ORIGINAL

LAKELAND ELECTRIC

Florida Public Service Commission
Blanca S. Bayó, Director
Bureau of Records & Hearing Services
Betty Easley Conference Center, Rm. 110
4075 Esplanade Way
Tallahassee, Florida 32399-0850

April 1, 2002

Dear Ms. Bayó:

Pursuant to Section 186.801, Florida Statutes and Rules 25-22.070-072 of Florida Administrative Code, Lakeland Electric hereby submits 25 copies of its 2002 Ten Year Site Plan. If you have any questions please do not hesitate to contact us.

Sincerely,

Paul H. Elwing
Legislative & Regulatory Affairs

AUS ___
CAF ___
CMP ___
COM ___
CTR ___
ECR ___
GCL ___
OPC ___
MMS ___
SEC 1
OTH ___

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LAKELAND

2002 Ten-Year Site Plan
For
Electrical Generating Facilities
And
Associated Transmission Lines

April 2002

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1.0 Introduction

This report contains the 2002 Lakeland Electric Ten-Year Site Plan (TYSP) pursuant to Florida Statutes and as adopted by Order No. PSC-97-1373-FOF-EU on October 30, 1997. The Lakeland TYSP reports the status of the utility's resource plans as of December 31, 2001. The TYSP is divided into the following nine 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, Analysis Results and Conclusions, Environmental and Land Use Information, and Ten-Year Site Plan Schedules. The contents of each section is summarized briefly in the remainder of this Introduction.

1.1 General Description of the Utility

Section 2.0 of the TYSP discusses Lakeland's existing generation and transmission facilities. The section includes a historical overview of Lakeland's system, and a description of existing power generating and transmission facilities. This section includes tables which show the source of the utility's current 891 MW of net winter generating capacity and 811 MW of net summer generating capacity (in the year 2001).

1.2 Forecast of Electrical Power Demand and Energy Consumption

Section 3.0 of the TYSP provides a summary of Lakeland's load forecast. Lakeland is projected to remain a winter peaking system throughout the planning period. The projected annual growth rates in peak demand for the winter and summer are 2.50% and 2.23% percent, respectively, for 2002 through 2012.

Net energy for load is projected to grow at an average annual rate of 2.28% percent for 2002 through 2012, a lower growth rate than occurred over the past 10 years. Projections are also developed for high and low load growth scenarios.

1.3 Demand-Side Management Programs

Section 4.0 provides descriptions of the existing conservation and demand-side management programs. Additional details regarding Lakeland's demand-side management programs are on file with the Florida Public Service Commission (FPSC).

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.

- Commercial Programs:
  - Commercial Lighting Program.
  - Thermal Energy Storage 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 discusses the forecasting methods used for the TYSP and outlines the assumptions applied for system planning. This section also summarizes the integrated resource plan for Lakeland and provides planning criteria for the Florida Municipal Power Pool, of which Lakeland is a member. The integrated resource plan is fully incorporated in the TYSP.

Fuel price projections are provided for coal, natural gas, oil, and petroleum coke; with brief descriptions of the methodology. Three sensitivities are provided for the fuel price forecast: a high fuel price scenario, a low fuel price scenario, and a constant differential scenario.

Assumptions for the economic parameters and evaluation criteria which are being applied in the evaluation are also included in Section 5.0.

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 ten-year planning horizon. Application of the reserve margin criteria indicates no need for additional capacity during the current ten year reporting period.

1.6 Analysis Results and Conclusions

Section 7.0 discusses the current status of any supply-side evaluation being undertaken by Lakeland to identify the best option for its system. It also discusses basic methodology used by Lakeland in its Generation Expansion Planning Process.

1.7 Environmental and Land Use Information

Section 8.0 discusses the land and environmental features of Lakeland's TYSP.

1.8 Ten-Year Site Plan Schedules

Section 9.0 presents the schedules required by the Florida Public Service Commission (FPSC) 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. Shortly thereafter the original light plant was built by Lakeland Light and Power Company at the corner of Cedar Street and Massachusetts Avenue. This plant had an original capacity of 50 kW. On May 26, 1891, plant manager Harry Sloan threw the switch to light Lakeland by electricity for the first time with five arc lamps. Incandescent lights were first installed in 1903.

Public power in Lakeland was established in 1904, when foresighted 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 the 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 estimated to have been 500 kW. The plant has since been expanded three times. The first expansion occurred in 1922 with the addition of 2,500 kW; in 1925, 5,000 kW additional capacity was added, followed by another 5,000 kW in 1938. With the final expansion, the removal of the initial 500 kW unit was required to make room for the addition of the 5,000 kW generating unit, resulting in a total peak plant capacity of 12,500 kW.

As the community continued to grow, 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 Larsen Plant Steam Unit No. 4 completed in 1950 was 20,000 kW. The first addition to the Larsen Plant was Steam Unit No. 5 (1956) which had a capacity of 25,000 kW. In 1959, Steam Unit No. 6 was added and increased the plant capacity by another 25,000 kW. 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 the Larsen Plant. This was Steam Unit No.7 having a nominal 44,000 kW capacity and an estimated cost of $9.6 million. This brought the total Larsen Plant nameplate capacity up to a nominal 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 and then retired in 1971.

As the city continued to grow during the late 1960's, the demand for power and electricity grew at a rapid rate, making evident the need for a new power plant. 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 into commercial operation, with a nominal rated capacity of 114,707 kW and at a cost of $25.77 million. This addition increased the total 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 the former 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 which became commercial on September 1, 1982. The unit is capable of using low sulfur oil as an alternate fuel and supplemented by prepared solid waste. The plant utilized 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.

As load continued to grow, Lakeland 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.

Although demand and energy savings arose from Lakeland's conservation and demand-side management programs, additional capacity was required in the early 1990's. Least cost planning studies resulted in the construction of Larsen Unit No. 8, a natural gas fired combined cycle unit with a nameplate generating capability of 124,000 kW. Larsen Unit No. 8 began simple cycle operation in July 1992, and combined cycle operation in November of that year.

In 1994, Lakeland made the decision to retire the first unit at Larsen Plant, Steam Unit No. 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 into cold shutdown, Larsen Unit No. 6, a 25 MW oil fired unit that was also nearing the end of its economic life.

In 1999, the construction of McIntosh Unit No. 5 Simple Cycle combustion turbine was completed. The unit was released for commercial operation in May, 2001. As of December 31, 2001, the unit was in the final stages of being converted to a combined cycle unit by the addition of a steam turbine generator. Construction of the conversion began July 24, 2000. The scheduled commercial operation date for the combined cycle unit is April 1, 2002.

During the summer of 2001, Lakeland took its first steps into the world of distributed generation with the groundbreaking of its Winston Peaking Station. The Winston Peaking Station, when completed, will consist of 20 quick start reciprocating engines each driving a 2.5 MW electric generator. This will provide Lakeland with 50 MW of peaking capacity that can be started and put on line at full load in ten minutes. The Station is near completion and undergoing startup and testing at the time of writing. These units are also expected to be declared commercial by April 1, 2002.

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 No. 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 the 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 that 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, another 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.

In 2001, Lakeland began the next phase of its 230kV transmission system with the construction of the Crews Lake 230/69kV substation. The substation was completed and placed in service in 2001. This project includes two 230kV ties and one 69kV tie with Tampa Electric, a 150MVA 230/69kV autotransformer and a 230kV line from Lakeland's Eaton Park 230kV substation to the Crews Lake substation. Lakeland's internal line is still under construction at the time of this writing and will be in service prior to summer of 2002.

Early transmission interconnections with other systems included a 69 kV tie at Larsen Plant with Tampa Electric Company (TECO), established 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 (Ridge), 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 the Ridge 69 kV transmission line. Later in 1996, the third tie line to TECO was built from East to TECO's Gapway substation. As mentioned above, in August of 2001, Lakeland completed two 230kV ties and one 69kV tie with TECO at Lakeland's Crews Lake 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, providing for greater reliability. At the present time, Lakeland has a total of approximately 114 miles of the 69 kV transmission and 18.3 miles of the 230 kV transmission lines in service along with six 150 MVA 230/69 kV autotransformers.

2.2 General Description: Lakeland Electric

2.2.1 Existing Generating Units

This section provides additional detail on Lakeland's existing units and transmission system. 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 on Lake Parker in Polk County, Florida. 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. Table 2-1 summarizes the environmental considerations for Lakeland's steam turbine generators and Table 2-2 provides other physical characteristics of all Lakeland generating units.

The Larsen site is located on the southeast shore of Lake Parker in Lakeland. The site has six existing units. The total net winter (summer) capacity of the plant is 226 MW (196 MW). Units 2 and 3, General Electric combustion turbines, have a net winter (summer) rating of 14 MW (10 MW). These units burn natural gas as the primary fuel with diesel backup. Unit No. 6 is a conventional steam boiler unit powering a General Electric generator with a net 24 MW rating. The unit burns natural gas as its primary fuel with No.6 residual oil as backup. This unit was placed in cold shutdown in the mid 1990's but was returned to service in 1998 due to the termination of two purchase power agreements. Unit No. 6 was then slated for retirement in March 1999, but due to the delay of commercial operation of McIntosh Unit No. 5, Unit No. 6 remained in operation until August 2001 when it was placed into extended cold stand-by. Lakeland is no longer counting the units capacity towards reserves at this point in time, but is reserving the option to re-power the unit if the economics are right at some future date. Unit No. 7 is also a conventional steam boiler unit powering a General Electric generator with a net 50 MW rating. The unit also burns natural gas as the primary fuel with No. 6 residual oil as a backup fuel. Historically, Larsen Unit No. 5 consisted of a boiler for steam generation and steam turbine to convert the steam to electrical power. When the boiler began to show signs of degradation beyond economical repair, a gas turbine with a heat recovery steam generator, Unit No. 8, was added to the facility. This allowed the gas turbine (Unit No. 8) to generate electricity and the waste steam from the turbine to be injected into the former Unit No. 5 steam turbine for a combined cycle configuration. The former Unit No. 5 steam turbine currently has a net winter (summer) rating of 31 MW (29 MW) and is referred to as Unit No. 8 Steam Turbine from this point on in this document and in the reporting of this unit. The Unit No. 8 combustion turbine has a net winter (summer) rating of 93 MW (73 MW).

The McIntosh site is located in the City of Lakeland along the northeastern shore of Lake Parker and encompasses 513 acres. Electricity generated by the McIntosh units is stepped up in voltage by generator step-up transformers to 69 kV and 230 kV for transmission via the power grid. The McIntosh site currently includes seven units in commercial operation having a total net winter and summer capacity of 689 MW and 639 MW, respectively. Unit CT1 consists of a General Electric combustion turbine with a net winter (summer) output rating of 20 MW (17 MW). Unit No. 1 is a natural gas/oil fired General Electric steam turbine with a net winter and summer output of 87 MW. Unit No. 2 is a natural gas/oil fired Westinghouse steam turbine with a winter and summer output of 103 MW. Unit No. 3 is a 342 MW pulverized coal fired unit owned 60 percent by Lakeland and 40 percent by OUC. Lakeland's share of the unit yields net winter and summer output of 205 MW. Technologies used for Unit 3 are very innovative making it a very environmentally friendly coal unit. Unit No. 3 was one of the first "zero-discharge" plants built, meaning no waste water products leave the plant site untreated. Unit No. 3 also includes a wet flue gas scrubber for SO_2 removal and uses treated sewage water for cooling water. The unit also burns municipal solid refuse along with the coal to reduce the City's impact to the county landfill. Two small diesel units with a net output of 3 MW each are also located at the McIntosh site.

McIntosh Unit No. 5, a Westinghouse 501G combustion turbine, was placed into commercial operation May, 2001. The combustion turbine unit has a net output of 268 MW (221 MW) in the winter (summer) and burns natural gas as the primary fuel. This unit was taken off line for conversion to combined cycle starting in mid September 2001 with construction being completed in December 2001. The unit is currently going through re-start and testing and is expected to be returned to commercial service by publication time of this report. The McIntosh Unit No. 5 conversion was approved by the FPSC and 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.

2.2.2 Capacity and Power Sales Contracts

Lakeland has one firm power sales contract in place as of December 31, 2001. The power sales contract is with the 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. The ownership breakdown is a 60 percent share for Lakeland and a 40 percent ownership share for OUC. The energy and capacity delivered to OUC from McIntosh Unit 3 is not considered a power sales contract because of the OUC ownership share.

2.2.3 Capacity and Power Purchase Contracts

Lakeland currently has no long term firm power purchase contracts.

2.2.4 Planned Unit Retirements

Lakeland currently has no set retirement plans in place for its units. Previous Ten Year Site Plans contemplated retiring several older, less efficient units as new capacity came on line and it made economical sense to do so. In late 2001, Lakeland revisited its long range generation plans by commissioning a complete review of its existing portfolio of resources and all plans on hand at the time. At the time of this writing, the results of that review are incomplete which has led Lakeland to put all expansion and retirement plans into abeyance until more information is available from which to make an informed decision. As noted in the previous section, Larsen Unit No. 6 has been placed on extended cold stand-by and its capacity removed from Lakeland's resource portfolio. The unit is not being slated for dismantlement as Lakeland wishes to preserve the option of re-powering that unit in the future if it makes economical sense to do so.

2.2.5 Load and Electrical Characteristics

Lakeland's load and electrical characteristics have many similarities with those of other peninsular Florida utilities. The peak demand has historically occurred during the winter months. Lakeland's actual total peak demand in the winter of 2000/01 was 707 MW, but was reduced to a net demand of 655 MW after accounting for 52 MW of residential load management. This peak occurred on January 05, 2001. The actual summer peak in 2001 was 546 MW and occurred on August 29, 2001. Lakeland's historical and projected summer and winter peak demands are presented in Section 3.0.

Lakeland is a member of the Florida Municipal Power Pool (FMPP), along with Orlando Utilities Commission (OUC), Florida Municipal Power Agency's (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.

2.3 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.

Table 2-1
Lakeland Electric and Water Utilities
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

Plant Name	Unit	Particulate	Flue Gas Cleaning SO_x	Flue Gas Cleaning NO_x	Type
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

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

Plant Name	Unit No.	Location	Unit Type[3]	Fuel[4] Pri	Fuel[4] Alt	Fuel Transport[5] Pri	Fuel Transport[5] Alt	Alt Fuel Days Use[2]	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Net Capability Summer MW	Net Capability Winter MW
Charles Larsen Memorial	2	16-17/28S/24E	GT	NG	DFO	PL	TK	NR	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	NR	12/62	Unknown	11,500	10	14
	6		ST	NG	RFO	PL	TK	NR	12/59	Extended Cold Standby 8/01	25,000	0	0
	7		ST	NG	RFO	PL	TK	NR	02/66	Unknown	50,000	50	50
	8		CA	WH	---	---	---	NR	04/56	Unknown	25,000	29	31
	8		CT	NG	DFO	PL	TK	NR	07/92	Unknown	101,520	73	93
Plant Total												172	202
C.D. McIntosh, Jr.	IC1	4-5/28S/24E	IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	3	3
	IC2		IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	3	3
	1GT		GT	NG	DFO	PL	TK	NR	05/73	Unknown	26,640	17	20
	ST1		ST	NG	RFO	PL	TK	NR	02/71	Unknown	103,000	87	87
	ST2		ST	NG	RFO	PL	TK	NR	06/76	Unknown	126,000	103	103
	ST3[1]		ST	BIT	---	RR	---	NR	09/82	Unknown	363,870	205	205
	GT5		GT	NG	DFO	PL	TK	NR	05/01	Unknown	292,950	221	268
Plant Total												639	689
System Total												811	891

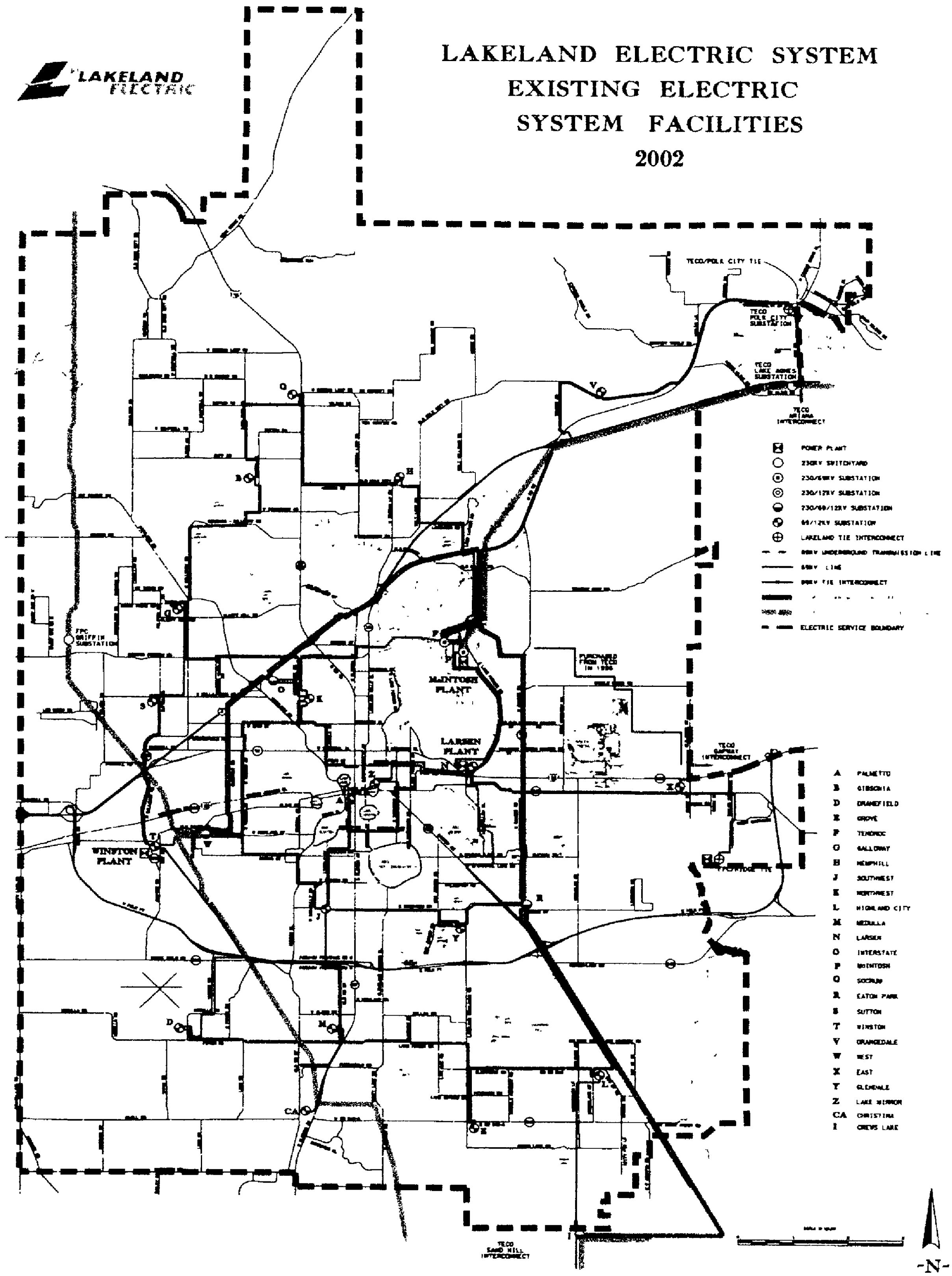
[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Lakeland does not maintain records of the number of days that alternate fuel is used.

[3]Unit Type
CA Combined Cycle Steam Part
CT Combined Cycle Combustion Turbine
GT Combustion Gas Turbine
ST Steam Turbine

[4]Fuel Type
DFO Distillate Fuel Oil
RFO Residual Fuel Oil
BIT Bituminous Coal
WH Waste Heat
NG Natural Gas

[5]Fuel Transportation Method
PL Pipeline
TK Truck
RR Railroad

Figure 2-1


LAKELAND ELECTRIC SYSTEM
EXISTING ELECTRIC
SYSTEM FACILITIES
2002
LAKELAND ELECTRIC
TECO/POLK CITY TIE
TECO POLK CITY SUBSTATION
TECO LAKE AGNES SUBSTATION
TECO ARIANA INTERCONNECT
FPC GRIFFIN SUBSTATION
McINTOSH PLANT
LARSEN PLANT
WINSTON PLANT
TECO GAPWAY INTERCONNECT
TECO SAND HILL INTERCONNECT
POWER PLANT
230KV SWITCHYARD
LAKELAND TIE INTERCONNECT
ELECTRIC SERVICE BOUNDARY
A PALMETTO
D ORANGEFIELD
E GROVE
F TENOROC
G GALLOWAY
H HEMPHILL
J SOUTHWEST
K NORTHWEST
L HIGHLAND CITY
M MEDULLA
N LARSEN
O INTERSTATE
P McINTOSH
R EATON PARK
S SUTTON
T WINSTON
V ORANGEDALE
W WEST
X EAST
Y GLENDALE
Z LAKE MIRROR
CA CHRISTINA
I CREWS LAKE
-N-

3.0 Forecast of Electrical Power Demand and Energy Consumption

Lakeland routinely develops a detailed long-term electric load and energy forecast for use in its long-term planning studies. The primary techniques used are econometric modeling and exponential smoothing. Lakeland also develops short-term forecasts for short-term budgeting and planning purposes using time-series decomposition models. Lakeland develops a detailed, long-term forecast for the following categories on a fiscal year basis, which ends September 30.

- Service territory population
- Number of accounts
- Energy Sales
- Net Energy for load
- Summer peak demand
- Winter peak demand

The following sections discuss each of the forecast categories.

3.1 Service Territory Population Forecast

The projections of the electric service territory population were developed using a variety of techniques. A regression model was developed using Polk County population as the independent variable. Historical growth rates (1971-2001), exponential smoothing (1971-2001) and a trend analysis (1971-2001) were also used in the development of the final forecast.

Lakeland's projection of Polk County population was taken from the Bureau of Economic and Business Research's (BEBR) Long-Term Economic Forecast, 2001. BEBR's Polk County population projections reflect data received out of the current 2000 Census study.

Prior to fiscal year 1989, Lakeland's historical population estimates were developed by using residential accounts inside and outside the city and multiplying them by a number of persons per household figure. We used BEBR's estimated Polk County persons per household figure. Beginning in fiscal year 1990, through to fiscal year 1998, Lakeland used actual persons per household data (Appliance Saturation Survey, 1994) and multiplied those numbers by the actual residential accounts by inside and outside the city limits. Lakeland, at this time, does not have current survey data in which to pull person per household information specific for the Lakeland area. Therefore, from fiscal year 1999 to current, Lakeland has taken the average of the two methodologies to determine its population estimates.

The resulting forecast projects the electric service territory population for the City of Lakeland to increase at a 1.30% average annual growth rate (AAGR) from 2002-2022. The historical and projected electric service area population estimates are shown in Table 9-2. (See Section 9 for this and other standard TYSP Schedules / Forms referenced in this Section.)

3.2 Number of Accounts Forecast

Lakeland forecasts the number of accounts in the following categories:

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

For residential, commercial and industrial accounts, projections are developed for inside and outside the city. Significant shifts between accounts inside and outside the city are due to the large amounts of property being annexed into the city limits. The forecasts for inside and outside the city have been adjusted for recent annexations that have occurred this year. The forecast has also been adjusted for future annexation estimates out to year fiscal year 2006. The following sections describe the projections, which are presented in Tables 9-2 and 9-3.

3.2.1 Residential Accounts

Residential account projections for inside and outside the city were based on a combination of techniques. A regression model was used where Polk County population was the independent variable. Historical growth rates (1991-2001) (1997-2001), trends

(1991-2001), exponential smoothing, and historical ratios were also used to determine a final forecast.

The Total Residential Account Forecast was a summation of account projections from inside and outside the city. The projected AAGR for total residential accounts is 1.27% (after annexations) for the 10-year period. Historical and projected residential accounts are presented in Table 9-2.

3.2.2 Commercial and Industrial Accounts

The General Service (GS) account projections for both inside and outside the city limits were based on a combination of techniques including historical ratios to residential accounts, historical ratios to Polk County population, historical growth rates (1993-2001), trends (1984-2001), (1993-2001), and exponential smoothing (1984-2001) (1993-2001). The total GS account projection was a summation of account projections for inside and outside the city.

The General Service Demand (GSD) account projections for both inside and outside the city limits were based on a combination of methodologies including: historical growth rates (1997-2001), trends (1997-2001), historical ratios to GS accounts, historical ratios to residential accounts, and historical ratios to Polk County population. Exponential smoothing (1994-2001) was also used in the development of the final forecast.

Lakeland then combines the GS and GSD classes to create the Commercial category found on the TYSP forms for this filing. These totals are found in Table 9-2. The combined Commercial class is projected to increase by an AAGR of 1.33% for the 10-year period.

Total GSLD accounts are projected as a whole, including GSLD, Contract and Interruptible accounts. Projections for both inside and outside the city were developed by analyzing historical ratios to Polk County population, historical ratios to residential accounts, to GS accounts, and to GSD accounts. Historical growth rates (1988-1995, prior to Contract and Interruptible rate classes) and trends (1984-2001) were also used in conjunction with these ratios to determine the final forecast.

The total number of GSLD accounts are expected to increase approximately 2.00% over the 10-year period. The number of historical and projected GSLD accounts are presented in Table 9-2 under the Industrial heading.

3.2.3 Total Accounts

The Total Account Forecast for the City of Lakeland is a summation of the individual forecasts provided above. Summation of the total accounts indicates an AAGR of 1.28% for the 10-year period from 2002-2011. Historically, Lakeland experienced a 1.32% AAGR over the past 10 years.

3.3 Energy Sales Forecast

Lakeland forecasts the energy sales for the following categories:

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

For residential, commercial and industrial energy sales, projections are developed for both inside and outside the city. Significant shifts between energy sales inside and outside the city are due to the large amounts of property being annexed into the city limits. The forecasts for inside and outside the city have also been adjusted for recent annexations that have occurred this year. The forecast has also been adjusted for future annexation estimates out to fiscal year 2006. The following sections describe the projections, which are presented in Tables 9-2 & 9-3.

3.3.1 Residential Sales Forecast

Residential energy sales inside the city was developed using a combination of techniques. A regression model was developed using number of residential accounts, heating degree-days and real per capita income as independent variables. Historical ratios to total residential energy sales, historical growth rates at different time-intervals including (1980-2001), (1996-2001), (1980-2001), (1990-2001), trends (1996-2001) (1989-2001) (1982-2001), and exponential smoothing were all used to determine the final forecast. Residential energy sales outside the city is the difference between total residential energy sales and residential energy sales inside the city.

Total residential energy sales were also based on a combination of techniques. A regression model was developed using heating degree-days, fiscal year and real per capita income as independent variables. Historical trends (1980-2001), (1989-2001) exponential smoothing (1973-2001), and historical growth rates (1996-2001) were also used. The Total Residential Energy Sales Forecast is projected to have an AAGR of 2.16% (after annexations) over the next 10-year period.

3.3.2 Commercial and Industrial Sales

General Service (GS) energy sales inside the city were developed using a combination of analyses. A regression model was developed using employment (EWS) and heads of households (HH) as independent variables. Heads of households was the most significant variable in the model. Historical growth rates (1992-1998), historical ratios and exponential smoothing (1984-2001) was also used in the development of the forecast. GS energy sales outside the city are the difference between the Total GS Energy Sales Forecast and the GS Energy Sales Forecast for inside the city.

Total GS sales were developed using a weighted average of several methodologies. They include ratios to residential energy sales, historical trends (1992-2001), exponential smoothing (1992-2001) and historical usage/account figures. Total GS energy sales are expected to increase at an AAGR of 1.80% throughout the 10-year period.

The General Service Demand (GSD) Energy Sales Forecast for inside the city was developed using several techniques. A regression model was developed using employment (EWS) and GSD accounts as independent variables. The number of accounts was the most significant variable in the model. Historical growth rates (1990-2001), ratios to residential energy sales, exponential smoothing (1984-2001) and historical trends (1987-2001) were used in the final development of the forecast. GSD energy sales outside the city are the difference between total GSD energy sales and GSD energy sales inside the city.

Total GSD energy sales were developed using historical ratios to residential energy sales, exponential smoothing (1990-2001), and historical trends (1987-2001), (1996-2001). The resulting GS & GSD classes were then combined for reporting purposes as the Commercial class found on Table 9-2. The combined energy sales are expected to increase at a rate of 1.80% AAGR over the 10 year reporting period.

The GSLD Energy Sales Forecast for inside the city was developed by looking at historical growth rates (1994-1998), historical trends (1984-2001), (1995-2001) and historical ratios to residential energy sales. The forecast for GSLD energy sales outside the city limits was developed by taking the difference between the Total GSLD Energy Sales Forecast and the GSLD Energy Sales Forecast for inside the city.

The Total GSLD Energy Sales Forecast was based on a combination of several methodologies. Historical growth rates (1995-2000), exponential smoothing (1984-2001) and historical trends (1984-2001) were used to develop the final forecast. Total GSLD energy sales are projected to increase at a 2.80% AAGR over the next 10-years.

3.3.3 Other Sales

Other energy sales are comprised of the following: municipal, private area lighting, water, electric and unmetered energy sales.

Municipal energy sales are based on a combination of techniques. A regression model was developed using real per capita income (RPCY) and fiscal year. Year was the most significant variable in the model. Historical growth rates were also analyzed at various times in history (1991-2001) (1996-2001) and used in the development of the final forecast.

Water energy sales were developed by looking at ratios to residential energy sales, and municipal energy sales. Trends were also analyzed at different time periods such as (1994-2001) and (1997-2001).

Electric energy sales were based on a combination of techniques. Historical growth rates (1992-2001), and trends of different time frames in history (1992-2000) and (1992-2001) were used in the development of the forecast.

Private area lighting energy sales for both inside and outside the city was based on a combination of techniques. They include exponential smoothing (1992-2001), historical growth rates (1992-2001) and a trending (1992-2001). The total Private Area Lighting Forecast is the summation of the inside and outside forecasts.

Unmetered energy sales are derived from the total of all municipal street and highway lighting. The forecast was developed by looking at historical growth rates (1988-2001), historical trends (1990-2001) and usage per residential account calculations. These miscellaneous classes are rolled up together for reporting purposes as the Other category as found on Table 9-3. This grouping is expected to increase at an AAGR of 2.59% over the 10 year reporting period. Historical and projected Other electric sales are presented in Table 9-3.

3.3.4 *Total Sales*

The Total Energy Sales Forecast for the City of Lakeland is a summation of the individual forecasts provided above. Summation of total energy sales indicates an AAGR of 2.22% from 2002-2011. This is lower than what was experienced in the past. A 3.20% AAGR was experienced over the last ten years. Historical and projected total energy sales are presented in Table 9-3.

3.4 Net Energy for Load Forecast

Net energy for load is defined as the net electricity generation by a system's own generating plants, and energy purchased from others, less the energy delivered for resale to their systems. Lakeland projects the growth rate for total percentage of system energy losses to remain relatively constant.

Net energy for load was derived at by looking at the combination of three methodologies. A regression model was developed using energy sales as the independent variable. A trend (1982-2001) was used along with a forecast where losses were expected to remain constant for the 20-year period. The loss factor used was 5.73%, which was based on a 10-yr historical average. The forecast expects net energy for load to increase at a rate of 2.28% AAGR over the forecast period. Net energy for load is summarized in Table 9-4.

3.5 Peak Demand

The winter season is defined as November through March. The summer is defined as April through October.

The Winter Peak Demand Forecast (base-case @ 29.6°) was developed using a weighted average of six different regression models, historical trends (1989-2001) and a load factor analyses. All six regression models used different combinations of the following independent variables: day of week, temperature at midnight, and temperature at time of winter peak, annual minimum temperature, year, heating degree-days, average temperature prior to day of winter peak, and minimum temperature of day prior to winter peak. Consistently, year, temperature at winter peak and minimum temperature were the most significant independent variables. Total Winter Peak Demand Forecast (less conservation and Interruptible load) is expected to increase by 2.50% AAGR throughout the 10-year reporting period.

The Summer Peak Demand Forecast (base-case @ 98.7°) was developed using a combination of regression models, historical trending (1987-2000) (1980-2001), and exponential smoothing. Load calculated by using historical load factor was also analyzed.

The most significant variables used in the regression models include annual maximum temperature, temperature at time of summer peak, year, and Polk County population. Polk County population was the most significant variable in the model. The Summer Peak Demand Forecast (less conservation and Interruptible load) is expected to increase at a rate of 2.21% AAGR through the 10-year reporting period.

Projections of the summer and winter demands are presented in Tables 9-5, and 9-6, respectively.

Table 3-1
Historical and Projected
Heating and Cooling Degree Days

Year	HDD	CDD
1992	669	3234
1993	832	2821
1994	391	4489
1995	380	3703
1996	819	3479
1997	387	3719
1998	604	3627
1999	308	4087
2000	418	3721
2001	741	3754
2002	507	3713
2003	507	3713
2004	507	3713
2005	507	3713
2006	507	3713
2007	507	3713
2008	507	3713
2009	507	3713
2010	507	3713
2011	507	3713

Table 3-2
Historical Monthly Peaks and Date

	1999		2000		2001	
Jan	611	Jan-06	610	Jan-27	655	Jan-05
Feb	483	Feb-23	508	Feb-06	508	Feb-06
Mar	420	Mar-05	407	Mar-31	431	Mar-08
Apr	468	Apr-26	416	Apr-03	472	Apr-13
May	458	May-25	504	May-26	494	May-30
Jun	503	Jun-15	532	Jun-20	542	Jun-13
Jul	531	Jul-21	552	Jul-20	539	Jul-30
Aug	535	Aug-02	539	Aug-24	546	Aug-29
Sep	478	Sep-29	528	Sep-14	519	Sep-04
Oct	458	Oct-01	510	Oct-05	471	Oct-24
Nov	377	Nov-01	476	Nov-22	360	Nov-01
Dec	473	Dec-02	597	Dec-31	465	Dec-27

3.6 Sensitivity Cases

Lakeland has conducted two sensitivity cases to the base load forecast, reflecting a high load growth case and a low load growth case. These two sensitivity cases provide a band across which Lakeland can evaluate potential power supply planning alternatives.

Standard deviations for the sensitivities were calculated within a 95% percent probability interval for sets of historical data related to winter and summer peaks. The results indicated a base temperature for winter to be 29.6 and summer to be 98.7 degrees.

3.6.1 High Load Sensitivity

The high load forecasts for demand were based on a summer temperature of 104.1 degrees and the winter temperature of 19 degrees. The high load forecast has an AAGR of 2.09% for winter and 2.03% for summer. Projections of high load sensitivities for summer and winter peak demands are presented in Tables 3-4, and 3-5.

3.6.2 Low Load Sensitivity

The low forecasts for demand were based on a summer temperature of 93.1 and a winter temperature of 40 degrees. The low load forecast has an AAGR of 2.04% for summer and a 2.51% AAGR for a low winter forecast. Projections of low load sensitivities for summer and winter peak demands are presented in Tables 3-4, and 3-5.

3.6.3 High and Low Net Energy for Load

Based on Lakeland's 95% confidence interval, Lakeland developed a banded high and low net energy for load Forecast. The high and low forecasts were developed using the 2.5% interval on either side of the confidence interval. Projections presenting the high and low case scenarios for net energy for load for the forecast period are presented in Table 3-6.

Table 3-4
Summer Peak Demand (MW)

Year	Low	Base	High
2002	556	560	561
2003	569	574	574
2004	583	587	587
2005	596	600	601
2006	610	614	615
2007	623	627	628
2008	637	641	642
2009	651	655	656
2010	664	668	669
2011	678	682	683
AAGR 2002-2011	2.23%	2.23%	2.21%

Table 3-5
Winter Peak Demand (MW)

Year	Low	Base	High
2002/03	576	658	735
2003/04	595	676	754
2004/05	613	695	772
2005/06	631	712	790
2006/07	649	731	808
2007/08	668	749	827
2008/09	686	768	845
2009/10	705	786	864
2010/11	722	803	881
2011/12	741	822	900
AAGR 2002-2011	2.84%	2.50%	2.28%

Table 3-6
Net Energy for Load (GWH)

Year	Low	Base	High
2002	2,672	2,762	2,853
2003	2,697	2,831	2,965
2004	2,732	2,899	3,065
2005	2,774	2,967	3,161
2006	2,819	3,036	3,254
2007	2,866	3,105	3,345
2008	2,915	3,175	3,434
2009	2,966	3,244	3,522
2010	3,018	3,314	3,609
2011	3,072	3,384	3,695
AAGR 2002-2011	1.56%	2.28%	2.92%

4.0 Demand-Side Management Programs

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 under evaluation. 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.

This section also includes a brief description of Lakeland's advances in solar technology. Lakeland has assumed a leadership position in the deployment and commissioning of numerous solar energy devices and has established their reputation as a pro-solar electric utility.

4.1 Existing Conservation and Demand-Side Management Programs

Lakeland has several existing conservation and demand-side management programs that are currently available and address three 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 at a lower cost.

The programs can be divided into two groups: those programs with demonstrable demand and energy savings and programs in which the impact of demand and energy savings cannot be directly 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.
- Commercial Programs:
  - Commercial Lighting Program.
  - Thermal Energy Storage 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 peak demand by 1 kW per account from each water heater control and 1.2 kW per account from control of HVAC systems.

4.1.1.2 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.

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 has implemented 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.

4.1.2 Non-Measurable Demand and Energy Savings

The programs outlined in this section cannot directly be measured in terms of demand and energy savings, but are very important in that they have been shown to influence public behavior and thereby help reduce energy requirements. Lakeland considers the following programs to be important part of its objective to cost-effectively reduce 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 promotes high energy-efficiency in the home and gives the customer an opportunity to learn about other utility conservation programs. The program provides Lakeland with a valuable customer interface and a good avenue for increased customer awareness.

4.1.2.1.2 Public Awareness Program. Lakeland believes that an informed public aware of the need to conserve electricity is the greatest conservation resource. Lakeland's 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, Lakeland conveys the message of better utilizing their electric resources on a regular basis in a low cost manner.

4.1.2.2 Commercial Programs.

4.1.2.2.1 Commercial Energy Audits. The Lakeland Commercial Audit Program includes educating customers about 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. Some of these efforts are summarized below.

4.1.3.1 Direct Expansion Ground Source Heat Pump Study.

In cooperation with ECR Technologies of Lakeland, Lakeland Electric was given the Governor's Energy Award for work in the evaluation and analysis of direct expansion ground source heat pump (GSHP) technology. This technology will reduce weather sensitive loads and promote greater energy efficiency for Lakeland's system. A study of the demand and energy savings associated with this technology was completed in an effort to establish its cost-effectiveness for new construction, as well as retrofitting the technology to existing homes. The original units were installed nearly ten years ago and are still in service. There is little customer interest due to the cost of the units. Currently, no new sites are being developed.

4.1.3.2 Whole House Demand Controller Study/Real Time Pricing.

The concept of this technology is to control multiple appliances in the customer's home. The initial study was designed such that when a customers demand reached a pre-set level, no additional appliances would be allowed to turn on. There has been no customer interest in this program as initially offered. A new version of this concept tied to real time pricing and customer choice is being considered as a pilot program and study.

4.1.3.3 Time-of-Day Rates.

Lakeland is currently offering a time of day program and plans to continue as this makes consumers aware of the variation in costs during the day. To date, there has been limited interest by Lakeland's customers in this demand-side management program.

4.2 Solar Program Activities

Lakeland Electric views solar energy devices as distributed generators whether they interconnect to the utility grid or not. As such they can potentially fill the much-desired role that an electric utility needs to avoid future costs of building new (and/or re-working existing) distribution systems.

4.2.1 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, 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. By installing these self sufficient, stand-alone solar lighting products, Lakeland Electric was able to avoid the construction costs related to expansion of its distribution system into remote areas. These avoided costs are estimated to be approximately $20,000. It is Lakeland's stated desire to continue to install solar area-lighting products where similar circumstances exist.

Lakeland currently has 20 solar powered streetlights that are in service. Each of these lights replace a traditional 70 watt fixture that Lakeland typically would use in this type of application and displaces the equivalent amount of energy that the 70 watt fixture would use on an annual basis. The primary application for this type of lighting is for remote areas as stated above. 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.

Figure 4-1
Solar Powered Streetlight

4.2.2 Solar Thermal Collectors for Water Heating.

The most effective application for solar energy is the heating of water for domestic use. Solar water heating provides energy directly to the end-user and results in a high level of end-user awareness. The sun's energy is stored directly in the heated water itself, reducing the effect of converting the energy to other forms.

Lakeland presently owns and operates 29 solar water heaters. These units are installed on the roofs of residential customers' homes, i.e. – at the point of consumption. Since this method of energy delivery bypasses the entire transmission and distribution system, there are other benefits than only avoided generation costs.

In Lakeland's program, each solar water heater remains the property of the utility, thereby allowing the customer to avoid the financial cost of the purchase. Lakeland's return on this investment is realized through the sale of the solar generated energy as a separate line item on the customer's monthly bill. This energy device is monitored by using a utility-utility Btu meter calibrated to read in kWh.

One of the purposes of this program is to demonstrate that solar thermal energy can be accurately metered and profitably sold to the everyday residential end-user of hot water. Lakeland Electric's fleet of 29 solar thermal energy generators displace approximately 3,000 kWh per year per installation on average.

4.2.3 Utility-Interactive Residential Photovoltaic Systems

This project is a collaborative effort between the Florida Energy Office (FEO), FSEC, the 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 workable approaches to interconnection of PV systems into the utility grid. Lakeland currently has 20 PV systems installed and operating, all of which are directly interconnected to the utility grid. These systems have an average nominal power rating of approximately 2 kilowatts peak (kWp) and are displacing approximately 2000 kWh per year per installation 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.

4.2.4 Utility-Interactive Photovoltaic Systems on Polk County Schools

Lakeland is also actively involved in a program called "Portable Power." 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. It will allow seventeen portable classrooms to be enrolled in former 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. An education package has been delivered to the schools for their teachers' use in the explanation of solar sciences. By addressing solar energy technologies in today's public school classrooms, Lakeland is informing the next generation of the environmental and economic need for alternate forms of energy production.

The "Portable Power" in the schools, shown in Figure 4-2, consists of installing 2kWp photovoltaics systems on seventeen portable classrooms. In addition to the educational awareness benefits of photovoltaic programs in 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 classroom 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 classroom 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.

Of extreme value to the photovoltaic industry, Lakeland Electric, in a partnership with the FSEC, provided on-site training sessions while installing the solar equipment on these school buildings. Attendees from other electric utilities were enrolled and given a hands-on opportunity to develop the technical and business skills needed to implement their own solar energy projects. The training classes covered all aspects of the solar photovoltaic experience from system design and assembly, safety and reliability, power quality, and troubleshooting to distributed generation and future requirements of deregulation.

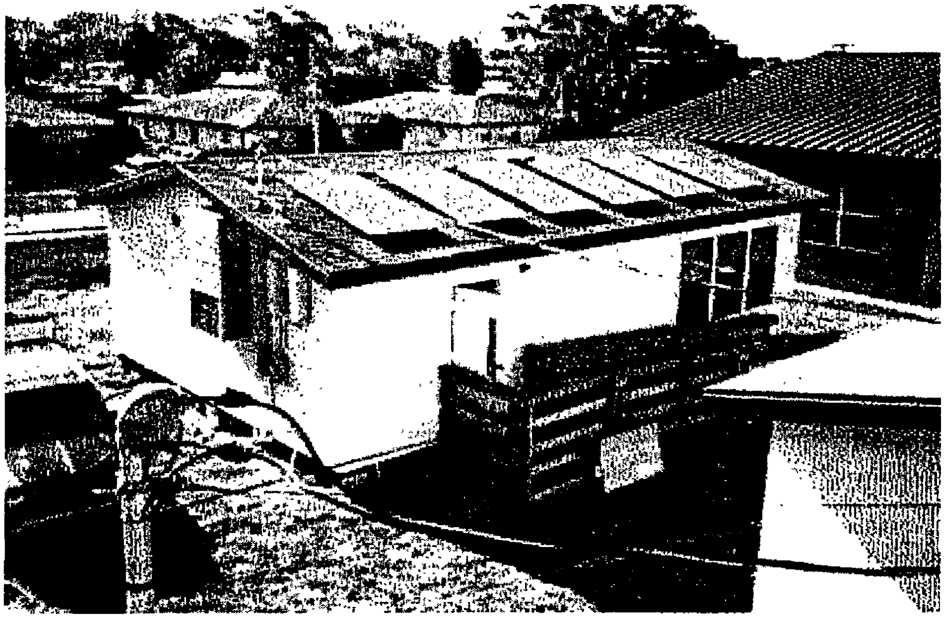


Figure 4-2
Portable Classroom Topped by PV Panels

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

4.2.5 Integrated Photovoltaics for Florida Residences

Lakeland's existing integrated photovoltaic program supports former President Clinton's "Million Solar Roofs Initiative". The Department of Energy granted five million dollars for solar electric businesses in addition to the existing privately funded twenty-seven million dollars, for a total of thirty-two million dollars for the program. 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. Lakeland is helping to accomplish this national goal.

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. As a research project, the goal is to see how much energy could be saved without factoring in the cost of the efficiency features.

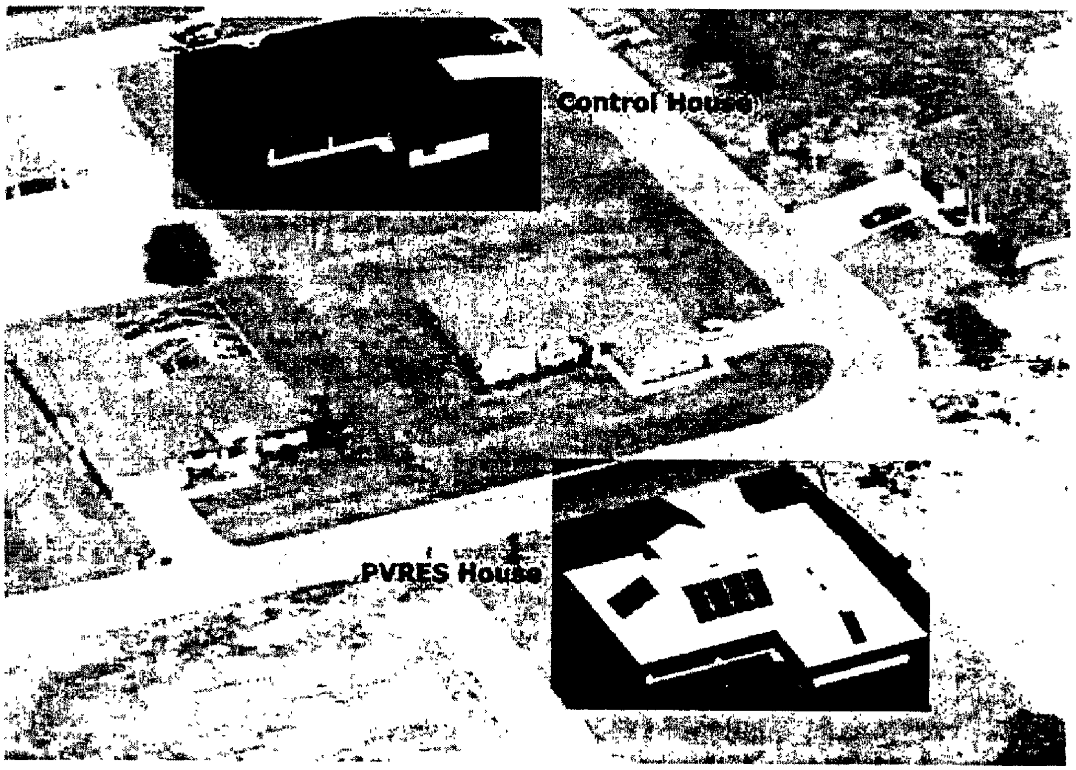


Figure 4-3
Solar House and Control House

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 4-3. 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.

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, the output of the photovoltaic system could be sent into the utility grid. The objective was to test the feasibility of constructing a new, single family residence that was engineered to reduce air conditioning loads to an absolute minimum so most of the cooling and other daytime electrical needs could be accomplished by the PV component.

4.3 Green Pricing Program

Because no long-term budgets have been established for the deployment of solar energy devices, many utilities are dependent on infrequent, somewhat unreliable sources of funding for their solar hardware purchases. To provide for a more regularly available budget, a number of utilities are looking into the voluntary participation of their customers. Recent market studies performed in numerous locations and among diverse population groups reveal a public willingness to pay equal or even slightly higher energy prices knowing that their payments are being directed towards renewable fuels.

The Florida Municipal Electric Association (FMEA) has assembled a workgroup called "Sunsmart". This workgroup is a committee composed of member utilities. Its purpose is to raise environmental awareness and implement "Green Pricing" programs that would call for regular periodic donations from customers who wish to invest in renewables. The Florida Solar Energy Center (FSEC) co-hosts this effort by providing meeting places and website advertising to recruit from statewide responses. A grant from the State of Florida Department of Community Affairs, Florida Energy Office has been appropriated to encourage utility involvement with Green Pricing.

Lakeland Electric is an active member of this committee and is actively pursuing the creation and implementation of a Green Pricing Program. A Green Pricing effort administered by the utility is a further demonstration that Lakeland Electric is engaged in cost-effective alternative energy sources.

5.0 Forecasting Methods and Procedures

This section describes and presents Lakeland's long-term integrated resource planning process, the economic parameter assumptions, plus the fuel price projections being used in the current evaluation process.

5.1 Integrated Resource Planning

Lakeland selects its capacity resources through an integrated resource planning process which it has used for a number of years. Lakeland's planning considers both conservation and demand-side management measures. 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 of the Florida Municipal Power Pool (FMPP) along with the Orlando Utilities Commission (OUC), Kissimmee Utility Authority, and the All-Requirements Project of the Florida Municipal Power Agency (FMPA). The four utilities operate as one control area. All FMPP capacity resources are committed and dispatched together from the OUC Operations Center.

The FMPP is not a capacity pool meaning that each member must plan for and maintain sufficient capacity to meet their own individual demands and reserve obligations. Any member of the FMPP can withdraw from FMPP with 1 year written notice. Lakeland, therefore, must ultimately plan on a stand-alone basis as reflected in this document.

5.3 Economic Parameters and Evaluation Criteria

This section presents the assumed values adopted for economic parameters and inputs used in Lakeland's planning process. The assumptions stated in this section are applied consistently throughout. Subsection 5.3.1 outlines the basic economic assumptions. Subsections 5.3.2 and 5.3.3 outline the base case, high and low, and constant differential fuel forecasts.

5.3.1 Economic Parameters

This section presents the values assumed for the economic parameters currently being used in Lakeland's least-cost planning analysis.

5.3.1.1 Inflation and Escalation Rates. The general inflation rate applied is assumed to be 2.5 percent per year. A 2.5 escalation rate is applied to capital costs and operation and maintenance (O&M) expenses. Fuel price escalation rates are discussed below in Section 5.3.2.

5.3.1.2 Bond Interest Rate. Consistent with the traditional tax exempt financing approach used by Lakeland, the self-owned supply-side alternatives assume 100 percent debt financing. Lakeland's long-term tax exempt bond interest rate is assumed to be 5.5 percent.

5.3.1.3 Present Worth Discount Rate. The present worth discount rate used in the analysis is set equal to Lakeland's assumed bond interest rate of 5.5 percent.

5.3.1.4 Interest During Construction. During construction of the plant, progress payments will be made to the EPC contractor and interest charges will accrue on loan drawdowns. The interest during construction rate is assumed to be 4.9 percent.

5.3.1.5 Fixed Charge Rates. The fixed charge rate is the sum of the project fixed charges as a percent of the project's total initial capital cost. When the fixed charge rate is applied to the initial investment, the product equals the revenue requirements needed to offset fixed costs for a given year. A separate fixed charge rate can be calculated and applied to each year of an economic analysis, but it is most common to used a Levelized fixed charge rate that has the same present value as the year by year fixed charged rates. Included in the fix charged rate calculation is an assumed 2.0 percent issuance fee, a 1.0 percent annual insurance cost, and a 6-month debt reserve fund earning interest at a rate equal to the bond interest rate.

5.3.2 Fuel Price Projections

This section presents the fuel price projections for coal, petroleum coke, natural gas and oil. The forecast presented has been prepared by Lakeland Electric's Wholesale Energy and Fuels Staff. The most recent Annual Energy Outlook (AEO) 2002 reports forecast of fuels is also presented for comparative purposes. The AEO 2002 report is published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2002 energy data is a nationally known source of domestic and international energy supply, consumption, and price information. It should be noted that the AEO reports represent national averages and do not always track conditions unique to specific geographical regions such as Florida.

AEO 2002 provides an energy price forecast through the year 2020 and attempts to take into account a number of important factors, some of which include:

- Restructuring of the U.S. electricity markets.
- Current regulations and legislation affecting the energy markets.

- Current energy issues:
  - Appliance, gasoline and diesel fuel, and renewable portfolio standards.
  - Expansion of natural gas industry.
  - Carbon emissions.
  - Competitive electricity pricing.

AEO 2002 energy information is considered objective and nonpartisan by Lakeland. It is used widely by both government and private sectors to assist in decision-making processes and in analyzing important policy issues.

AEO 2002 publishes real fuel price projections for the individual years of 1999, 2000, 2005, 2010, 2015, and 2020. Table 5-1 shows the real AEO 2002 forecast for the various fuel types. Table 5-2 is Lakeland's delivered fuel price forecast in 2002 real dollars by fuel type. Additional assumptions and results of the fuel price forecasts are discussed by fuel type in the following subsections.

Table 5-1
2002 Annual Energy Outlook Real Fuel Price Projections

AEO Forecast	2000	2005	2010	2015	2020
No. 2 Oil, \$/mmbtu	6.89	4.93	5.23	5.73	5.87
Residual Oil, \$/mmbtu	4.11	3.53	3.60	3.69	3.81
Coal, \$/mmbtu	1.20	1.13	1.05	1.01	0.97
Natural Gas, \$/mmbtu	4.41	3.19	3.38	3.65	3.87

Source: DOE Energy Information Administration Annual Energy Outlook 2002 Page 129

5.3.2.1 Natural Gas. Natural gas, also known as methane, is a colorless, odorless fuel that burns cleaner than many other traditional fossil fuels. Natural gas can be used for heating, cooling, and production of electricity, and other industry uses.

Natural gas is found in the Earth's crust. Once the gas is brought to the surface, it is refined to remove impurities such as water, sand, and other gases. The natural gas is then transmitted through pipelines and delivered to the customer either directly from the pipeline or through a distribution company or utility. When natural gas reaches its destination through a pipeline, it is often stored prior to distribution.

Table 5-2
Base Case Fuel Price Forecast Summary (Real **Delivered** Price $/mmbtu, No Inflation Added)

	McIntosh 3 Coal		Natural Gas		High Sulfur #6 Oil	Low Sulfur #6 Oil	#2 Diesel Oil	Petroleum Coke
2002	1.83		3.75		4.25	5.25	7.34	1.16
2003	1.81		3.81		4.25	5.25	7.70	1.17
2004	1.81		3.65		4.25	5.25	8.08	1.17
2005	1.82		3.65		4.26	5.26	8.47	1.18
2006	1.82		3.65		4.26	5.26	8.75	1.17
2007	1.82		3.67		4.26	5.26	9.05	1.17
2008	1.83		3.83		4.26	5.26	9.34	1.16
2009	1.83		4.00		4.26	5.26	9.66	1.15
2010	1.83		4.08		4.26	5.27	9.97	1.15
2011	1.85		4.17		4.27	5.27	10.34	1.15
2012	1.85		4.27		4.27	5.27	10.70	1.16
2013	1.85		4.37		4.27	5.27	11.09	1.16
2014	1.86		4.47		4.27	5.28	11.49	1.17
2015	1.86		4.56		4.27	5.28	11.88	1.17
2016	1.87		4.69		4.27	5.28	12.27	1.18
2017	1.87		4.82		4.28	5.28	12.69	1.18
2018	1.87		4.94		4.28	5.28	13.10	1.18
2019	1.88		5.07		4.28	5.29	13.51	1.19
2020	1.88		5.07		4.28	5.29	13.93	1.19
2021	1.88		5.07		4.28	5.29	13.93	1.19
Average Annual Growth Rate	0.13%		1.60%		0.04%	0.04%	3.43%	0.13%

5.3.2.1.1 Natural gas supply and availability. Natural gas reserves exist both in the United States and North American mainland and coastal regions. Natural gas reserves are mostly dependent on domestic production. Increasing demand for natural gas as a fuel for both home and heating and new power generation projects is contributing to the price volatility seen in 2001.

5.3.2.1.2 Natural gas transportation. There is currently one transportation company serving Peninsular Florida, Florida Gas Transmission Company (FGT). One additional pipeline, Gulfstream, received final approval from the Federal Energy Regulatory Commission (FERC) in February of 2001.

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

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

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

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

5.3.2.1.2.2 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.

5.3.2.1.2.3 Gulfstream pipeline. The Gulfstream pipeline will be a 744-mile pipeline originating in the Mobile Bay region and crossing the Gulf of Mexico to a landfall in Manatee County (south Tampa Bay). The pipeline is expected to supply Florida with 1.1 billion cubic feet of gas per day serving existing and prospective electric generation and industrial projects in southern Florida. Figure 5-1 shows the proposed route for the Gulfstream pipeline.

The 1.6 billion-dollar pipeline won FERC approval, subject to environmental review, on April 24, 2000. Final environmental and routing approvals by FERC were given in February of 2001. Construction for the Gulfstream pipeline began in 2001 with an estimated operation date of June of 2002.

The first major acquisition of right-of-way occurred July 20, 2000 with a signed agreement between Coastal Corporation and the Manatee County Port Authority. The Gulfstream pipeline gained the permanent right of way easement to cross through Port Manatee.

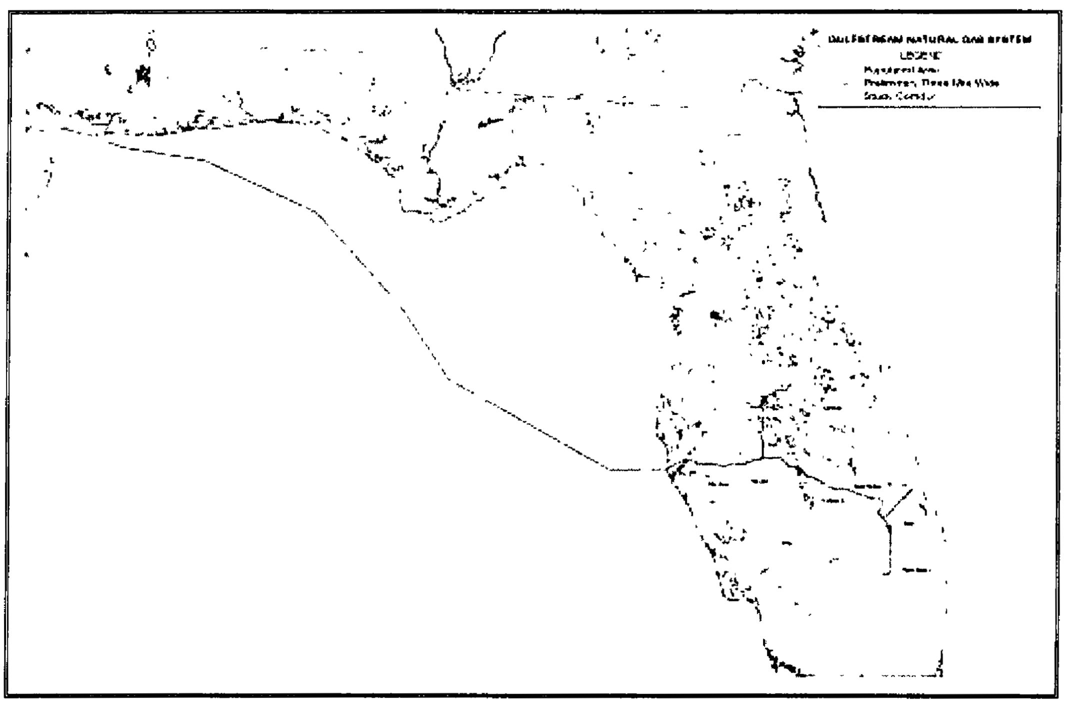


Figure 5-1
Gulfstream Natural Gas Pipeline

5.3.2.1.3 Natural gas price forecast. The price forecast for natural gas developed by Lakeland is based on historical experience and future expectations for the market. The forecast takes into account the fixed long term contracts that Lakeland has in place for a portion of its gas along with new or spot purchases of gas to meet its needs. The cost of transportation is included in the prices in Table 5-2. As previously stated, natural gas prices were extremely volatile in 2001. Lakeland saw average monthly purchase prices swing from $2.80 / mmbtu to as high as $11.35 / mmbtu with an average calendar year price of $4.08 / mmbtu.

Lakeland currently has a ten-year contract with El Paso for the supply of 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 plans to enter into one to five year (spot market) contracts for the balance of its natural gas requirements.

Natural gas transportation from FGT is currently supplied under two tariffs, FTS-1 and FTS-2. Rates in FTS-1 are based on FGT's Phase II expansion and rates in 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 the 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 5-3.

For purposes of projecting delivered gas prices, transportation charges of $0.62/mmbtu were applied for existing units as this is the average cost for Lakeland to obtain natural gas transportation for those units. This average rate is realized through a current mix of FTS-1, FTS-2 and Gulfstream FTS transportation, including consideration of Lakeland's ability to relinquish FTS-2 transportation and acquire other firm and interruptible gas transportation on the market.

Lakeland's forecast for natural gas escalates faster than the AEO 2002 forecast. Lakeland obviously takes a slightly more pessimistic view of gas prices based on the fact that almost all new generation that is being planned in both Florida and the nation as a whole is natural gas fired. Lakeland feels this will keep pressure on supply and result in strong pricing.

Table 5-3
Natural Gas Transportation Rates

Rates And Surcharges	Rate Schedules			
	FGT FTS-1 w/surcharges (cents/DTH)*	FGT FTS-2 w/surcharges (cents/DTH)*	FGT ITS-1	Gulfstream FTS-1
Reservation	37.53	77.85	33.84	80.65
Usage	4.34	2.63	0.00	0.02
Total	41.87	80.48	33.84	80.67
Fuel Charge	2.75%	2.75%	2.75%	1.27%

* A DTH is equivalent to 1 mmbtu or 1 mcf

5.3.2.2 Coal. Coal has been used as an energy source for hundreds of years and provided the energy which fueled the Industrial Revolution of the 19th Century and it was a primary fuel of the electric era in the 20th Century. As of 1998, some 37 percent of the electricity generated worldwide and over half (57 percent) of the electricity generated in the United States was produced from coal.

5.3.2.2.1 Coal supply and availability. Lakeland's current coal purchase contracts are approximately 60 percent long-term and 40 percent spot purchases. Spot purchases can extend from several months to two years in length. Lakeland maintains a 30 – 35 day coal supply reserve (90,000 – 110,000 tons) at the McIntosh site.

5.3.2.2.2 Coal transportation. McIntosh Unit 3 is Lakeland's only unit burning coal. Lakeland projects McIntosh Unit 3 will burn approximately 850,000 tons of coal per year. The coal sources are located in eastern Kentucky, which affords Lakeland a single rail line haul via CSX Transportation.

5.3.2.2.3 Coal price forecast

Currently, Lakeland's long-term purchase of coal for McIntosh 3 is under a contract which expires in December of 2006. Lakeland is not expecting a significant increase in coal costs when a new contract is crafted for 2007 and beyond. Continued improvements in mine productivity and the increasing availability of foreign coal is expected to keep real prices in check over the forecast period. The AEO 2002 forecast exhibits similar trends for coal. Lakeland's forecast for coal is slightly higher due to the additional transportation costs to get the coal to Florida.

5.3.2.3 Petroleum Coke price forecast. Lakeland utilizes petroleum coke as a supplemental fuel in its McIntosh Unit 3 as a means of reducing overall costs to its customers. Petroleum coke is a by-product of the oil refining process. This by-product is a solid residue produced from the cracking of heavy residual oil to produce lighter hydrocarbons. Petroleum coke is high in fixed carbon with heating values in the range of 14,200 to 14,600 Btu/lb. Other product characteristics are low volatile content, low ash content, high sulfur content and varying degrees of hardness. The physical and chemical specifications of petroleum coke are a direct function of the oils being processed by the refinery. The amount of petroleum coke produced is increasing due to the increase in refining capacity for heavy crude oils and the declining demand for residual fuel oil. The coking process allows for a higher yield of light oil products, specifically gasoline.

5.3.2.3.1 Petroleum coke supply and availability. While the production of petroleum coke is not the primary product of a refinery, it's production is linked to the production of high value products such as gasoline, jet fuel, diesel and other light products. The increasing demand for these high value products has led to expansions and modifications of current cokers and the addition of new cokers, thus increasing the availability of petroleum coke. The arrival of this new coker capacity began in late 2000 and should be completed by early 2004. This incremental coker capacity will add approximately 20 million tons to the annual production capability of petroleum coke. Ninety-two percent of the announced petroleum coke will be produced in the Americas.

Traditionally, the majority of the petroleum coke production has been consumed by the cement, lime and steel industry. But as the availability and acceptance of petroleum coke increases, the use of petroleum coke as a fuel in the electric utility industry will significantly increase a means to remain competitive in a deregulated industry.

Approximately 65 to 70 percent of the petroleum coke produced is a fuel-grade coke, which has a sulfur content of more than four percent. The remaining petroleum coke produced is an anode-grade coke, which has a sulfur content less than four percent. The anode-grade coke is calcined and sold as a premium-grade petroleum coke used in the manufacture of aluminum anodes, furnace electrodes and liners, and shaped graphite products.

Aside from the market dynamics of supply and demand, the primary factor that drives the price of fuel-grade petroleum coke is the sulfur content. A high sulfur content, 6 percent or higher, will normally result in a lower priced product as opposed to a product with a sulfur content in the range of 4.5 to 5.5 percent. A secondary factor to be considered in the price of fuel-grade petroleum coke is the hardness of the petroleum coke. As measured by the Hardgrove Grindability Index (HGI), the harder the petroleum coke, an HGI of less than 40, then typically the lower the market price for the product. Therefore, a fuel-grade petroleum coke product with a high sulfur content and a low HGI will result in the most favorable pricing opportunities.

The availability of a high sulfur, low HGI petroleum coke product is directly tied to the specifications of the heavy crude oils being refined. During the next three to four years there will be available approximately four to six million tons annually of this particular petroleum coke product (high sulfur/low HGI). During the same time frame, another petroleum coke product with a medium range of sulfur of 5 to 5.5 percent and a HGI range of 35 to 40, with an annual production of approximately eight to ten million tons will also be available. This medium grade petroleum coke will be sourced from Venezuela. The pricing of the above products will normally be at a deeper discount than a lower sulfur, (4.5 to 5 percent) and high HGI (48 plus) petroleum coke product. Further, if the lower grade petroleum coke product can be obtained from a foreign based refinery, then the transportation cost will be approximately one-quarter to one-third of the domestic transportation cost.

As the use of fuel-grade petroleum coke has increased and gained acceptance in the electric utility industry, the sophistication of the buyers and sellers has increased as well. In the past, the petroleum coke market witnessed contract terms normally a year of less, refineries were not willing to sell direct, and pricing arrangements which were not always market price sensitive. Now sellers of petroleum coke are entering into longer-term contracts, refineries are either selling or entertaining the sale of their product direct and the pricing mechanisms are allowing both the buyer and seller to stay market price sensitive in a longer term arrangement.

McIntosh Unit 3 burns approximately 100,000 tons of petroleum coke annually, a very small amount compared to overall market availability. The petroleum coke burned in McIntosh Unit 3 is a higher grade, lower sulfur, more expensive petroleum coke than what would be burned in a unit specifically designed to burn petroleum coke. Therefore, the petroleum coke price forecast resembles the expected price for the higher grade, low sulfur petroleum coke that can be supplemented in existing coal fired units. Petroleum coke prices for new solid fuel units designed to burn this full would be at a discount to the forecast presented here.

5.3.2.3.2 Petroleum coke transportation. In general, petroleum coke is amenable to transport by truck, rail, barges, ocean going ships, or a combination of these modes of transportation. Currently, petroleum coke for McIntosh 3 is transported to the McIntosh site by truck.

5.3.2.3.3 Petroleum coke price forecast. The petroleum coke price presented in this forecast is based on Lakeland's historical experience, Lakeland's current contract for the fuel and the expected supply and demand conditions in the petroleum coke market in the future.

5.3.2.4 Fuel Oil

5.3.2.4.1 Fuel oil supply and availability. The city of Lakeland currently obtains all of its fuel oil through spot market purchases 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.

5.3.2.4.2 Fuel oil transportation. Although the City of Lakeland is not a large consumer of fuel oils, a small amount is consumed during operations for backup fuel and diesel unit operations. Fuel oil is transported to Lakeland by truck.

5.3.2.4.3 Fuel oil price forecast. Lakeland's price forecast for residual fuels is consistent with the AEO 2002 forecast. Both forecasts expect residual oil prices to remain relatively flat over the forecast period. Lakeland expects the price of #2 Diesel, also referred to as Distillate Fuel, to escalate faster than the AEO 2002 forecast. Lakeland feels in part this is due to the mandates to reduce sulfur content in this fuel which will command higher prices to produce along with this fuel being the backup fuel for most of the natural gas fired generation being built. This will keep demand higher and thus the price will follow. Another distinct difference in Lakeland's forecast compared to the AEO forecast is the fact that the AEO forecast is an annual average price. As Lakeland only uses this fuel during times of high demand and does not have major storage capabilities, the corresponding price tends to be higher during those peak times.

5.3.3 *Fuel Forecast Sensitivities*

Lakeland did not forecast fuel price sensitivities in this years planning cycle. As mentioned earlier in this report, the results of Lakeland's internal resource evaluation is not complete and therefore Lakeland has frozen all retirements and expansion plans. Based on current installed capacity versus forecasted demand, Lakeland shows no need for additional resources in the next ten years thus making fuel forecast sensitivities a moot point for this planning cycle.

6.0 Forecast of Facilities Requirements

6.1 Need for Capacity

This section addresses the need for additional electric capacity to serve 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 is 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 are provided in Tables 3-4 & 3-5. The peak demands reflect reductions for Lakeland's conservation and demand-side management programs and interruptible loads.

6.1.2 Reserve Requirements

Prudent utility planning requires that utilities secure firm generating resources over and above the expected peak system demand to account for unanticipated demand levels and supply constraints. Several methods of estimating the appropriate level of reserve capacity are used. The most commonly used approach is the reserve margin method, which is calculated as follows:

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

Lakeland had been studying its reserve margin levels closely in the late 1990's. Even though Lakeland had been able to meet its load obligations with the level of reserve margin it had been carrying, Lakeland felt that it was operating too close to the edge, so to speak, and subsequently after further analysis increased its reserve margins in the spring of 2000. By April 1, 2000 those new reserve margin targets were in effect as published in Lakeland's 2000 Ten Year Site Plan.

Lakeland began using a more probabilistic approach to determine its reserve margin needs in late 1999. This was done by applying certainty factors to capacity availability at time of peak, firm load forecasts, load management and interruptible load availability at time of peak. Ten years of historical data and performance were analyzed and revealed that capacity availability had a significant impact on reserve margin. Components on the load side, forecast uncertainty and availability of load management and interruptible load had a very small impact on reserves, indicating that Lakeland's forecasting process is reasonably adequate.

Generation availability was reviewed and found to be within industry standards for the types of units that Lakeland has, indicating adequate and prudent maintenance was taking place. The impact to Lakeland is the fact that for its size, Lakeland's capacity is supplied by just a few units and the loss of one of those units at time of peak has a significant impact on its system. The analysis lead Lakeland to the decision that a 20% summer peak reserve margin and 22% winter peak reserve margin would better provide Lakeland with adequate reserves to cover the loss of a unit and/or uncertainties in forecasting. As Lakeland's needs and fleet of resources change through time, these reserve margin levels will be periodically reviewed and adjusted as appropriate.

6.1.3 Additional Capacity Requirements

By comparing the load forecast plus reserves with firm supply, the additional capacity required on a system over time can be identified. Lakeland's requirements for additional capacity are presented in Tables 6-1 through 6-4 which show the projected reliability levels for winter and summer base cases, and winter high and low load demands, respectively. Lakeland's capacity requirements are driven by the winter peak demand forecasts.

Table 6-1 shows a 170 MW capacity increase from the winter 2002/03 season to the winter 2003/04 season. This increase is made up of two projects being completed and undergoing start-up and testing at the time of this writing. Those projects are the 120 MW addition to McIntosh 5, the combined cycle build out, and the 50 MW Winston Peaking Station.

The last column of Table 6-1 indicates that using the base winter forecast, Lakeland will not need any additional capacity in the current ten year planning cycle. This is a change from last years filing and is due to Lakeland putting all retirements for the current planning cycle into abeyance until additional analysis can be completed to determine the best and most cost effective plan for meeting future customers needs. All capacity currently counted for Lakeland's forecasted load and reserve obligations is capable of running the next ten years with proper maintenance thus making the decision to forgo any retirements achievable.

Table 6-2 also indicates that no additional capacity is needed for the current ten year planning cycle. Tables 6-3 and 6-4 show the high and low winter load forecasts for Lakeland. The high forecast indicates a need for capacity for the winter of 2005/06 while the low projects no need for capacity until well beyond the current ten year planning cycle.

6.1.3.1 Winston Peaking Station

Lakeland Electric, has constructed a 50-megawatt electric peaking station adjacent to its Winston Substation. The purpose of the peaking plant is to provide additional quick start generation for Lakeland's system during times of peak loads. Lakeland's peak loads occur during high temperature conditions in the summer and low temperature conditions in the winter. This is also Lakeland's first experience with distributed generation.

The project consists of twenty (20) EMD 20 cylinder reciprocating engines driving 2.5 MW generators. The units are housed in a single building of steel frame construction with concrete facade. There is a 294,000 gallon #2 fuel oil storage tank on site, although, natural gas with a 5% mix of #2 fuel oil (for ignition) will be the primary fuel once a natural gas pipeline is completed to the site.

The plant will be operated by a staff of two (2) or three (3) when the plant is operating. There will be no staff on site when the plant is not operating except for times of routine maintenance. The plant has remote start/run capability for extreme emergencies at times when the plant is unmanned.

The station does not use open cooling towers. This results in minimal water or wastewater requirements. Less than three quarters of the six (6) acre site was developed leaving considerable room for water retention.

The engines are equipped with hospital grade noise suppression equipment on the exhausts. Emission control is achieved by Selective Catalytic Reduction (SCR) using 19% aqueous ammonia. The SCR system will allow the plant to operate within the Minor New Source levels permitted by the Florida Department of Environmental Protection (DEP).

This is Lakeland's first venture into distributed generation. Winston Peaking Station (WPS) was constructed adjacent to Lakeland's Winston Distribution Load Substation. Power generated at WPS goes directly into Winston Substation at the 12.47kV distribution level of the substation and has sufficient capacity to serve the substation loads. Winston Substation serves several of Lakeland's largest and most critical accounts. Should Winston loose all three 69kV circuits to the substation, WPS can be on line and serving load in ten minutes. In addition to increasing the substation's reliability, this arrangement will allow Lakeland to delay the installation of a third 69kV to 12.47kV transformer by several years and also contributes to lowering loads on Lakeland's transmission system.

Table 6-1
Projected Reliability Levels - Winter / Base 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 22% Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2001/2002	891	0	100	791	659*	597**	20.0	32.5	(13)	63
2002/2003	1061	0	100	961	719	658	33.7	46.0	84	158
2003/2004	1061	0	100	961	737	676	30.4	42.2	62	136
2004/2005	1061	0	100	961	756	695	27.1	38.3	39	113
2005/2006	1061	0	100	961	774	712	24.2	35.0	17	92
2006/2007	1061	0	100	961	793	731	21.2	31.5	(6)	69
2007/2008	1061	0	100	961	811	749	18.5	28.3	(28)	47
2008/2009	1061	0	100	961	830	768	15.8	25.1	(52)	24
2009/2010	1061	0	100	961	848	786	13.3	22.3	(74)	2
2010/2011	1061	0	0	1061	866	803	22.5	32.1	4	81
2011/2012	1061	0	0	1061	885	822	19.9	29.1	(19)	58

* Actual Jan 2002 Peak, No Load Management and/or Interruptible used at time of Peak

** Adjusted Jan 2002 Peak if Load Management and Interruptible had been used at time of Peak

Table 6-2
Projected Reliability Levels - Summer / Base 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% Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2002	981	0	100	881	593	560	48.6	57.3	169	209
2003	981	0	100	881	607	574	45.1	53.5	153	192
2004	981	0	100	881	620	587	42.1	50.1	137	177
2005	981	0	100	881	633	600	39.2	46.8	121	161
2006	981	0	100	881	647	614	36.2	43.5	105	144
2007	981	0	100	881	661	627	33.3	40.5	88	129
2008	981	0	100	881	675	641	30.5	37.4	71	112
2009	981	0	100	881	689	655	27.9	34.5	54	95
2010	981	0	100	881	702	668	25.5	31.9	39	79
2011	981	0	0	981	716	682	37.0	43.8	122	163

Table 6-3
Projected Reliability Levels - Winter / High 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 (%)	Reserve Margin: After Interruptible and Load Management (%)	Excess/ (Deficit) to Maintain 22% Reserve Margin: Before Interruptible and Load Management (MW)	Excess/ (Deficit) to Maintain 22% Reserve Margin: After Interruptible and Load Management (MW)
2001/2002	891	0	100	791	659*	597**	20.0	32.5	(13)	63
2002/2003	1061	0	100	961	797	736	20.6	30.6	(11)	63
2003/2004	1061	0	100	961	815	754	17.9	27.5	(33)	41
2004/2005	1061	0	100	961	834	773	15.2	24.3	(56)	18
2005/2006	1061	0	100	961	852	790	12.8	21.6	(78)	(3)
2006/2007	1061	0	100	961	871	809	10.3	18.8	(120)	(26)
2007/2008	1061	0	100	961	889	827	8.1	16.2	(124)	(48)
2008/2009	1061	0	100	961	908	846	5.8	13.6	(147)	(71)
2009/2010	1061	0	100	961	926	864	3.8	11.2	(169)	(93)
2010/2011	1061	0	0	1061	944	881	12.4	20.4	(91)	(14)
2011/2012	1061	0	0	1061	963	900	10.2	17.9	(114)	(37)

* Actual Jan 2002 Peak, No Load Management and/or Interruptible used at time of Peak

** Adjusted Jan 2002 Peak if Load Management and Interruptible had been used at time of Peak

Table 6-4
Projected Reliability Levels - Winter / Low 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 22% Reserve Margin	
					Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2001/2002	891	0	100	791	659*	597**	20.0	32.5	(13)	63
2002/2003	1061	0	100	961	639	578	50.4	66.3	181	256
2003/2004	1061	0	100	961	657	596	46.3	61.2	159	234
2004/2005	1061	0	100	961	675	614	42.4	56.5	138	212
2005/2006	1061	0	100	961	694	632	38.5	52.1	114	190
2006/2007	1061	0	100	961	712	650	35.0	47.8	92	168
2007/2008	1061	0	100	961	731	669	31.5	43.6	69	145
2008/2009	1061	0	100	961	749	687	28.3	39.9	47	123
2009/2010	1061	0	100	961	768	706	25.1	36.1	24	100
2010/2011	1061	0	0	1061	786	723	35.0	46.7	102	179
2011/2012	1061	0	0	1061	804	741	32.0	43.2	80	157

* Actual Jan 2002 Peak, No Load Management and/or Interruptible used at time of Peak

** Adjusted Jan 2002 Peak if Load Management and Interruptible had been used at time of Peak

7.0 Generation Expansion Analysis Results and Conclusions

This section discusses the status of Lakeland's Generation Expansion plans as of December 31, 2001. At the time of this filing, Lakeland is continuing its evaluation of resource options along with existing resources and what the proper mix of existing and/or new resources should be, if any. Options being considered have included but were not limited to remaining in or leaving the generation business, diversification of existing resource portfolio and proper diversification of future resource portfolio's. As no final decision has been made at the time of this writing, all resources and plans have been frozen in place meaning no planned retirements of existing facilities and no planned additions beyond what is currently under construction are being proposed for the current ten year planning cycle. The demand and capacity analysis presented in Section 6 indicates that this position is feasible and achievable for the current planning cycle.

7.1 Background

As noted in Lakeland's 2001 Ten Year Site Plan, Lakeland was formally pursuing a solid fuel addition with a capacity of approximately 300 MW coming into operation in the 2005/06 time frame. This addition would be justified in part by a need for additional capacity due to load growth, the economic retirement of older units (fuel savings from a stable solid fuel versus more volatile oil and gas) and fuel diversity.

An RFP process was initiated as a means to implement the plan in a cost-effective manner, and was issued on June 12, 2000. Given the extreme volatility in the natural gas market recently, and due to Lakeland's dependence on natural gas, the RFP indicated a preference for solid fuel capacity or, if not solid fuel, a guaranteed escalation of fuel costs. Capacity resources from 200 MW to 400 MW were sought, and bidders were informed of the price and non-price criteria which would be used for the evaluation of proposals.

Lakeland held a pre-bidder's conference in August 2000, after which a number of prospective bidders asked that the due date for the proposals be extended beyond the initial due date of October 6, 2000. Lakeland agreed to extend the due date to December 1, 2000 at which time three proposals were received and deemed to be responsive. Two of the three proposals were for circulating fluidized bed (CPB) units burning petroleum coke to be built at the McIntosh site. The third proposal was for purchase power from an integrated coal gas production unit burning petroleum coke with an option for equity participation.

Lakeland and their consultant at the time, Black & Veatch, performed independent analyses of the RFP results and both identified the same least cost proposal from the three RFP responses.

A number of things were happening in parallel at Lakeland during this time. A new Management team had come on board in the middle of this process which brought some fresh ideas to Lakeland, the national economic scene started to become very uncertain and start-up problems with the McIntosh 5 project became painfully obvious. The prospect of delay on the McIntosh 5 project prompted the exploration of possibly obtaining cost-effective replacement capacity as an insurance policy of sorts. Also coming to light were the operational challenges Lakeland could potentially face with three large base load facilities, McIntosh 3, 5, and the proposed Unit 4 project. Those units combined with insufficient off-peak load to maximize the benefits those units would bring to Lakeland were a growing concern.

As a result of these concerns, Lakeland made the a number of decisions. The first being to re-explore peaking options and thus Lakeland issued an RFP in late 2000 to purchase 50 MW of quick start peaking capacity. There were no specifications for the type of prime mover to be used. Lakeland only specified that the resource should have dual fuel and quick start capabilities. Responses to this RFP included both purchase power options as well as physical machines to be built on Lakeland sites. Analysis of the RFP responses led Lakeland to the decision to award the bid to a local company, Genertek, for the purchase and installation of 50 MW of quick start peaking capacity as described in Section 6.1.3.1. Major construction was completed in late December 2001 and the units are going through start-up and acceptance testing.

During this time, start-up and testing activities of McIntosh 5 CT were completed and the CT portion of the project was declared commercial in May 2001. The unit ran successfully from May to mid September. In mid September 2001, the Unit was taken down for the scheduled conversion to combined cycle. Major construction was also completed in mid December 2001 and the unit is currently in start-up and acceptance testing at the time of this writing.

Another decision prompted by Lakeland's growing concerns regarding future generation plans and operations was to completely revisit not only the expansion plans, but the overall strategies and visions for the utility and how Lakeland's decision(s) would fit into the rapidly changing business environment the industry is facing. This has resulted in Lakeland wiping the board clean so-to-speak and taking a fresh look at existing resources, future resource options, what is the proper mix of each along with a re-evaluation of whether to even stay in the generation business at all. A formal study was commissioned in the summer of 2001 and has not been completed as of yet.

After analysis of Lakeland's load and reserve requirements as compared to existing resources, it has been decided to put all proposed generation additions and retirements into abeyance until the final results of the formal study are completed. Tables 6-1 through 6-4 clearly indicate that under expected conditions no capacity is needed until after the current ten year planning cycle. Even in high load conditions, Lakeland would be able to serve its load and sales obligations for the ten year period, only slightly falling below the FPSC's 15% reserve margin target for the winters of 2008/09 and 2009/10. Lakeland fully anticipates completing this study in 2002 and preparing a new generation expansion plan in time for the 2003 filing of the Ten Year Site Plan.

7.1.1 Supply-Side Economic Analysis

The supply-side evaluations of generating unit alternatives is being performed in house by Lakeland staff utilizing Lakeland's production costing program, POWRSYM3, along with Lakeland's outside consultants using market analysis tools covering the Southeast region of the U.S. .

7.1.2 Demand-Side Economic Analysis

Lakeland continues actively monitor Demand-Side Options to find the most cost-effective way to meet our customers needs. To date, no additional cost-effective DSM measures have been identified. Lakeland continues to include the effects of existing DSM programs in the overall analysis.

7.2 Sensitivity Analyses

Once a preferred option is selected, Lakeland will perform several sensitivity analyses to measure the impact of important assumptions on the option(s) selected. The sensitivity analyses may include but not be limited to 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, a best plan over the planning horizon will be identified. The sensitivity analyses will be performed over the same planning period used throughout the economic evaluations, with a projection of annual costs and cumulative present worth costs.

7.3 Transmission

All options selected will be analyzed for impacts to the transmission system and the costs of any upgrades will be factored into the final analysis and decision.

At present, Lakeland does not anticipate the need for any major transmission upgrades to accommodate additional generation resources.

8.0 Environmental and Land Use Information

Lakeland's 2002 Ten-Year Site Plan has no capacity additions in it and thus no additional environmental or land use information is required at this time. All existing units are fully permitted and meet all permitted requirements.

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. Lakeland has attempted to provide complete information for the FPSC whenever possible.

9.1 Abbreviations and Descriptions

The following abbreviations are used throughout the Ten-Year Site Plan Schedules.

Abbreviation	Description
Unit Type	
CA	Combined Cycle Steam Part
GT	Combustion Gas Turbine
ST	Steam Turbine
CT	Combined Cycle Combustion Turbine
IC	Internal Combustion Engine
Fuel Type	
NG	Natural Gas
DFO	Distillate Fuel Oil
RFO	Residual Fuel Oil
BIT	Bituminous Coal
WH	Waste Heat
Fuel Transportation Method	
PL	Pipeline
TK	Truck
RR	Railroad
Unit Status Code	
RE	Retired
SB	Cold Standby (Reserve)
TS	Construction Complete, not yet in commercial operation
U	Under Construction
P	Planned for installation

Table 9-1
Schedule 1.0: Existing Generating Facilities as of December 31, 2001

(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	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate kW	Summer MW	Winter MW
Charles Larsen Memorial	2	16-17/28S/24E	GT	NG	DFO	PL	TK	28	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	28	12/62	Unknown	11,500	10	14
	6		ST	NG	RFO	PL	TK		12/59	Extended Cold Standby 8/01	25,000	0	0
	7		ST	NG	RFO	PL	TK	7	02/66	Unknown	50,000	50	50
	8		CA	WH	---				04/56	Unknown	25,000	29	31
	8		CT	NG	DFO	PL	TK	5	07/92	Unknown	101,520	73	93
Plant Total												172	202
C.D. McIntosh, Jr.	D1	4-5/28S/24E	IC	DFO	---	TK	---		01/70	Unknown	2,500	3	3
	D2		IC	DFO	---	TK	---		01/70	Unknown	2,500	3	3
	GT1		GT	NG	DFO	PL	TK	2	05/73	Unknown	26,640	17	20
	1		ST	NG	RFO	PL	TK	29	02/71	Unknown	103,000	87	87
	2		ST	NG	RFO	PL	TK	25	06/76	Unknown	126,000	103	103
	3[1]		ST	BIT	---	RR	---		09/82	Unknown	363,870	205	205
	5		CT	NG	DFO	PL	TK	3	05/01	Unknown	292,950	221	268
Plant Total												639	689
System Total												811	891

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

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
1992	198,763	2.53	988	78,427	12,598	529	9,740	54,312
1993	201,649	2.54	1,012	79,493	12,731	536	9,759	54,924
1994	206,040	2.55	1,085	80,909	13,410	563	9,887	56,943
1995	210,095	2.55	1,134	82,445	13,755	594	10,030	59,222
1996	213,347	2.55	1,213	83,656	14,500	588	9,747	60,326
1997	216,782	2.55	1,170	84,941	13,774	607	9,835	61,718
1998	218,959	2.55	1,249	85,840	14,550	625	10,003	62,294
1999	221,060	2.53	1,239	87,222	14,205	642	10,346	62,053
2000	224,882	2.53	1,263	88,740	14,233	659	10,513	62,684
2001	224,116	2.53	1,328	88,663	14,978	665	10,529	63,159
Forecast								
2002	227,201	2.53	1,356	89,800	15,100	677	10,673	63,431
2003	230,286	2.53	1,388	90,952	15,371	690	10,830	63,712
2004	233,339	2.53	1,419	92,103	15,407	703	10,974	64,061
2005	236,605	2.54	1,451	93,301	15,552	716	11,121	64,383
2006	239,988	2.54	1,482	94,528	15,678	729	11,272	64,674
2007	243,338	2.54	1,514	95,753	15,812	742	11,423	64,957
2008	246,594	2.54	1,546	96,963	15,944	755	11,571	65,249
2009	249,779	2.54	1,578	98,161	16,076	768	11,718	65,540
2010	252,977	2.55	1,610	99,368	16,202	782	11,867	65,897
2011	256,226	2.55	1,644	100,591	16,343	795	12,018	66,151

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
1992	349	47	7,425,532	0	13	65	1,944
1993	377	50	7,540,000	0	13	67	2,005
1994	387	51	7,588,235	0	14	69	2,118
1995	429	51	8,411,765	0	15	73	2,245
1996	428	57	7,508,772	0	15	77	2,321
1997	459	62	7,403,226	0	16	78	2,330
1998	462	62	7,451,613	0	16	80	2,432
1999	485	70	6,928,571	0	17	79	2,462
2000	506	83	6,096,386	0	18	84	2,530
2001	488	80	6,100,000	0	19	82	2,582
Forecast							
2002	504	82	6,146,341	0	19	85	2,641
2003	519	84	6,178,571	0	20	87	2,714
2004	535	85	6,294,118	0	21	90	2,768
2005	551	87	6,333,333	0	21	92	2,831
2006	566	88	6,431,818	0	22	95	2,894
2007	582	90	6,466,667	0	23	97	2,958
2008	598	92	6,500,000	0	23	100	3,022
2009	614	94	6,531,915	0	24	102	3,086
2010	630	95	6,631,579	0	25	105	3,152
2011	646	98	6,591,837	0	25	107	3,217

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

(1)	(2)	(3)	(4)	(5)	(6)
Fiscal Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy for Load GWh	Other Customers (Average No.)	Total No. of Customers
1992	0	135	2,079	0	88,214
1993	0	135	2,140	0	89,302
1994	0	161	2,279	0	90,847
1995	0	145	2,390	0	92,526
1996	0	127	2,448	0	93,460
1997	0	113	2,443	0	94,838
1998	0	117	2,549	0	95,935
1999	0	123	2,585	0	97,638
2000	0	139	2,669	0	99,336
2001	0	112	2,694	0	99,272
Forecast					
2002	0	121	2,762	0	100,555
2003	0	117	2,831	0	101,866
2004	0	131	2,899	0	103,162
2005	0	136	2,967	0	104,509
2006	0	142	3,036	0	105,888
2007	0	147	3,105	0	107,266
2008	0	153	3,175	0	108,626
2009	0	158	3,244	0	109,973
2010	0	162	3,314	0	111,330
2011	0	167	3,384	0	112,707

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
					Residential		Commercial/Industrial		
Year	Total	Wholesale	Retail	Interrupt.	Load Management	Conservation	Load Management	Conservation	Net Firm Demand
1992	434	0	434	0	0	0	0	0	434
1993	459	0	459	0	0	0	0	0	459
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	0	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
2000	573	0	573	0	21	0	0	0	552
2001	546	0	546	0	0	0	0	0	546
Forecast									
2002	593	0	593	12	21	0	0	0	560
2003	607	0	607	12	21	0	0	0	574
2004	620	0	620	12	21	0	0	0	587
2005	633	0	633	12	21	0	0	0	600
2006	647	0	647	12	21	0	0	0	614
2007	661	0	661	12	22	0	0	0	627
2008	675	0	675	12	22	0	0	0	641
2009	689	0	689	12	22	0	0	0	655
2010	702	0	702	12	22	0	0	0	668
2011	716	0	716	12	22	0	0	0	682

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

(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
1992/93	480	0	480	0	23	0	0	0	457
1993/94	485	0	485	0	0	0	0	0	445
1994/95	578	0	578	0	40	0	0	0	538
1995/96	655	0	655	0	45	0	0	0	610
1996/97	552	0	552	0	0	0	0	0	552
1997/98	476	0	476	0	0	0	0	0	476
1998/99	611	0	611	0	0	0	0	0	611
1999/2000	661	0	661	0	51	0	0	0	610
2000/01	706	0	706	0	51	0	0	0	655
2001/02	659	0	659	0	0	0	0	0	659
Forecast									
2002/03	720	0	720	10	52	0	0	0	658
2003/04	739	0	739	10	53	0	0	0	676
2004/05	758	0	758	10	53	0	0	0	695
2005/06	776	0	776	10	54	0	0	0	712
2006/07	796	0	796	11	54	0	0	0	731
2007/08	815	0	815	11	55	0	0	0	749
2008/09	834	0	834	11	55	0	0	0	768
2009/10	853	0	853	11	56	0	0	0	786
2010/11	870	0	870	11	56	0	0	0	803
2011/12	889	0	889	11	56	0	0	0	822

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

(1)	(2)	(3)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
1992	1,944	0	0	1,944	0	135	2,079	53.0
1993	2,005	0	0	2,005	0	135	2,140	53.5
1994	2,118	0	0	2,118	0	161	2,279	58.5
1995	2,245	0	0	2,245	0	145	2,390	50.7
1996	2,321	0	0	2,321	0	127	2,448	45.4
1997	2,330	0	0	2,330	0	113	2,443	50.5
1998	2,432	0	0	2,432	0	117	2,549	61.1
1999	2,462	0	0	2,462	0	123	2,585	48.3
2000	2,530	0	0	2,530	0	139	2,669	49.8
2001	2,582	0	0	2,582	0	112	2,694	47.0
Forecast								
2002	2,641	0	0	2,641	0	121	2,762	47.8
2003	2,714	0	0	2,714	0	117	2,831	49.1
2004	2,768	0	0	2,768	0	131	2,899	48.8
2005	2,831	0	0	2,831	0	136	2,967	48.7
2006	2,894	0	0	2,894	0	142	3,036	48.7
2007	2,958	0	0	2,958	0	147	3,105	48.5
2008	3,022	0	0	3,022	0	153	3,175	48.3
2009	3,086	0	0	3,086	0	158	3,244	48.2
2010	3,152	0	0	3,152	0	162	3,314	48.1
2011	3,217	0	0	3,217	0	167	3,384	48.1

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)
Month	Actual		2002 Forecast		2003 Forecast	
	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	655	250	639	266	658	273
February	508	182	586	194	603	199
March	431	196	508	209	523	214
April	472	203	457	216	468	222
May	494	232	507	247	519	253
June	542	247	547	263	561	270
July	539	254	555	271	569	277
August	546	271	560	289	574	296
September	519	223	545	238	559	244
October	471	191	497	204	508	209
November	360	165	478	176	491	180
December	465	178	580	189	596	194

[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)
				Calendar Year										
	Fuel Requirements	Type	Units	2001 - Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal[1]		1000 Ton	623	527	501	399	503	525	534	547	559	570	580
(3)	Residual	Steam	1000 BBL	332	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL											
(5)		CT	1000 BBL											
(6)		Total	1000 BBL	332	0	0	0	0	0	0	0	0	0	0
(7)	Distillate	Steam	1000 BBL											
(8)		CC	1000 BBL											
(9)		CT	1000 BBL	11										
(10)		Total	1000 BBL	11	0	0	0	0	0	0	0	0	0	0
(11)	Natural Gas	Steam	1000 MCF	1,962	1,478	905	908	637	713	752	815	907	1,109	1,227
(12)		CC	1000 MCF	2,233	9,944	13,164	15,074	14,119	14,285	14,501	14,671	14,838	14,956	15,138
(13)		CT	1000 MCF	4,007	2,216	21	48	22	30	44	50	55	74	83
(14)		Total	1000 MCF	8,202	13,638	14,090	16,030	14,778	15,028	15,297	15,536	15,800	16,139	16,448
(15)	Other		Trillion Btu											

[1] Includes Petroleum Coke and Refuse Derived Fuel.

Table 9-10
Schedule 6.1: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Calendar Year										
	Energy Sources	Type	Units	2001 - Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Inter-Regional Interchange		GWh											
(2)	Nuclear		GWh											
(3)	Coal[1]		GWh	1,582	1,319	1,246	995	1,254	1,315	1,341	1,376	1,410	1,441	1,470
(4)	Residual	Steam	GWh	186	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh											
(6)		CT	GWh											
(7)		Total	GWh	186	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Steam	GWh											
(9)		CC	GWh											
(10)		CT	GWh	6	1	0	0	0	0	0	0	0	0	0
(11)		Total	GWh	6	1	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Steam	GWh	483	142	87	85	89	66	70	77	86	106	119
(13)		CC	GWh	409	1,523	1,964	2,274	2,114	2,109	2,141	2,163	2,185	2,196	2,219
(14)		CT	GWh	197	249	2	4	2	3	4	4	5	7	8
(15)		Total	GWh	1,089	1,914	2,053	2,363	2,175	2,178	2,215	2,244	2,276	2,309	2,346
(16)	NUG													
(17)	Hydro													
(18)	Other (Specify) Firm Sale to FMPA as Net Interchange			-169	-472	-468	-459	-462	-457	-451	-445	-442	-436	-432
(19)	Net Energy for Load		GWh	2,694	2,762	2,831	2,899	2,967	3,036	3,105	3,175	3,244	3,314	3,384

[1] Includes Petroleum Coke and Refuse Derived Fuel.

Table 9-11
Schedule 6.2: Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Calendar Year										
	Energy Source	Type	Units	2001 - Actual	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Inter-Regional Interchange		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(2)	Nuclear		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(3)	Coal[1]	Total	%	58 72%	47 76%	44 01%	34.32%	42.26%	43.31%	43.19%	43.24%	43.46%	43 48%	43.44%
(4)	Residual	Steam	%	6 90%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(5)		CC	%	0%										
(6)		CT	%	0%										
(7)		Total	%	6 90%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(8)	Distillate	Steam	%	0%										
(9)		CC	%	0%										
(10)		CT	%	0 22%	0 04%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		Total	%	0 22%	0.04%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(12)	Natural Gas	Steam	%	17.93%	5.14%	3.07%	2.93%	1.99%	2.17%	2.25%	2 42%	2 65%	3 20%	3 52%
(13)		CC	%	15.18%	55.14%	69 37%	78 44%	71 25%	69 47%	68.95%	67.98%	67.36%	66.26%	65 57%
(14)		CT	%	7 31%	9 02%	0.07%	0 14%	0.07%	0.10%	0 13%	0 13%	0 15%	0 21%	0.24%
(15)		Total	%	40.42%	69 30%	72.52%	81.51%	73 31%	71.74%	71.34%	70.52%	70.16%	69.67%	69 33%
(16)	NUG Hydro Other (Specify)		%	-6 27%	-17 09%	-16 53%	-15.83%	-15 57%	-15 05%	-14 52%	-13.76%	-13.63%	-13.16%	-12.77%
(18)	Net Energy for Load		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

[1] Includes Petroleum Coke and Refuse Derived Fuel.

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	Projected Firm Net To Grid from NUG	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance[1]		Scheduled Maintenance	Reserve Margin After Maintenance[1]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2002	981	0	100	0	881	560	209	57.3	0	209	57.3
2003	981	0	100	0	881	574	192	53.5	0	192	53.5
2004	981	0	100	0	881	587	177	50.1	0	177	50.1
2005	981	0	100	0	881	600	161	46.8	0	161	46.8
2006	981	0	100	0	881	614	144	43.5	0	144	43.5
2007	981	0	100	0	881	627	129	40.5	0	129	40.5
2008	981	0	100	0	881	641	112	37.4	0	112	37.4
2009	981	0	100	0	881	655	95	34.5	0	95	34.5
2010	981	0	100	0	881	668	79	31.9	0	79	31.9
2011	981	0	0	0	981	682	163	43.8	0	163	43.8

[1] Included exercising Load Management and Interruptible Load.

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	Projected Firm Net To Grid from NUG	Total Capacity Available	System Firm Peak Demand	Reserve Margin Before Maintenance[1]		Scheduled Maintenance	Reserve Margin After Maintenance[1]	
	MW	MW	MW	MW	MW	MW	MW	%	MW	MW	%
2002/03	1061	0	100	0	961	658	158	46.0	0	158	46.0
2003/04	1061	0	100	0	961	676	136	42.2	0	136	42.2
2004/05	1061	0	100	0	961	695	113	38.3	0	113	38.3
2005/06	1061	0	100	0	961	712	92	35.0	0	92	35.0
2006/07	1061	0	100	0	961	731	69	31.5	0	69	31.5
2007/08	1061	0	100	0	961	749	47	28.3	0	47	28.3
2008/09	1061	0	100	0	961	768	24	25.1	0	24	25.1
2009/10	1061	0	100	0	961	786	2	22.3	0	2	22.3
2010/11	1061	0	0	0	1061	803	81	32.1	0	81	32.1
2011/12	1061	0	0	0	1061	822	58	29.1	0	58	29.1

[1] Included exercising Load Management and Interruptible Load.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Plant Name	Unit No.	Location	Unit Type	Fuel		Fuel Transport		Const Start	Commercial In-Service	Expected Retirement	Gen Max Nameplate	Net Capability		Status
				Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	kW	Sum MW	Win MW	
Charles Larsen Memorial	6	Polk County	ST	NG	RFO	PL	TK			Extended Cold Standby 8/01	25,000	0	0	SB
Winston Peaking Station	D1-20	Polk County	IC	NG	DFO	PL	TK	7/01	04/02	Unknown	2,500 each	50	50	TS
C.D. McIntosh Jr.	5 ST	Polk County	ST	WH				07/00	04/02	Unknown	120,000	120	120	TS

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

(1)	Plant Name and Unit Number:	McIntosh Unit 5ST
(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:	07/01/00
(8)	Commercial In-Service date:	04/01/02
(9)	Fuel	
(10)	Primary	Waste Heat
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Not Applicable on Waste Heat Turbine
(13)	Cooling Method:	Mechanical Cooling Tower
(14)	Total Site Area:	9.5 Acres
(15)	Construction Status:	Completed
(16)	Certification Status:	Completed
(17)	Status with Federal Agencies:	Approved
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	4.38%
(20)	Forced Outage Factor (FOF):	4.50%
(21)	Equivalent Availability Factor (EAF):	91.2%
(22)	Resulting Capacity Factor (%):	91.2%
(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

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

(1)	Plant Name and Unit Number:	Winston Peaking Station Units 1-20
(2)	Capacity:	
(3)	Summer MW	50 MW (20 units X 2.5 MW each)
(4)	Winter MW	50 MW (20 units X 2.5 MW each)
(5)	Technology Type:	Internal Combustion
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	07/15/01
(8)	Commercial In-Service date:	04/01/02
(9)	Fuel	
(10)	Primary	Distillate Fuel Oil
(11)	Alternate	
(12)	Air Pollution Control Strategy:	Aqueous Ammonia
(13)	Cooling Method:	Closed Loop Water/Glycol Forced Air
(14)	Total Site Area:	6 Acres
(15)	Construction Status:	Completed
(16)	Certification Status:	Not Applicable
(17)	Status with Federal Agencies:	Approved
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	4.81%
(20)	Forced Outage Factor (FOF):	0.5%
(21)	Equivalent Availability Factor (EAF):	95.0%
(22)	Resulting Capacity Factor (%):	1.0%
(23)	Average Net Operating Heat Rate (ANOHR):	10,000 Btu/kWh
(24)	Projected Unit Financial Data:	
(25)	Book Life:	30
(26)	Total Installed Cost (In-Service year $/kW):	$420.00
(27)	Direct Construction Cost ($/kW):	$420.00
(28)	AFUDC Amount ($/kW):	0
(29)	Escalation ($/kW):	0
(30)	Fixed O&M ($/kW-yr):	$60.00
(31)	Variable O&M ($/MWh):	$5.00

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

(1)	Plant Name and Unit Number:	None in Current Planning Cycle
(2)	Capacity:	
(3)	Summer MW	
(4)	Winter MW	
(5)	Technology Type:	
(6)	Anticipated Construction Timing:	
(7)	Field Construction Start-date:	
(8)	Commercial In-Service date:	
(9)	Fuel	
(10)	Primary	
(11)	Alternate	
(12)	Air Pollution Control Strategy:	
(13)	Cooling Method:	
(14)	Total Site Area:	
(15)	Construction Status:	
(16)	Certification Status:	
(17)	Status with Federal Agencies:	
(18)	Projected Unit Performance Data:	
(19)	Planned Outage Factor (POF):	
(20)	Forced Outage Factor (FOF):	
(21)	Equivalent Availability Factor (EAF):	
(22)	Resulting Capacity Factor (%):	
(23)	Average Net Operating Heat Rate (ANOHR):	
(24)	Projected Unit Financial Data:	
(25)	Book Life:	
(26)	Total Installed Cost (In-Service year $/kW):	
(27)	Direct Construction Cost ($/kW):	
(28)	AFUDC Amount ($/kW):	
(29)	Escalation ($/kW):	
(30)	Fixed O&M ($/kW-yr):	
(31)	Variable O&M ($/MWh):	

Table 9-17 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.