 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.


LAKELAND ELECTRIC SYSTEM
EXISTING ELECTRIC TRANSMISSION
SYSTEM FACILITIES
2000
LAKELAND ELECTRIC
FPC KATHLEEN INTERCONNECT
TECO/POLK CITY TIE
TECO POLK CITY SUBSTATION
LAKE AGNES
TECO LAKE AGNES SUBSTATION
OUC TAFT INTERCONNECT
TECO ARIANA INTERCONNECT
LEGEND
POWER PLANT
230KV SWITCHYARD
230/69KV SUBSTATION
230/12KV SUBSTATION
230/69/12KV SUBSTATION
69/12KV SUBSTATION
LAKELAND TIE INTERCONNECT
69KV UNDERGROUND TRANSMISSION LINE
69KV TRANSMISSION LINE
69KV TRANSMISSION TIE INTERCONNECT
230KV TRANSMISSION LINE
230KV TRANSMISSION TIE INTERCONNECT
ELECTRIC SERVICE BOUNDARY
LAKE GIBSON
FPC GRIFFIN SUBSTATION
McINTOSH PLANT
LAKE PARKER
LARSEN PLANT
TECO GAPWAY INTERCONNECT
FPC/RIDGE TIE
LAKE HOLLINGSWORTH
SCOTT LAKE
LAKE HANCOCK
FPC BARCOLA INTERCONNECT
TECO SAND HILL INTERCONNECT
KEY
A PALMETTO
B GIBSONIA
D DRANEFIELD
E GROVE
F TENOROC
G GALLOWAY
H HEMPHILL
J SOUTHWEST
K NORTHWEST
L HIGHLAND CITY
M MEDULLA
N LARSEN
O INTERSTATE
OB OWENS BROCKWAY
P McINTOSH
Q SOCRUM
R EATON PARK
S SUTTON
T WINSTON
V ORANGEDALE
W WEST
X EAST
Y GLENDALE
Z LAKE MIRROR
LAKELAND ELECTRIC
LAKELAND ELECTRIC SYSTEM - GENERATION, TRANSMISSION & SUBSTATION FACILITIES EXISTING 1998
-N-

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. Lakeland's fiscal year ends on September 30.

Lakeland develops forecasts for the following areas:

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

The following sections discuss each of the forecast areas. The information is presented on a fiscal year basis and is aggregated as required by Florida Reliability Coordinating Council (FRCC).

3.1 Population Forecast

Lakeland used the 1998 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 service territory population is projected to increase at a 1.41 percent average annual growth rate (AAGR) from 2000 through 2019. The service area population is shown in Table 3-1.

3.2 Accounts Forecast

Lakeland forecasts the number of accounts in the following categories:

- Residential.
- Commercial:
  - General Service.
  - General Service Demand.
- Industrial:
  - General Service Large Demand.
- Street & Highway Lighting
  - Private Area Lighting
  - Unmetered
- Other:
  - Electric.
  - Water.
  - Municipal.

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 3-1.

3.2.1 Residential Accounts

The residential account projection for inside the city was based on a combination of analyses including a regression model using the Polk County Population (PCP) as the independent variable, historical growth rates, and historical ratios of residential accounts to PCP. The residential account projection for outside the city was based on similar analyses. The projection of the total number of residential accounts was a summation of the residential inside and outside the city account projections. The projected AAGR for residential accounts is 1.23 percent for 2000 through 2019. Historical and projected residential accounts are presented in Table 3-1.

3.2.2 Commercial and Industrial Accounts

The General Service (GS) account projection for both inside and outside the city was based on historical trends. The total General Service account projection is the sum of the General Service account projections for inside and outside the city. Historical trends were also analyzed to develop the inside and outside the city projections for General Service Demand (GSD) accounts. The total General Service Demand accounts is the summation of the inside and outside the city General Service Demand accounts.

Table 3-1
Forecast of Total Accounts and Sales For Lakeland

Fiscal Year	Service Territory Population	Rural and Residential GWh	Rural and Residential Average No. of Customers	Rural and Residential kWh/Cust	Commercial GWh	Commercial Average No. of Customers	Commercial kWh/Cust
1990	184,984	916	73,082	12,528	509	9,084	56,055
1991	189,445	951	74,845	12,711	523	9,344	56,005
1992	198,763	988	78,427	12,604	529	9,740	54,310
1993	201,748	1,012	79,493	12,728	536	9,759	54,944
1994	206,040	1,085	80,909	13,406	563	9,887	56,924
1995	210,095	1,134	82,445	13,760	594	10,030	59,258
1996	213,347	1,213	83,656	14,500	588	9,746	60,347
1997	216,782	1,170	84,941	13,776	607	9,835	61,722
1998	218,959	1,249	85,840	14,550	625	10,032	62,277
1999	221,921	1,239	87,222	14,202	642	10,338	62,102
Forecast							
2000	226,339	1,274	88,362	14,415	635	10,501	60,518
2001	230,143	1,299	89,540	14,510	650	10,650	61,060
2002	233,947	1,325	90,720	14,610	666	10,799	61,632
2003	237,751	1,352	91,903	14,710	681	10,950	62,189
2004	241,555	1,379	93,090	14,810	696	11,101	62,738
2005	245,359	1,406	94,281	14,910	712	11,252	63,279
2006	248,931	1,433	95,464	15,010	728	11,402	63,815
2007	252,504	1,460	96,651	15,110	743	11,555	64,332
2008	256,076	1,488	97,842	15,210	759	11,708	64,842
2009	259,648	1,516	99,037	15,310	775	11,862	65,341
2010	263,220	1,545	100,235	15,410	791	12,016	65,832
2011	266,793	1,574	101,498	15,510	807	12,177	66,290
2012	270,365	1,603	102,722	15,610	823	12,335	66,754
2013	273,937	1,633	103,948	15,710	840	12,495	67,208
2014	277,509	1,663	105,179	15,810	856	12,654	67,657
2015	281,082	1,693	106,415	15,910	873	12,814	68,096
2016	284,654	1,724	107,654	16,010	889	12,976	68,524
2017	288,226	1,754	108,898	16,110	906	13,138	68,944
2018	291,798	1,785	110,146	16,210	923	13,301	69,356
2019	295,371	1,817	111,397	16,310	939	13,465	69,763

Table 3-1 (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
1990	336	42	8,000,000	20	55	1,836	174	2,009
1991	350	45	7,780,467	18	55	1,898	149	2,047
1992	349	47	7,424,707	21	57	1,944	135	2,079
1993	377	50	7,548,484	22	58	2,006	134	2,140
1994	387	51	7,589,265	23	60	2,118	162	2,279
1995	429	51	8,417,875	24	64	2,246	144	2,390
1996	428	57	7,511,573	25	68	2,322	126	2,448
1997	459	61	7,526,069	25	69	2,331	113	2,443
1998	462	61	7,638,456	26	70	2,432	117	2,549
1999	486	70	6,938,491	27	71	2,465	120	2,585
Forecast								
2000	521	85	6,130,161	26	73	2,529	118	2,648
2001	539	87	6,207,316	26	76	2,591	122	2,712
2002	557	89	6,278,889	27	78	2,653	125	2,778
2003	574	91	6,314,851	28	80	2,715	129	2,844
2004	591	93	6,341,549	29	83	2,777	133	2,910
2005	608	95	6,368,597	29	85	2,840	136	2,976
2006	625	97	6,423,648	30	87	2,903	140	3,043
2007	642	99	6,479,025	31	90	2,966	143	3,110
2008	659	101	6,532,505	31	92	3,030	147	3,177
2009	676	103	6,554,660	32	95	3,095	150	3,245
2010	694	105	6,577,487	33	97	3,159	153	3,313
2011	711	107	6,649,319	34	100	3,226	156	3,382
2012	728	109	6,655,093	34	102	3,292	160	3,451
2013	745	111	6,722,110	35	105	3,358	163	3,521
2014	763	113	6,758,150	36	107	3,425	166	3,591
2015	780	115	6,793,809	37	110	3,492	169	3,661
2016	797	117	6,799,510	37	113	3,560	172	3,732
2017	814	119	6,863,714	38	115	3,628	175	3,803
2018	831	121	6,870,714	39	118	3,696	178	3,875
2019	848	123	6,904,453	40	121	3,765	181	3,946

The General Service Large Demand (GSLD) account projection for inside the city was based on historical relationships between GSLD accounts to PCP, residential accounts to GSLD accounts, GS accounts to GSLD accounts, and GSD accounts to GSLD accounts. The historical trend between GSLD accounts outside to residential accounts outside was used to develop the GSLD outside the city account projection. The total GSLD is the summation of the GSLD inside and outside the city accounts.

The commercial and industrial customer forecasts are presented in Table 3-1. The number of commercial and industrial customers is projected to increase at an AAGR of 1.32 and 1.96 percent from 2000 through 2019.

3.2.3 Other Accounts

Other accounts include electric, water, and municipal accounts. The Electric account projection was based on historical trends. 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 four years. The Municipal account projection was also based on historical trends. The projections indicate approximately 8 to 12 new accounts a year for the planning horizon.

Street and Highway Lighting accounts consist of private area lighting and unmetered. The Private Area Lighting accounts projection was based on historical trends. The projections indicate approximately 50-80 new private area lighting accounts a year inside the city. The projection of Private Area Lighting accounts for outside the city were also developed based on historical relationships and trends. The forecast indicates approximately 350 new accounts a year. The total Private Area Lighting account forecast is the summation of the inside and outside the city forecasts.

3.3 Sales Forecast

Lakeland develops sales forecasts for each of the account categories presented in Section 3.2.

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 inside the city. The total residential sales used a regression model with year, heating degree-days, and real per capital income as the independent variables. Residential sales are projected to have an AAGR of 1.89 percent from 2000 through 2019 and are presented in Table 3-1.

3.3.2 Commercial and Industrial Sales

Projections inside the city were based on a regression model using employment and heads of households 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 employment 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 2.08 and 2.60 percent for 2000 through 2019, and are presented in Table 3-1.

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. Water sales were projected using a weighted average of the ratio of water sales to municipal sales and a trend projection. Projections were based on a historical trend using Polk County population. Electric sales projections were based on a ratio of electric sales to municipal sales.

Private Area Lighting inside sales were based on a regression model using private area light accounts and residential accounts inside as the independent variables. Private Area Lighting outside sales were based on a regression model using year as the independent variable. Unmetered sales are those derived from municipal lighting.

Street and highway lighting and other sales have projected AAGRs of 2.34 and 2.66 percent, respectively, for 2000 through 2019 and are presented in Table 3-1.

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 2.12 percent from 2000 through 2019. This is a lower growth rate than experienced in the past. A 3.33 percent AAGR was experienced over the last 10 years of historical sales. Historical and projected total sales are presented in Table 3-1.

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 on a fiscal year basis, including conservation, for the base case is summarized in Table 3-2. The projected AAGR for the base case is 2.12 percent for 2000 through 2019. The projected AAGR represents a reduction from the historical AAGR of 2.84 percent for the last 10 years.

3.5 Peak Demand

Lakeland forecasts electric system winter and summer season peak demands for each fiscal 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 3-2. The projected AAGR for the summer and winter peak demand for the base case after conservation and interruptible load for the period 2000 through 2019 are 2.15 percent and 1.60 percent.

Table 3-2
Summer, Winter, and Net Energy for Load--Base Case

Calendar Year	Summer, MW(1)		Winter, MW(1)		Net Energy For Load, GWh
	Before(2)	After(3)	Before(2)	After(3)	
2000	536	526	610	610	2,663
2001	550	540	585	576	2,728
2002	564	554	600	591	2,793
2003	578	568	613	604	2,859
2004	591	581	627	618	2,925
2005	605	595	641	631	2,991
2006	619	609	655	645	3,058
2007	633	623	668	658	3,125
2008	646	636	681	671	3,193
2009	660	650	695	685	3,260
2010	674	664	708	698	3,329
2011	688	678	723	713	3,398
2012	702	692	737	727	3,467
2013	716	706	751	741	3,537
2014	730	720	765	755	3,607
2015	744	734	779	769	3,677
2016	757	747	792	782	3,748
2017	771	761	807	797	3,819
2018	785	775	820	810	3,891
2019	799	789	835	825	3,963

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

3.6 Sensitivity Cases

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 an annual growth rate that is 1.5 percent greater than the base case load forecast. The base case load forecast has an AAGR of 2.15 and 1.60 percent for summer and winter peak demand after conservation and interruptible load. Therefore, the winter high load growth case has an AAGR of 1.60 + 1.50 = 3.10. The 1.5 percent was determined to be a reasonable upper limit based on a review of historical forecasts and actual growth rates. Table 3-3 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 2.15 and 1.60 percent for summer and winter peak demand after conservation and interruptible load, therefore the low load growth case has an AAGR of 1.60 - 1.50 = 0.10. The 1.5 percent was determined to be a reasonable lower limit based on a review of historical forecasts and actual growth rates. Table 3-4 displays the summer and winter peak demand forecasts and net energy for load for the planning horizon for the low load growth sensitivity.

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

Calendar Year	Summer, MW[(1)]	Winter, MW[(1)]	Net Energy for Load, GWh
2000	534	619	2,702
2001	554	638	2,795
2002	574	658	2,891
2003	595	679	2,990
2004	617	700	3,092
2005	639	721	3,198
2006	662	744	3,307
2007	687	767	3,420
2008	712	791	3,537
2009	738	815	3,659
2010	765	840	3,784
2011	793	866	3,913
2012	822	893	4,047
2013	852	921	4,186
2014	883	950	4,329
2015	915	979	4,477
2016	948	1,009	4,630
2017	983	1,041	4,789
2018	1,019	1,073	4,953
2019	1,056	1,106	5,122

[(1)]Peak demand after conservation and interruptible exercised.

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

Calendar Year	Summer, $MW^{(1)}$	Winter, $MW^{(1)}$	Net Energy for Load, GWh
2000	518	601	2,623
2001	522	601	2,634
2002	525	602	2,645
2003	529	603	2,656
2004	532	603	2,667
2005	536	604	2,679
2006	539	605	2,690
2007	543	605	2,701
2008	546	606	2,713
2009	550	606	2,724
2010	553	607	2,736
2011	557	608	2,747
2012	560	608	2,759
2013	564	609	2,770
2014	568	609	2,782
2015	571	610	2,794
2016	575	611	2,806
2017	579	611	2,818
2018	583	612	2,829
2019	587	613	2,841

$^{(1)}$Peak demand after conservation and interruptible exercised.

4.0 Conservation and Demand-Side Management

Lakeland Electric 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 continuing to pursue additional cost-effective 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 for 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 Section 3.0 and Section 9.0.

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.
- Reduction in use of expensive petroleum fuels.

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

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 844 kWh per account annually. In December of 1999 Lakeland decided to stop the current Loan Program while it evaluates how best to proceed with the program in the future.

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 0.05 MW and 104 MWh annually by 2007.

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

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

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

4.1.2 Existing Programs with No Demonstrable Demand and Energy Savings

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

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

4.1.2.1 Residential Programs.

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

4.1.2.1.2 Public Awareness Program. 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 , the Polk County Home Show and numerous school engagements through the year. The display centers on themes of energy and water conservation, including electric safety.

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

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

4.1.2.2 Commercial Programs.

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

4.1.3 Demand-Side Management Technology Research

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

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

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

4.1.3.3 Time-of-Day Rates. There has been limited interest by Lakeland's customers in this demand-side management program. Lakeland is currently offering this program and will continue 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.
- 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 a reliable, cost-effective solution 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 20 solar powered street lights that are in service. Lakeland installed these 20 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 heated water itself, reducing the effect of converting the energy to other forms. In 1999, Solar Water Heaters (29 of them) generated 32,800 kWh for hot water.

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 the 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. For a family of four, the household should purchase enough energy 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. In 1999, Lakeland evaluated the performance of 18 PV systems. These systems generated 14,937 kWh.

As part of the program, the operation of six residential photovoltaic systems will be evaluated and analyzed. 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 5 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 2 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, onsite 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, Florida Solar Energy Research and Education Foundation, Florida Solar Energy Center and the Utility Photovoltaic Group which will allow seventeen 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 seventeen 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

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 Photovoltaic Group, the investment will support 1,000 PV systems in 12 states and Puerto Rico and hopes 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 solar devices on one million roofs by the year 2010. In 1999, Lakeland generated a total of 47,737 kWh of "green" power by using its 18 photovoltaics systems and 29 Solar Water Heaters.

This program provides research in the integration of photovoltaics in newly constructed homes. Two new homes, having identical floor plans, were built in "side-by-side" fashion. The dwellings are being measured for performance under two conditions: occupied and unoccupied. Data is being collected for end-use load and PV system interface.

The first solar home was unveiled May 28, 1998, in Lakeland, Florida. The home construction includes a 4 kW photovoltaic system, white tiled roof, argon filled windows, exterior wall insulation, improved interior duct system, high performance heat pump and high efficiency appliances. An identical home with strictly conventional construction features was also built 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. Living conditions were simulated in the unoccupied home. With regard to total power, the solar home used 50 percent less electricity than the air conditioning consumption of the control home.

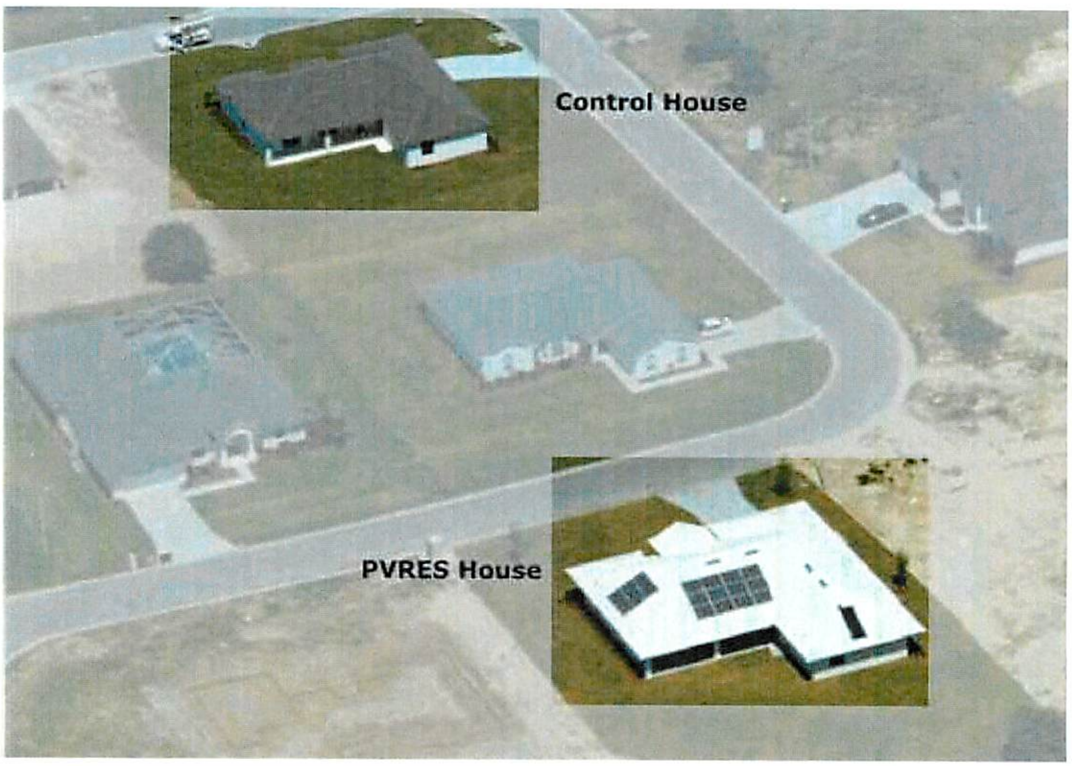


Figure 4-2
Solar House and Control House

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 being consumed on the premises consumption, the output of the photovoltaic system could be sent into the utility grid. The objective of the solar house design was to be as efficient as possible, not necessarily 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) measures existed as alternatives to the least cost supply-side alternative, Lakeland evaluated 66 DSM measures using the Florida Integrated Resource Evaluator (FIRE) model as part of the Need for Power Docket for McIntosh Unit 5. Florida Power Corporation originally developed the FIRE model and several utilities in Florida have applied this model. None of the 66 DSM measures evaluated were found to be cost-effective.

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 measure 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 places 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 are 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 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 restaurants 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 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 were 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 are 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 are 30.2 percent.

- Compares three 4'-34W fluorescent lamps and one electronic ballast with three 4'-40W fluorescent lamps and one EE ballast in new buildings only. Estimated lighting energy and demand savings are 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 are 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 are 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 are 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 are 72 percent. Annual maintenance costs of replacing both incandescent and HPS lamps during the lifetime of the HPS ballast are 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 are 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 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 are 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 are 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 are 15 percent. This measure was only analyzed in all 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.

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 considers both conservation and demand side management measures in meeting its customers' requirements. The integrated resource planning process employed by Lakeland continuously monitors supply and demand side alternatives and as promising alternatives emerge, they are included in the evaluation process.

5.2 Florida Municipal Power Pool

Lakeland is a member, along with the Orlando Utilities Commission (OUC), Kissimmee Utility Authority, and the All-Requirements Project of the Florida Municipal Power Agency (FMPA), of the Florida Municipal Power Pool (FMPP). The four utilities operate as one control area. All FMPP capacity resources are committed and dispatched together from the OUC Operations center. FMPP has 2,429 MW summer capacity and 2,538 MW winter capacity per the 1999 Load and Resource Plan published by the Florida Reliability Coordinating Council.

The FMPP does not provide for the sharing of planning reserves among its members. Members are 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.

5.3.1 Economic Parameters

5.3.1.1 Escalation rates. The general inflation rate applied is assumed to be 3.0 percent. The escalation rate for capital costs and operation and maintenance (O&M) expenses is also assumed to be 3.0 percent.

5.3.1.2 Lakeland Municipal Bond Interest Rate. Lakeland's current municipal long-term bond interest rate is assumed to be 6.0 percent.

5.3.1.3 Present Worth Discount Rate. The present worth discount rate is assumed equal to the bond interest rate of 6.0 percent.

5.3.1.4 Interest During Construction Interest Rate. The interest during construction interest rate for Lakeland is assumed to be 6.0 percent.

5.3.1.5 Fixed Charge Rate. Lakeland's assumed fixed charge rate is based on a 2.0 percent issuance fee, a 1.0 percent annual insurance cost, a 6 month debt reserve fund earning interest equal to the bond interest rate of 6 percent and a 6 percent bond interest rate. A 30-year bond term is used for solid fuel alternatives and a 25-year bond term is used for combustion turbine and combined cycles. The resultant fixed charge rates are 8.47 and 9.07 respectively for the 30 year and 25 year bond terms.

5.4 Economic Evaluation Methodology

Economic evaluation is conducted over a 20 year period from 2000 through 2019. The economic evaluation is based on the cumulative present worth of annual costs for capital costs, new unit additions, non-fuel O&M costs and fuel costs. Costs that are common to all expansion alternatives such as conservation and demand-side management cost, transmission and distribution cost, and administrative and general costs are not included. Capital costs for new generating units are included by applying the annual fixed charge rate beginning 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. Lakeland's fuel forecast was developed using the Energy Information Administration's (EIA) annual forecast, the 2000 Annual Energy Outlook (AEO).

Lakeland's actual 1999 fuel costs were escalated based on the escalation rates presented in the AEO forecast. The average annual escalation rates for coal, natural gas, distillate oil and residual oil on a real basis plus the 3 percent general inflation rate were applied over the five year intervals presented in the 2000 AEO and then applied to Lakeland's 1999 actual fuel costs. The 1999 fuel cost for coal actually represents the mix of coal, petroleum coke and refuse derived fuel (RDF) burned at McIntosh. For natural gas, the AEO escalation rates are applied to Lakeland's 1999 commodity price for natural gas and then transportation costs are added. Because AEO does not publish fuel price projections for petroleum coke, Lakeland developed a forecast for petroleum coke. Lakeland's nominal delivered fuel cost projections are presented in Table 5-1.

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. The coal forecast in Table 5-1 represents a mixture of coal, refuse derived fuel (RDF) and petroleum coke burned at McIntosh 3. No cost was included for the RDF in the coal mixture price forecast.

5.5.1.1 Coal. Lakeland's current coal purchase contracts are approximately 50 percent long term and 50 percent spot purchases. Spot purchases can extend from several months to two years in length.

5.5.1.2 High and Low Sulfur No. 6 Oil and Diesel. 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.

5.5.1.3 Natural Gas. Florida Gas Transmission Company (FGT) supplies natural gas transportation in Florida. Details of FGT's system are presented in Section 5.7.3.1. Natural Gas transportation from FGT is currently supplied under two tariffs, FTS-1 and FTS-2. Rates for FTS-1 are based on FGT's Phase II expansion and similarly rates for FTS-2 are based on the Phase III expansion. The Phase III expansion was extensive and rates for FTS-2 transportation are significantly higher than FTS-1. Rates for the Phase IV, Phase V and any other future expansions will be set by Federal Energy Regulatory Commission (FERC) rate cases at the completion of the projects. Costs for future expansions are anticipated to be rolled in with Phase III costs and the resultant rates are expected to be similar to the existing Phase III rates. Current FTS-1 and FTS-2 transportation rates along with FGT's interruptible transportation rate ITS-1 are shown in Table 5-2.

For purposes of projecting delivered gas prices, transportation charges of $0.55/MBtu were applied for existing units including McIntosh 5 based on Lakeland's current mix of FTS-1 and FTS-2 transportation including consideration of Lakeland's ability to relinquish FTS-2 transportation and acquire other firm and interruptible gas transportation on the market. In other words, a $0.55/MBtu represents the average cost for Lakeland to obtain natural gas transportation for existing units. For new units, the FTS-2 transportation rate is used. Table 5-1 presents the delivered natural gas price forecast for both existing units and new units.

Lakeland currently has a ten-year contract to supply natural gas for fifty 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 one to five 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 Petroleum Coke. McIntosh 3 burns approximately 58,000 tons of petroleum coke annually. This petroleum coke is currently supplied under a one year contract.

The proposed McIntosh Unit 4 PFBC is expected to be fueled 100 percent with petroleum coke with coal as its backup fuel. Lakeland plans to contract with a producer/supplier for the required volume of petroleum coke. Lakeland will be able to obtain lower costs based on the larger quantities of petroleum coke purchased and likely long term contract agreements. Lakeland also projects less expensive transportation costs associated with transporting the fuel by rail rather than the existing truck transportation.

5.5.1.5 Refuse-Derived Fuel. McIntosh 3 is assumed to burn approximately 26,000 tons annually of RDF provided by the City. Since the City provides the RDF, the energy from the RDF is assumed to displace the coal that would otherwise be burned. For evaluation purposes, the energy from the RDF serves to reduce the cost of fuel for McIntosh 3. As such, no forecast for the price of RDF is provided.

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

Year	Coal[1] $/MBtu	Natural Gas Existing Units $/MBtu	Natural Gas New Units $/MBtu	HS Oil $/MBtu	LS Oil $/MBtu	Diesel $/MBtu	Pet Coke $/MBtu
2000	1.62	3.43	3.71	2.61	4.14	4.57	0.86
2001	1.64	3.60	3.87	2.83	4.49	5.01	0.88
2002	1.66	3.77	4.05	3.07	4.87	5.50	0.90
2003	1.68	3.95	4.23	3.33	5.28	6.04	0.92
2004	1.70	4.14	4.42	3.61	5.73	6.63	0.94
2005	1.74	4.33	4.61	3.73	5.91	6.87	0.98
2006	1.78	4.52	4.80	3.84	6.09	7.11	1.02
2007	1.82	4.73	5.01	3.96	6.28	7.37	1.07
2008	1.86	4.95	5.23	4.09	6.48	7.63	1.12
2009	1.90	5.18	5.45	4.22	6.68	7.90	1.17
2010	1.94	5.36	5.63	4.36	6.91	8.13	1.22
2011	1.99	5.54	5.82	4.51	7.14	8.37	1.27
2012	2.03	5.73	6.01	4.66	7.38	8.61	1.32
2013	2.08	5.93	6.21	4.82	7.63	8.86	1.38
2014	2.12	6.14	6.42	4.98	7.89	9.12	1.44
2015	2.16	6.35	6.63	5.16	8.19	9.44	1.50
2016	2.21	6.57	6.84	5.36	8.49	9.78	1.57
2017	2.25	6.79	7.07	5.55	8.80	10.12	1.63
2018	2.30	7.03	7.30	5.76	9.13	10.48	1.70
2019	2.34	7.27	7.55	5.97	9.47	10.85	1.78
Average Annual Escalation Rate	**1.96%**	**4.03%**	**3.81%**	**4.45%**	**4.45%**	**4.66%**	**3.91%**

[1]Blend of coal, petroleum coke and refuse derived fuel burned at McIntosh Unit 3.

Table 5-2: FGT Transportation Rates

Rates and Surcharges	Rate Schedule		
	FTS-1 w/surcharges (cents/DTH)	FTS-2 w/surcharges (cents/DTH)	ITS-1
Reservation	37.53	77.85	33.84
Usage	4.34	2.63	0.00
Total	41.87	80.48	33.84
Fuel Charge	2.75%	2.75%	2.75%

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 natural gas/oil and coal.

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 for the high fuel price an escalation of 2.5 percent above the base case forecast is a reasonable upper limit. For natural gas, the additional escalation rate is only applied to the commodity price. The forecast is provided in Table 5-3.

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 for the low fuel price scenario an escalation of 2.5 percent below the base case forecast is a reasonable lower limit. For natural gas, the lower escalation rate is only applied to the commodity price. The forecast is provided in Table 5-4.

5.6.3 Constant Differential Between Fuels

Lakeland also conducts a sensitivity analysis that assumes a constant differential between fuels 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 compared to projected coal prices. Table 5-5 displays the fuel price forecast for this scenario.

Table 5-3: High Fuel Price Forecast Summary (Delivered Price)

Year	Coal[1] $/MBtu	Natural Gas Existing Units $/MBtu	Natural Gas New Units $/MBtu	HS Oil $/MBtu	LS Oil $/MBtu	Diesel $/MBtu	Pet Coke $/MBtu
2000	1.66	3.50	3.78	2.68	4.24	4.67	0.88
2001	1.72	3.75	4.02	2.97	4.71	5.25	0.92
2002	1.79	4.01	4.29	3.30	5.23	5.90	0.97
2003	1.86	4.29	4.57	3.66	5.80	6.63	1.01
2004	1.93	4.60	4.88	4.06	6.44	7.44	1.06
2005	2.02	4.92	5.19	4.29	6.81	7.90	1.14
2006	2.12	5.26	5.53	4.54	7.20	8.39	1.22
2007	2.22	5.62	5.90	4.80	7.61	8.90	1.30
2008	2.33	6.01	6.29	5.07	8.04	9.45	1.40
2009	2.44	6.44	6.72	5.36	8.50	10.03	1.50
2010	2.56	6.82	7.10	5.68	9.01	10.58	1.60
2011	2.68	7.22	7.50	6.02	9.54	11.16	1.71
2012	2.81	7.65	7.93	6.38	10.11	11.78	1.82
2013	2.94	8.11	8.38	6.76	10.72	12.42	1.95
2014	3.09	8.59	8.87	7.16	11.36	13.11	2.08
2015	3.23	9.10	9.38	7.61	12.07	13.91	2.22
2016	3.37	9.64	9.92	8.09	12.83	14.75	2.38
2017	3.53	10.22	10.49	8.60	13.63	15.65	2.54
2018	3.69	10.83	11.11	9.14	14.49	16.61	2.72
2019	3.86	11.48	11.76	9.71	15.40	17.62	2.90

[1]Blend of coal, petroleum coke and refuse derived fuel burned at McIntosh Unit 3.

Table 5-4: Low Fuel Price Forecast Summary (Delivered Price)							
Year	Coal[1] $/MBtu	Natural Gas Existing Units $/MBtu	Natural Gas New Units $/MBtu	HS Oil $/MBtu	LS Oil $/MBtu	Diesel $/MBtu	Pet Coke $/MBtu
2000	1.58	3.36	3.64	2.55	4.04	4.46	0.84
2001	1.56	3.45	3.73	2.70	4.28	4.78	0.83
2002	1.54	3.54	3.82	2.86	4.53	5.12	0.83
2003	1.52	3.63	3.91	3.03	4.80	5.49	0.83
2004	1.50	3.72	4.00	3.20	5.08	5.89	0.83
2005	1.49	3.81	4.08	3.22	5.11	5.95	0.84
2006	1.49	3.89	4.17	3.24	5.13	6.01	0.86
2007	1.48	3.98	4.26	3.26	5.16	6.07	0.87
2008	1.48	4.07	4.35	3.28	5.19	6.13	0.89
2009	1.47	4.16	4.44	3.29	5.22	6.19	0.91
2010	1.47	4.21	4.49	3.32	5.26	6.21	0.92
2011	1.46	4.26	4.53	3.35	5.31	6.23	0.94
2012	1.46	4.30	4.58	3.38	5.35	6.25	0.95
2013	1.45	4.35	4.63	3.40	5.39	6.27	0.97
2014	1.45	4.40	4.68	3.43	5.44	6.29	0.99
2015	1.44	4.45	4.72	3.47	5.50	6.35	1.00
2016	1.43	4.49	4.77	3.51	5.56	6.41	1.02
2017	1.42	4.54	4.81	3.55	5.62	6.47	1.04
2018	1.41	4.58	4.86	3.59	5.69	6.54	1.06
2019	1.40	4.63	4.91	3.63	5.75	6.60	1.08

[1]Blend of coal, petroleum coke and refuse derived fuel burned at McIntosh Unit 3.

Table 5-5: Constant Differential Fuel Price Forecast Summary (Delivered Price)

Year	Coal[1] $/MBtu	Natural Gas Existing Units $/MBtu	Natural Gas New Units $/MBtu	HS Oil $/MBtu	LS Oil $/MBtu	Diesel $/MBtu	Pet Coke $/MBtu
2000	1.62	3.30	3.58	2.43	3.84	4.18	0.86
2001	1.64	3.32	3.60	2.45	3.86	4.20	0.88
2002	1.66	3.34	3.62	2.47	3.88	4.22	0.90
2003	1.68	3.36	3.64	2.49	3.90	4.24	0.92
2004	1.70	3.38	3.66	2.51	3.92	4.26	0.94
2005	1.74	3.42	3.70	2.55	3.96	4.30	0.98
2006	1.78	3.46	3.74	2.59	4.00	4.34	1.02
2007	1.82	3.50	3.78	2.63	4.04	4.38	1.06
2008	1.86	3.54	3.82	2.67	4.08	4.42	1.10
2009	1.90	3.58	3.86	2.71	4.12	4.46	1.14
2010	1.94	3.63	3.90	2.76	4.17	4.51	1.19
2011	1.99	3.67	3.95	2.80	4.21	4.55	1.23
2012	2.03	3.71	3.99	2.84	4.25	4.59	1.27
2013	2.08	3.76	4.04	2.89	4.30	4.64	1.32
2014	2.12	3.80	4.08	2.93	4.34	4.68	1.36
2015	2.16	3.85	4.12	2.98	4.39	4.73	1.41
2016	2.21	3.89	4.17	3.02	4.43	4.77	1.45
2017	2.25	3.93	4.21	3.06	4.47	4.81	1.49
2018	2.30	3.98	4.25	3.11	4.52	4.86	1.54
2019	2.34	4.02	4.30	3.15	4.56	4.90	1.58

[1]Blend of coal, petroleum coke and refuse derived fuel burned at McIntosh Unit 3.

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. The coal sources are located in eastern Kentucky, which affords Lakeland a single rail line haul via CSX Transportation (CSX). Lakeland has the capacity to purchase additional spot market coal for its additional needs.

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 spot market, and has no long term contracts. This strategy provides the lowest cost for fuel oil consistent with usage, current price stabilization, and on-site 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 dual pipeline system extending from South Texas to Miami, Florida. FGT is a subsidiary of Citrus Corporation, which is jointly owned by a subsidiary of Enron Corporation (50 percent), the largest integrated natural gas company in America, and El Paso Energy (50 percent).

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 May 2001.

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 139 miles of underground pipelines. Additionally FGT proposes to add 38,220 horsepower of compression to its system. The proposed additions will add approximately 199,000 MBtu per day of incremental firm transportation service to Peninsular Florida. The estimated cost of the expansion is $268 million. FGT now anticipates construction of this project will begin in April of 2000, and is scheduled for completion and placed in service by May 2001.

FGT also filed for Federal Energy Regulatory Commission (FERC) approvals of the Phase V expansion program December 1, 1999. The filing consists of expanding several areas of the existing pipeline, totaling 231 additional miles. The proposed additions will add approximately 404,000 MBtu per day of incremental firm transportation service to Peninsular Florida. The estimated cost of the expansion is $438 million. The target in-service date for the Phase V expansion is April 1, 2002.

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. One initiative 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 (non-environmental) 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.

Williams Energy, one of the nation's largest transporters of natural gas, filed another pipeline proposal with FERC on October 28, 1999. On February 10, 2000, Williams Energy entered into a 50/50 ownership agreement with Duke Energy to jointly develop, construct, and operate the project. With this partnership, the Buccaneer Pipeline has firm commitments for over 50 percent of the project's total capacity.

The Buccaneer Gas Pipeline is a 674 mile pipeline system designed to deliver 900,000 MBtu of natural gas per day. The proposed system will consist of 411 miles of 36-inch pipeline extending from Mobile County, Alabama, under the Gulf of Mexico to Pasco County, Florida. On shore in Florida, 121 miles of 36 inch mainline and 142 miles of 16 to 30 inch laterals will deliver natural gas throughout central Florida. The route has an additional pipeline lateral to serve a Panda Energy International power plant in Lake County, Florida. The lateral will consist of 24 inch pipe, extend 37 miles, and would be almost entirely co-located with a FPC powerline easement. The onshore route has been sited to co-locate with existing rights-of-way for approximately 70 percent of the total length. The targeted in-service date is April 1, 2002 and has an estimated cost of $1.5 billion.

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, power sales contracts, existing generating and unit capability and scheduled retirements of generating units.

6.1.1 Load Forecast

The load forecast described in Section 3.0 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 and interruptible loads.

6.1.2 Reserve Requirements

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

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

Based on the above equation, Lakeland has adopted a 22 percent minimum reserve margin requirement for the winter season and a 20 percent reserve margin for the summer season as its planning criteria.

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 summer high and low load demands respectively. The capacity requirements are driven by the summer peak demand forecasts.

Table 6-1
Summary of Load Forecast

Year	Winter Peak Demand			Summer Peak Demand		
	Base	High	Low	Base	High	Low
2000	610	619	601	526	534	518
2001	576	638	602	540	554	521
2002	591	658	602	554	574	525
2003	604	679	603	568	595	528
2004	618	700	603	581	617	531
2005	631	721	604	595	639	534
2006	645	744	605	609	662	537
2007	658	767	605	623	687	540
2008	671	791	606	636	712	543
2009	685	815	607	650	738	547
2010	698	840	607	664	765	550
2011	713	866	608	678	793	553
2012	727	893	609	692	822	556
2013	741	921	609	706	852	560
2014	755	950	610	720	883	563
2015	769	979	611	734	915	566
2016	782	1,009	612	747	948	570
2017	797	1,041	612	761	983	573
2018	810	1,073	613	775	1,019	576
2019	825	1,106	614	789	1,056	580

*Includes reduction for conservation reductions and interruptible load.

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

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 22%	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
1999/2000	649	0	25	624	661	610	(5.60)	2.30	(182)	(120)
2000/2001	886	0	75	811	637	576	27.38	40.86	34	109
2001/2002	956	0	100	856	652	591	31.35	44.90	61	135
2002/2003	869	0	100	769	666	604	15.52	27.38	(43)	33
2003/2004	869	0	100	769	680	618	13.14	24.50	(60)	15
2004/2005	869	0	100	769	695	631	10.70	21.93	(79)	(0)
2005/2006	766	0	100	666	709	645	(6.01)	3.31	(199)	(121)
2006/2007	766	0	100	666	723	658	(7.83)	1.27	(216)	(136)
2007/2008	766	0	100	666	737	671	(9.58)	(0.69)	(233)	(152)
2008/2009	766	0	100	666	751	685	(11.27)	(2.72)	(250)	(169)
2009/2010	766	0	100	666	765	698	(12.89)	(4.53)	(267)	(185)
2010/2011	766	0	0	766	780	713	(1.75)	7.49	(185)	(103)
2011/2012	766	0	0	766	795	727	(3.60)	5.42	(204)	(121)
2012/2013	766	0	0	766	809	741	(5.27)	3.43	(221)	(138)
2013/2014	766	0	0	766	824	755	(6.99)	1.51	(239)	(155)
2014/2015	766	0	0	766	838	769	(8.55)	(0.34)	(256)	(172)
2015/2016	766	0	0	766	852	782	(10.05)	(2.00)	(273)	(188)
2016/2017	766	0	0	766	867	797	(11.61)	(3.84)	(291)	(206)
2017/2018	766	0	0	766	881	810	(13.01)	(5.39)	(308)	(222)
2018/2019	766	0	0	766	896	825	(14.47)	(7.11)	(327)	(240)

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

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 20%	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	807	0	179	628	558	526	12.46	19.23	(42)	(4)
2001	757	0	100	657	572	540	14.77	21.53	(30)	8
2002	877	0	100	777	586	554	32.51	40.11	73	111
2003	790	0	100	690	600	568	14.92	21.35	(30)	8
2004	790	0	100	690	614	581	12.30	18.66	(47)	(8)
2005	790	0	100	690	628	595	9.79	15.86	(64)	(25)
2006	687	0	100	587	642	609	(8.64)	(3.71)	(184)	(144)
2007	687	0	100	587	656	623	(10.59)	(5.87)	(201)	(161)
2008	687	0	100	587	670	636	(12.46)	(7.78)	(217)	(177)
2009	687	0	100	587	684	650	(14.25)	(9.77)	(234)	(193)
2010	687	0	100	587	698	664	(15.97)	(11.67)	(251)	(210)
2011	687	0	0	687	712	678	(3.58)	1.27	(168)	(127)
2012	687	0	0	687	727	692	(5.57)	(0.78)	(186)	(144)
2013	687	0	0	687	741	706	(7.35)	(2.75)	(203)	(161)
2014	687	0	0	687	755	720	(9.07)	(4.64)	(219)	(177)
2015	687	0	0	687	769	734	(10.73)	(6.44)	(236)	(194)
2016	687	0	0	687	783	747	(12.32)	(8.07)	(253)	(210)
2017	687	0	0	687	797	761	(13.86)	(9.77)	(270)	(226)
2018	687	0	0	687	811	775	(15.35)	(11.38)	(287)	(243)
2019	687	0	0	687	826	789	(16.89)	(12.96)	(305)	(260)

Table 6-4
Projected Reliability Levels - Summer / High Load Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand: Before Interruptible and Load Management (MW)	System Peak Demand: After Interruptible and Load Management (MW)	Reserve Margin: Before Interruptible and Load Management (MW)	Reserve Margin: After Interruptible and Load Management (MW)	Excess/ (Deficit) to Maintain 20%: Before Interruptible and Load Management (MW)	Excess/ (Deficit) to Maintain 20%: After Interruptible and Load Management (MW)
2000	807	0	179	628	566	534	10.79	17.47	(52)	(14)
2001	757	0	100	657	587	554	11.90	18.57	(48)	(8)
2002	877	0	100	777	608	574	27.77	35.30	47	88
2003	790	0	100	690	630	595	9.53	15.91	(66)	(24)
2004	790	0	100	690	652	617	5.74	11.82	(93)	(50)
2005	790	0	100	690	675	639	2.08	7.88	(121)	(77)
2006	687	0	100	587	700	662	(16.18)	(11.47)	(253)	(208)
2007	687	0	100	587	725	687	(19.08)	(14.58)	(283)	(237)
2008	687	0	100	587	751	712	(21.88)	(17.59)	(314)	(268)
2009	687	0	100	587	778	738	(24.58)	(20.50)	(347)	(299)
2010	687	0	100	587	806	765	(27.19)	(23.30)	(380)	(331)
2011	687	0	0	687	834	793	(17.73)	(13.38)	(315)	(265)
2012	687	0	0	687	864	822	(20.58)	(16.44)	(351)	(299)
2013	687	0	0	687	895	852	(23.33)	(19.38)	(388)	(335)
2014	687	0	0	687	927	883	(25.98)	(22.22)	(426)	(373)
2015	687	0	0	687	961	915	(28.54)	(24.96)	(466)	(411)
2016	687	0	0	687	995	948	(31.02)	(27.60)	(508)	(451)
2017	687	0	0	687	1,031	983	(33.41)	(30.15)	(551)	(493)
2018	687	0	0	687	1,068	1019	(35.71)	(32.62)	(595)	(536)
2019	687	0	0	687	1,106	1056	(37.94)	(34.99)	(641)	(581)

Table 6-5
Projected Reliability Levels - Summer / Low Load Case

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 20%	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	807	0	179	628	566	518	10.79	21.05	(52)	5
2001	757	0	100	657	570	521	15.24	25.90	(27)	31
2002	877	0	100	777	573	525	35.51	48.04	89	147
2003	790	0	100	690	576	528	19.63	30.68	(2)	56
2004	790	0	100	690	580	531	18.93	29.91	(6)	53
2005	790	0	100	690	583	534	18.24	29.15	(10)	49
2006	687	0	100	587	587	537	(0.01)	9.21	(117)	(58)
2007	687	0	100	587	590	540	(0.59)	8.57	(122)	(62)
2008	687	0	100	587	593	543	(1.17)	7.94	(126)	(66)
2009	687	0	100	587	597	547	(1.75)	7.30	(130)	(69)
2010	687	0	100	587	600	550	(2.32)	6.67	(134)	(73)
2011	687	0	0	687	604	553	13.67	24.13	(38)	23
2012	687	0	0	687	607	556	13.01	23.40	(42)	19
2013	687	0	0	687	611	560	12.35	22.68	(47)	15
2014	687	0	0	687	615	563	11.69	21.96	(51)	11
2015	687	0	0	687	618	566	11.04	21.24	(55)	7
2016	687	0	0	687	622	570	10.40	20.53	(60)	3
2017	687	0	0	687	626	573	9.75	19.82	(64)	(1)
2018	687	0	0	687	629	576	9.11	19.12	(68)	(5)
2019	687	0	0	687	633	580	8.48	18.42	(73)	(9)

Table 6-2 indicates that 121 MW of capacity is required for the 2005/2006 winter season to maintain a 22 percent reserve margin. This would result in a need to add capacity by December 1, 2005. The capacity need includes the need to replace the capacity from McIntosh 2, which is scheduled to be retired in October of 2005. However, even if McIntosh 2 were not retired, Lakeland would still need 18 MW of capacity for the 2005/2006 winter season.

Table 6-3 indicates that 8 MW of capacity is required for the 2004 summer season to maintain a 20 percent reserve margin. Without additional capacity, Lakeland is projected to have an 18.7 percent reserve margin for the summer 2004 season. The 18.7 percent reserve margin is very close to the targeted 20 percent reserve margin and significantly above Lakeland's historical reserve margin of 15 percent. Thus in order to take full advantage of capacity additions that can be scheduled for June 1, 2005, Lakeland will defer installing additional capacity until the summer of 2005 at which time Lakeland is projected to need 25 MW of additional capacity. Thus for planning purposes, Lakeland is assumed to be required to add new capacity by June 1, 2005.

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 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 eliminates 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:

- Pressurized Fluidized Bed Combined Cycle.
- Pulverized coal.
- Atmospheric 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 2000 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 not 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 Capital Cost and O&M Cost Assumptions.

6.2.2.2.1 Capital Costs. 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). Capital costs were developed on the basis of the current competitive generation market. Additional direct costs are outlined as follows:

- Substation costs.
- Direct costs for the combined cycle alternatives include bypass stacks with dampers, along with continuous emissions monitoring equipment. Combined cycles include a selective catalytic reducer (SCR).
- Direct costs for natural gas alternatives include a 3-day supply fuel oil storage tank.
- Direct costs for the circulating fluidized bed include dry scrubber and a selective non-catalytic reducer (SNCR).
- Direct cost for the pulverized coal unit includes dry scrubber, fabric filter and SCR.
- Makeup water treatment.
- Wastewater treatment.
- Startup spare parts.

The following lists the indirect costs included in the capital cost estimates.

- General Indirects.
    - Relay checkouts and testing.
    - Instrumentation and control equipment calibration and testing.
    - Systems and plant start up.

- Operating crew during test and initial operation period.
- Operating crew training.
- Electricity and water and fuel used during construction.
- Insurance.
    - General liability.
    - Builders risk.
    - Liquidated damage.
- Engineering and related services.
    - A/E services.
    - Owner office engineers.
    - Outside consultants.
    - Other related costs incurred in the permit and licensing process.
- Field construction management services.
    - Field management staff including supporting staff personnel.
    - Field contract administration.
    - Field inspection and quality assurance.
    - Project control.
    - Technical direction.
    - Management of start up and testing.
- Miscellaneous.
    - Cleanup expense for the portion not included in the direct cost construction contracts.
    - Safety and medical services.
    - Guards and other security services.
    - Insurance premiums.
    - Other required labor related to insurance.
    - Performance bond and liability insurance for equipment and tools.
    - Telephone and other utility bills associated with temporary services.
    - Permitting and licensing.
    - Owner's cost.
    - Transmission and distribution.

6.2.2.2 O&M Costs. For simple and combined cycle units, O&M estimates are based on a unit life of 25 years. A base load capacity factor of 90 percent was assumed for combined cycle units and a peak load capacity factor of 10 percent was assumed for simple cycle units. O&M estimates for coal units are based on a unit life of 30 years and a base load capacity factor near 90 percent.

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 are typically referred to as non-fuel 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.

6.2.2.2.2.1 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. Staffing estimates provided are based on recent utility experience with modern facilities. Variable operations costs include an assumed lime cost for flue gas desulfurization (FGD), waste disposal, 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.

Additional variable O&M costs have been included on each coal unit for emission control equipment. The pulverized coal unit requires additional costs for a SCR and dry scrubber. The pressurized fluidized bed unit requires additional variable costs for the operation of a SNCR and dry scrubber.

6.2.2.2.2.2 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 for combustion turbine generation (CTG).
- NO_x control method – (SCR) for combined cycle units.
- Capacity and heat rate degradation has been included in the performance estimates.
- CTG specialized labor cost estimated at $38/man-hour for Siemens-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.
- 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.
- Variable O&M costs are based on 200 starts per year and 10 percent capacity factor for simple cycle combustion turbines and 30 starts per year and 90 percent capacity factor for combined cycles.

6.2.2.3 Pulverized Coal. A 250 MW pulverized coal unit with dry scrubber, fabric filter 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 Circulating Fluidized Bed. A 250 MW atmospheric circulating fluidized bed unit (CFB) with dry scrubber, fabric filter and 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 petroleum coke. Like the pulverized coal unit, the CFB is assumed to be located at the existing McIntosh site. Petroleum coke 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 Fluidized Bed Combined-Cycle – ABB. The pressurized fluidized bed combined cycle (PFBC) technology is based on 20 years of intensive research and development and is now proven in commercial operation to be the world's most advanced coal fired generation system. The PFBC is clean, emissions are low irrespective of fuel quality, waste products are harmless, and is highly efficient. The PFBC can burn coal or petroleum coke and for expansion planning purposes is assumed to burn petroleum coke.

The PFBC cycle begins with a mix of limestone and petroleum coke in a pressurized fluidized bed boiler. The steam generated travels from the pressurized combustor vessel and is expanded through the steam turbine, which produces about 80 percent of the electrical output. The flue gas is carried to a specially developed gas turbine with a modified shaft and increased blade stages, among other modifications, which can handle high-pressure flue gases, resist fouling and erosion, and handle a range of air flow and gas flow (between 40-100%) without drops in efficiency.

The pressurized fluidized bed operates at pressures of 175 - 235 psi and less than 900° F. The lower firing temperatures reduce the amount of thermal NO_x emissions. Other emissions such as SO_x and CO_2 are also reduced significantly. Through the clean coal technology, less ash is produced. Recent investigations and trials have shown the potential for ash resale in the construction industry. Plant efficiency increase, and correspondingly fuel cost decreases, are estimated to be in the range of 10 - 15 percent.

Service hatches allow maintenance crews easy access to internal components. The cool down period is 20 hours, but from a cold start, full load can be reached in only 6 - 8 hours. The ABB PFBC has over 50,000 hours of proven commercial operation.

Table 6-8 presents the estimated cost and performance of the 288 MW PFBC unit.

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, 2000 $1,000	205,421
Indirect Capital Cost, 2000 $1,000	64,896
Total Capital Cost, 2000 $1,000 [1]	270,317
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2000 $/kW-y	26.76
Variable O&M Cost, 2000 $/MWh	3.67
Equivalent Availability, percent	85
Equivalent Forced Outage Rate, percent	7
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	1,500
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]Does not include 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, 2000 $1,000	211,314
Indirect Capital Cost, 2000 $1,000	64,720
Total Capital Cost, 2000 $1,000[1]	276,034
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2000 $/kW-y	30.15
Variable O&M Cost, 2000 $/MWh	5.97
Equivalent Availability, percent	85
Equivalent Forced Outage Rate, percent	7
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	2,670
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]Does not include interest during construction.

Table 6-8
Generating Unit Characteristics
Pressurized Fluidized Bed Combined Cycle

Item	
Steam Pressure, psia	2,610
Steam Temperature, °F	1,050
Reheat Steam Temperature, °F	1,050
Direct Capital Cost, 2000 $1,000	340,250
Indirect Capital Cost, 2000 $1,000	39,000
Total Capital Cost, 2000 $1,000[1]	379,250
O&M Cost-Baseload Duty	
Fixed O&M Cost, 2000 $/kW-y	20.76
Variable O&M Cost, 2000 $/MWh	4.53
Equivalent Availability, percent	81
Equivalent Forced Outage Rate, percent	12
Planned Maintenance Outage, weeks/y	4
Startup Fuel (cold start), MBtu	2,840
Construction Period, months	36
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh	
100 Percent of Full Load	288,000 / 8,452
75 Percent of Full Load	216,000 / 8,578
50 Percent of Full Load	144,000 / 8,705
25 Percent of Full Load	72,000 / 8,831
Minimum Load	48,000 / 8,873

[1]Does not include interest during construction.

6.2.2.6 Combined Cycle. Five 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).
- 2 x 1 Westinghouse 501F -- (Table 6-12)
- 1 x 1 Westinghouse 501G--(Table 6-13).

The combined cycles all utilize conventional, heavy-duty, industrial type combustion turbines. Several other vendors provide combustion turbines with 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 and SCR. 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. The combined cycles include bypass stacks and dampers to allow simple cycle operation.

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

- General Electric LM6000--(Table 6-14).
- General Electric 7EA--(Table 6-15).
- General Electric 7FA--(Table 6-16).

The 7EA and 7FA 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 6-9
Generating Unit Characteristics
General Electric 7EA 1 x 1 Combined Cycle

Item		
Steam Pressure, psia	1,265	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2000 $1,000	64,950	
Indirect Capital Cost, 2000 $1,000	23,669	
Total Capital Cost, 2000 $1,000[1]	88,620	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	7.17	
Variable O&M Cost, 2000 $/MWh	2.59	
Equivalent Availability, percent	95.32	
Equivalent Forced Outage Rate, percent	2.4	
Planned Maintenance Outage, weeks/y	1.86	
Startup Fuel (cold start), MBtu	1,905	
Construction Period, months	18	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	107,506 / 8,190	130,087 / 7,874
75 Percent of Full Load	80,634 / 7,692	97,570 / 8,388
50 Percent of Full Load	53,753 / 9,102	65,043 / 9,877
25 Percent of Full Load	26,881 / 12,800	32,526 / 13,825

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

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

Item		
Steam Pressure, psia	1,265	
Steam Temperature, °F	940	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2000 $1,000	112,816	
Indirect Capital Cost, 2000 $1,000	36,138	
Total Capital Cost, 2000 $1,000[1]	148,954	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	3.54	
Variable O&M Cost, 2000 $/MWh	2.36	
Equivalent Availability, percent	94.64	
Equivalent Forced Outage Rate, percent	3.77	
Planned Maintenance Outage, weeks/y	2.29	
Startup Fuel (cold start), MBtu	5,650	
Construction Period, months	21	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	218,773 / 8,050	263,842 / 7,765
75 Percent of Full Load	164,080 / 8,374	197,881 / 8,038
50 Percent of Full Load	109,387 / 9,730	131,921 / 9,294
25 Percent of Full Load	54,693 / 10,004	65,960 / 9,511

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

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

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2000 $1,000	111,963	
Indirect Capital Cost, 2000 $1,000	35,216	
Total Capital Cost, 2000 $1,000[1]	147,179	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	3.39	
Variable O&M Cost, 2000 $/MWh	2.50	
Equivalent Availability, percent	94.41	
Equivalent Forced Outage Rate, percent	2.86	
Planned Maintenance Outage, weeks/y	2.14	
Startup Fuel (cold start), MBtu	3,649	
Construction Period, months	23	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	236,908 / 7,182	274,602 / 7,045
75 Percent of Full Load	177,679 / 7,573	205,956 / 7,392
50 Percent of Full Load	118,459 / 8,330	137,301 / 8,091
25 Percent of Full Load	59,229 / 10,973	68,655 / 10,608

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

Table 6-12
Generating Unit Characteristics
Westinghouse 2 x 1 501F Combined Cycle

Item		
Steam Pressure, psia	1,815	
Steam Temperature, °F	1,050	
Reheat Steam Temperature, °F	1,050	
Direct Capital Cost, 2000 $1,000	201,212	
Indirect Capital Cost, 2000 $1,000	57,663	
Total Capital Cost, 2000 $1,000[1]	258,875	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	1.67	
Variable O&M Cost, 2000 $/MWh	2.34	
Equivalent Availability, percent	92.7	
Equivalent Forced Outage Rate, percent	4.57	
Planned Maintenance Outage, weeks/y	3.71	
Startup Fuel (cold start), MBtu	10,729	
Construction Period, months	25	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	476,232 / 7,146	557,952 / 6,936
75 Percent of Full Load	357,177 / 8,438	418,466 / 7,235
50 Percent of Full Load	238,121 / 9,269	278,981 / 7,909
25 Percent of Full Load	119,056 / 9,886	139,486 / 8,396

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

Table 6-13
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, 2000 $1,000	137,740	
Indirect Capital Cost, 2000 $1,000	45,169	
Total Capital Cost, 2000 $1,000[1]	182,909	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	2.68	
Variable O&M Cost, 2000 $/MWh	2.71	
Equivalent Availability, percent	93.76	
Equivalent Forced Outage Rate, percent	3.32	
Planned Maintenance Outage, weeks/y	2.43	
Startup Fuel (cold start), MBtu	4,511	
Construction Period, months	25	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	295,310 / 6,987	351,806 / 6,704
75 Percent of Full Load	221,488 / 7,571	263,859 / 7,034
50 Percent of Full Load	147,655 / 8,327	175,903 / 7,699
25 Percent of Full Load	73,832 / 10,970	87,956 / 10,095

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

Table 6-14
Generating Unit Characteristics
General Electric LM6000 Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2000 $1,000	21,209	
Indirect Capital Cost, 2000 $1,000	10,487	
Total Capital Cost, 2000 $1,000[1]	31,696	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	10.59	
Variable O&M Cost, 2000 $/MWh	3.58	
Equivalent Availability, percent	98.04	
Equivalent Forced Outage Rate, percent	1.49	
Planned Maintenance Outage, weeks/y	0.29	
Startup Fuel (cold start), MBtu	38	
Construction Period, months	8	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	32,050 / 10,040	46,064 / 9,351
75 Percent of Full Load	24,037 / 11,537	34,553 / 10,241
50 Percent of Full Load	16,025 / 14,578	23,032 / 12,695
25 Percent of Full Load	8,012 / 21,502	11,521 / 15,192

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

Table 6-15
Generating Unit Characteristics
General Electric 7EA Simple Cycle

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2000 $1,000	30,427	
Indirect Capital Cost, 2000 $1,000	13,243	
Total Capital Cost, 2000 $1,000[1]	43,670	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	5.30	
Variable O&M Cost, 2000 $/MWh	9.88	
Equivalent Availability, percent	97.49	
Equivalent Forced Outage Rate, percent	1.48	
Planned Maintenance Outage, weeks/y	0.57	
Startup Fuel (cold start), MBtu	125	
Construction Period, months	10	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	72,335 / 12,437	87,986 / 11,899
75 Percent of Full Load	54,256 / 13,639	65,992 / 12,708
50 Percent of Full Load	36,167 / 16,436	43,998 / 15,353
25 Percent of Full Load	18,088 / 23,706	21,994 / 21,568

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

Table 6-16
Generating Unit Characteristics
General Electric 7FA Simple Cycle Combustion Turbine

Item		
Steam Pressure, psia	--	
Steam Temperature, °F	--	
Reheat Steam Temperature, °F	--	
Direct Capital Cost, 2000 $1,000	52,805	
Indirect Capital Cost, 2000 $1,000	19,270	
Total Capital Cost, 2000 $1,000[1]	72,075	
O&M Cost-Baseload Duty		
Fixed O&M Cost, 2000 $/kW-y	2.63	
Variable O&M Cost, 2000 $/MWh	11.68	
Equivalent Availability, percent	96.20	
Equivalent Forced Outage Rate, percent	1.96	
Planned Maintenance Outage, weeks/y	0.86	
Startup Fuel (cold start), MBtu	224	
Construction Period, months	12	
kW Output, Net Plant Heat Rate (NPHR), HHV, Btu/kWh, after degradation[2]	97° F	30° F
100 Percent of Full Load	145,926 / 11,200	174,167 / 10,616
75 Percent of Full Load	109,442 / 12,333	130,630 / 11,482
50 Percent of Full Load	72,968 / 14,807	87,084 / 13,839
25 Percent of Full Load	36,484 / 20,840	43,547 / 18,968

[1]Does not include interest during construction.
[2]Includes output and heat rate degradation.

7.0 Environmental and Land Use Information

Lakeland's Ten Year Site Plan includes McIntosh Unit 5 for which the simple cycle installation is complete and formal commercial operation is scheduled for April 1, 2000. The combined cycle conversion of McIntosh Unit 5 was approved by the PSC on May 10, 1999 in order No. PSC-99-0931-FOF-EM and construction is planned to begin June 1, 2000. The Site Certification Application for McIntosh Unit No. 5 Steam Cycle which has been filed with all the agencies for the Site Certification, contains detailed environmental and land use information.

The other units in Lakeland's Ten Year Site Plan include McIntosh Unit 4 in 2005 and a simple cycle LM6000 combustion turbine in 2009. The specific configuration of McIntosh Unit 4 will be determined as part of the Request for Proposal (RFP) process for McIntosh Unit 4. For purposes of the Ten Year Site Plan, McIntosh Unit 4 is assumed to a jointly owned 288 MW PFBC consisting of three P200 modules with petroleum coke as the primary fuel and coal as the secondary fuel. For the sake of brevity, most of the environmental land use information for McIntosh Unit 4 is contained in the Site Certification Application for McIntosh Unit No. 5 Steam Cycle and is not reproduced in the Ten Year Site Plan. The simple cycle LM6000 in 2009 is also assumed to be located at the McIntosh site and likewise, no specific environmental and land use information is presented for the LM6000. The following discussion is focused on McIntosh Unit 4.

7.1 Status of Site Certification

Lakeland is planning on conducting a RFP process for the purchase of power or installation of new generation. Based on the results of the RFP process, Lakeland plans to file Need for Power and Site Certification Applications in the summer of 2000.

7.2 Land and Environmental Features

Emissions will be minimized through the use of the highly efficient the pressurized fluidized bed clean fuel technology. Irrespective of fuel quality or sulfur content, the PFBC produces very low emissions. This is due to the advantage of burning fuel in a fluidized bed under pressure at temperatures of less than 900 degrees. The low burn temperature deters the production of thermal NO_x. Also, a lower excess air level means that NO_x developing from fuel bound nitrogen is lower than for conventional boilers. The PFBC's firing temperature encourages the calcium in the sorbent to be extremely reactive and remove up to 99 percent of the sulfur.

Reclaimed water from treated sewage effluent is assumed for supply of the Unit 4 cooling towers. Use of reclaimed water will conserve valuable water resources. It is assumed that cooling tower blowdown will be treated for reuse as part of the design features of Unit 4. Return of wastewater to the City Wastewater Treatment Facility may be possible which would reduce costs but there is limited additional capacity for this alternative. 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 4 is also provided in Figure 7-1.

7.3 Air Emissions

The proposed commercial operating date for McIntosh Unit 4 is June of 2005. Estimated emissions for McIntosh 4 are as follows:

SO_2, lb/MBtu – 0.20 (requires zero stage cyclone and sorbent consumption of 40,000 lb/hr per module with 8 percent fuel sulfur).

NO_x, lb/MBtu – 0.09

CO, lb/MBtu – 0.022

Particulate, lb/MBtu – 0.011

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.

7.4.1 Authority to Construct

McIntosh Unit 4 is required to comply with the Clean Air Act and the current Florida air quality requirements stemming from the Act. Lakeland's Authority to Construct (ATC) permit for McIntosh 4 will be obtained through the Site Certification Process. One aspect of the ATC permit will be the determination of Best Available Control Technology (BACT). Major criteria pollutants included in the BACT analysis are SO_2, NO_x, VOC, CO, and PM/PM10. Lakeland believes that the inherently low emission profile presented in Section 7.3 will meet BACT with no additional treatment requirements.

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 4 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 Unit 4 will emit relatively low levels of sulfur dioxide while running on either petroleum coke or coal. As an affected unit, McIntosh Unit 4 must have allowances available for emission of sulfur dioxide to comply with its future Title IV Acid Rain permit. Lakeland's ATC permit will set a limit of sulfur dioxide emissions from McIntosh Unit 4. Lakeland's share for current operation of the McIntosh and Larsen Units result in a combined sulfur dioxide emission rate of approximately 8,680 tons per year for 1999. Lakeland currently has 12,809 allowances available annually leaving enough allowances for McIntosh Unit 5 and proposed McIntosh Unit 4. Purchasing allowances will be the compliance strategy utilized if, for any reason, Lakeland's existing allowances are insufficient.

7.5 Waste Supply and Use

Water supply for the McIntosh Unit 4 cooling towers will be reclaimed sewage treatment plant effluent water using the existing reclaimed water pipeline at the site. Additional filtration facilities will be required to ensure the water quality is suitable for the cooling towers and to meet Florida requirements for reuse. Process makeup for ash systems will primarily be cooling tower blowdown. Demineralized water supply will be treated well water using a new demineralizer system.

7.6 Wastewater Discharge

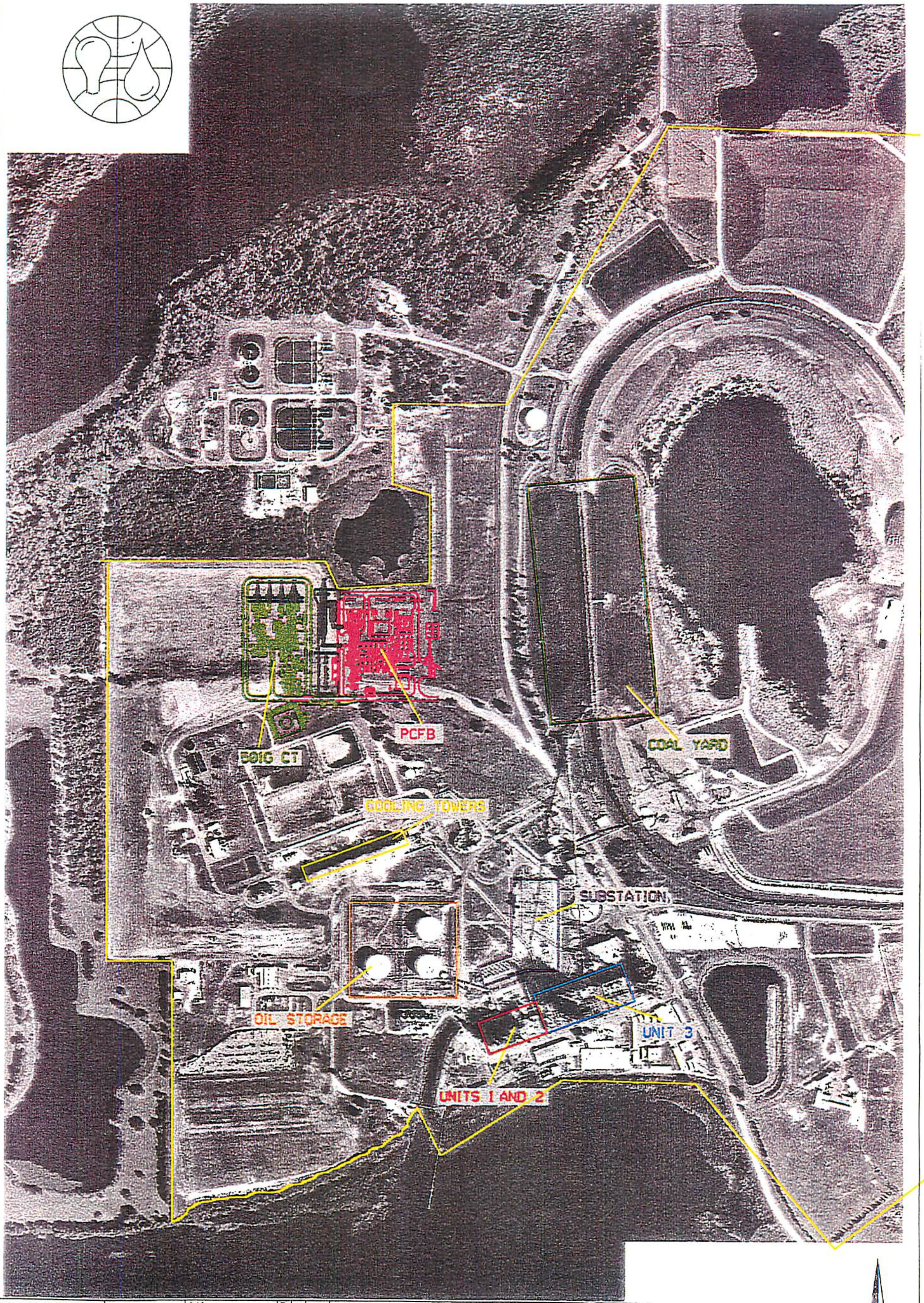
An existing wastewater disposal pump station and pipeline exists at the site which transports wastewater back to the City's wastewater treatment plants for treatment and disposal. Because of pending discharge salinity restrictions, there may not be capacity for additional cooling tower blowdown wastewater to be disposed at the treatment facilities.

Therefore, it has been assumed that cooling tower blowdown wastewater will be treated on-site at McIntosh for reuse. Cooling tower blowdown quality is suitable for direct reuse in ash conditioning systems. Excess blowdown would need to be treated by a process using reverse osmosis and evaporation technology to produce a low salinity product water and a solid waste that could be landfilled.

7.7 Fuel Delivery and Storage

McIntosh Unit 4 is expected to burn 100 percent petroleum coke. The secondary fuel will be the same coal as McIntosh Unit 3 burns. The choice of the secondary fuel saves in the cost of an additional fuel storage space. Unit trains will deliver the petroleum coke and coal. The coal is presently delivered by unit train to the site.

A separate storage pile for petroleum coke is planned adjacent to the existing coal pile for McIntosh Unit 3. Coal for secondary fuel use will be stored in the existing McIntosh Unit 3 coal pile.



CITY OF LAKELAND DEPARTMENT OF ELECTRIC & WATER UTILITIES

McINTOSH PLANT GENERAL ARRANGEMENT

8.0 Analysis Results and Conclusions

8.1 Economic Evaluation

A three phase economic analysis was conducted to determine Lakeland's optimum capacity expansion plan. The three phases included supply-side evaluations, demand-side evaluations and sensitivity analyses. Capacity and energy savings from Lakeland's demand-side management programs are included in the loads used to evaluate the supply-side alternatives. The results of the supply-side analyses are included in this section and discussed in detail. The sensitivity analyses are discussed in Section 8.2. Lakeland is currently planning to issue a request for proposals (RFP). The results from the RFP will add a fourth phase to the evaluation process.

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 on a calendar year basis while maintaining user-defined reliability criteria. The reserve criterion utilized was a minimum reserve margin of 22 percent for winter and 20 percent for summer. All capacity expansion plans were analyzed over a 20 year period from 2000 to 2019.

The revenue requirements evaluated include system fuel and variable O&M costs, fixed O&M costs for new unit additions (fixed O&M costs are not included for existing units because they are common to all plans), and capital costs for new unit additions (capital costs for existing units are not included since they are common to all plans).

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 planned reserve margins. 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 the base case scenario. The expansion plan units are listed in the table according to their year of commercial operation. For example: McIntosh 5 simple cycle is listed in the expansion plan for the year 2000, but actually is not scheduled for commercial operation until April 1, 2000.

All units were modeled using the average yearly temperature for the City of Lakeland. Table 8-3 displays the reserve margins for the base case after the construction of the resources identified.

8.1.2 Demand-Side Economic Analysis

Demand Side Management (DSM) alternatives are evaluated to determine if any cost-effective measures can delay or mitigate the need for the capacity addition. The analysis includes all the cost-effective DSM programs identified by Lakeland.

8.1.3 Power Supply RFP

Lakeland is currently planning to conduct an RFP for the construction of a generating unit at the McIntosh site or for purchase power. Lakeland will either own the generating unit or purchase power. Lakeland expects the RFP process to result in a solid fuel unit being the least cost alternative based Lakeland's existing system.

Table 8-1
Summary of Generation Alternatives (2000 $)

Description	Capital Costs $(1,000)	Capacity		O&M Costs		Fuel Type	Full Load Heat Rate(1) (Btu/kWh)	Forced Outage Rate (percent)	Planned Maintenance (weeks)
		Summer (kW)	Winter (kW)	Variable ($/MWh)	Fixed ($kW-Yr)				
Pulverized Coal	270,317	250,000	250,000	3.67	26.76	Coal	10,141	7.00	4
Fluidized Bed	276,034	250,000	250,000	5.97	30.15	Pet Coke	10,543	7.00	4
PFBC	379,250	288,000	288,000	4.53	20.76	Pet Coke	8,452	12.0	4
7EA 1x1 CC	88,620	107,506	130,087	2.59	7.17	Nat. Gas	7,874	2.40	1.86
7EA 2x1 CC	148,954	218,773	263,842	2.36	3.54	Nat. Gas	7,765	3.77	2.29
501F 1x1 CC	147,179	236,908	274,602	2.50	3.39	Nat. Gas	7,045	2.86	2.14
501F 2x1 CC	258,875	476,232	557,952	2.34	1.67	Nat. Gas	6,936	4.57	3.71
501G 1x1 CC	182,909	295,310	351,806	2.71	2.68	Nat. Gas	6,704	3.32	2.43
LM6000 SC	31,696	32,050	46,064	3.58	10.59	Nat. Gas	9,351	1.49	0.29
7EA SC	43,670	72,335	87,986	9.88	5.30	Nat. Gas	11,899	1.48	0.57
7FA SC	72,075	145,926	174,167	11.68	2.63	Nat. Gas	10,616	1.96	1.00

Table 8-2
Base Case Expansion Plan[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	83,528	83,528
2001	Larsen 7 retired (50 MW)	94,811	172,972
2002	Convert McIntosh 5 to CC (120 MW)	79,215	243,473
2003	McIntosh 1 retired (87MW)	84,353	314,297
2004		90,706	386,145
2005	McIntosh 4 PFBC (188 MW)	103,717	463,649
2006	McIntosh 2 retired (103 MW)	116,650	545,882
2007		122,190	627,146
2008		127,268	706,995
2009	LM 6000 (32 MW)	135,113	786,968
2010		142,382	866,474
2011		139,105	939,753
2012		144,629	1,011,629
2013		151,087	1,082,464
2014		157,761	1,152,242
2015		164,533	1,220,896
2016		343,907	1,356,273
2017	LM 6000 (32 MW)	182,483	1,424,041
2018		192,166	1,491,365
2019		200,273	1,557,558

[1]Capacity is stated in summer ratings.

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

Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 20%	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2000	807	0	179	628	558	526	12.46	19.23	(42)	(4)
2001	757	0	100	657	572	540	14.77	21.53	(30)	8
2002	877	0	100	777	586	554	32.51	40.11	73	111
2003	790	0	100	690	600	568	14.92	21.35	(30)	8
2004	790	0	100	690	614	581	12.30	18.66	(47)	(8)
2005	978	0	100	878	628	595	39.73	47.46	124	163
2006	875	0	100	775	642	609	20.64	27.16	4	44
2007	875	0	100	775	656	623	18.07	24.30	(13)	27
2008	875	0	100	775	670	636	15.60	21.78	(29)	11
2009	907	0	100	807	684	650	17.91	24.08	(14)	27
2010	907	0	100	807	698	664	15.55	21.46	(31)	10
2011	907	0	0	907	712	678	27.32	33.72	52	93
2012	907	0	0	907	727	692	24.69	31.02	34	76
2013	907	0	0	907	741	706	22.34	28.42	17	59
2014	907	0	0	907	755	720	20.07	25.92	1	43
2015	907	0	0	907	769	734	17.88	23.54	(16)	26
2016	907	0	0	907	783	747	15.77	21.39	(33)	10
2017	939	0	0	939	797	761	17.75	23.36	(18)	26
2018	939	0	0	939	811	775	15.72	21.14	(35)	9
2019	939	0	0	939	826	789	13.62	18.99	(53)	(8)

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 8.2.5, which include the following:

- High load and energy growth.
- Low load and energy growth.
- High fuel price escalation.
- Low fuel price escalation.
- Constant differential between oil/gas and coal prices over the planning horizon.

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 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 combined installation of simple cycle combustion turbines and the McIntosh Unit 4 PFBC unit are 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.

The high load growth results in a much earlier need for capacity additions with the first additional unit needed in 2003. The lead-time required for the PFBC precludes its installation before 2005. As a result a 7FA General Electric simple cycle combustion turbine is the first unit selected for installation in 2003. The installation of the 7FA simple cycle combustion turbine allows the installation of the PFBC to be deferred until 2006.

8.2.2 Low Load and Energy Growth

The low load and energy growth sensitivity is based upon the low load and energy growth forecast presented in Subsection 3.6.2. 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 8-5 indicates the need for capacity in 2006 based upon the low load and energy forecast.

8.2.3 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 5.3. Table 8-6 displays the results of the economic evaluation for the least cost expansion plan for the high fuel price escalation sensitivity. The expansion plan for the high fuel price scenario is the same as the base case.

8.2.4 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. Table 8-7 displays the results of the economic evaluation for the least cost expansion plan for the low fuel price escalation sensitivity. With lower fuel prices, only simple cycle combustion turbines are installed.

8.2.5 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 5-5 displays the constant differential fuel price forecast. The economic evaluation results of the analysis are included in Table 8-8. With the differential price between natural gas / oil and coal remaining constant, only simple cycle combustion turbines are installed.

Table 8-4
High Load and Energy Growth Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	83,631	83,631
2001	Larsen 7 retired (50 MW)	97,966	176,052
2002	Convert McIntosh 5 to CC (120 MW)	82,870	249,806
2003	7FA CT (146 MW); McIntosh 1 retired (87MW)	96,728	331,021
2004		104,448	413,753
2005		111,842	497,328
2006	PFBC (188 MW); McIntosh 2 retired (103 MW)	130,498	589,324
2007		137,906	681,040
2008		145,371	772,248
2009		153,807	863,286
2010	LM 6000 (32 MW)	165,564	955,736
2011		164,189	1,042,229
2012		173,025	1,128,217
2013		183,056	1,214,041
2014	7EA CT (72 MW)	200,005	1,302,503
2015		211,545	1,390,773
2016	CFB (150 MW)	256,789	1,491,857
2017		269,017	1,591,761
2018		282,104	1,690,594
2019		297,110	1,788,792

[1]Capacity is stated in summer ratings.

Table 8-5
Low Load and Energy Growth Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	82,067	82,067
2001	Larsen 7 retired (50 MW)	91,238	168,140
2002	Convert McIntosh 5 to CC (120 MW)	75,571	235,398
2003	McIntosh 1 retired (87MW)	79,605	302,236
2004		84,535	369,196
2005		87,835	434,831
2006	7EA CT (72 MW); McIntosh 2 retired (103 MW)	94,052	501,134
2007		100,899	568,237
2008		104,540	633,827
2009		107,834	697,654
2010		111,820	760,093
2011		102,209	813,935
2012		107,843	867,530
2013		111,257	919,692
2014		112,445	969,426
2015		116,263	1,017,938
2016		120,378	1,065,325
2017		127,146	1,112,542
2018		131,294	1,158,540
2019		135,717	1,203,397

[1]Capacity is stated in summer ratings.

Table 8-6
High Fuel Price Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	85,124	85,124
2001	Larsen 7 retired (50 MW)	98,340	177,898
2002	Convert McIntosh 5 to CC (120 MW)	83,854	252,527
2003	McIntosh 1 retired (87MW)	92,447	330,148
2004		99,922	409,295
2005	McIntosh 4 PFBC (188 MW)	114,060	494,528
2006	McIntosh 2 retired (103 MW)	129,501	585,821
2007		136,911	676,874
2008		145,392	768,095
2009	LM 6000 (32 MW)	156,588	860,779
2010		164,757	952,779
2011		166,952	1,040,727
2012		177,045	1,128,713
2013		188,912	1,217,283
2014		200,246	1,305,852
2015		213,204	1,394,814
2016		226,925	1,484,142
2017	LM 6000 (32 MW)	245,314	1,575,243
2018		263,094	1,667,416
2019		280,092	1,759,990

[1]Capacity is stated in summer ratings.

Table 8-7
Low Fuel Price Sensitivity[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	82,057	82,057
2001	Larsen 7 retired (50 MW)	91,054	167,957
2002	Convert McIntosh 5 to CC (120 MW)	74,754	234,488
2003	McIntosh 1 retired (87MW)	79,372	301,130
2004		82,449	366,438
2005	7FA CT(146 MW)	90,569	434,116
2006	McIntosh 2 retired (103 MW)	98,341	503,443
2007	7EA CT (72 MW)	105,254	573,443
2008		110,089	642,514
2009		114,191	710,103
2010		117,900	775,938
2011		110,575	834,188
2012		114,698	891,189
2013		117,566	946,309
2014		123,014	1,000,718
2015		125,734	1,053,182
2016		130,953	1,104,732
2017		134,207	1,154,571
2018	LM 6000 (32 MW)	141,433	1,204,121
2019		147,363	1,252,827

[1]Capacity is stated in summer ratings.

Table 8-8
Constant Differential Between Coal Versus Natural Gas/Oil[1]

Year	Expansion Plan	Annual Costs ($1,000)	Cumulative Present Worth ($1,000)
2000	McIntosh 5 SC (218 MW); Larsen 6 retired (25 MW)	81,726	81,726
2001	Larsen 7 retired (50 MW)	90,276	166,892
2002	Convert McIntosh 5 to CC (120 MW)	71,188	230,249
2003	McIntosh 1 retired (87MW)	73,643	292,081
2004		79,491	355,046
2005	7FA CT (146 MW)	83,746	417,626
2006	McIntosh 2 retired (103 MW)	95,499	484,949
2007	7EA CT (72 MW)	101,218	552,264
2008		101,536	615,969
2009		104,872	678,043
2010		109,559	739,220
2011		103,133	793,549
2012		107,170	846,809
2013		116,152	901,265
2014		120,277	954,464
2015		124,790	1,006,534
2016		129,189	1,057,389
2017		129,741	1,105,570
2018	LM 6000 (32 MW)	141,125	1,155,012
2019		143,958	1,202,592

[1]Capacity is stated in summer ratings.

8.3 Transmission

The generating units evaluated can generally be installed at the McIntosh site. Evaluation of purchase power alternatives resulting from Lakeland's potential 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. There are no current plans for transmission upgrades with the proposed installation of McIntosh Unit 4.

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 installation of McIntosh Unit 4. These include excellent efficiency, existing site which can support the project capacity, electric industry deregulation, environmental benefits and increased fuel diversity.

8.4.1 Efficiency

Lakeland strives to provide its customers with the lowest rates achievable while maintaining sound operating principles and environmentally clean units. The new PFBC unit represents the best available solid fuel technology. With the installation of McIntosh Unit 4, the unit will yield high efficiency, strengthen Lakeland's fuel diversity and provide a very clean burning solution to meet Lakeland's load growth. The efficiency of the PFBC unit and low fuel costs ensures that McIntosh Unit 4 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 2005 time frame. The McIntosh Unit 4 offers the least cost solution for meeting Lakeland's expected load growth and reserve margin requirement of 22 percent in the winter and 20 percent in the summer. Also, with the increased fuel diversity, Lakeland customers will benefit from a more reliable power source.

8.4.3 Deregulation

In a deregulated environment, the clean coal unit will be an economical unit due to its high efficiency, low heat rate and enhanced stability due to fuel diversity. 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 4 becoming a stranded asset should retail access occur in the state.

8.4.4 Timing

With the installation of McIntosh Unit 4, Lakeland will benefit in many ways. The installation of McIntosh Unit 4 will counteract the scheduled retirements of older less efficient units. Lakeland also benefits from the current tax exempt financing available to municipal utilities.

Customers will benefit from the replacement of older generation with cleaner more efficient generation and better operating characteristics of the solid fuel McIntosh 4. The financial savings from more efficient generation and fewer emissions will be passed along to the customers.

Lakeland has the opportunity to utilize its strategic advantage of low cost tax exempt municipal financing for the more capital intensive McIntosh Unit 4. The ability to use the tax exempt financing may not continue to be available as the industry deregulates.

8.4.5 Fuel Risk

McIntosh Unit 4 will utilize petroleum coke which reduces the risks of natural gas dependency. The unit is also capable of burning the coal used for McIntosh 3, thus providing Lakeland with fuel diversity in situations in which petroleum coke supply may be interrupted.

Currently Lakeland is dependent on the supply of natural gas. As of December 31, 1999, Lakeland is 67 percent dependent on natural gas. By December of 2005, Lakeland will be 72 percent dependent on natural gas. The installation of McIntosh Unit 4 will significantly decrease Lakeland's dependency on natural gas and create a more diverse and proportionate fuel dependency. With increased fuel diversity, Lakeland will become a more reliable source of energy generation for Lakeland's customers, FMPP, and the state of Florida.

A depressed market for solid fuel is expected in the future due to the potential strict regulations on unit emissions and fuel sulfur content. In a depressed market, Lakeland will be able to obtain the fuel for McIntosh Unit 4 much lower than the forecasted fuel price in Section 5.0 thus making the unit more cost-effective.

8.4.6 Environmental 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 4 unit 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.

The PFBC is clean, emissions are low irrespective of fuel quality, waste products are harmless, and the unit is highly efficient. The PFBC can burn coal or petroleum coke and for expansion planning purposes is assumed to burn petroleum coke. The pressurized fluidized bed operates at pressures of 175–235 psi and less than 900° F. The lower firing temperatures reduce the amount of thermal NO_x emissions. Other emissions such as SO_x and CO_2 are also reduced significantly. Through the clean fuel technology, less ash is produced. Recent investigations and trials have shown the potential for ash resale in the construction industry. Plant efficiency increase, and correspondingly fuel cost decreases, are estimated to be in the range of 10 - 15 percent.

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 1.0: Existing Generating Facilities as of December 31, 1999

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability[2]	
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Alt Fuel Days Use[3]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Summer MW	Winter MW
Charles	2	16-17/28S/24E	GT	NG	FO2	PL	TK	NR	11/62	Unknown	11,500	10.0	14.0
Larsen	3		GT	NG	FO2	PL	TK	NR	12/62	Unknown	11,500	10.0	14.0
Memorial	5		CW	WH	NA	NA	NA	NR	04/56	Unknown	25,000	29.0	31.0
	6		ST	NG	FO6	PL	TK	NR	12/59	07/00	25,000	25.0	27.0
	7		ST	NG	FO6	PL	TK	NR	02/66	03/01	50,000	50.0	50.0
	8		CT	NG	FO2	PL	TK	NR	07/92	Unknown	101,520	73.0	93.0
Plant Total												197.0	229.0
C.D.	IC1	4-5/28S/24E	IC	FO2	NA	TK	NA	NR	01/70	Unknown	2,500	2.5	2.5
McIntosh, Jr.	IC2		IC	FO2	NA	TK	NA	NR	01/70	Unknown	2,500	2.5	2.5
	1GT		GT	NG	FO2	PL	TK	NR	05/73	Unknown	26,640	17.0	20.0
	1		ST	NG	FO6	PL	TK	NR	02/71	10/02	103,000	87.0	87.0
	2		ST	NG	FO6	PL	TK	NR	06/76	10/05	126,000	103.0	103.0
	3[1]		ST	BIT	REF	RR	TK	NR	09/82	Unknown	363,870	205.0	205.0
Plant Total												417.0	420.0
System Total												614.0	649.0

[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.

[2]Net Normal.

[3]Lakeland does not maintain records of the number of days that alternate fuel is used.

Source: Lakeland Power Production Unit Rating Group

Table 9-2
Schedule 2.1: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial		
Fiscal Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption per Customer	GWh	Average No. of Customers	Average kWh Consumption per Customer
1990	184,984	2.5	916	73,082	12,528	509	9,084	56,055
1991	189,445	2.5	951	74,845	12,711	523	9,344	56,005
1992	198,763	2.5	988	78,427	12,604	529	9,740	54,310
1993	201,748	2.5	1,012	79,493	12,728	536	9,759	54,944
1994	206,040	2.5	1,085	80,909	13,406	563	9,887	56,924
1995	210,095	2.5	1,134	82,445	13,760	594	10,030	59,258
1996	213,347	2.6	1,213	83,656	14,500	588	9,746	60,347
1997	216,782	2.6	1,170	84,941	13,776	607	9,835	61,722
1998	218,959	2.6	1,249	85,840	14,550	625	10,032	62,277
1999	221,921	2.5	1,239	87,222	14,202	642	10,338	62,102
Forecast								
2000	226,339	2.6	1,274	88,362	14,415	635	10,501	60,518
2001	230,143	2.6	1,299	89,540	14,510	650	10,650	61,060
2002	233,947	2.6	1,325	90,720	14,610	666	10,799	61,632
2003	237,751	2.6	1,352	91,903	14,710	681	10,950	62,189
2004	241,555	2.6	1,379	93,090	14,810	696	11,101	62,738
2005	245,359	2.6	1,406	94,281	14,910	712	11,252	63,279
2006	248,931	2.6	1,433	95,464	15,010	728	11,402	63,815
2007	252,504	2.6	1,460	96,651	15,110	743	11,555	64,332
2008	256,076	2.6	1,488	97,842	15,210	759	11,708	64,842
2009	259,648	2.6	1,516	99,037	15,310	775	11,862	65,341

Table 9-3
Schedule 2.2: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Fiscal Year	GWh	Average No. of Customers	Average kWh Consumption per Customer	Railroads and Railways	Street & Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1990	336	42	8,000,000	0	20	55	1,836
1991	350	45	7,780,467	0	18	55	1,898
1992	349	47	7,424,707	0	21	57	1,944
1993	377	50	7,548,484	0	22	58	2,006
1994	387	51	7,589,265	0	23	60	2,118
1995	429	51	8,417,875	0	24	64	2,246
1996	428	57	7,511,573	0	25	68	2,322
1997	459	61	7,526,069	0	25	69	2,331
1998	462	61	7,638,456	0	26	70	2,432
1999	486	70	6,938,491	0	27	71	2,465
Forecast							
2000	521	85	6,130,161	0	26	73	2,529
2001	539	87	6,207,316	0	26	76	2,591
2002	557	89	6,278,889	0	27	78	2,653
2003	574	91	6,314,851	0	28	80	2,715
2004	591	93	6,341,549	0	29	83	2,777
2005	608	95	6,368,597	0	29	85	2,840
2006	625	97	6,423,648	0	30	87	2,903
2007	642	99	6,479,025	0	31	90	2,966
2008	659	101	6,532,505	0	31	92	3,030
2009	676	103	6,554,660	0	32	95	3,095

Table 9-4
Schedule 2.3: History and Forecast of Energy Consumption and Number of Customers by Customer Class

(1) Fiscal Year	(2) Sales for Resale GWh	(3) Utility Use & Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers (Average No.)	(6) Total No. of Customers
1990	0	174	2,009	0	82,208
1991	0	149	2,047	0	84,234
1992	0	135	2,079	0	88,214
1993	0	134	2,140	0	89,302
1994	0	162	2,279	0	90,847
1995	0	144	2,390	0	92,526
1996	0	126	2,448	0	93,459
1997	0	113	2,443	0	94,837
1998	0	117	2,549	0	95,933
1999	0	120	2,585	0	97,630
Forecast					
2000	0	118	2,648	0	98,948
2001	0	122	2,712	0	100,277
2002	0	125	2,778	0	101,608
2003	0	129	2,844	0	102,944
2004	0	133	2,910	0	104,284
2005	0	136	2,976	0	105,628
2006	0	140	3,043	0	106,963
2007	0	143	3,110	0	108,305
2008	0	147	3,177	0	109,651
2009	0	150	3,245	0	111,002

Table 9-5
Schedule 3.1: History and Forecast of Summer Peak Demand Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial/Industrial		
Year	Total	Whole-sale	Retail	Interrupt.	Load Management	Conservation	Load Management	Conservation	Net Firm Demand
1990	408	0	408	0	0	0	0	0	408
1991	424	0	424	0	0	0	0	0	424
1992	434	0	434	0	0	0	0	0	434
1993	477	0	477	0	0	0	0	0	477
1994	455	0	455	0	0	0	0	0	455
1995	481	0	481	0	0	0	0	0	481
1996	490	0	490	0	8	0	0	0	482
1997	509	0	509	0	0	0	0	0	509
1998	535	0	535	0	0	0	0	0	535
1999	557	0	557	0	22	0	0	0	535
Forecast									
2000	558	0	558	10	22	0	0	0	526
2001	572	0	572	10	22	0	0	0	540
2002	586	0	586	10	22	0	0	0	554
2003	600	0	600	10	22	0	0	0	568
2004	614	0	614	10	23	0	0	0	581
2005	628	0	628	10	23	0	0	0	595
2006	642	0	642	10	23	0	0	0	609
2007	656	0	656	10	23	0	0	0	623
2008	670	0	670	10	24	0	0	0	636
2009	684	0	684	10	24	0	0	0	650

Table 9-6
Schedule 3.2: History and Forecast of Winter Peak Demand Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Comm./Ind.		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Conservation	Load Management	Conservation	Net Firm Demand
1990/1991	446	0	446	0	6	0	0	0	440
1991/1992	464	0	464	0	20	0	0	0	444
1992/1993	480	0	480	0	23	0	0	0	457
1993/1994	485	0	485	0	0	0	0	0	445
1994/1995	578	0	578	0	40	0	0	0	538
1995/1996	655	0	655	0	45	0	0	0	610
1996/1997	552	0	552	0	0	0	0	0	552
1997/1998	476	0	476	0	0	0	0	0	476
1998/1999	611	0	611	0	0	0	0	0	611
1999/2000	661	0	661	0	51	0	0	0	610
Forecast									
2000/2001	637	0	637	9	52	0	0	0	576
2001/2002	652	0	652	9	52	0	0	0	591
2002/2003	666	0	666	9	53	0	0	0	604
2003/2004	680	0	680	9	53	0	0	0	618
2004/2005	695	0	695	10	54	0	0	0	631
2005/2006	709	0	709	10	54	0	0	0	645
2006/2007	723	0	723	10	55	0	0	0	658
2007/2008	737	0	737	10	56	0	0	0	671
2008/2009	751	0	751	10	56	0	0	0	685
2009/2010	765	0	765	10	57	0	0	0	698

Table 9-7
Schedule 3.3: History and Forecast of Annual Net Energy for Load – GWH
Base Case

(1) Fiscal Year	(2) Total	(3) Residential Conservation	(5) Comm./Ind. Conservation	(6) Retail	(7) Wholesale	(8) Utility Use & Losses	(9) Net Energy for Load	(10) Load factor %
1990	1,836	0	0	1,836	0	174	2,009	45
1991	1,898	0	0	1,898	0	149	2,047	52
1992	1,944	0	0	1,944	0	135	2,079	51
1993	2,006	0	0	2,006	0	134	2,140	51
1994	2,118	0	0	2,118	0	162	2,279	54
1995	2,246	0	0	2,246	0	144	2,390	45
1996	2,322	0	0	2,322	0	126	2,448	43
1997	2,331	1	0	2,330	0	113	2,443	50
1998	2,432	1	0	2,431	0	117	2,549	54
1999	2,465	0	0	2,465	0	120	2,585	48
Forecast								
2000	2,529	0	0	2,529	0	118	2,648	48
2001	2,591	0	0	2,591	0	122	2,712	49
2002	2,653	0	0	2,653	0	125	2,778	49
2003	2,715	0	0	2,715	0	129	2,844	49
2004	2,777	0	0	2,777	0	133	2,910	49
2005	2,840	0	0	2,840	0	136	2,976	49
2006	2,903	0	0	2,903	0	140	3,043	49
2007	2,966	0	0	2,966	0	143	3,110	49
2008	3,030	0	0	3,030	0	147	3,177	49
2009	3,095	0	0	3,095	0	150	3,245	49

Table 9-8
Schedule 4: Previous Year and Two Year Forecast of Retail Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Actual		2000 Forecast		2001 Forecast	
Month	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	611	197	610	225	576	230
February	438	175	508	194	530	199
March	420	186	442	198	452	203
April	468	208	420	191	432	195
May	458	217	477	225	490	230
June	503	231	516	245	530	251
July	531	263	522	257	536	263
August	535	260	526	261	540	268
September	478	242	513	243	526	249
October	458	216	452	216	465	221
November	377	179	396	193	405	198
December	473	200	490	215	501	221

[1] After Load Management, Conservation and Interruptible Load exercised as needed.

Table 9-9
Schedule 5: Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Calendar Year											
	Fuel Requirements	Type	Units	1998 - Actual	1999 - Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Nuclear		1000 MBtu												
(2)	Coal		1000 Ton	385	455	389	506	260	268	278	200	171	199	237	245
(3)	Residual[1]	Total	1000 BBL	184	181	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	184	181	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL												
(6)		CT	1000 BBL												
(7)		Diesel	1000 BBL												
(8)	Distillate[2]	Total	1000 BBL	5	3	1	2	1	2	2	1	2	2	2	2
(9)		Steam	1000 BBL												
(10)		CC	1000 BBL	3	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	2	3	1	2	1	2	2	1	2	2	2	2
(12)		Diesel	1000 BBL												
(13)	Natural Gas	Total	1000 MCF	5,090	9,280	15,361	14,411	15,859	15,876	16,105	13,870	11,882	12,178	11,496	11,625
(14)		Steam	1000 MCF	2,042	3,769	3,875	4,247	1,173	891	943	539	0	0	0	0
(15)		CC	1000 MCF	2,962	5,120	5,815	5,787	14,637	14,915	15,087	13,252	11,793	12,078	11,383	11,500
(16)		CT	1000 MCF	86	391	5,671	4,377	49	70	75	79	89	100	113	125
(17)		Diesel	1000 MCF												
(18)	Pet Coke	Total	1000 Ton								213	364	341	355	360
(19)		Steam	1000 Ton								213	364	341	355	360
(20)		CC	1000 Ton												
(21)		CT	1000 Ton												
(22)		Diesel	1000 Ton												
(23)	Other		1000 MBtu												

[1] Residual includes #4, #5 and #6 oil.

[2] Distillate includes #1, #2 oil, kerosene, jet fuel and amounts used at coal burning plants for flame stabilization and on start up.

Table 9-10
Schedule 6.1: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Calendar Year											
	Fuel Requirements	Type	Units	1998 - Actual	1999 - Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Firm Interchange		GWh	704	-18	-6	-187	-250	-218	-211	-251	-288	-273	-247	-241
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	1,126	1,144	997	1,299	624	639	663	468	400	464	519	584
(4)	Residual	Total	GWh	106	100	0	1	1	1	1	1	1	1	1	1
(5)		Steam	GWh	106	99	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	1	0	1	1	1	1	1	1	1	1	1
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate[2]	Total	GWh	2	0	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	1	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	1	0	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	627	1,192	1,561	1,471	2,349	2,366	2,398	2,019	1,700	1,759	1,666	1,685
(15)		Steam	GWh	321	631	337	381	109	81	86	50	0	0	0	0
(16)		CC	GWh	301	534	657	657	2,237	2,280	2,307	1,963	1,694	1,752	1,658	1,676
(17)		CT	GWh	5	27	567	433	3	5	5	6	6	7	8	9
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Pet Coke & RDF	Total	GWh	0	157	111	144	69	71	74	754	1,245	1,174	1,254	1,231
(20)		Steam	GWh	0	157	111	144	69	71	74	754	1,245	1,174	1,254	1,231
(21)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(22)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(24)	Net Energy for Load		GWh	2,565	2,575	2,663	2,728	2,793	2,859	2,925	2,991	3,058	3,125	3,193	3,260

[1] Data includes petroleum coke and refuse derived fuel.
[2] Distillate fuel is included in the residual requirements for years 2000 - 2009.

Table 9-11
Schedule 6.2: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Calendar Year											
	Energy Source	Type	Units	1998 - Actual	1999 - Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
(1)	Firm Interchange[1]		%	27%	-1%	0%	-7%	-9%	-8%	-7%	-8%	-9%	-9%	-8%	-7%
(2)	Nuclear		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(3)	Coal		%	44%	44%	37%	48%	22%	22%	23%	16%	13%	15%	16%	18%
(4)	Residual	Total	%	4%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(5)		Steam	%	4%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(6)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(7)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(8)		Diesel	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)	Distillate	Total	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(10)		Steam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(12)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(13)		Diesel	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(14)	Natural Gas	Total	%	24%	46%	59%	54%	84%	83%	82%	68%	56%	56%	52%	52%
(15)		Steam	%	13%	25%	13%	14%	4%	3%	3%	2%	0%	0%	0%	0%
(16)		CC	%	12%	21%	25%	24%	80%	80%	79%	66%	55%	56%	52%	51%
(17)		CT	%	0%	1%	21%	16%	0%	0%	0%	0%	0%	0%	0%	0%
(18)		Diesel	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(19)	Pet Coke & RDF	Total	%	0%	6%	4%	5%	2%	2%	3%	25%	41%	38%	39%	38%
(20)		Steam	%	0%	6%	4%	5%	2%	2%	3%	25%	41%	38%	39%	38%
(21)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(22)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(23)		Diesel	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(24)	Net Energy for Load		GWh	2,565	2,575	2,663	2,728	2,793	2,859	2,925	2,991	3,058	3,125	3,193	3,260

[1]A negative percentage exhibits sales from Lakeland to other utilities.

Table 9-12

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 After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2000	807	0	179	0	628	526	102	19	0	102	19
2001	757	0	100	0	657	540	117	22	0	117	22
2002	877	0	100	0	777	554	223	40	0	223	40
2003	790	0	100	0	690	568	122	21	0	122	21
2004	790	0	100	0	690	581	109	19	0	109	19
2005	978	0	100	0	878	595	283	48	0	283	48
2006	875	0	100	0	775	609	166	27	0	166	27
2007	875	0	100	0	775	623	152	24	0	152	24
2008	875	0	100	0	775	636	139	22	0	139	22
2009	912	0	100	0	812	650	162	25	0	162	25

Table 9-13

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 After Maintenance	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2000	649	0	25	0	624	610	14	2	0	14	2
2001	886	0	75	0	811	576	235	41	0	235	41
2002	956	0	100	0	856	591	265	45	0	265	45
2003	869	0	100	0	769	604	165	27	0	165	27
2004	869	0	100	0	769	618	151	25	0	151	25
2005	869	0	100	0	769	631	138	22	0	138	22
2006	954	0	100	0	854	645	209	33	0	209	33
2007	954	0	100	0	854	658	196	30	0	196	30
2008	954	0	100	0	854	671	183	27	0	183	27
2009	991	0	100	0	891	685	206	30	0	169	30

Table 9-14
Schedule 8.0: Planned and Prospective Generating Facility Additions and Changes

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel	(6)	(7) Fuel Transport	(8)	(9) Const Start	(10) Commercial In-Service	(11) Expected Retirement	(12) Gen Max Nameplate	(13) Net Capability	(14)	(15) Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	
Charles Larsen Memorial	6	Polk County	ST	NG	FO6	PL	TK			07/00	25,000	25.0	27.0	R
	7	Polk County	ST	NG	FO6	PL	TK			03/01	50,000	50.0	50.0	R
C.D. McIntosh Jr.	501G	Polk County	CT	NG	FO6	PL	TK	06/98	04/00	Unknown	245,000	232	245	W
	501G		ST	WH				06/00	01/02	Unknown	120,000	120	120	L
	ABB PFBC	Polk County	ST	PC	Coal	RR	RR	01/02	06/05	Unknown	288,000	188[1]	188[1]	P

[1]Lakeland's ownership share.

Table 9-15
Schedule 9.1: Status Report and Specifications of Approved Generating Facilities

(1)	Plant Name and Unit Number:	McIntosh Unit 5
(2)	Capacity:	
(3)	Summer MW	120 MW (steam turbine only)
(4)	Winter MW	120 MW (steam turbine only)
(5)	Technology Type:	Combined Cycle
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	06/01/00
(8)	Commercial In-Service date:	01/01/02
(9)	Fuel	
(10)	Primary	Waste Heat
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Ultra Low NOx burners.
(13)	Cooling Method:	Mechanical Cooling Tower
(14)	Total Site Area:	9.5 acres.
(15)	Construction Status:	Combustion turbine complete. Steam turbine planned.
(16)	Certification Status:	Need for Power approved. Site Certification hearing completed. Site Certification order pending.
(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 (%):	91.2 percent
(23)	Average Net Operating Heat Rate (ANOHR):	6,523 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	25 years
(26)	Total Installed Cost (In-Service year $/kW):	748.99
(27)	Direct Construction Cost ($/kW):	670.83
(28)	AFUDC Amount ($/kW):	32.03
(29)	Escalation ($/kW):	46.13
(30)	Fixed O&M ($/kW-yr):	1.133
(31)	Variable O&M ($/MWh):	1.266
(32)	K factor	1.2283

Table 9-16
Schedule 9.2: Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number:	McIntosh Unit 4
(2) Capacity:	
(3) Summer MW	288 MW (Lakeland ownership share of 188 MW)
(4) Winter MW	288 MW (Lakeland ownership share of 188 MW)
(5) Technology Type:	Pressurized Fluidized Bed Combine Cycle
(6) Anticipated Construction Timing:	
(7) Field Construction Start-date:	06/01/02
(8) Commercial In-Service date:	06/01/05
(9) Fuel	
(10) Primary	Petroleum Coke
(11) Alternate	Coal
(12) Air Pollution Control Strategy:	SNCR, limestone, fabric filters or electrostatic precipitators for particulate matter.
(13) Cooling Method:	Cooling Tower
(14) Total Site Area:	PFBC Island dimensions: 510-ft.x560 ft. for Unit itself, Total site 513 acres).
(15) Construction Status:	None.
(16) Certification Status:	Filing planned summer 2000.
(17) Status with Federal Agencies:	No status.
(18) Projected Unit Performance Data:	
(19) Planned Outage Factor (POF):	7.6 percent
(20) Forced Outage Factor (FOF):	12.0 percent
(21) Equivalent Availability Factor (EAF):	81 percent
(22) Resulting Capacity Factor (%):	81 percent
(23) Average Net Operating Heat Rate (ANOHR):	8,452 Btu/kWh
(24) Projected Unit Financial Data:	
(25) Book Life:	30 years
(26) Total Installed Cost (In-Service year $/kW):	1,617
(27) Direct Construction Cost ($/kW):	1,317
(28) AFUDC Amount ($/kW):	135
(29) Escalation ($/kW):	165
(30) Fixed O&M ($/kW-yr):	20.76
(31) Variable O&M ($/MWh):	4.53 (including limestone)
(32) K factor	1.2355

Table 9-17
Schedule 9.3: Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number:	McIntosh Unit 6
(2) Capacity:	
(3) Summer MW	32 MW
(4) Winter MW	46 MW
(5) Technology Type:	LM 6000 Simple Cycle Combustion Turbine
(6) Anticipated Construction Timing:	
(7) Field Construction Start-date:	10/01/08
(8) Commercial In-Service date:	06/01/09
(9) Fuel	
(10) Primary	Natural Gas
(11) Alternate	No. 2 Oil
(12) Air Pollution Control Strategy:	Dry low NOx combustors.
(13) Cooling Method:	N/A
(14) Total Site Area:	1 acre.
(15) Construction Status:	None.
(16) Certification Status:	N/A.
(17) Status with Federal Agencies:	No status.
(18) Projected Unit Performance Data:	
(19) Planned Outage Factor (POF):	0.6 percent
(20) Forced Outage Factor (FOF):	1.5 percent
(21) Equivalent Availability Factor (EAF):	98 percent
(22) Resulting Capacity Factor (%):	6 percent
(23) Average Net Operating Heat Rate (ANOHR):	10,624 Btu/kWh
(24) Projected Unit Financial Data:	
(25) Book Life:	25 years
(26) Total Installed Cost (In-Service year $/kW):	992
(27) Direct Construction Cost ($/kW):	742
(28) AFUDC Amount ($/kW):	19
(29) Escalation ($/kW):	231
(30) Fixed O&M ($/kW-yr):	10.59
(31) Variable O&M ($/MWh):	3.58
(32) K factor	1.2283

Table 9-18
Schedule 10: Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	None planned.
(2)	Number of Lines:	None planned.
(3)	Right of Way:	None planned.
(4)	Line Length:	None planned.
(5)	Voltage:	None planned.
(6)	Anticipated Construction Time:	None planned.
(7)	Anticipated Capital Investment:	None planned.
(8)	Substations:	None planned.
(9)	Participation with Other Utilities:	None planned.