LAKELAND ELECTRIC

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Bureau of Records & Hearing Services
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Tallahassee, Florida 32399-0850

April 1, 2004

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 printed copies of its 2004 Ten Year Site Plan. Also included on the enclosed CD is one electronic copy of the document in Adobe .PDF format. If you have any questions please do not hesitate to contact us.

Sincerely,

Paul H. Elwing
Legislative & Regulatory Affairs

xc: J. Flanigan
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LAKELAND ELECTRIC

2004 Ten-Year Site Plan For Electrical Generating Facilities And Associated Transmission Lines

April 2004

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1.0 Introduction

This report contains the 2004 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, 2003. The TYSP is divided into the following nine sections: Introduction, General Description of Utility, Forecast of Electrical Power Demand and Energy Consumption, Demand-Side Management Programs, Forecasting Methods and Procedures, Forecast of Facilities Requirements, Generation Expansion Analysis Results and Conclusions, Environmental and Land Use Information, and Ten-Year Site Plan Schedules. The contents of each section are 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 1045 MW of net winter generating capacity and 963 MW of net summer generating capacity (in the year 2003).

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 1.96% and 2.12% percent, respectively, for 2004 through 2013.

Net energy for load is projected to grow at an average annual rate of 2.34% percent for 2004 through 2013, a higher 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. 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 Generation Expansion 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 was designed to use low sulfur oil as an alternate fuel but an alternate fuel has never been used in the unit. The unit uses a minimal amount of natural gas or #2 diesel oil for flame stabilization during startups. Petroleum Coke has been used in recent years as a supplemental fuel to coal based on economics. The plant utilizes 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). Changes to the FEECA rules in 1993 exempted Lakeland from conservation requirements, but Lakeland has remained active in promoting and implementing cost-effective conservation programs. 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. Beginning in September 2001, the unit underwent conversion to a combined cycle unit through the addition of a nominal 120 MW steam turbine generator. Construction was completed in Spring 2002 with the unit being declared commercial in May 2002. The resulting combined cycle capacity of the unit is 322 MW summer and 365 MW winter.

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, consists of 20 quick start reciprocating engines each driving a 2.5 MW electric generator. This provides Lakeland with 50 MW of peaking capacity that can be started and put on line at full load in ten minutes. The Station was declared commercial in late December 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 south-west 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.

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 117 miles of 69 kV transmission and 28 miles of 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 201 MW (171 MW). Units 2 and 3, General Electric combustion turbines, have a combined net winter (summer) rating of 27 MW (19 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 794 MW and 742 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 106 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. Two small diesel units with a net output of 2.5 MW each are also located at the McIntosh site.

McIntosh Unit No. 5, a Westinghouse 501G combined cycle unit, was initially built and operated as a simple cycle combustion turbine that was placed into commercial operation May, 2001. The unit was taken off line for conversion to combined cycle starting in mid September 2001 and was returned to commercial service in May 2002 as a combined cycle unit with a rating of 371 MW winter and 322 MW summer. The unit is equipped with a Selective Catalytic Reduction (SCR) module for NO_x control.

Lakeland Electric, constructed a 50-megawatt electric peaking station adjacent to its Winston Substation in 2001. The purpose of the peaking plant was to provide additional quick start generation for Lakeland's system during times of peak loads. This is Lakeland's first experience with distributed generation.

The station consists of twenty (20) EMD 20 cylinder reciprocating engines driving 2.5 MW generators. The units are currently fueled by #2 fuel oil but have the capability to burn a mix of 5% #2 oil and 95% natural gas. Lakeland currently does not have natural gas service to the site.

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 lose 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.

2.2.2 Capacity and Power Sales Contracts

Lakeland has one firm power sales contract in place as of December 31, 2003. 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 due to the current economic conditions of the electric utility industry and the uncertainty that those conditions present. When that is combined with an ample reserve margin, Lakeland deems that its most prudent decision for the moment is to continue to put all expansion and retirement plans into abeyance until market conditions encourage a change. Lakeland is currently engaging an Integrated Resource Planning Process that will be looking at optimal solutions for supply and demand side needs and resources. 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 2002/03 was 694 MW which occurred on January 24th. That peak could have been reduced to a net demand of 642 MW had residential load management been implemented. Lakeland has not utilized its load management for several years and is currently not longer adding new customers to the load management program as ample capacity is available to serve the total load and the cost-effectiveness of the program is in question. The actual summer peak in 2003 was 579 MW and occurred on July 8th. 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) and the Florida Municipal Power Agency's (FMPA) All-Requirements Project. The FMPP operates as an hourly energy pool with all FMPP capacity from its 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 of which approximately 199 square miles is outside of Lakeland's city limits.

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

Plant Name	Unit	Particulate	Flue Gas Cleaning		Type
			SO_x	NO_x	
Charles Larsen Memorial	6	None	None	None	OTF
	7	None	None	None	OTF
	8ST	N/A	N/A	N/A	
C. D. McIntosh, Jr.	1	None	None	None	OTF
	2	None	LS	FGR	WCTM
	3	EP	S	LNB	WCTM
	5ST	N/A	N/A	N/A	

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 2-2a
Lakeland Electric 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	---	11/62	Unknown	11,500	10	14
	3		GT	NG	DFO	PL	TK	---	12/62	Unknown	11,500	9	13
	6		ST	NG	RFO	PL	TK	---	12/59	Extended Cold Standby 8/01	25,000	0	0
	7		ST	NG	RFO	PL	TK	---	02/66	Unknown	50,000	50	50
	8		CA	WH	---	---	---	---	04/56	Unknown	25,000	29	31
	8		CT	NG	DFO	PL	TK	---	07/92	Unknown	101,520	73	93
Plant Total												171	201

[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**		[4]**Fuel Type**		[5]**Fuel Transportation Method**	
CA	Combined Cycle Steam Part	DFO	Distillate Fuel Oil	PL	Pipeline
CT	Combined Cycle Combustion Turbine	RFO	Residual Fuel Oil	TK	Truck
GT	Combustion Gas Turbine	BIT	Bituminous Coal	RR	Railroad
ST	Steam Turbine	WH	Waste Heat		
		NG	Natural Gas		

Table 2-2b
Lakeland Electric 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
Winston Peaking Station	1-20	21/28S/23E	IC	NG	DFO	PL	TK	NR	12/01	Unknown	2,500 each	50	50
Plant Total												50	50
C.D. McIntosh, Jr.	D1	4-5/28S/24E	IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	2.5	2.5
	D2		IC	DFO	---	TK	---	NR	01/70	Unknown	2,500	2.5	2.5
	GT1		GT	NG	DFO	PL	TK	NR	05/73	Unknown	26,640	17	20
	1		ST	NG	RFO	PL	TK	NR	02/71	Unknown	103,000	87	87
	2		ST	NG	RFO	PL	TK	NR	06/76	Unknown	126,000	106	106
	3[1]		ST	BIT	---	RR	---	NR	09/82	Unknown	363,870	205	205
	5		CT	NG	DFO	PL	TK	NR	05/01	Unknown	292,950	210	250
	5		CA	WH	---	---	---	NR	05/02	Unknown	135,000	112	121
Plant Total												742	794
System Total												**963**	**1045**

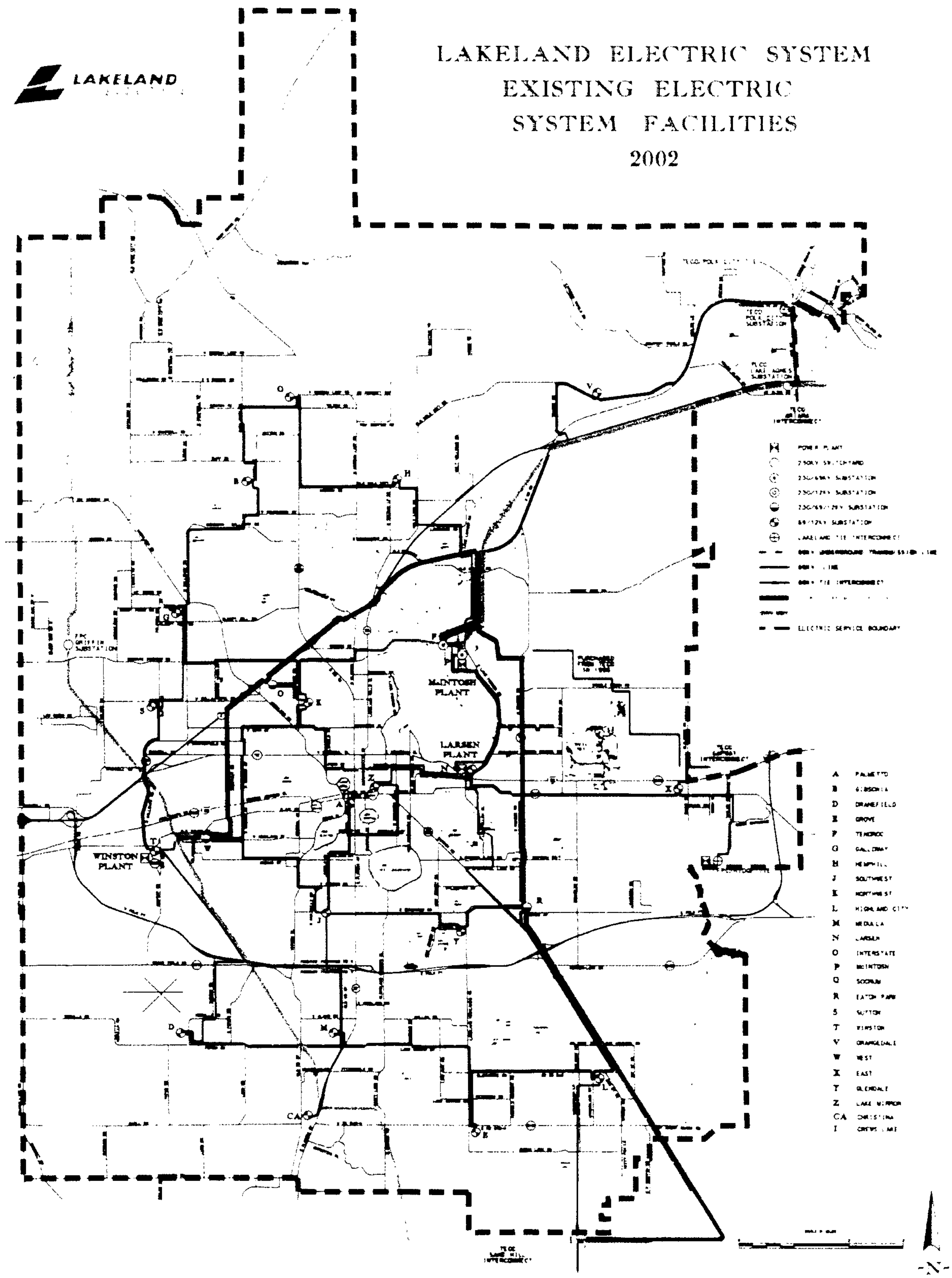
[1]Lakeland's 60 percent portion of joint ownership with Orlando Utilities Commission.
[2]Lakeland does not maintain records of the number of days that alternate fuel is used.

[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
LAKELAND ELECTRIC SYSTEM
EXISTING ELECTRIC
SYSTEM FACILITIES
2002
McINTOSH PLANT
LARSEN PLANT
WINSTON PLANT
-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 planning studies. This is undertaken on a fiscal year basis with each year ending September 30th. Techniques employed include econometric and multiple regression modeling, study of historical relationships and growth rates, trend analysis, and exponential smoothing. Lakeland also reviews the forecasts for reasonableness, compares projections to historical patterns, and modifies the results as needed using informed judgment.

Lakeland also develops monthly, short-term forecasts for budgeting and planning purposes using historical monthly ratios.

The long-term forecast categories below are discussed at length in the remaining portion of this section:

- Service Territory Population
- Number of Accounts
- Energy Sales
- Net Energy for Load
- Summer Peak Demand
- Winter Peak Demand

3.1 Service Territory Population Forecast

Projections of electric service territory population were developed using a combination of forecasting techniques. They include two regression models, exponential smoothing (1971-2003) and historical trending (1971-2003, 1992-2003). Polk County population was the primary driver in both regression models.

Polk County population projections used in the forecast models were derived from two data sources: University of Florida's Bureau of Economic and Business Research (BEBR), and Economy.com.

Electric service territory population for the City of Lakeland is projected to increase at a 1.59% average annual growth rate (AAGR) from fiscal years 2004 through 2013. This represents a slight increase over last year's projected 1.37% AAGR (presented in Table 9-2).

3.2 Number of Accounts Forecast

Lakeland forecasts the number of accounts for the following categories and subcategories (presented in Tables 9-2 and 9-3):

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

Projections for inside and outside the city have been developed for residential, commercial, industrial and private area lighting accounts. Significant shifts among these are due to the large number of annexations that have taken place since fiscal year 2001. Forecasts for inside and outside the city have been adjusted to reflect these in addition to those projected to occur between now and fiscal year 2007.

3.2.1 Residential Accounts

Total residential account projections, as well as those for inside the city, were based on a combination of methods that include the study of historical growth rates (1991-2003, 1991-2000), historical trending (1991-2003, 1992-2003) and exponential smoothing (1970-2003, 1992-2003). The examination of historical relationships to Polk County population and to total residential accounts was also factored into the final residential account forecast.

Residential account projections for outside city limits were determined by taking the difference between total residential accounts and those inside the city.

Projected AAGR for total residential accounts is 1.45% for fiscal years 2004 through 2013 (presented in Table 9-2).

3.2.2 Commercial and Industrial Accounts

Total General Service (GS) accounts were projected using a combination of forecasting techniques. They include historical ratios to total commercial accounts, to total residential accounts, and to Polk County population. Other methods used were trend analysis (1996-2003) and exponential smoothing (1984-2003). General Service (GS) account projections for inside the city limits were determined by examining their historical relationship to total GS accounts. GS account projections for outside the city limits were based on the difference between accounts inside the city limits and the total number of GS accounts.

Total General Service Demand (GSD) accounts were projected based on a weighted average of their historical relationship to total commercial accounts, to total residential accounts, and to Polk County population. Exponential smoothing (1984-2003) was also used to develop the final forecast. GSD account projections for inside the city limits were developed by examining their historical relationship to total GSD accounts. GSD account projections for outside the city limits were based on the difference between total GSD accounts and inside GSD accounts.

The Commercial category found on the TYSP forms for this filing represents the combination of GS and GSD classes. Commercial accounts are projected to increase by an AAGR of 1.41% for the 10-year reporting period (presented in Table 9-2).

Industrial accounts represent the combination of General Service Large Demand (GSLD), Contract, and Interruptible accounts. Projections for accounts inside and outside the city were developed using several forecasting techniques. They include examining historical ratios to Polk County population, to total residential accounts, as well as, to the combined total of Commercial and Industrial categories (GS, GSD, GSLD, and CONT & INT). Historical growth rates (1988-1995), prior to establishment of Contract and Interruptible rate classes, were also examined in conjunction with these methods to determine the final forecast. Special consideration was also given to new major commercial and industrial development projects.

Industrial accounts are expected to increase at approximately 1.50% AAGR over the 10-year reporting period (presented in Table 9-2).

3.2.3 Total Accounts

The Total Account Forecast for the City of Lakeland is the sum of individual forecasts provided above. Total accounts are expected to increase at 1.48% AAGR over the 10-year reporting period.

3.3 Energy Sales Forecast

Lakeland forecasts energy sales for the following categories and subcategories (presented in Tables 9-2 and 9-3):

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

Projections are developed for inside and outside of the city for residential, commercial, industrial, and private area lighting energy sales. Significant shifts among these are due to the large number of annexations that have taken place since fiscal year 2001. Forecasts for inside and outside the city have been adjusted to reflect these in addition to those projected to occur between now and fiscal year 2007.

3.3.1 Residential Sales Forecast

The residential energy sales forecast for inside the city limits was developed using a combination of forecasting methods. They include historical ratios to total residential energy sales, historical growth rates (1990-2003), historical trending (1996-2003, 1989-2003, 1982-2003) and exponential smoothing (1980-2003).

The total residential energy sales forecast was based on a weighted average of trend analysis (1982-2003, 1997-2003) and exponential smoothing (1973-2003, 1980-2003, 1982-2003).

The forecast for residential energy sales outside the city was determined by taking the difference between total residential energy sales and residential energy sales inside the city.

The Total Residential Energy Sales Forecast is projected to increase at 2.20% AAGR over the 10-year reporting period (presented in Table 9-2).

3.3.2 Commercial and Industrial Sales

General Service (GS) energy sales inside the city were projected using a combination of forecasting methods. They include exponential smoothing (1984-2003, 1992-2003), as well as, historical ratios to total residential energy sales and to total GS energy sales. Total GS energy sales were projected by examining the historical ratios to total residential energy sales and to total commercial energy sales. Trend analysis (1992-2003, 1987-2003) and exponential smoothing (1992-2003, 1984-2003) were also used to develop the final forecast. Projected GS energy sales for outside the city was developed by taking the difference between total GS energy sales and GS energy sales for inside the city.

Total GS energy sales are expected to increase at 2.41% AAGR over the 10-year reporting period.

General Service Demand (GSD) energy sales for inside the city were developed using a combination of forecasting methods. They include historical growth rates (1996-2001, 1990-2003) and historical ratios to residential energy sales and to Polk County population. Other methods include historical trending (1987-2003) and exponential smoothing (1984-2003). Total GSD energy sales were developed using a weighted average of historical growth rates (1995-2003), historical relationships to Polk County population and to total commercial energy sales, trend analysis (1987-2003, 1995-2003) and exponential smoothing (1973-2003, 1983-2003, 1990-2003). Projections for GSD energy sales outside the city limits were developed by taking the difference between total GSD energy sales and GSD energy sales inside the city.

The Commercial category represents the combination of GS and GSD classes. Ratio of GS and GSD energy sales to this total commercial value were used as a final check in developing the forecast. Commercial energy sales are expected to increase at 2.07% AAGR over the 10-year reporting period (presented in Table 9-2).

GSLD energy sales for inside the city were developed using a weighted average of historical growth rates (1984-2001) before annexations, as well as, historical ratios to residential energy sales, total GSLD energy sales, and to total commercial and industrial energy sales. Total GSLD energy sales were projected based on a weighted average of several forecasting methods. They include historical ratios to total commercial and industrial energy sales, trend analysis (1984-2003) and exponential smoothing (1995-2003, 1984-2003). Special consideration was also given to major commercial and industrial development projects. Each large account was interviewed to determine future expected demand and energy requirements. Energy sales projections for GSLD accounts outside the city limits were developed by taking the difference between the total GSLD energy sales and GSLD energy sales inside the city limits.

Total GSLD energy sales are projected to increase at a 2.62% AAGR over the 10-year reporting period.

3.3.3 Other Sales

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

Municipal energy sales were based on a combination of techniques that include the historical ratios to Polk County population, trend analysis (1985-2003, 2001-2003) and exponential smoothing (1984-2003, 1970-2003). Municipal energy sales are projected to increase at 1.93% AAGR over the 10-year reporting period.

Water energy sales were developed using a combination of methods including historical ratios to municipal energy sales, and to residential energy sales. Other methods used include historical trending (1994-2002, 1988-2003), historical usage per account and historical usage per capita estimates. Water energy sales are projected to increase at 1.17% AAGR over the 10-year reporting period.

Electric energy sales were developed using a weighted average of historical growth rates (1992-2003), historical trending (1992-2003, 1996-2003), historical ratios to municipal energy sales and exponential smoothing (1984-2003). Electric energy sales are projected to increase at a 2.58% AAGR over the 10-year forecast period.

Total private area lighting energy sales were developed using exponential smoothing (1992-2003, 1973-2003) and trend analysis (1992-2003, 1992-2001). Private area lighting energy sales for inside and outside were determined by analyzing their historical ratios to total private area lighting energy sales. Energy sales for private area lighting are expected to increase at 2.78% AAGR over the 10-year reporting period.

Unmetered energy sales represent the total municipal street and highway lighting energy sales. The forecast was developed by using trend analysis (1988-2003), historical growth rates (1988-2003), and historical ratios to municipal energy sales.

Other energy sales are expected to increase at 1.00% AAGR over the 10-year reporting period (presented in Table 9-3).

3.3.4 Total Sales

The Total Energy Sales Forecast for the City of Lakeland is the sum of the individual forecasts provided above. Total energy sales are projected to grow at 2.26% AAGR over the 10-year reporting period (presented in Table 9-3).

3.4 Net Energy for Load Forecast

Net energy for load is defined as the electricity generated by a system's own generating plants in addition to energy purchased from others less that delivered for resale.

The Net Energy for Load Forecast was developed using a combination of methods including trend analysis (1982-2003, 1974-2003, 1992-2003), exponential smoothing (1974-2003, 1980-2003) and historical ratios to energy sales. Electric losses, energy loss as a percentage of total system energy (NEL), are expected to average around 6.5% of total sales over the 10-year forecast. Net energy for load is projected to increase at 2.34% AAGR over the 10-year reporting period (presented in Table 9-4).

3.5 Peak Demand

Lakeland Electric's winter season is defined as November through March; the utility's summer season is defined as April through October. Lakeland is, and continues to be, a winter peaking utility. Lakeland's 2003 winter peak was 694 MW's (net integrated).

Lakeland owns and operates 13 weather stations. The weather stations are strategically placed throughout the service territory to provide the best estimate of overall temperature for the Lakeland service area.

The Winter Peak Demand Forecast (base-case of 30.4°) was developed using a combination of methods including two regression models and an analysis of historical load factors. Each of the regression models used different combinations of the following independent variables: dummy variable representing day of week, day of week [-1] lagged by one period, temperature at time of winter peak, annual minimum temperature, minimum temperature of week prior to winter peak and an autoregressive term. Historical trending (1977-2003, 1993-2003) and exponential smoothing (1989-2003) were also used as a check in determining the final winter peak forecast. The Total Winter Peak Demand Forecast is expected to increase at 2.11% AAGR over the 10-year reporting period (presented in Table 9-6).

The Summer Peak Demand Forecast (base-case at 95.1°) was developed using a combination of methods including trend analysis (1977-2003, 1983-2003, 1999-2003, 1993-2003), exponential smoothing (1980-2003, 1989-2003), four regression models and an analysis of historical load factors. The primary drivers in the regression models include annual maximum temperature, temperature at time of summer peak, maximum temperature prior to summer peak and Polk County population. The Summer Peak

Demand Forecast is expected to increase at 2.09% AAGR over the 10-year reporting period (presented Table in 9-5).

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

Year	HDD	CDD
1993	702	3,117
1994	429	4,060
1995	399	3,607
1996	812	3,395
1997	314	3,611
1998	618	3,450
1999	405	3,497
2000	481	3,233
2001	780	3,238
2002	425	3,743
2003	748	3,302
2004	569	3,528
2005	569	3,528
2006	569	3,528
2007	569	3,528
2008	569	3,528
2009	569	3,528
2010	569	3,528
2011	569	3,528
2012	569	3,528
2013	569	3,528

Table 3-2
Historical Monthly Peaks and Date

	2001		2002		2003	
Jan	655	Jan-05	659	Jan-09	694	Jan-24
Feb	508	Feb-06	582	Feb-28	445	Feb-02
Mar	431	Mar-08	536	Mar-05	497	Mar-20
Apr	472	Apr-13	515	Apr-30	491	Apr-7
May	494	May-30	524	May-06	539	May-12
Jun	542	Jun-13	551	Jun-03	562	Jun-11
Jul	539	Jul-30	576	Jul-17	579	Jul-8
Aug	546	Aug-29	557	Aug-06	547	Aug-18
Sep	519	Sep-04	526	Sep-03	547	Sep-24
Oct	471	Oct-24	509	Oct-11	496	Oct-13
Nov	360	Nov-01	448	Nov-12	468	Nov-05
Dec	465	Dec-27	525	Dec-16	533	Dec-21

3.6 Sensitivity Cases

A high load growth case and a low load growth case were created in addition to that of the base-case forecast for peak demand and Net Energy for Load. These two additional sensitivity cases provide a bandwidth across which Lakeland can evaluate potential power supply planning alternative scenarios. The bandwidth for the temperature ranges were developed at a 95% confidence level assuming normally distributed data. High and low Polk County population growth differences were also used in the development of the high and low cases for peak demand.

3.6.1 High Load Sensitivity

The high-case demand forecasts were based on a summer temperature at time of peak of 96.1° and a winter temperature at time of peak of 28.1°. The high load forecast for the 10-year forecasting period has a 2.35% AAGR for winter and 2.40% AAGR for summer (presented in Tables 3-3 and 3-4).

3.6.2 Low Load Sensitivity

The low-case demand forecasts were based on a summer temperature at time of peak of 94.1° and a winter temperature at time of peak of 32.7° degrees. The low load forecast has 1.93% AAGR for summer and 2.11% AAGR for winter (presented in Tables 3-3 and 3-4).

3.6.3 High and Low Net Energy for Load

Forecasts were prepared using cases for high and low net energy for load. The bandwidth for these was developed at a 95% confidence level (presented in Table 3-5).

Table 3-3
Summer Peak Demand (MW)

Year	Low	Base	High
2004	581	591	610
2005	592	604	624
2006	604	618	641
2007	616	632	657
2008	629	644	672
2009	641	658	688
2010	654	672	704
2011	666	686	721
2012	678	699	738
2013	690	714	755
AAGR 2004-2013	1.93%	2.12%	2.40%

Table 3-4
Winter Peak Demand (MW)

Year	Low	Base	High
2003/04	687	712	723
2004/05	703	719	749
2005/06	710	730	766
2006/07	726	747	782
2007/08	748	763	799
2008/09	766	780	816
2009/10	777	795	834
2010/11	792	811	853
2011/12	812	830	871
2012/13	829	848	891
AAGR 2004-2013	2.11%	1.96%	2.35%

Table 3-5
Net Energy for Load (GWH)

Year	Low	Base	High
2004	2,757	2,985	3,213
2005	2,835	3,063	3,291
2006	2,911	3,138	3,366
2007	2,986	3,214	3,442
2008	3,062	3,290	3,517
2009	3,138	3,366	3,594
2010	3,215	3,443	3,670
2011	3,292	3,520	3,748
2012	3,370	3,598	3,825
2013	3,448	3,676	3,904
AAGR 2004-2013	2.52%	2.34%	2.19%

4.0 Demand-Side Management Programs

Lakeland Electric is committed to the efficient use of electric energy and is committed to providing cost-effective conservation and demand reduction programs for all its consumers. Lakeland is not subject to FEECA rules but has in place several cost-effective Demand-Side Management (DSM) programs and remains committed to utilizing cost-effective conservation and DSM programs that will benefit its customers. Presented in this section are the currently active programs. Additional 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 and a new LED traffic light retrofit program. Lakeland has been a pioneer in the deployment and commissioning of solar energy devices and continues to support and look for opportunities to promote solar energy technologies.

4.1 Existing Conservation and Demand-Side Management Programs

Lakeland has the following 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.

4.1.1 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.

4.1.1.1 Residential Programs.

4.1.1.1.1 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.

4.1.1.1.2 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.

4.1.1.1.3 Mobile Display Unit. The mobile display unit is presented at a number of area activities each year, including 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.

4.1.1.1.4 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.

4.1.1.1.5 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.

4.1.1.2 Commercial Programs.

4.1.1.2.1 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.

4.1.2 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.

4.1.2.1 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 over 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.

4.1.2.2 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.

4.1.2.3 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.

4.1.2.4 SMART Load Management Program. In 1981, Lakeland began a 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. The program reduced winter peak demand by 1 kW per account from each water heater control and 1.2 kW per account from control of HVAC systems.

Lakeland required all new residential homes to have control devices installed when the program was expanded in 1990. As the cost-effectiveness of the program diminished due to lower capital and production costs, Lakeland relaxed the mandatory portion of the program for new customers and reduced rebates on two separate occasions in an attempt to keep the program viable from a financial point of view. The program remained active as a voluntary program until July 2003. The program was last used to control demand at time of system peak in January of 2001. Since that time there had not been a need to reduce peak demand for capacity or reserve needs. As the program was no longer being utilized, it no longer made good economic sense to continue issuing rebates to customers. In July 2003, the City Commission voted to discontinue issuing rebates and as a result the program is currently on hold and not being operated. The control devices remain at participating customer locations allowing for their potential use in the future. The program is being studied this year to determine if it can restructured in a fashion that can provide benefit and financial viability for Lakeland and its customers.

4.2 Solar Program Activities

Lakeland Electric views solar energy devices as distributed generators whether they interconnect to the utility grid or not. Solar also contributes to reducing both peak demand and energy. 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 $40,000.

Lakeland currently has 20 solar powered streetlights that are in service. Each of these lights replaces 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).

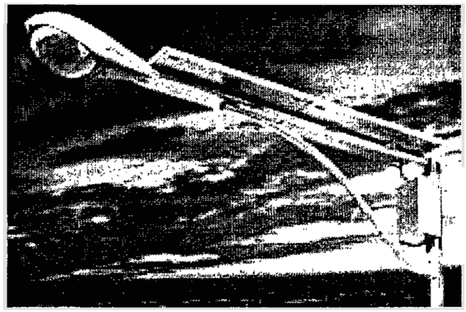


Figure 4-1
Solar Powered Streetlight

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 59 solar water heaters. Lakeland recently chose a second type of solar water heater with a simpler connection and metering setup. Two of these new units are currently installed and data is being gathered to compare their efficiency to the 57 installed in prior years. All 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-quality 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 59 solar thermal energy generators displaces over 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, Lakeland Electric, 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 3 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 2900 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 has been continuously collected via telephone modem line for the least 5 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 Lakeland Electric, 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 1.8kWp photovoltaic systems on 17 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 produce 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.

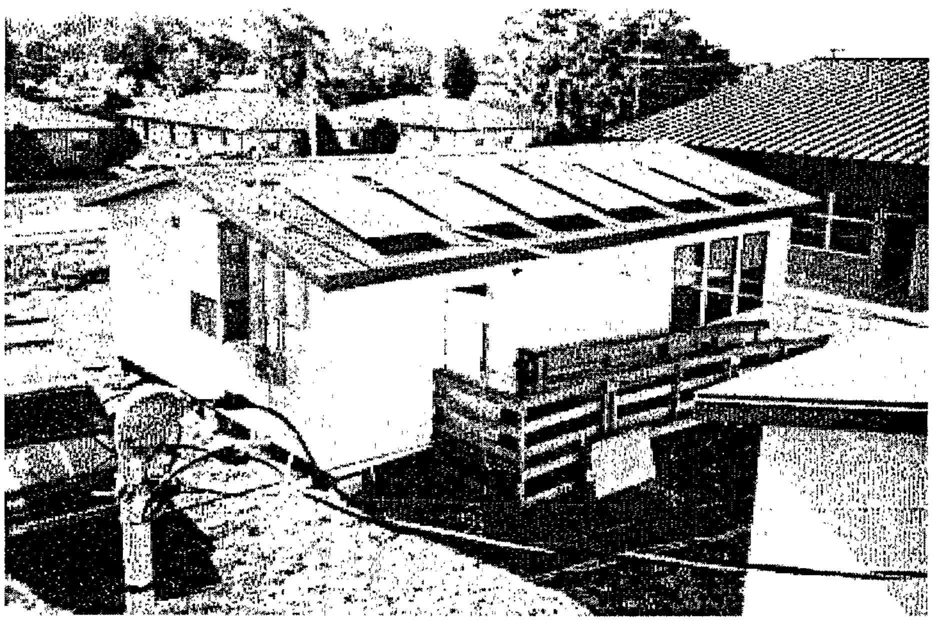


Figure 4-2
Portable Classroom Topped by PV Panels

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.

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.

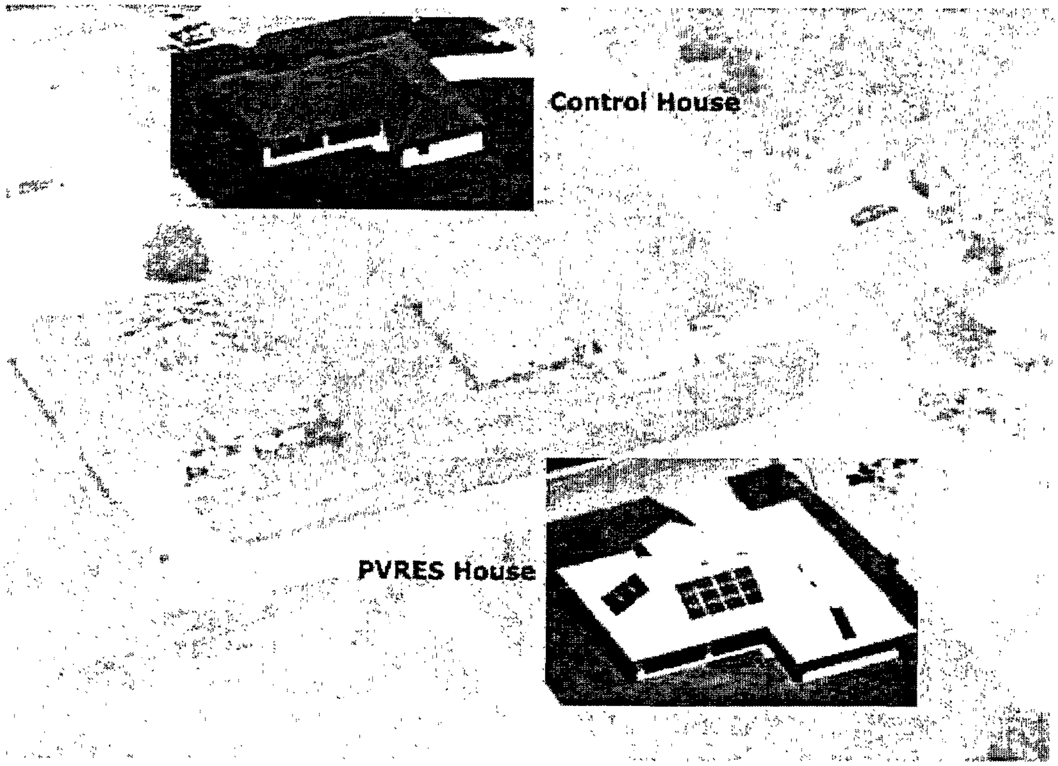


Figure 4-3
Solar House and Control House

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 investigating the marketability and public acceptance of a Green Pricing Program in its service territory.

4.4 LED Traffic Light Retrofit Program

The City of Lakeland is responsible for the operation and maintenance of 3,411 traffic lights at over 171 intersections. Historically, these traffic signals have used incandescent bulbs which are replaced every 18 months and use approximately 135 watts of electricity per bulb. This amounts to an annual electrical consumption of 1,633,525 kwh for all 12" red and green signals, arrow signals and pedestrian crossing signals.

This project will retrofit the existing bulbs with highly efficient Light Emitting Diodes (LEDs). The LEDs will use approximately 10 watts of energy which is more than a 90% decrease in energy consumption as compared to their incandescent counterparts and have a longer life span, up to seven years, which reduces maintenance costs as well.

The Florida Department of Transportation (FDOT) has agreed to help fund Lakeland's project to retrofit the signals. The FDOT will contribute $50,000 for new LED traffic signal equipment at 14 key intersections on state roadways within Lakeland's city limits. The FDOT views this as a "good neighbor policy" since FDOT depends on city crews to maintain the signals on its roads and highways within the city's limits.

The project began in December, 2002 and was completed in June 2003. The project is expected to save the City of Lakeland $150,000 per year in maintenance and electricity costs.

Later this year, Lakeland Electric plans to add backup power supply equipment at 14 intersections earmarked for FDOT-funded LED signals. The UPS systems will improve safety by keeping traffic signals operating during power outages and accidents. Lakeland will be one of the first cities in Florida to have the UPS systems applied to the LED signals.

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. Lakeland's planning process considers conservation, demand-side management measures, and supply-side resources along with the needs of the T&D system. The integrated resource planning process employed by Lakeland continuously monitors supply and demand-side alternatives. 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) and the All-Requirements Project of the Florida Municipal Power Agency (FMPA). The three 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 to meet its own load and reserve requirements 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 this document. 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 3.0 percent per year based on the US forecasted Producer Price Index. A 2.5 escalation rate is applied to 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 4.7 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 4.7 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 draw downs. The interest during construction rate is assumed to be 4.7 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 use 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) 2004 reports forecast of fuels is also presented for comparative purposes. The AEO 2004 report is published by the Energy Information Administration (EIA), which is an independent agency of the Department of Energy (DOE). The AEO 2004 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 2004 provides an energy price forecast through the year 2025 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 2004 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 2004 publishes real fuel price projections for the individual years of 2001, 2002, 2010, 2015, 2020 and 2025. Table 5-1 shows the real AEO 2004 forecast for the various fuel types. Table 5-2 is Lakeland's fuel price forecast in 2004 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
2004 Annual Energy Outlook Real Fuel Price Projections

AEO Forecast	2002	2010	2015	2020	2025
No. 2 Oil, $/mmbtu	5.58	4.92	5.09	5.47	5.62
Residual Oil, $/mmbtu	4.04	3.99	4.14	4.31	4.50
Coal, $/mmbtu	1.26	1.22	1.22	1.20	1.22
Natural Gas, $/mmbtu	3.77	4.04	4.78	4.85	4.92

Source: DOE Energy Information Administration Annual Energy Outlook 2004 Page 137.

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 Price $/mmbtu, No Inflation Added)

	McIntosh 3 Coal[1]	Natural Gas[2]	High Sulfur #6 Oil[1]	Low Sulfur #6 Oil[1]	#2 Diesel Oil[1]	Petroleum Coke[1]
2004	2.10	5.57	4.97	5.74	7.13	1.25
2005	2.20	5.47	5.14	5.93	7.21	1.30
2006	2.22	5.36	5.20	6.01	7.25	1.35
2007	2.25	5.42	5.26	6.08	7.27	1.37
2008	2.27	5.47	5.31	6.14	7.29	1.38
2009	2.29	5.53	5.37	6.20	7.31	1.40
2010	2.32	5.59	5.42	6.27	7.33	1.42
2011	2.34	5.65	5.48	6.33	7.35	1.43
2012	2.36	5.71	5.53	6.40	7.37	1.45
2013	2.39	5.77	5.59	6.47	7.39	1.47
2014	2.41	5.83	5.65	6.54	7.41	1.48
2015	2.44	5.89	5.71	6.61	7.43	1.50
2016	2.46	5.95	5.76	6.67	7.45	1.52
2017	2.49	6.01	5.82	6.74	7.47	1.54
2018	2.51	6.08	5.88	6.82	7.49	1.56
2019	2.54	6.14	5.94	6.89	7.51	1.57
2020	2.57	6.20	6.01	6.96	7.53	1.59
2021	2.59	6.27	6.07	7.03	7.55	1.61
2022	2.62	6.33	6.13	7.11	7.57	1.63
2023	2.65	6.40	6.19	7.18	7.59	1.65
Average Annual Growth Rate	1.23%	0.73%	1.16%	1.19%	0.33%	1.47%

[1]Prices represent delivered prices.

[2]Does not include reservation charges.

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 recent years. Liquefied Natural Gas (LNG) feasibility is currently being explored by three companies proposing pipelines from the Bahamas to Florida.

5.3.2.1.2 Natural gas transportation. There are now two transportation companies serving Peninsular Florida, Florida Gas Transmission Company (FGT) and Gulfstream. Lakeland Electric has interconnections and service agreements with both companies to provide diversification and competition in delivery.

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 2.0 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 is 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 has the capability 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 route for the Gulfstream pipeline. Phase I of the pipeline has been completed and ends in Polk County, Florida. The pipeline will be extended to FP&L's Martin Plant. Construction for the Gulfstream pipeline began in 2001 and was completed in 2002.

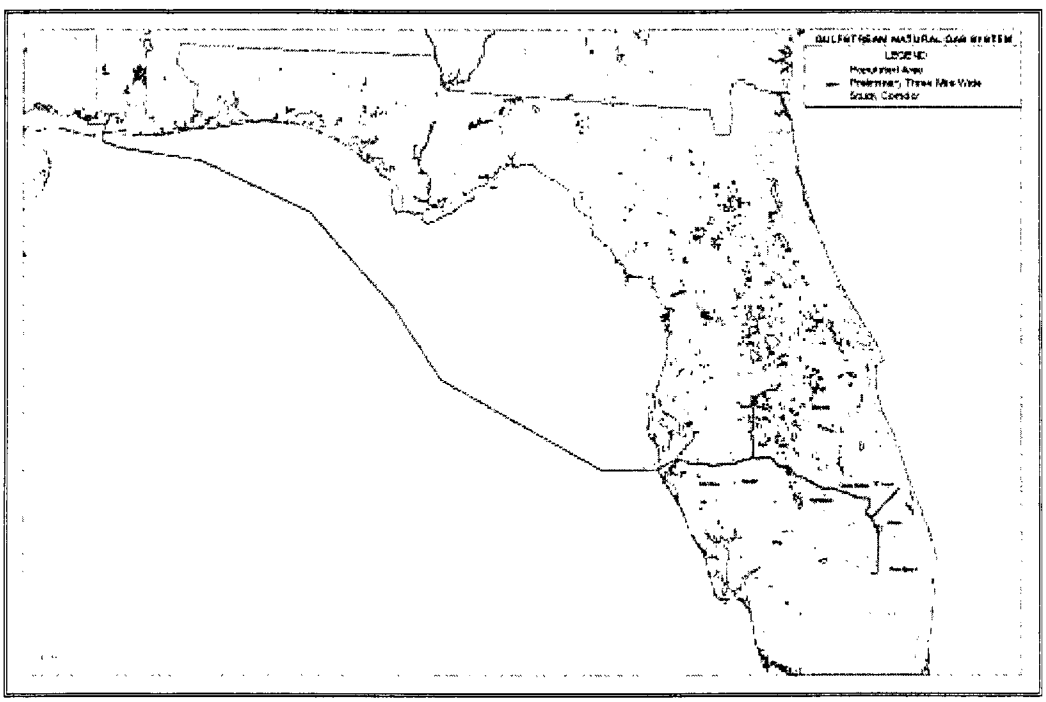


Figure 5-1
Gulfstream Natural Gas Pipeline

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 reservation is not included in the price of natural gas in Table 5-2. All other fuel types in the table are delivered prices. As previously stated, natural gas prices have been extremely volatile in recent years. To address this volatility, Lakeland Electric has initiated a formal fuels hedging program in 2003. Risk Management Inc., a Chicago company, was selected as a consultant to assist in the formation of policies and procedures as well as the implementation of the program.

Lakeland currently has a ten-year contract with El Paso for the supply of natural gas for a portion of Lakeland's base natural gas requirements. Lakeland purchases "seasonal" gas to supplement the base requirement and purchase "as needed" daily gas to round out its supply needs.

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.

Table 5-3
Natural Gas Tariff 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

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.

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 40 percent long-term and 60 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. Lakeland also imports a portion of its coal needs from South American sources.

5.3.2.2.3 Coal price forecast

Currently, Lakeland's long-term purchase of coal for McIntosh 3 is under two contracts which expire in December of 2006. Lakeland is expecting a steady increase in coal costs as new contracts are crafted for 2007 and beyond. The AEO 2004 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 has utilized 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.

McIntosh Unit 3 has burned 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. Lakeland will continue to evaluate the price and availability and will supplement this fuel as economics allow.

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. Petroleum coke for McIntosh 3 has been transported to the McIntosh site by truck.

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 reasonably consistent with the AEO 2004 forecast. Both forecasts expect residual and distillate oil prices to remain relatively flat over the forecast period.

5.3.3 Fuel Forecast Sensitivities

Lakeland did not forecast fuel price sensitivities in this years planning cycle. 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 3-3 and 3-4. 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 began using a 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 is reviewed annually and is found to be within industry standards for the types of units that Lakeland has in its fleet, indicating adequate and prudent maintenance is taking place. Lakeland's winter and summer reserve margin target was 20% when its load management was active and being used. Load Management accounted for approximately 7% of Lakeland's reserve margin meaning only 13% of the 20% target would be based on actual generating units. As Lakeland has currently stopped operating its Load Management system, Lakeland has revised its reserve margin target to be 15% based on actual generating units. As Lakeland's needs and fleet of resources continue to change through time, reserve margin levels will be 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.

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. Lakeland has been reviewing its long range generation plans by studying its existing portfolio of resources and available future options but has not come to final conclusion as of this writing. This is in part, due to the current economic conditions of the electric utility industry and the uncertainty that those conditions present. When that is combined with the ample reserve margin on hand from recent additions, Lakeland deems that its most prudent decision for the moment is to continue to put all expansion and retirement plans into abeyance until market conditions encourage a change. As noted previously in this document, 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. All capacity currently counted for in Lakeland's forecasted load and reserve obligations is capable of running for 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 during the summer peak seasons for the current ten year planning cycle. Tables 6-3 and 6-4 show the high and low winter load forecasts for Lakeland.

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 15% 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)
2003/2004	1045	0	100	945	578*	568**	63.5	66.4	280	292
2004/2005	1045	0	100	945	729	719	29.6	31.4	107	118
2005/2006	1045	0	100	945	741	730	27.5	29.5	93	106
2006/2007	1045	0	100	945	758	747	24.7	26.5	73	86
2007/2008	1045	0	100	945	774	763	22.1	23.9	55	68
2008/2009	1045	0	100	945	791	780	19.5	21.2	35	48
2009/2010	1045	0	100	945	806	795	17.2	18.9	18	31
2010/2011	1045	0	0	1045	822	811	27.1	28.9	100	112
2011/2012	1045	0	0	1045	841	830	24.3	25.9	78	91
2012/2013	1045	0	0	1045	859	848	21.7	23.2	57	70
2013/2014	1045	0	0	1045	877	866	19.2	20.7	36	49

* Actual Jan 2004 Peak, No Interruptible used at time of Peak

** Adjusted Jan 2004 Peak if Interruptible had been used at time of Peak

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

					System Peak Demand		Reserve Margin		Excess/ (Deficit) to Maintain 15% Reserve Margin	
Year	Net Generating Capacity (MW)	Net System Purchases (MW)	Net System Sales (MW)	Net System Capacity (MW)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)	Before Interruptible and Load Management (%)	After Interruptible and Load Management (%)	Before Interruptible and Load Management (MW)	After Interruptible and Load Management (MW)
2004	963	0	100	863	603	591	43.1	46.0	169	183
2005	963	0	100	863	617	604	39.9	42.9	153	168
2006	963	0	100	863	631	618	36.8	39.6	137	152
2007	963	0	100	863	645	632	33.8	36.6	121	136
2008	963	0	100	863	657	644	31.4	34.0	107	122
2009	963	0	100	863	671	658	28.6	31.2	91	106
2010	963	0	100	863	685	672	26.0	28.4	75	90
2011	963	0	0	963	699	686	23.5	25.8	59	74
2012	963	0	0	963	713	699	35.1	37.8	143	159
2013	963	0	0	963	728	714	32.3	34.9	126	142

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		Reserve Margin		Excess/ (Deficit) to Maintain 15% 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)
2003/2004	1045	0	100	945	578*	568**	63.5	66.4	280	292
2004/2005	1045	0	100	945	759	749	24.5	26.2	72	84
2005/2006	1045	0	100	945	777	766	21.6	23.4	51	64
2006/2007	1045	0	100	945	793	782	19.2	20.8	33	46
2007/2008	1045	0	100	945	810	799	16.7	18.3	14	26
2008/2009	1045	0	100	945	827	816	14.3	15.8	(6)	7
2009/2010	1045	0	100	945	845	834	11.8	13.3	(27)	(14)
2010/2011	1045	0	0	1045	864	853	20.9	22.5	51	64
2011/2012	1045	0	0	1045	882	871	18.5	20.0	31	43
2012/2013	1045	0	0	1045	902	891	15.9	17.3	8	20
2013/2014	1045	0	0	1045	923	912	13.2	14.6	(16)	(4)

* Actual Jan 2004 Peak, No Interruptible used at time of Peak

** Adjusted Jan 2004 Peak if 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 15% 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)
2003/2004	1045	0	100	945	578*	568**	63.5	66.4	280	292
2004/2005	1045	0	100	945	713	703	32.5	34.4	125	137
2005/2006	1045	0	100	945	721	710	31.1	33.1	116	129
2006/2007	1045	0	100	945	737	726	28.2	30.2	97	110
2007/2008	1045	0	100	945	759	748	24.5	26.3	72	85
2008/2009	1045	0	100	945	777	766	21.6	23.4	51	64
2009/2010	1045	0	100	945	788	777	19.9	21.6	39	51
2010/2011	1045	0	0	1045	803	792	30.1	31.9	122	134
2011/2012	1045	0	0	1045	823	812	27.0	28.7	99	111
2012/2013	1045	0	0	1045	840	829	24.4	26.1	79	92
2013/2014	1045	0	0	1045	857	846	21.9	23.5	59	72

* Actual Jan 2003 Peak, No Interruptible used at time of Peak

** Adjusted Jan 2003 Peak if 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, 2003. 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 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 Supply-Side Economic Analysis

The supply-side evaluations of generating unit alternatives are 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.

7.2 Demand-Side Economic Analysis

Lakeland continues to 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 will be re-evaluating its Load Management program to see if it can be restructured in a way to be operated in a cost-effective manner.

7.3 Sensitivity Analysis

In Lakeland's normal course of analysis a preferred option would be selected. Lakeland would then 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 would be identified. The sensitivity analyses would be performed over the same planning period used throughout the economic evaluations, with a projection of annual costs and cumulative present worth costs.

7.4 Transmission and Distribution

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

8.0 Environmental and Land Use Information

Lakeland's 2004 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. Any future additions would comply with all applicable environmental and land use 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 9-1a
Schedule 1.0: Existing Generating Facilities as of December 31, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability[1]	
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	9	13
	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												171	201

[1]Net Normal.

Source: Lakeland Power Production Unit Rating Group

Table 9-1b
Schedule 1.0: Existing Generating Facilities as of December 31, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Fuel Transport						Net Capability[1]	
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
Winston Peaking Station	1-20	21/28S/23E	IC	NG	DFO	PL	TK	3	12/01	Unknown	2,500 each	50	50
Plant Total												50	50
C.D. McIntosh, Jr.	D1	4-5/28S/24E	IC	DFO	---	TK	---		01/70	Unknown	2,500	2.5	2.5
	D2		IC	DFO	---	TK	---		01/70	Unknown	2,500	2.5	2.5
	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	106	106
	3[2]		ST	BIT	---	RR	---		09/82	Unknown	363,870	205	205
	5		CT	NG	DFO	PL	TK	3	05/01	Unknown	292,950	210	250
	5		CA	WH	---				05/02	Unknown	135,000	112	121
Plant Total												742	794
System Total												963	1045

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

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
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	1,231	84,941	14,492	607	9,835	61,718
1998	219,021	2.55	1,249	85,840	14,550	625	10,033	62,294
1999	221,123	2.54	1,239	87,222	14,205	642	10,338	62,101
2000	224,963	2.54	1,263	88,740	14,233	659	10,550	62,684
2001	224,386	2.53	1,328	88,663	14,978	665	10,529	63,159
2002	229,134	2.52	1,328	90,915	14,607	686	10,725	63,963
2003	235,030	2.52	1,418	93,126	15,227	688	11,013	62,472
Forecast								
2004	240,925	2.55	1,453	94,555	15,367	703	11,179	62,886
2005	244,961	2.55	1,488	95,984	15,503	719	11,345	63,376
2006	249,063	2.56	1,523	97,445	15,629	735	11,515	63,830
2007	253,161	2.56	1,558	98,903	15,753	751	11,683	64,281
2008	257,255	2.57	1,593	100,270	15,887	766	11,836	64,718
2009	261,349	2.57	1,627	101,728	15,994	782	12,002	65,156
2010	265,445	2.57	1,662	103,199	16,105	798	12,171	65,566
2011	269,500	2.57	1,697	104,679	16,211	814	12,341	65,959
2012	273,557	2.58	1,732	106,158	16,315	830	12,509	66,352
2013	277,620	2.58	1,767	107,659	16,413	846	12,680	66,719

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
1994	387	51	7,588,235	0	14	69	2,118
1995	429	51	8,411,765	0	15	73	2,245
1996	428	56	7,642,857	0	15	77	2,321
1997	459	62	7,403,226	0	16	78	2,391
1998	462	62	7,451,613	0	16	80	2,432
1999	485	70	6,928,571	0	17	79	2,462
2000	507	83	6,108,434	0	18	84	2,531
2001	488	80	6,100,000	0	19	82	2,582
2002	513	89	5,764,045	0	19	80	2,626
2003	521	90	5,788,889	0	19	80	2,726
Forecast							
2004	551	91	6,054,945	0	20	82	2,809
2005	567	93	6,096,774	0	21	86	2,881
2006	582	94	6,191,489	0	22	89	2,951
2007	598	95	6,294,737	0	22	90	3,019
2008	614	97	6,329,897	0	23	91	3,087
2009	630	98	6,428,571	0	24	93	3,156
2010	646	100	6,460,000	0	24	95	3,225
2011	662	101	6,554,455	0	25	97	3,295
2012	679	103	6,592,233	0	25	98	3,364
2013	696	104	6,692,308	0	26	99	3,434

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
1994	0	161	2,279	0	90,847
1995	0	145	2,390	0	92,526
1996	0	127	2,448	0	93,459
1997	0	52	2,443	0	94,838
1998	0	117	2,549	0	95,935
1999	0	123	2,585	0	97,630
2000	0	138	2,669	0	99,373
2001	0	112	2,694	0	99,272
2002	0	150	2,776	0	101,729
2003	0	181	2,907	0	104,229
Forecast					
2004	0	176	2,985	0	105,825
2005	0	182	3,063	0	107,422
2006	0	187	3,138	0	109,054
2007	0	195	3,214	0	110,681
2008	0	203	3,290	0	112,203
2009	0	210	3,366	0	113,828
2010	0	218	3,443	0	115,470
2011	0	225	3,520	0	117,121
2012	0	234	3,598	0	118,770
2013	0	242	3,676	0	120,443

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
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
2002	576	0	576	0	0	0	0	0	576
2003	579	0	579	0	0	0	0	0	579
Forecast									
2004	603	0	603	12	0	0	0	0	591
2005	617	0	617	13	0	0	0	0	604
2006	631	0	631	13	0	0	0	0	618
2007	645	0	645	13	0	0	0	0	632
2008	657	0	657	13	0	0	0	0	644
2009	671	0	671	13	0	0	0	0	658
2010	685	0	685	13	0	0	0	0	672
2011	699	0	699	13	0	0	0	0	686
2012	713	0	713	14	0	0	0	0	699
2013	728	0	728	14	0	0	0	0	714

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
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
2002/03	694	0	694	0	0	0	0	0	694
2003/04	578	0	578	0	0	0	0	0	578
Forecast									
2004/05	729	0	729	10	0	0	0	0	719
2005/06	741	0	741	11	0	0	0	0	730
2006/07	758	0	758	11	0	0	0	0	747
2007/08	774	0	774	11	0	0	0	0	763
2008/09	791	0	791	11	0	0	0	0	780
2009/10	806	0	806	11	0	0	0	0	795
2010/11	822	0	822	11	0	0	0	0	811
2011/12	841	0	841	11	0	0	0	0	830
2012/13	759	0	859	11	0	0	0	0	848
2013/14	877	0	877	11	0	0	0	0	866

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 %
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	45.8
1997	2,391	0	0	2,391	0	52	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	2,531	0	0	2,531	0	138	2,669	49.9
2001	2,582	0	0	2,582	0	112	2,694	47.0
2002	2,626	0	0	2,626	0	151	2,777	48.1
2003	2,726	0	0	2,726	0	181	2,907	47.8
Forecast								
2004	2,809	0	0	2,809	0	176	2,985	59.0
2005	2,881	0	0	2,881	0	182	3,063	48.6
2006	2,951	0	0	2,951	0	187	3,138	49.1
2007	3,019	0	0	3,019	0	195	3,214	49.1
2008	3,087	0	0	3,087	0	203	3,290	49.2
2009	3,156	0	0	3,156	0	210	3,366	49.3
2010	3,225	0	0	3,225	0	218	3,443	49.4
2011	3,295	0	0	3,295	0	225	3,520	49.5
2012	3,364	0	0	3,364	0	234	3,598	49.5
2013	3,434	0	0	3,434	0	242	3,676	49.5

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		2004 Forecast		2005 Forecast	
	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh	Peak Demand[1] MW	NEL GWh
January	694	255	578	251	719	258
February	445	186	656	215	672	220
March	497	243	576	224	590	230
April	491	216	474	218	485	223
May	539	270	528	257	540	264
June	562	253	573	277	586	285
July	579	279	583	293	596	300
August	547	271	591	299	604	306
September	547	259	576	278	589	285
October	496	254	513	233	525	239
November	468	190	525	207	534	213
December	533	231	638	233	648	240

[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	2003 - Actual	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Nuclear		Trillion Btu											
(2)	Coal[1]		1000 Ton	565	526	593	603	570	565	574	579	584	591	597
(3)	Residual	Steam	1000 BBL	316	10	16	27	16	14	12	18	22	34	39
(4)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		Total	1000 BBL	316	10	16	27	16	14	12	18	22	34	39
(7)	Distillate	Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	52	7	14	9	3	1	2	2	3	4	4
(10)		Total	1000 BBL	52	7	14	9	3	1	2	2	3	4	4
(11)	Natural Gas	Steam	1000 MCF	199	77	156	283	154	200	179	246	275	321	350
(12)		CC	1000 MCF	13,686	15,216	16,177	17,902	16,120	16,061	16,833	17,347	18,076	18,754	19,380
(13)		CT	1000 MCF	45	4	58	24	15	12	6	17	19	26	34
(14)		Total	1000 MCF	13,930	15,297	16,391	18,209	16,289	16,273	17,018	17,610	18,370	19,101	19,764
(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	2003 - Actual	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	Inter-Regional Interchange		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal[1]		GWh	1,369	1,341	1,531	1,557	1,464	1,449	1,474	1,489	1,505	1,522	1,540
(4)	Residual	Steam	GWh	206	18	16	18	9	7	7	10	12	18	21
(5)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(7)		Total	GWh	206	18	16	18	9	7	7	10	12	18	21
(8)	Distillate	Steam	GWh	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWh	12	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWh	18	2	0	0	0	0	0	0	0	0	0
(11)		Total	GWh	30	2	0	0	0	0	0	0	0	0	0
(12)	Natural Gas	Steam	GWh	72	8	20	34	20	23	20	29	33	41	46
(13)		CC	GWh	1,270	2,112	2,253	2,525	2,238	2,244	2,366	2,441	2,539	2,632	2,720
(14)		CT	GWh	2	0	12	7	3	1	2	2	3	4	5
(15)		Total	GWh	1,344	2,120	2,285	2,566	2,261	2,268	2,388	2,472	2,575	2,677	2,771
(16)	NUG			0	0	0	0	0	0	0	0	0	0	0
(17)	Hydro			0	0	0	0	0	0	0	0	0	0	0
(18)	Other (Specify)[2]			-42	-496	-769	-1,003	-520	-434	-503	-528	-572	-619	-656
(19)	Net Energy for Load		GWh	2,907	2,985	3,063	3,138	3,214	3,290	3,366	3,443	3,520	3,598	3,676

[1] Includes Petroleum Coke and Refuse Derived Fuel.
[2] Intra-Regional Net Interchange including Firm Sale to FMPA

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	2002 - Actual	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
(1)	Inter-Regional Interchange		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2)	Nuclear		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Coal[1]	Total	%	45.88	45.71	49.97	49.63	45.54	44.04	43.78	43.25	42.77	42.31	41.89
(4)	Residual	Steam	%	6.90	0.61	0.52	0.57	0.28	0.21	0.21	0.29	0.34	0.50	0.57
(5)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7)		Total	%	6.90	0.61	0.52	0.57	0.28	0.21	0.21	0.29	0.34	0.50	0.57
(8)	Distillate	Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)		CC	%	0.40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		CT	%	0.60	0.07	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(11)		Total	%	1.00	0.07	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)	Natural Gas	Steam	%	2.41	0.27	0.65	1.08	0.62	0.70	0.59	0.84	0.94	1.14	1.25
(13)		CC	%	42.56	71.98	73.53	80.49	69.61	68.21	70.27	70.90	72.15	73.17	73.99
(14)		CT	%	0.07	0.0	0.39	0.22	0.09	0.03	0.06	0.06	0.09	0.11	0.14
(15)		Total	%	45.04	72.76	74.58	81.80	70.33	68.94	70.92	71.80	73.17	74.42	75.38
(16)	NUG			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Hydro			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other (Specify)[2]		%	1.17	-18.64	-25.07	-32.01	-16.14	-13.19	-14.91	-15.34	-16.28	-17.24	-17.85
(18)	Net Energy for Load		%	100	100	100	100	100	100	100	100	100	100	100

[1] Includes Petroleum Coke and Refuse Derived Fuel.
[2] Other = Intra-Regional Net Interchange Including Firm Sale to FMPA.

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	%
2004	963	0	100	0	863	591	272	46.0	0	272	46.0
2005	963	0	100	0	863	604	259	42.9	0	259	42.9
2006	963	0	100	0	863	618	245	39.6	0	245	39.6
2007	963	0	100	0	863	632	231	36.6	0	231	36.6
2008	963	0	100	0	863	644	219	34.0	0	219	34.0
2009	963	0	100	0	863	658	205	31.2	0	205	31.2
2010	963	0	100	0	863	672	191	28.4	0	191	28.4
2011	963	0	0	0	963	686	277	40.4	0	277	40.4
2012	963	0	0	0	963	699	264	37.8	0	264	37.8
2013	963	0	0	0	963	714	249	34.9	0	249	34.9

[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	%
2004/05	1045	0	100	0	945	719	226	31.4	0	226	31.4
2005/06	1045	0	100	0	945	730	215	29.5	0	215	29.5
2006/07	1045	0	100	0	945	747	198	26.5	0	198	26.5
2007/08	1045	0	100	0	945	763	182	23.9	0	182	23.9
2008/09	1045	0	100	0	945	780	165	21.2	0	165	21.2
2009/10	1045	0	100	0	945	795	150	18.9	0	150	18.9
2010/11	1045	0	0	0	1045	811	234	28.9	0	234	28.9
2011/12	1045	0	0	0	1045	830	215	25.9	0	215	25.9
2012/13	1045	0	0	0	1045	848	197	23.2	0	197	23.2
2013/14	1045	0	0	0	1045	866	179	20.7	0	179	20.7

[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	

Table 9-15

Schedule 9.1: Status Report and Specifications of Approved Generating Facilities

(1)	Plant Name and Unit Number:	
(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 9-16
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.