GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning Department

March 31, 1999

Blanca S. Bayo, Director
Florida Public Service Commission
Division of Records & Reporting
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Ms. Bayo:

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071, Florida Administrative Code, Gainesville Regional Utilities' hereby submits 25 copies of its 1999 Ten Year Site Plan for your review. Should you have any questions regarding this Ten Year Site Plan, please contact me at (352) 334-3400 x1272 or:

Roger Westphal (Generation Planning)	352.334.3400x1289
Todd Kamhoot (Forecasting)	352.334.3400x1280

Sincerely,

Ed Regan

Ed Regan
Strategic Planning Director

Enclosures

File: PSC - Ten Year Site Plan

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P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1260 Fax: (352) 334-3151

ORIGINAL

Gainesville Regional Utilities

1999 Ten Year Site Plan

Submitted to:

The Public Service Commission

April 1, 1999

GAINESVILLE REGIONAL UTILITIES

1999 TEN-YEAR SITE PLAN

GRU

Submitted to:

The Florida Public Service Commission

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1. INTRODUCTION

The 1999 Ten-Year Site Plan for Gainesville Regional Utilities (GRU) is submitted to the Florida Public Service Commission pursuant to Section 186.801, Florida Statutes. The contents of this report conform to information requirements listed in Form PSC/EAG 43, as specified by Rule 25-22.072, Florida Administrative Code. The six sections of the 1999 Ten-Year Site Plan are:

- Introduction
- Description of Existing Facilities
- Forecast of Electric Energy and Demand
- Forecast of Facilities Requirements
- Site Description and Impact Analysis
- Environmental Considerations for Proposed Facility Siting

Gainesville Regional Utilities is a municipal electric, natural gas, water, wastewater, and telecommunications utility system. The GRU retail electric system service area includes the City of Gainesville and the surrounding urban area. The highest net integrated peak demand recorded to date on GRU's electrical system was 396 megawatts on June 18, 1998. Net summer capability is 550 megawatts. In consideration of the load forecast, reserve margin requirements, and system reliability, GRU's Electric System will require additional generating capacity before 2008. An extensive three-year integrated resource planning study has revealed that repowering J. R. Kelly Unit 8 as a nominal 110 megawatt combined-cycle unit is the best and most robust choice when subjected to an exhaustive array of scenarios. Because of the opportunity to improve operating efficiency, reduce emission rates, reduce total emissions, and better participate in the redevelopment of downtown Gainesville, while increasing the electric system's capacity at a time when the reserve margin for Peninsular Florida is getting tight, The Gainesville City Commission has approved moving the installation target date to 2001.

2. DESCRIPTION OF EXISTING FACILITIES

The City of Gainesville owns a fully integrated electric power production, transmission, and distribution system (herein referred to as "the System"). GRU is the City of Gainesville enterprise arm that has the responsibility to operate and maintain the System. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and to Clay Electric Cooperative, Inc. (Clay). GRU's distribution system serves approximately 130 square miles and 74,928 customers (December, 1998). The general locations of GRU electric facilities and the electric system service area are shown in Figure 2.1.

2.1 GENERATION

The existing generating facilities operated by GRU are tabulated in Schedule 1, found at the end of this chapter. Two types of generating units are located at the System's two generating plant sites: steam turbines and gas turbines.

The present summer net capability is 550 MW and the winter net capability is 563 MW[1]. Currently, the System's energy is produced by four fossil fuel steam turbines, six combustion turbines, and a 1.4% ownership share of the Crystal River 3 nuclear unit, which is operated by Florida Power Corporation (FPC).

2.1.1 Generating Units

2.1.1.1 Steam Turbines. The System's four operational steam turbines are powered by fossil fuels and Crystal River 3 is nuclear powered. John R. Kelly (Kelly) 6, a fossil steam turbine, was placed in cold standby in August, 1989 and is no longer considered operational for planning purposes. The fossil fueled steam turbines

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[1] Net capability is that specified by the "SERC Guideline Number Two for Uniform Generator Ratings for Reporting." The winter rating will normally exceed the summer rating because generating plant efficiencies are increased by lower ambient air temperatures and lower cooling water temperatures.

comprise 70.1% of the System's net summer capability and produced 90.1% of the electric energy supplied by the System in 1998. These units range in size from 23.2 MW to 228.4 MW. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 2.0% of the System's net summer capability.

Both Deerhaven 2 and Crystal River 3 are used for base load purposes, while Kelly 7 and 8 and Deerhaven 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 27.8% of the System's summer generating capability. These units are utilized for peaking purposes only because their energy conversion efficiencies are considerably lower than steam units. As a result, they yield higher operating costs and are consequently unsuitable for base load operation. Gas turbines are advantageous in that they can be started and placed on line in thirty minutes or less. The System's gas turbines are most economically used as peaking units during high demand periods when base and intermediate units cannot serve all of the System loads.

2.1.1.3 Environmental Considerations. All of the System's steam turbines, except for Crystal River 3, utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. Crystal River 3 uses a once-through cooling system aided by helper towers. Only Deerhaven 2 has flue gas cleaning equipment.

2.1.2 Generating Plant Sites

The locations of the two generating plants owned by the City of Gainesville are shown on Figure 2.1.

2.1.2.1 John R. Kelly Plant. The Kelly Station is located in southeast Gainesville near the downtown business district and consists of three steam turbines (including Kelly 6, which is in cold standby), three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

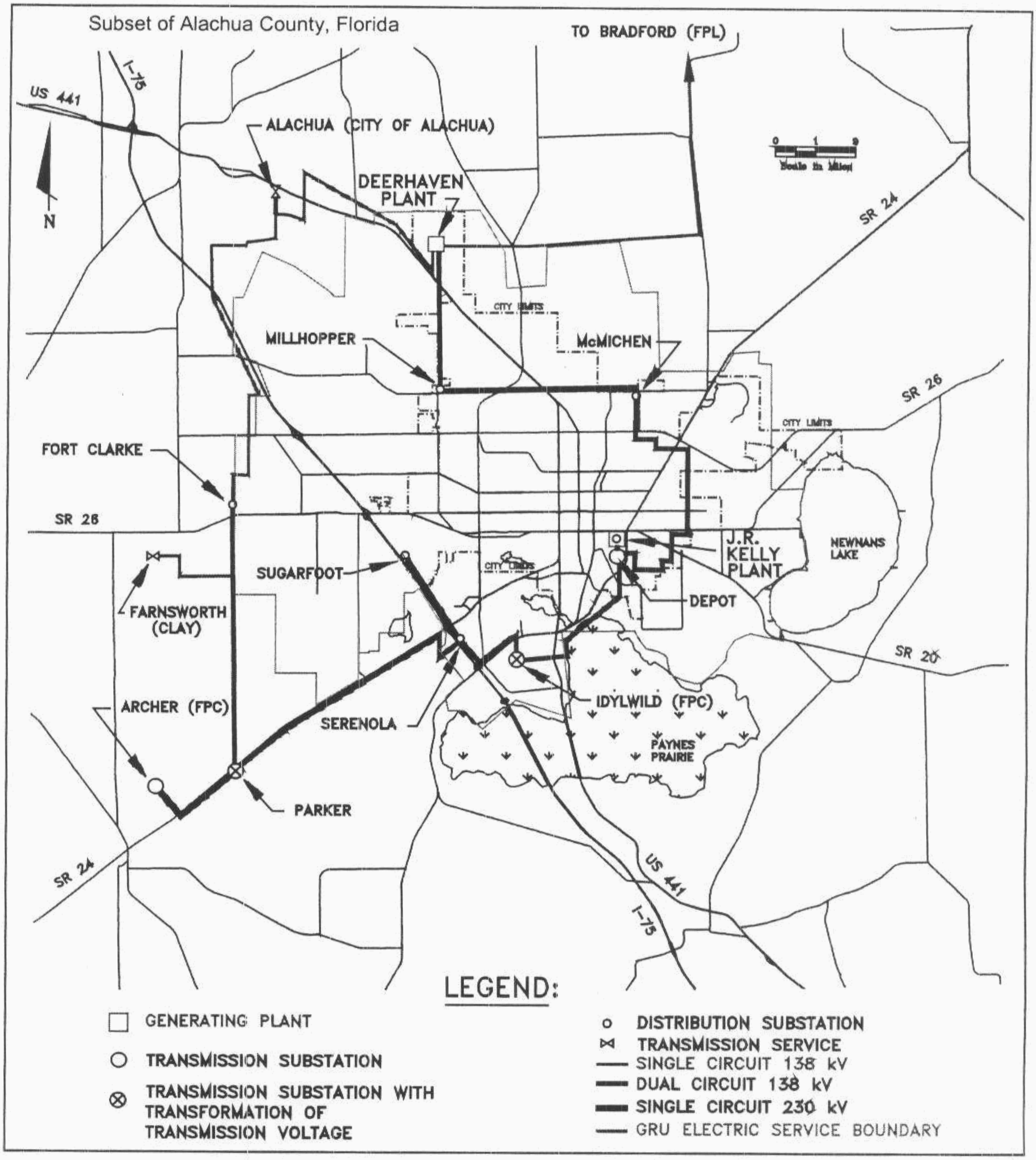

FIGURE 2.1 Gainesville Regional Electric Facilities

2.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The site is a 1,116 acre parcel of partially forested land. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. With the addition of Deerhaven 2 in 1981, the site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats water effluent from both steam units.

2.2 TRANSMISSION

2.2.1 The Transmission Network

GRU's bulk power transmission network consists of a 138 kV loop connecting the following:

1) GRU's two generating stations,
2) GRU's six distribution substations,
3) Three interties with Florida Power Corporation,
4) An intertie with Florida Power and Light Company,
5) An interconnection with Clay at Farnsworth Substation, and
6) An interconnection with the City of Alachua at Alachua No. 1 Substation

Refer to Figure 2.1 for line geographical locations and Figure 2.2 for electrical connectivity and line numbers.

2.2.2 Transmission Lines

The ratings for all of GRU's transmission lines are given in Table 2.1. The load ratings for GRU's transmission lines were developed in Appendix 6.1 of GRU's Long-Range Transmission Planning Study, March 1991. Refer to Figure 2.2 for a one-line diagram of GRU's electric system. The criteria for normal and emergency loading are taken to be:

- Normal loading: conductor temperature not to exceed 100° C (212° F).

- Emergency loading: conductor temperature not to exceed 125° C (257° F).

The present transmission network consists of the following:

Line	Circuit Miles	Conductor
138 KV double circuit	80.87	795 MCM ACSR
138 KV single circuit	16.47	1192 MCM ACSR
138 KV single circuit	20.60	795 MCM ACSR
230 KV single circuit	2.51	795 MCM ACSR
Total	120.45	

As part of the Long-Range Transmission Planning Study, March 1991, the transmission system was subjected to scenario analysis. Each scenario represents a system configuration with different contingencies modeled. A contingency is an occurrence that depends on chance or uncertain conditions and, as used here, represents various equipment failures that may occur. The following conclusions were drawn from this analysis:

Reliability contingencies:

(a) Single contingency transmission line and generator outages (the failure of any one generator or any one transmission line) -- No identifiable problems.

(b) All right-of-way outages (two lines - common pole) -- No problems if a 20 MVAR capacitor bank is installed at Sugarfoot Substation. GRU's 138 kV/24 MVAR capacitor installation at Sugarfoot Substation was completed July, 1993.

(c) Meeting future load and interchange requirements -- No identifiable problems.

2.2.3 State Interconnections

The System is currently interconnected with FPC and Florida Power and Light (FPL) at a total of four separate points. The System interconnects with FPC's Archer Substation via a 230 kV transmission line to the System's Parker Substation with 224 MVA of transformation capacity from 230 kV to 138 kV. The System also interconnects with FPC's Idylwild Substation with two separate circuits via a 168 MVA 138/69 kV transformer at the Idylwild Substation. The System interconnects with FPL via a 138 kV tie between FPL's Bradford Substation and the System's Deerhaven Substation. This interconnection has a thermal capacity of 222 MVA.

2.3 DISTRIBUTION

The System has six major distribution substations connected to the transmission network: Millhopper, McMichen, Serenola, Sugarfoot, Ft. Clarke, and Kelly Substations. The locations of these substations are shown on Figure 2.1.

GRU's current distribution substations are all connected to the 138 kV bulk power transmission network with dual feeds. This prevents the outage of a single transmission line from causing the outage of a distribution station. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities and present number of circuits are listed in Table 2.2.

The last substation added by GRU, Sugarfoot, was brought on-line in 1986 to serve the growing load in the area of State Road 26 and Interstate Highway I-75. McMichen, Serenola, Ft. Clarke, and Kelly Substations currently consist of two transformers of equal size allowing these stations to be loaded under normal conditions

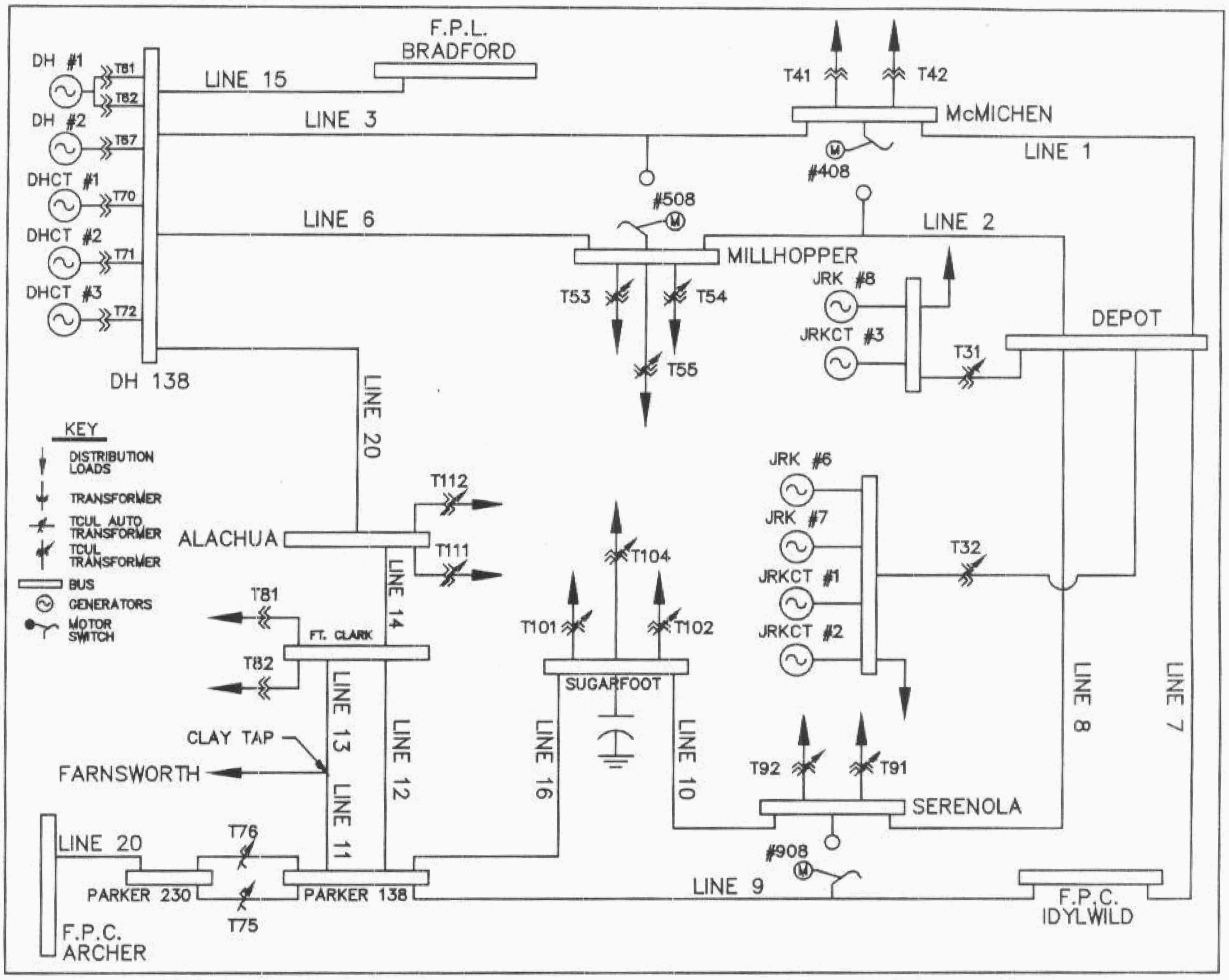

FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.

to 80 percent of the capabilities shown in Table 2.2. Millhopper and Sugarfoot Substations currently consist of three transformers of equal size allowing both of these substations to be loaded under normal conditions to 100 percent of the capability shown in Table 2.2.

2.4 WHOLESALE ENERGY

The System provides wholesale electric service to Clay Electric Cooperative (Clay) through a contract between GRU and Seminole Electric Cooperative (Seminole), of which Clay is a member. The System began the 138 kV service at Clay's Farnsworth

Substation in February 1975. This substation is supplied through a 2.4 mile radial line connected to the System's transmission facilities.

The System also provides wholesale electric service to the City of Alachua at two points of service. The Alachua No. 1 Substation is supplied with GRU's looped 138 kV transmission system. Approximately 400 residences and a few commercial customers within Alachua's city limits are served by a 12.47 kV distribution circuit, known as the Hague point of service. The System provides approximately 88% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the Crystal River 3 and St. Lucie 2 nuclear units. Energy supplied to Alachua by these nuclear units is wheeled over GRU's transmission network, with GRU providing generation backup in the event of outages of these nuclear units.

2.5 EXPORT COMMITMENTS

GRU has a Schedule D firm interchange service commitment with the City of Starke (Starke). The agreement with Starke is non-unit specific and provides for the sale of System capacity (includes reserves). This agreement was renewed January 1, 1994 and continues through 2003, with optional three year extensions available indefinitely and allows Starke the option to expand the capacity commitment.

GRU has a Schedule D firm interchange service commitment with the Florida Municipal Power Agency (FMPA). The agreement with FMPA is unit specific with Deerhaven Unit #2 (DH2) and provides capacity for 1999.

GRU has a contract with PECO Energy Company to provide peaking capacity and energy during June, July, August, and September of 1999.

GRU has a Service Schedule J - Negotiated Interchange Service with Seminole

Electric Cooperative, Inc. to provide firm electric capacity and energy from its generation and purchased power resources during January and February of 1999.

GRU has a negotiated Transaction with The Energy Authority, Inc. to provide electric capacity and associated energy to JEA from its generation and purchased power resources between May 15, 1999 and September 15, 1999.

These sale schedules are contemplated herein and are consistent with GRU's needs for generating capacity and associated reserve margins. Schedules 7.1 and 7.2 at the end of Section 4 summarize GRU's reserve margins.

TABLE 2.1

SUMMER POWER FLOW LIMITS

Line Number	Description	Normal (MVA)	Limiting Device	Emergency (MVA)	Limiting Device
1	McMichen - Depot East	245.7	Conductor	288.3	Conductor
2	Millhopper - Depot West	245.7	Conductor	288.3	Conductor
3	Deerhaven - McMichen	245.7	Conductor	288.3	Conductor
6	Deerhaven - Millhopper	245.7	Conductor	288.3	Conductor
7	Depot East - Idylwild	205.6	Line Trap	205.6	Line Trap
8	Depot West - Serenola	245.7	Conductor	288.3	Conductor
9	Idylwild - Parker	205.6	Line Trap	205.6	Line Trap
10	Serenola - Sugarfoot	245.7	Conductor	288.3	Conductor
11	Parker - Clay Tap	245.7	Conductor	288.3	Conductor
12	Parker - Ft. Clarke	245.7	Conductor	288.3	Conductor
13	Clay Tap - Ft. Clarke	245.7	Conductor	288.3	Conductor
14	Ft. Clarke - Alachua	313.0	Conductor	369.1	Conductor
15	Deerhaven - Bradford	222.0	Transformer	222.0	Transformer
16	Sugarfoot - Parker	245.7	Conductor	288.3	Conductor
20	Parker - Archer	179.2	Transformer	224.0	Transformer
22	Alachua - Deerhaven	313.0	Conductor	369.1	Conductor
xx	Clay Tap - Farnsworth	245.7	Conductor	288.3	Conductor
xx	Idylwild - FPC	168.0	Transformer	168.0	Transformer

TABLE 2.2

CURRENT SUBSTATION TRANSFORMATION AND CIRCUITS

STATION	TRANSFORMER RATED CAPABILITY	NUMBER OF CIRCUITS
Millhopper	100.8 MVA	8
McMichen	44.8 MVA	6
J. R. Kelly[2]	112.0 MVA	18
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	7
Ft. Clarke	44.8 MVA	4

[2] J. R. Kelly is a Generating Station (115 MW) as well as a distribution Substation.

Schedule 1

EXISTING GENERATING FACILITIES
(As of December 31, 1998)

(1) Plant Name	(2) Unit No.	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Expected Retirement Month/Year	(12) Gen. Max. Nameplate kW	(13) Net Capability Summer MW	(14) Net Capability Winter MW	Status	Notes
J. R. Kelly		12-001										115	118		
		(Alachua Co.,													
	8	Section 4, Township	ST	NG	FO6	PL	TK	8	4/65	Unknown	46,000	50	50		
	7	10 S, Range 20E)	ST	NG	FO6	PL	TK	0	8/61	Unknown	23,020	23	23		
	6	(GRU)	ST	NG	FO6	PL	TK	0	3/58	Unknown	0	0	0	M	(1)
	3		GT	NG	FO2	PL	TK	0	2/69	Unknown	16,320	14	15		
	2		GT	NG	FO2	PL	TK	0	2/68	Unknown	16,320	14	15		
	1		GT	NG	FO2	PL	TK	0	2/68	Unknown	16,320	14	15		
Deerhaven		12-001										424	434		
		(Alachua Co., Sections													
	2	26,27,35, Township	ST	BIT		RR			10/81	Unknown	250,750	228	228		
	1	8 S, Range 19 E)	ST	NG	FO6	PL	TK	11	8/72	Unknown	75,000	85	85		
	3	(GRU)	GT	NG	FO2	PL	TK	1	1/96	Unknown	103,500	75	81		
	2		GT	NG	FO2	PL	TK	0	8/76	Unknown	24,600	18	20		
	1		GT	NG	FO2	PL	TK	0	7/76	Unknown	24,600	18	20		
Crystal River (818/815)	3	12-017 (Citrus Co., Section 33, Township 17 S, Range 16 E) (FPC)	NP	UR		TK			3/77	Unknown		11	11		
System Total												550	563		

Unit Type
GT = Gas Turbine
NP = Nuclear Power
ST = Steam

Fuel Type
NG = Natural Gas
BIT = Bituminous Coal
UR = Uranium
FO6 = Fuel Oil #6 (Residual)
FO2 = Fuel Oil #2 (Distillate)

Transportation Method
PL = Pipe Line
RR = Railroad
TK = Truck

Status
M = Cold standby, extended cold shutdown or long-term reserve shutdown.

Notes: (1) JRK Unit 6 was placed in cold standby in August, 1989.

Sch1.xls

3. FORECAST OF ELECTRIC ENERGY AND DEMAND REQUIREMENTS

Section 3 includes documentation of GRU's forecast of number of customers, energy sales and seasonal peak demands, as well as a forecast of energy sources and fuel requirements and an overview of GRU's involvement in demand-side management programs.

The accompanying tables provide historical and forecast information for calendar years 1989-2008. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2 and 2.3. Schedules 3.1, 3.1H and 3.1L give components of summer peak demand for the base case, high band forecast and low band forecast. Schedules 3.2, 3.2H and 3.2L present the components of winter peak demand for each forecast scenario. Schedules 3.3, 3.3H and 3.3L similarly present components of net energy for load. Short-term monthly retail load data is presented in Schedule 4. Projected net energy requirements for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy shown in Schedule 6.1 are given in Schedule 6.2. The quantities of fuel expected to be used to generate the energy requirements shown in Schedule 6.1 are given by fuel type in Schedule 5.

3.1 FORECAST ASSUMPTIONS AND DATA SOURCES

(1) All regression analyses were based on annual data. Historical data were assimilated for calendar years 1970 through 1997. System data, such as net energy for load, seasonal peak demands, customer counts and energy sales, were obtained from GRU records and sources.

(2) Estimates and projections of Alachua County population were obtained from the Florida Population Studies, January, 1998 (Bulletin No. 120), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Normal weather conditions were assumed. Normal heating degree days and cooling degree days are projected to equal the median value of the available data for the Gainesville Municipal Airport weather station (1984-1997).

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 1986, using a price index developed to represent inflationary trends in Alachua County. This "Alachua County Price Index" is developed by comparing changes in the Consumer Price Index (U.S. Bureau of Labor Statistics) and the Florida Price Level Index (Florida Department of Education). Inflation is assumed to begin at 3.25% and increase linearly to 3.5% by the end of this ten-year forecast horizon.

(5) The U. S. Department of Commerce provided historical estimates of total income and per capita income for Alachua County. The BEBR projected income levels for Alachua County in The Florida Long Term Economic Forecast, July 1997.

(6) The Florida Long Term Economic Forecast and Florida Population Studies, Bulletin 119, were used to estimate and project the number of persons per household (household size) in Alachua County.

(7) The Florida Long Term Economic Forecast was the source for historical estimates and projections of non-agricultural employment in Alachua County.

(8) GRU's corporate model was the basis for projections of the average price of 1,000 kWh of electricity for all customer classes. GRU's corporate model evaluates projected revenue and revenue requirements for the forecast horizon and determines revenue sufficiency under prevailing rates. If present rates are insufficient, rate changes are programmed in and become GRU's official rate program plan. Programmed rate increases from the model for all retail rate classes are projected to be less than the rate of inflation, yielding declining real prices of electricity over the forecast horizon.

(9) Estimates of energy and demand reductions resulting from demand-side management programs were incorporated into all retail forecasts. Programs outlined in both GRU's 1990 Energy Conservation Plan and GRU's 1996 Demand-Side Management Plan, both submitted to the FPSC, are incorporated in this forecast. GRU's demand-side management programs are described in more detail later in this section.

(10) The City of Alachua will generate (via generation entitlement shares of Florida Power Corporation and Florida Power and Light nuclear units) approximately 8,077 MWh of its annual energy requirements.

3.2 DOCUMENTATION OF CUSTOMER, ENERGY AND SEASONAL PEAK DEMAND FORECASTS

Number of customers, energy sales and seasonal peak demands were forecast from 1999 through 2008. Separate energy sales forecasts were developed for each of the following customer classes: residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to Alachua. Separate forecasts of number of customers were developed for residential, general service non-demand, general service demand and large power retail rate classifications. The basis for these independent forecasts originated with the development of least-squares regression models. All modeling was performed in-house using the Statistical Analysis System (SAS)[3]. The following text describes the regression equations utilized to forecast energy sales and number of customers.

3.2.1 Residential Sector

The equation of the model developed to project residential average annual energy use (kilowatt-hours per year) specifies average use as a function of household income in Alachua County, residential price of electricity and weather variation, measured by heating degree days and cooling degree days. The form of this equation is as follows:

$$RESAVUSE = 4464.1 + 0.12\,(HHY86) - 11.04\,(RESPR86) + 0.57\,(HDD) + 0.85\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use
HHY86	=	Average Household Income
RESPR86	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

[3] SAS is the registered trademark of SAS Institute, Inc., Cary, NC.

Adjusted R^2	=	0.8440
DF (error)	=	22
t - statistics:		
Intercept	=	3.19
HHY86	=	6.28
RESPR86	=	-1.45
HDD	=	3.61
CDD	=	3.06

Projections of the average annual number of residential customers were developed from a linear regression model stating the number of customers as a function of Alachua County population. The residential customer model specifications are:

$$RESCUS = -29838 + 447.39\ (POP)$$

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9967
DF (error)	=	18
t - statistics:		
Intercept	=	-28.93
POP	=	76.22

The product of forecasted values of average use and number of customers yielded the projected energy sales for the residential sector.

3.2.2 General Service Non-Demand Sector

The general service non-demand customer class includes non-residential customers with maximum annual demands generally less than 50 kilowatts (kW). Average annual energy use per general service non-demand customer has exhibited neither an increasing nor decreasing trend over the past 19 years. From 1979 through 1997, average annual consumption ranged from a low of 26,049 kWh in 1997 to a high of 28,968 kWh in 1990. Some, but not a sufficient amount, of the variation in historical use was fit using regression models. Therefore, average use was projected to remain constant at 27,680 kWh (the median of the historical series) per customer per year.

The number of general service non-demand customers was projected using an equation specifying customers as a function of population in Alachua County. The specifications of the general service non-demand customer model are as follows:

$$GNDCUS = -5633.4 + 62.00\,(POP)$$

Where:

GNDCUS = Number of General Service Non-Demand Customers

POP = Alachua County Population (thousands)

Adjusted R^2 = 0.9855

DF (error) = 18

t - statistics:

Intercept = -18.61

POP = 35.98

Forecasted energy sales to general service non-demand customers were derived from the product of projected number of customers and the projected average annual use per customer.

3.2.3 General Service Demand Sector

The general service demand customer class includes non-residential customers with established annual maximum demands generally of at least 50 kW but less than 1,000 kW. Average annual energy use per customer was projected using an equation specifying average use as a function of per capita income for residents of Alachua County. A significant portion of the energy load in this sector is from large retailers such as department stores and grocery stores, whose business activity is related to income levels of area residents. Average energy use projections for general service demand customers result from the following model:

$$DEMAVUSE = 383.84 + 0.01\ (PCY86)$$

Where:

DEMAVUSE	=	Average Annual Energy Use for General Service Demand Customers (MWh per Year)
PCY86	=	Per Capita Income in Alachua County
Adjusted R^2	=	0.7094
DF (error)	=	17
t - statistics:		
Intercept	=	17.71
PCY86	=	6.70

The annual average number of customers was projected based on the results of a regression model in which Alachua County population was the independent variable. The specifications of the general service demand customer model are as follows:

$$DEMCUS = -526.06 + 5.94\ (POP)$$

Where:

DEMCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)

Adjusted R^2 = 0.9720

DF (error) = 18

t - statistics:

Intercept = -12.96

POP = 25.70

The forecast of energy sales to general service demand customers was the resultant product of projected number of customers and projected average annual use per customer.

3.2.4 Large Power Sector

The large power customer class includes 15 customers with billing demands of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 1997. The model developed to project average use by large power customers includes Alachua County nonagricultural employment and large power price of electricity as independent variables. Energy use per customer is expected to increase due to the expansion of existing facilities. This growth is measured in the model by local employment levels. Anticipated load growth in this customer class was also explicitly added to include one expansion of an existing facility and the addition of one new facility. The specifications of the large power average use model are as follows:

LPAVUSE = *10461 + 18.90 (NONAG) - 61.19 (LPPR86)*

Where:

LPAVUSE = Average Annual Energy Consumption (MWh per Year)

NONAG = Alachua County Nonagricultural Employment (000's)

LPPR86 = Average Price for 1,000 kWh in the Large Power Sector

Adjusted R^2 = 0.8677

DF (error) = 19

t - statistics:

INTERCEPT	=	5.65
NONAG	=	1.91
LPPR86	=	-3.06

The forecast of energy sales to the large power sector was derived from the product of projected average use per customer and the projected number of large power customers.

3.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of streetlight, traffic light, and rental light accounts. Lighting energy sales account for less than 1.5% of total energy sales. Adjustments to lighting inventories in recent years have produced an erratic and unreliable time series of historical lighting sales. To date, this has precluded modeling of outdoor lighting energy sales as a function of demographic or economic data. Future forecast revisions will include attempts to develop a regression-based model for lighting energy sales. Lighting energy sales are forecast to grow at one-third the rate of change in the number of residential customers.

3.2.6 Wholesale Energy Sales

The System presently serves two wholesale customers: Clay Electric Cooperative, Inc. (Clay) at the Farnsworth Substation and, the City of Alachua (Alachua) at the Alachua No. 1 Substation and at the Hague Point of Service. Approximately 12% of Alachua's 1998 energy requirements were met through generation entitlements of nuclear generating units operated by Florida Power Corporation and Florida Power and Light. Each wholesale delivery point serves an urban area that is either included in, or adjacent to the Gainesville Urban Area.

Sales to Clay were modeled with an equation in which total county income was the independent variable. The form of this equation is as follows:

CLYMWH	=	*-24069 + 28.20 (COY86)*
Where:		
CLYMWH	=	Megawatt-Hour Sales to Clay
COY86	=	Total Personal Income (Alachua County)
Adjusted R^2	=	0.9502
DF (error)	=	16
t - statistics:		
Intercept	=	-6.35
COY86	=	18.03

Net energy requirements for Alachua were estimated using a model in which City of Alachua total income was the independent variable. This variable represents the product of City of Alachua population and Alachua County per capita income. Population projections were developed by modeling City of Alachua population as a function of Alachua County population. The model used to develop projections of sales to the City of Alachua is of the following form:

ALANEL	=	*-5649.6 + 0.77 (ALAY86)*
Where:		
ALANEL	=	Net Energy Requirements of Alachua
ALAY86	=	City of Alachua Total Income
Adjusted R^2	=	0.9742
DF (error)	=	16
t - statistics:		
Intercept	=	-2.88
ALAPOP	=	25.35

To obtain a final forecast of the System's sales to Alachua, projected net energy requirements were reduced by 8,077 MWh reflecting the City of Alachua's nuclear generation entitlements.

3.2.7 Total System Sales, Net Energy for Load, Seasonal Peak Demands and DSM Impacts

The forecast of total system energy sales was derived by summing energy sales projections for each customer class; residential, general service non-demand, general service demand, large power, outdoor lighting, sales to Clay, and sales to Alachua. Net energy for load was then forecast by applying a "delivered efficiency" factor for the System to total energy sales. The projected "delivered efficiency" factor (0.9458) was the median of total energy sales divided by net energy for load from 1984 through 1997.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load and assumed that the winter peak will occur in January of each year and the summer peak will occur in August of each year. The average ratio of the most recent 16 years' monthly net energy for load for January and August, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and August net energy for load over the forecast horizon. The medians of the past 16 years' load factors for January and August were applied to January and August net energy for load projections, yielding seasonal peak demand projections. Load data has converged over time to a point that winter peak demands are forecast to be equal for January and February. Likewise, the data indicates that summer peak demands are likely to be equal in July and August. Adjustments to seasonal peak demands were included explicitly to account for impacts from demand-side management programs.

Transmission and distribution line loss improvement programs undertaken by GRU have resulted in relatively stable losses ranging from 5% to 6% of net generation. Post 1981 load factors and energy allocation factors are believed to reflect the most recent trends in appliance efficiencies, appliance penetrations, response to electricity prices and response to customer and utility induced conservation efforts.

3.2.8 Low Band and High Band Forecast Scenarios

Much of the error in long-term forecasts results from variation in expected customer growth, while a primary determinant of short-term forecast error is weather variation. GRU bands its forecasts with a long-term perspective for resource planning purposes by allowing assumptions underlying customer growth to vary. Projections of one independent variable in each customer class were allowed to vary from the base case assumptions in order to develop the banded forecasts. The fundamental variable used to develop alternative forecast scenarios was the series of population projections for Alachua County. Low band and high band forecast scenarios were derived from the same equations used to develop the base case forecasts. Low band and high band population scenarios were set to approximately equal the midpoints of the BEBR low-to-medium and medium-to-high population projections, respectively.

In the residential, general service non-demand, and general service demand revenue sectors, banded energy sales forecasts resulted from banded customer forecasts, which were developed from banded county population projections. Forecasts of average annual energy use per customer were not modified. In the large power sector, non-agricultural employment was the primary explanatory variable used to forecast use per customer. Employment projections were originally derived from population projections. Banded employment projections were input into the original equation yielding alternative energy sales scenarios for this class. Sales to Clay were modeled as a function of total county income. Total county income was projected as the product of per capita income and population. Banded income projections were input into the original equation yielding alternative forecasts of sales to Clay. Sales to Alachua were modeled as a function of City of Alachua total income, which was derived from City of Alachua population and county per capita income. City of Alachua population was projected from a model which stated City population to be a function of county population. Banded City of Alachua population projections, yielding banded City of Alachua income projections, were input into the original equation to obtain alternative scenarios of energy sales to the City of Alachua. Impacts of demand-side management programs were also allowed to vary based upon the ratio of low-to-base and base-to-high band population projections, respectively.

3.3 DOCUMENTATION OF ENERGY SOURCES AND FUEL REQUIREMENTS

3.3.1 Fuels Used by System

Presently, the system is capable of using coal, residual oil, distillate oil, natural gas, and a small percentage of nuclear fuel to satisfy its fuel requirements. Since the completion of the Deerhaven 2 coal-fired unit, the System has relied upon coal to fulfill much of its fuel requirements. It should be noted that these fuel requirements are those necessary to serve native load and existing schedule D contracts only. The System expects to market coal and natural gas based electric energy to other utilities in an expanding and increasingly open marketplace. To the extent that the System realizes these extra "outside" sales, actual consumption of these fuels will likely exceed the base case requirements indicated in Table 3.5.

3.3.2 Methodology

The fuel use projections were produced using the Electric Generation Expansion Analysis System (EGEAS) developed under Electric Power Research Institute guidance and maintained by Stone & Webster Management Consultants. This is the same software the System uses to perform long-range integrated resource planning. EGEAS has the ability to model a variety of technologies from thermal units to DSM options and include the effects of environmental limits, of dual fuel units, of reliability constraints, and of maintenance scheduling, to list only a few. The optimization process uses piece-wise linear and cumulants techniques. The production modeling process uses a load-duration curve convolution and probability process.

The input data to this model includes:

(1) Long-term forecast of System electric energy and power demand needs;

(2) Projected fuel prices, outage parameters, nuclear refueling cycle (as needed), and maintenance schedules for each generating unit in the System;

(3) Similar data for the new plants that will be added to the system to maintain system reliability.

The output of this model includes:

(1) Monthly, yearly and total out-of-pocket operating fuel expenses and their dispersion among various generating units; and

(2) Monthly and yearly capacity factors, energy production, hours of operation, fuel utilization, and heat rates for each unit in the system.

3.4 DEMAND-SIDE MANAGEMENT

3.4.1 Demand-Side Management Plan

Demand and energy forecasts and generation expansion plans outlined in this Ten Year Site Plan are consistent with GRU's 1990 Energy Conservation Plan and GRU's 1996 Demand-Side Management Plan. The System forecast reflects historical program implementations recorded under both plans and projected program implementations scheduled in the 1996 DSM Plan. Both plans address a similar array of DSM measures and both plans were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU.

The 1996 DSM Plan contains programs which increase the efficiency of energy consumption and reduce the consumption of scarce natural resources. DSM programs are available for all native customers, including commercial and industrial customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

GRU is active in the following conservation efforts: residential and commercial energy audits; low income household weatherization and natural gas extension; promotion of natural gas in residential construction; promotion of natural gas for cooling and dehumidification; promotion of natural gas for displacement of electric water heating and space heating in existing structures; commercial lighting efficiency and maintenance services; customer conservation education and information programs; the Trade Alliance Program, which offers a series of workshops providing technical assistance to builders, contractors, installers, code officials and home buyers covering topics such as: *Build Green and Profit, Home Buyer's Seminar, Code Workshops, Energy Star Homes*, and *Uncontrolled Airflow;* and the Business Partner's Program, which offers a series of workshops pertaining to energy and power conservation in the commercial and industrial sectors.

GRU is evaluating the implementation of additional conservation efforts including programs addressing high-efficiency air conditioning, heat recovery, duct leakage, mobile home roof coatings, commercial natural gas water heating and thermal energy storage systems. GRU is also investigating customer demand for a second-generation green-pricing program for solar-derived electricity and plans to implement a new program this year.

GRU has also produced numerous *factsheets,* publications and videos which are available at no charge to customers to assist them in making informed decisions effecting their energy utilization patterns. Examples include: Passive Solar Design-Factors for North Central Florida, a booklet which provides detailed solar and environmental data for passive solar designs in this area; Solar Guidebook, a brochure which explains common applications of solar energy in Gainesville; and The Energy Book, a guide to saving home energy dollars.

The expected effect of DSM program participation was derived from a comparative analysis of historical load and energy consumption of DSM program participants and non-participants. The methodology upon which the currently approved plan is based includes consideration of what would happen anyway, the fact that the conservation induced by utility involvement tends to "buy" conservation at the margin, adjustment for behavioral rebound and price elasticity effects and effects of abnormal weather. Known interactions between measures and programs were accounted for when possible. At the end of each device's life cycle, the energy and demand savings assumed to have been induced by GRU are reduced to zero to represent the retirement of the given device. Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth.

DSM program implementations are expected to provide 20 MW of summer peak reduction, 24 MW of winter peak reduction and 89 GWh of annual energy savings by the year 2008. These figures represent cumulative impacts of programs since 1980. The System's projections of energy sales and peak demands reflect the effects of these DSM programs.

3.4.2 Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) is a nine-member citizen group that is charged with formulating recommendations to the Gainesville City Commission concerning national, state and local energy-related issues. The GEAC offers advice and guidance on energy management studies and consumer awareness programs. The GEAC's efforts have resulted in numerous contributions, accomplishments, and achievements for the City of Gainesville. Specifically, the GEAC helped establish a residential energy audit program in 1979. The GEAC was initially involved in the ratemaking process in 1980 which ultimately lead to the approval of an inverted block residential rate and a voluntary residential time-of-use rate. The GEAC recognized *Solar Month* in October of 1991 by sponsoring a seminar to foster the viability of solar energy as an alternative to conventional means of energy supply. Representatives from Sandia National Laboratories, the Florida Solar Energy Center, FPC, and GRU gave presentations on various solar projects and technologies. A recommendation from GEAC followed the Solar Day Seminars for GRU to investigate offering its citizen-ratepayers the option of contributing to photovoltaic power production through monthly donations on their utility bills. The interest generated by the seminars along with grant money from the State of Florida Department of Community Affairs and the Utility PhotoVoltaic Group and donations from GRU customers and friends of solar energy resulted in a 10 kilowatt PV system at the Electric System Control Center (ESCC). GRU solicited public input on its solar water heater rebate program through the GEAC, and the committee in turn formally supported the program. The GEAC sponsored a Biomass Seminar for a joint meeting of the Gainesville City Commission and the Alachua County Commission. Although there are a number of biomass enthusiasts in the county the cost of the facilities and the amount and cost of the available supply do not support a project at this time.

3.4.3 Supply Side Programs

Deerhaven 2 is also contributing to reduced oil use by other utilities through the Florida Energy Broker. Prior to the addition of Deerhaven Unit 2 in 1982, the System was relying on oil and natural gas for over 90% of native load energy requirements. In 1998, oil-fired generation comprised 1.1% of total net generation, natural gas-fired generation contributed 23.7%, nuclear fuel contributed 4.4%, and coal-fired generation provided 70.8% of total net generation. The PV system at ESCC provides slightly more than 10 kilowatts of capacity at solar noon on clear days.

The System has several programs to improve the adequacy and reliability of the transmission and distribution systems, which will also result in decreased energy losses. Each year the major distribution feeders are evaluated to determine whether the costs of reconductoring will produce an internal rate of return sufficient to justify expenses when compared to the savings realized from reduced distribution losses, and if so, reconductoring is recommended. Generating units are continually evaluated to ensure that they are maintaining design efficiencies. Transmission facilities are also studied to determine the potential savings from loss reductions achieved by the installation of capacitor banks. System losses have stabilized at approximately 5% to 6% of net generation as reflected in the forecasted relationship of total energy sales to net energy for load.

3.5 FUEL PRICE FORECAST ASSUMPTIONS

Forecast prices for each type of fossil fuel analyzed by GRU were generally developed in two parts. Short-term monthly forecasts extending through 1999 were developed in-house by GRU's Fuels Department staff. Long-term fuel price forecasts were developed based upon forecasts of the U.S. Department of Energy's Energy Information Administration (EIA) as published in the Annual Energy Outlook 1998. In essence, the end-point of the GRU short-term forecasts became the starting point for the long-term forecasts, subject to adjustment such that escalation rates within the long term forecasts were consistent with those in EIA forecasts. EIA's real price projections were converted to "nominal" by application of EIA's forecast Implicit Price Deflator. Fossil fuel transportation costs were forecast separately from fuel commodity costs. Forecast fuel commodity costs and transportation costs were aggregated to develop forecast delivered fuel costs. The following documentation describes GRU's fuel price forecasts by fuel type.

3.5.1 Oil

GRU does not have access to waterborne deliveries of oil and there are no pipelines in this area. Consequently, GRU relies on "spot" or as needed purchases from nearby vendors. The cost for purchasing and then trucking relatively insignificant quantities of oil to GRU's generating sites usually makes oil the most expensive and less favored of fuel sources available to GRU. Accordingly, short-term oil price forecasts for No.6 (residual oil) and No.2 (distillate or diesel oil) were based on actual costs to GRU over the past three years and on near term expectations for this limited market. An additional cost component, representing freight charges, was added to yield the final delivered oil price forecasts.

Based on the above factors, the price of No.2 oil delivered to GRU is expected to increase 3.0% annually while the actual volume of oil used remains small. Based on the above factors, the price of No.6 oil delivered to GRU is expected to increase 3.9% annually while the actual volume of oil used remains small.

3.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity. Abundant U.S. supplies of coal and increasing technological improvement in mining methods as well as the cost of new coal plants, competition from other fuels and a better labor environment will tend to limit the price increases of coal. Resource planning studies require forecasts of three types of coal: low sulphur compliance coal, which is presently used by the System; pulverized coal for flue gas desulphurization; and fluidized bed combustion coal.

The short-term forecast price of low sulfur compliance coal was based on GRU's contractual options with its coal supplier. The long-term forecast price of low sulfur compliance coal was developed by applying the long term EIA forecast in the same manner as explained previously. Base line prices were determined for pulverized coal for flue gas desulphurization and fluidized bed compatible coal by utilizing a combination of acknowledged transactions and confidential state of the trade discussions with buyers and sellers of coal as reported in Coal Week. The base line prices were then escalated by applying the long term EIA forecast in the same manner as described previously.

GRU's long term contract with CSXT allows for delivery of coal through 2019. The short-term forecast transportation rate for all coals was based on actual rates from the pertinent coal supply districts for aluminum cars and four-hour loading facilities and on known contractual provisions. The long-term forecast of transportation rates was developed by applying the long term Rail Cost Adjustment Factor indices, adjusted and unadjusted, to the short term forecast. The indices were based on forecasts supplied by Fieldston, a coal transportation consulting company.

Based on the above factors, the price for coal delivered to GRU is expected to increase at an average annual rate of 1.4%, 1.0%, and 0.8% for low sulphur compliance coal, pulverized coal for flue gas desulphurization, and fluidized bed compatible coal, respectively.

3.5.3 Natural Gas

Natural gas is expected to experience a higher rate of growth in demand than other fuels. The supply of natural gas is also expected to increase faster than the demand in the short-term, which is expected to cause short-term prices to be lower than present levels.

GRU's purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. The starting point for GRU's gas cost is the weighted average cost of gas (WACOG). The sum of the following components make up GRU's delivered cost of natural gas: the WACOG; Florida Gas Transmission's (FGT) fuel charge; FGT's demand or usage charge; and the Market Value of Gas Transportation (MVGT) for firm transportation.

Short-term natural gas prices were projected based upon recent trends in historical prices and price trends in the NYMEX gas "future" market. The long-term forecast was then developed by applying the long term EIA forecast in the same manner as described previously.

Transportation charges were projected by applying EIA's forecast Implicit Price Deflator to the actual 1997 FGT usage charge. MVGT costs were adjusted such that they approximated FGT's tariff charges for Firm Transportation Service by the year 2000, the time at which excess transportation capacity is expected to diminish as the pipeline becomes fully subscribed. (The MVGT is believed to be depressed currently because of the amount of excess pipeline capacity available.) After 2000, MVGT costs are expected to escalate at the rate of the Implicit Price Deflator as forecast by EIA.

Based on the above factors, the price of natural gas delivered to GRU is expected to increase at an annual rate of 3.1%.

3.5.4 Nuclear Fuel

GRU's nuclear fuel price forecast is based on Florida Power Corporation's (FPC) forecast of nuclear fuel prices. The FPC forecast projects the price of nuclear fuel to increase approximately 0.2% per year through the forecast horizon.

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 AND RESIDENTIAL					COMMERCIAL *		
Year	Service Area Population	Persons per Household	GWh	Average Number of Customers	Average kWh per Customer	GWh	Average Number of Customers	Average kWh per Customer
1989	125,537	2.41	562	52,090	10,782	458	6,250	73,353
1990	129,432	2.40	594	53,930	11,023	481	6,394	75,240
1991	131,873	2.39	602	55,177	10,906	491	6,527	75,222
1992	135,678	2.39	610	56,769	10,739	507	6,730	75,284
1993	141,163	2.39	637	59,064	10,778	524	6,998	74,824
1994	145,460	2.39	649	60,862	10,670	558	7,059	79,024
1995	148,491	2.39	704	62,130	11,329	590	7,305	80,767
1996	151,591	2.39	718	63,427	11,313	594	7,539	78,813
1997	155,713	2.39	705	65,152	10,817	598	7,750	77,193
1998	159,466	2.39	777	66,722	11,649	640	7,868	81,363
1999	163,305	2.39	745	68,329	10,909	641	8,232	77,912
2000	167,048	2.39	766	69,894	10,954	659	8,470	77,859
2001	170,683	2.39	785	71,416	10,997	678	8,701	77,966
2002	174,319	2.39	804	72,937	11,027	698	8,932	78,102
2003	177,847	2.39	822	74,413	11,051	716	9,156	78,239
2004	181,376	2.39	839	75,890	11,061	735	9,381	78,339
2005	184,905	2.39	857	77,366	11,072	754	9,605	78,467
2006	188,326	2.39	874	78,798	11,091	772	9,822	78,603
2007	191,748	2.39	891	80,229	11,110	791	10,040	78,786
2008	195,170	2.39	910	81,661	11,139	810	10,257	78,962

* Commercial represents GS Non-Demand and GS Demand Rate Classes.

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 **						
Year	GWh	Average Number of Customers	Average MWh per Customer	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1989	120	13	9,023	0	16	0	1,156
1990	126	14	9,024	0	16	0	1,218
1991	128	14	9,392	0	16	0	1,237
1992	128	13	9,853	0	16	0	1,261
1993	132	13	10,121	0	16	0	1,308
1994	134	13	10,344	0	18	0	1,359
1995	137	13	10,521	0	18	0	1,449
1996	148	15	9,893	0	19	0	1,479
1997	151	15	10,059	0	21	0	1,475
1998	157	15	10,443	0	21	0	1,595
1999	164	15	10,943	0	21	0	1,572
2000	178	16	11,113	0	21	0	1,624
2001	180	16	11,277	0	21	0	1,665
2002	182	16	11,379	0	21	0	1,705
2003	184	16	11,477	0	22	0	1,744
2004	185	16	11,565	0	22	0	1,781
2005	186	16	11,653	0	22	0	1,819
2006	188	16	11,739	0	22	0	1,856
2007	189	16	11,825	0	22	0	1,894
2008	191	16	11,908	0	22	0	1,932

** Industrial represents Large Power Rate Class.

Schedule 2.3
History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales For Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers	(6) Total Number of Customers
1989	76	91	1,323	0	58,353
1990	85	60	1,363	0	60,338
1991	90	85	1,411	0	61,718
1992	93	70	1,424	0	63,512
1993	94	100	1,502	0	66,075
1994	91	69	1,519	0	67,934
1995	101	97	1,648	0	69,448
1996	105	75	1,659	0	70,981
1997	104	82	1,661	0	72,917
1998	108	76	1,779	0	74,605
1999	109	96	1,778	0	76,576
2000	114	100	1,837	0	78,381
2001	119	102	1,886	0	80,133
2002	124	105	1,934	0	81,885
2003	129	107	1,980	0	83,586
2004	134	110	2,025	0	85,286
2005	139	112	2,069	0	86,987
2006	144	115	2,114	0	88,636
2007	149	117	2,159	0	90,285
2008	154	120	2,205	0	91,934

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989	307	21	275	0	0	8	0	3	296
1990	317	21	284	0	0	8	0	4	305
1991	310	21	276	0	0	9	0	4	297
1992	334	23	297	0	0	9	0	5	320
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	412	26	370	0	0	8	0	8	396
1999	407	25	366	0	0	8	0	8	391
2000	419	26	377	0	0	8	0	8	403
2001	430	28	386	0	0	8	0	8	414
2002	441	29	396	0	0	8	0	8	425
2003	451	30	405	0	0	9	0	7	435
2004	462	31	414	0	0	10	0	7	445
2005	473	32	423	0	0	11	0	7	455
2006	483	33	431	0	0	12	0	7	464
2007	494	34	440	0	0	13	0	7	474
2008	503	36	447	0	0	14	0	6	483

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Schedule 3.1H
History and Forecast of Summer Peak Demand
High Band Forecast

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989	307	21	275	0	0	8	0	3	296
1990	317	21	284	0	0	8	0	4	305
1991	310	21	276	0	0	9	0	4	297
1992	334	23	297	0	0	9	0	5	320
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	412	26	370	0	0	8	0	8	396
1999	419	26	376	0	0	9	0	8	402
2000	436	27	392	0	0	9	0	8	419
2001	451	28	406	0	0	8	0	8	434
2002	466	30	419	0	0	9	0	8	449
2003	480	31	432	0	0	10	0	8	463
2004	496	32	446	0	0	11	0	8	478
2005	510	34	457	0	0	12	0	8	491
2006	527	35	471	0	0	13	0	8	506
2007	542	37	483	0	0	14	0	7	520
2008	556	38	496	0	0	15	0	7	534

Schedule 3.1L
History and Forecast of Summer Peak Demand
Low Band Forecast

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989	307	21	275	0	0	8	0	3	296
1990	317	21	284	0	0	8	0	4	305
1991	310	21	276	0	0	9	0	4	297
1992	334	23	297	0	0	9	0	5	320
1993	355	23	316	0	0	10	0	6	339
1994	347	21	310	0	0	9	0	7	331
1995	377	24	337	0	0	9	0	7	361
1996	380	24	341	0	0	8	0	7	365
1997	388	24	349	0	0	8	0	7	373
1998	412	26	370	0	0	8	0	8	396
1999	396	25	355	0	0	8	0	7	380
2000	405	26	363	0	0	8	0	8	389
2001	412	27	370	0	0	8	0	7	397
2002	419	28	376	0	0	8	0	7	404
2003	426	29	382	0	0	9	0	7	411
2004	433	30	387	0	0	9	0	7	417
2005	439	31	391	0	0	10	0	7	422
2006	445	32	396	0	0	11	0	6	428
2007	451	33	400	0	0	12	0	6	433
2008	457	34	405	0	0	13	0	6	439

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Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989	280	25	237	0	0	15	0	3	262
1990	246	20	205	0	0	17	0	4	225
1991	262	22	216	0	0	20	0	4	238
1992	306	25	253	0	0	23	0	5	278
1993	290	22	237	0	0	25	0	6	259
1994	319	23	262	0	0	27	0	7	285
1995	350	25	289	0	0	29	0	7	314
1996	381	28	317	0	0	29	0	7	345
1997	321	26	258	0	0	30	0	7	284
1998	301	23	240	0	0	30	0	7	263
1999	355	26	291	0	0	31	0	7	317
2000	366	27	303	0	0	29	0	7	330
2001	375	28	313	0	0	28	0	6	341
2002	384	29	322	0	0	27	0	6	351
2003	391	31	328	0	0	27	0	5	359
2004	401	32	338	0	0	27	0	5	370
2005	409	33	346	0	0	26	0	4	379
2006	418	34	355	0	0	25	0	3	389
2007	427	35	365	0	0	24	0	3	400
2008	434	36	374	0	0	23	0	2	410

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Schedule 3.2H
History and Forecast of Winter Peak Demand
High Band Forecast

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989	280	25	237	0	0	15	0	3	262
1990	246	20	205	0	0	17	0	4	225
1991	262	22	216	0	0	20	0	4	238
1992	306	25	253	0	0	23	0	5	278
1993	290	22	237	0	0	25	0	6	259
1994	319	23	262	0	0	27	0	7	285
1995	350	25	289	0	0	29	0	7	314
1996	381	28	317	0	0	29	0	7	345
1997	321	26	258	0	0	30	0	7	284
1998	301	23	240	0	0	30	0	7	263
1999	365	26	300	0	0	32	0	7	326
2000	380	28	315	0	0	30	0	7	343
2001	393	29	328	0	0	30	0	7	357
2002	405	30	340	0	0	29	0	6	370
2003	418	32	352	0	0	29	0	5	384
2004	431	33	364	0	0	29	0	5	397
2005	443	35	375	0	0	28	0	4	410
2006	455	36	388	0	0	27	0	4	424
2007	467	37	401	0	0	26	0	3	438
2008	480	39	414	0	0	25	0	2	453

Schedule 3.2L
History and Forecast of Winter Peak Demand
Low Band Forecast

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1989	280	25	237	0	0	15	0	3	262
1990	246	20	205	0	0	17	0	4	225
1991	262	22	216	0	0	20	0	4	238
1992	306	25	253	0	0	23	0	5	278
1993	290	22	237	0	0	25	0	6	259
1994	319	23	262	0	0	27	0	7	285
1995	350	25	289	0	0	29	0	7	314
1996	381	28	317	0	0	29	0	7	345
1997	321	26	258	0	0	30	0	7	284
1998	301	23	240	0	0	30	0	7	263
1999	346	26	283	0	0	30	0	7	309
2000	354	26	293	0	0	28	0	7	319
2001	360	27	300	0	0	27	0	6	327
2002	366	28	306	0	0	26	0	5	334
2003	370	29	311	0	0	26	0	5	340
2004	375	30	316	0	0	25	0	4	346
2005	381	31	322	0	0	24	0	4	353
2006	385	32	327	0	0	23	0	3	359
2007	391	33	333	0	0	22	0	2	366
2008	395	34	339	0	0	21	0	2	373

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

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1989	1,362	31	8	1,156	76	91	1,323	51.02%
1990	1,407	34	10	1,217	85	61	1,363	51.01%
1991	1,460	37	12	1,236	90	85	1,411	54.23%
1992	1,479	41	14	1,261	93	70	1,424	50.80%
1993	1,563	44	17	1,308	94	100	1,502	50.58%
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,848	47	21	1,595	108	76	1,779	51.28%
1999	1,850	51	21	1,572	109	97	1,778	51.91%
2000	1,910	51	22	1,624	114	99	1,837	52.04%
2001	1,960	53	21	1,665	119	102	1,886	52.00%
2002	2,009	55	20	1,705	124	105	1,934	51.95%
2003	2,058	58	19	1,744	129	107	1,980	51.96%
2004	2,106	62	19	1,781	134	110	2,025	51.95%
2005	2,153	66	18	1,818	139	112	2,069	51.91%
2006	2,200	69	17	1,856	144	114	2,114	52.01%
2007	2,246	72	15	1,893	149	117	2,159	52.00%
2008	2,294	75	14	1,932	154	119	2,205	52.11%

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Schedule 3.3H
History and Forecast of Net Energy for Load - GWH
High Band Forecast

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1989	1,362	31	8	1,156	76	91	1,323	51.02%
1990	1,407	34	10	1,217	85	61	1,363	51.01%
1991	1,460	37	12	1,236	90	85	1,411	54.23%
1992	1,479	41	14	1,261	93	70	1,424	50.80%
1993	1,563	44	17	1,308	94	100	1,502	50.58%
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,848	47	21	1,595	108	76	1,779	51.28%
1999	1,904	52	22	1,620	111	99	1,830	51.97%
2000	1,983	53	22	1,687	117	103	1,907	51.96%
2001	2,052	55	22	1,746	122	107	1,975	51.95%
2002	2,122	59	21	1,803	128	111	2,042	51.92%
2003	2,191	62	20	1,860	134	114	2,108	51.97%
2004	2,260	67	20	1,915	140	118	2,173	51.90%
2005	2,327	71	19	2,010	146	81	2,237	52.01%
2006	2,396	75	18	2,026	152	125	2,303	51.96%
2007	2,465	79	17	2,083	158	128	2,369	52.01%
2008	2,535	82	15	2,141	164	132	2,437	52.10%

Schedule 3.3L
History and Forecast of Net Energy for Load - GWH
Low Band Forecast

(1) Year	(2) Total	(3) Residential Conservation	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor %
1989	1,362	31	8	1,156	76	91	1,323	51.02%
1990	1,407	34	10	1,217	85	61	1,363	51.01%
1991	1,460	37	12	1,236	90	85	1,411	54.23%
1992	1,479	41	14	1,261	93	70	1,424	50.80%
1993	1,563	44	17	1,308	94	100	1,502	50.58%
1994	1,581	44	18	1,359	91	69	1,519	52.39%
1995	1,711	43	20	1,449	101	98	1,648	52.11%
1996	1,721	42	21	1,479	105	75	1,659	51.89%
1997	1,726	44	21	1,475	104	82	1,661	50.83%
1998	1,848	47	21	1,595	108	76	1,779	51.28%
1999	1,802	49	21	1,530	108	94	1,732	52.03%
2000	1,845	50	21	1,568	111	96	1,775	52.09%
2001	1,880	51	20	1,595	116	98	1,809	52.02%
2002	1,911	53	19	1,620	120	99	1,839	51.96%
2003	1,942	55	18	1,643	124	102	1,869	51.91%
2004	1,972	58	17	1,665	128	103	1,896	51.90%
2005	2,001	61	16	1,686	133	104	1,923	52.02%
2006	2,029	64	15	1,707	137	106	1,950	52.01%
2007	2,057	66	14	1,728	141	108	1,977	52.12%
2008	2,083	68	13	1,750	145	108	2,003	52.08%

Schedule 4

Previous Year and 2-Year Forecast of RETAIL Peak Demand and Net Energy for Load

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 1998		FORECAST 1999		FORECAST 2000	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	242	125	317	140	328	144
FEB	256	114	317	120	328	124
MAR	263	127	268	126	277	130
APR	266	122	280	125	289	129
MAY	352	159	330	150	341	155
JUN	396	190	374	167	387	173
JUL	381	188	387	183	400	189
AUG	381	184	391	187	403	193
SEP	344	165	368	171	380	177
OCT	326	152	320	144	331	149
NOV	257	125	278	127	287	131
DEC	242	128	301	138	311	143

Schedule 5
Fuel Requirements

(1)	(2) Fuel Type	(3)	(4) Units	(5) Actual 1997	(6) Actual 1998	(7) 1999	(8) 2000	(9) 2001	(10) 2002	(11) 2003	(12) 2004	(13) 2005	(14) 2006	(15) 2007	(16) 2008
(1)	NUCLEAR		Btu x 10^{12}	0.0	0.9	0.7	0.9	0.7	0.7	0.9	0.7	0.7	0.9	0.7	0.7
(2)	COAL	Total	1000 Tons	584	570	550	552	556	567	562	577	580	586	590	590
(3)	RESIDUAL (1)	Total	1000 bbl	24	37	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 bbl	24	37	0	0	0	0	0	0	0	0	0	0
(5)		CC (2)	1000 bbl	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT (3)	1000 bbl	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 bbl	0	0	0	0	0	0	0	0	0	0	0	0
(8)	DISTILLATE (4)	Total	1000 bbl	0	1	0	0	0	0	0	0	0	0	0	0
(9)		Steam	1000 bbl	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC (2)	1000 bbl	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT (3)	1000 bbl	0	1	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 bbl	0	0	0	0	0	0	0	0	0	0	0	0
(13)	NATURAL GAS	Total	cf x 10^{6}	4,268	4,739	4,008	3,973	3,841	4,015	4,608	4,930	4,734	4,938	5,275	5,956
(14)		Steam	cf x 10^{6}	3,552	3,448	2,769	2,905	629	697	934	1,027	921	992	1,129	1,408
(15)		CC (2)	cf x 10^{6}	0	0	0	0	2,986	3,057	3,238	3,412	3,442	3,520	3,669	3,784
(16)		CT (3)	cf x 10^{6}	716	1,292	1,239	1,068	226	261	436	491	371	426	477	764
(17)	Other (Specify)		Btu x 10^{12}	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(1) RESIDUAL - INCLUDES #4, #5, AND #6 OIL.
(2) CC - COMBINED CYCLE UNIT.
(3) CT - COMBUSTION TURBINE UNIT (INCLUDES DIESEL).
(4) DISTILLATE - INCLUDES #1 AND #2 OIL, KEROSENE, JET FUEL AND AMOUNTS USED AT COAL BURNING PLANTS FOR FLAME STABILIZATION AND FOR STARTUP.

Schedule 6.1
Energy Sources

(1)	(2) CAPABILITY/FUEL TYPE	(3)	(4)	(5) Actual 1997	(6) Actual 1998	(7) 1999	(8) 2000	(9) 2001	(10) 2002	(11) 2003	(12) 2004	(13) 2005	(14) 2006	(15) 2007	(16) 2008
(1)	Annual Firm Interchange (1),(2)		GWh	-171	-92	-47	-1	-1	-1	-1	0	0	0	0	0
(2)	NUCLEAR		GWh	0	89	72	82	71	71	82	71	71	82	71	71
(3)	Residual	Total	GWh	13	20	0	0	0	0	0	0	0	0	0	0
(4)		Steam	GWh	13	20	0	0	0	0	0	0	0	0	0	0
(5)		CC	GWh	0	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	0
(7)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	GWh	358	396	326	325	394	414	474	506	488	511	544	606
(14)		Steam	GWh	303	299	235	249	55	60	81	89	79	85	97	122
(15)		CC	GWh	0	0	0	0	325	337	363	383	384	397	414	431
(16)		CT	GWh	55	97	91	76	14	17	30	34	25	29	33	53
(17)	Coal		GWh	1,413	1,373	1,377	1,431	1,422	1,450	1,425	1,448	1,510	1,521	1,544	1,528
(17)	Non-Firm Interchange		GWh	48	49	74	0	0	0	0	0	0	0	0	0
(18)	Net Energy for Load			1,661	1,835	1,802	1,837	1,886	1,934	1,980	2,025	2,069	2,114	2,159	2,205

Notes:
(1) Economy interchange not included for 1998-2003 (schedule D & G only).
(2) Net energy purchased(+)/sold(-) to other utilities within Peninsular Florida.

Row: (17) Other (Specify)

Schedule 6.2
Energy Sources

(1)	(2) CAPABILITY/FUEL TYPE	(3)	(4)	(5) Actual 1997	(6) Actual 1998	(7) 1999	(8) 2000	(9) 2001	(10) 2002	(11) 2003	(12) 2004	(13) 2005	(14) 2006	(15) 2007	(16) 2008
(1)	Annual Firm Interchange (1,2)		GWh	-10.3%	-5.0%	-2.6%	-0.1%	-0.1%	-0.1%	-0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	NUCLEAR		GWh	0.0%	4.9%	4.0%	4.5%	3.8%	3.7%	4.1%	3.5%	3.4%	3.9%	3.3%	3.2%
(3)	Residual	Total	GWh	0.8%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(4)		Steam	GWh	0.8%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		CC	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		Diesel	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(8)	Distillate	Total	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		Steam	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CC	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		CT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(12)		Diesel	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(13)	Natural Gas	Total	GWh	21.6%	21.6%	18.1%	17.7%	20.9%	21.4%	23.9%	25.0%	23.6%	24.2%	25.2%	27.5%
(14)		Steam	GWh	18.2%	16.3%	13.0%	13.6%	2.9%	3.1%	4.1%	4.4%	3.8%	4.0%	4.5%	5.5%
(15)		CC	GWh	0.0%	0.0%	0.0%	0.0%	17.2%	17.4%	18.3%	18.9%	18.6%	18.8%	19.2%	19.5%
(16)		CT	GWh	3.3%	5.3%	5.0%	4.1%	0.7%	0.9%	1.5%	1.7%	1.2%	1.4%	1.5%	2.4%
(17)	Coal		GWh	85.1%	74.8%	76.4%	77.9%	75.4%	75.0%	72.0%	71.5%	73.0%	71.9%	71.5%	69.3%
(17)	Non-Firm Interchange		GWh	2.9%	2.7%	4.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	Net Energy for Load			100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Notes: (1) Economy interchange not included for 1998-2003 (schedule D & G only).
(2) Net energy purchased(+)/sold(-) to other utilities within Peninsular Florida.

Row: (17) Other (Specify)

4. FORECAST OF FACILITIES REQUIREMENTS

4.1 GENERATION RETIREMENTS AND ADDITIONS

4.1.1 Least-Cost Planning Selection

The System does not expect to retire any of its currently operating generating units prior to 2011. One of the recommendations from the Integrated Resource Least-Cost Planning Study, prepared by Stone & Webster Management Consultants, Inc. (S&W), New York, March 1992, was to "continue the current level of operation and maintenance at the Kelly Station and implement the maintenance suggestions contained in Stone & Webster Engineering Corporation's report." Further, Stone & Webster Engineering Corporation found no reason to recommend the System retire any currently operating units and suggested that these units should continue to operate through 2010. The System's newest combustion turbine (DHCT3) at the Deerhaven Station, entered commercial operation January 26, 1996. As an option, this CT was sited to accommodate conversion to combined-cycle capacity, via the addition of a heat-recovery steam generator and small steam turbine.

GRU performed an integrated least-cost planning study to determine the best plan for serving our customers well into the next century. This process took several years and involved: examining several RFPs to discover unknown options from other Utilities and Power Marketers; multiple sensitivities using combinations of high, base, low, and constant differential fuel price forecasts and high, base, and low load and energy forecasts; combinations of investors, purchase, partnership, and sole ownership of new generating facilities, reconfiguring and repowering of existing facilities; as well as, continuing to evaluate and refine, as necessary, existing conservation and load control options. The modeling tools used for the least-cost planning was the EGEAS model described in Chapter 3 and EXPAN which uses analytical, probabilistic, and graphical tools and provides enhanced expansion plan risk analysis. GRU used a planning criteria of 15% operating reserve margin (suggested for emergency power pricing purposes by Florida Public Service Commission Rule 25-6.035). The optimization is based on lowest NPV of revenue requirements, considering the NPV of the optimization time frame. Schedule 9 is included at the end of this section.

In consideration of the load forecast, reserve margin requirements, and system reliability, GRU's Electric System will require additional generating capacity before 2007. An extensive three-year integrated resource planning study has revealed that repowering J. R. Kelly Unit 8 as a nominal 110 megawatt combined-cycle unit is the best and most robust choice when subjected to an exhaustive array of scenarios. These scenarios included several partnership options and partnerships on the repowering of J. R. Kelly Unit 8 and still the best and most robust choice for GRU's customers was for GRU to do this project. Because of the opportunity to improve operating efficiency, reduce emission rates, reduce total emissions, and better participate in the redevelopment of downtown Gainesville, while increasing the electric system's capacity at a time when the reserve margin for Peninsular Florida is getting tight, The Gainesville City Commission has approved moving the installation target date to 2001. Schedule 8 provides a listing of proposed changes to the System's generation facilities.

Prior to deciding to construct Deerhaven CT3, a request was issued by Utility Purchasing on March 23, 1995 for Non-Binding Power Supply Proposals. The RFP was sent out to validate prior studies which concluded that the addition of a third combustion turbine generating unit at our Deerhaven Station was the most cost-effective option for serving our customers' future energy needs. The findings of that RFP process were that the best option for The System was to proceed with the installation of a gas-fired General Electric 7EA Combustion Turbine and to negotiate with the tender of the highest ranked offer, which was LG&E POWER MARKETING INC. ("LPM"), a California corporation. As of November, 1995 staff was able to negotiate a mutually beneficial agreement. Under the terms of the power purchase agreement, the System has been and will be able to import financially firm peaking power at very attractive prices. Although LG&E Power Marketing Inc. no longer exists the contract negotiated with LPM was sold/transferred in 1998 to El Paso Power Services.

4.1.2 Green Pricing

Photovoltaic systems have demonstrated remarkable reductions in cost over the last decade and have the potential to somewhat offset GRU's summer peaks. Although not considered cost-effective in the planning horizon, the Community has demonstrated a philosophical commitment to such systems by participating in a contribution campaign which has allowed customers to either make direct contributions or enroll to contribute on a monthly basis via their utility bill. Green-pricing was used, in conjunction with State and Federal grants, to build the 10 kilowatt photovoltaic array at ESCC.

The Gainesville City Commission has authorized GRU to proceed with offering a new PV program in a joint project with the Florida Municipal Electric Association and the Florida Solar Energy Center. The program design is in the formative stages and will most likely be designed on the basis of a capacity-based subscription.

4.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

Available generating capacities are compared with System summer peak demands in Schedule 7.1 and System winter peak demands in Schedule 7.2. Higher peak demands in summer and lower unit operating efficiencies in summer result in lower reserve margins during the summer season than in winter. A minimum reserve margin of 21% of peak demand is expected in 1999.

4.3 DISTRIBUTION SYSTEM ADDITIONS

Two new identical mini-power delivery substations (PDS) planned for the GRU system. The first, to be located near the intersection of SW Williston Road and SW 23rd Terrace in Gainesville, will be installed by the summer of 2000. The second, to be located in the 8500 block of SW Archer Road, is planned for the summer of 2002. These new PDSs have been planned in response to heavy loading on the existing Serenola and Sugarfoot substations, with more major load development planned for those areas.

Each PDS will consist of one 138-12.47 KV, 33.6 MVA, wye-wye substation transformer with a maximum of four distribution circuits. The proximity of these new PDSs to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

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)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Summer Peak Demand	Reserve Margin1 before Maintenance		Scheduled Maintenance	Reserve Margin1 after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1989	467	0	33	0	434	296	138	47%	0	138	47%
1990	452	0	63	0	389	305	84	28%	0	84	28%
1991	452	0	53	0	399	297	102	34%	0	102	34%
1992	452	0	43	0	409	320	89	28%	0	89	28%
1993	452	0	33	0	419	339	80	24%	0	80	24%
1994	452	0	13	0	439	331	108	33%	0	108	33%
1995	452	0	33	0	419	361	58	16%	0	58	16%
1996	527	18	43	0	502	365	137	38%	0	137	38%
1997	527	30	85	0	472	373	99	27%	0	99	27%
1998	550	31	73	0	508	396	112	28%	0	112	28%
1999	550	32	110	0	472	391	81	21%	0	81	21%
2000	550	0	3	0	547	403	144	36%	0	144	36%
2001	610	0	3	0	607	414	193	47%	0	193	47%
2002	610	0	3	0	607	425	182	43%	0	182	43%
2003	610	0	3	0	607	435	172	40%	0	172	40%
2004	610	0	0	0	610	445	165	37%	0	165	37%
2005	610	0	0	0	610	455	155	34%	0	155	34%
2006	610	0	0	0	610	464	146	31%	0	146	31%
2007	610	0	0	0	610	474	136	29%	0	136	29%
2008	610	0	0	0	610	483	127	26%	0	127	26%

(1) GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

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)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin1 before Maintenance		Scheduled Maintenance	Reserve Margin1 after Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1988 /89	474	0	33	0	441	262	179	68%	0	179	68%
1989 /90	459	0	33	0	426	225	201	89%	0	201	89%
1990 /91	459	0	53	0	406	238	168	71%	0	168	71%
1991 /92	459	0	43	0	416	278	138	50%	0	138	50%
1992 /93	459	0	33	0	426	259	167	64%	0	167	64%
1993 /94	459	0	13	0	446	285	161	56%	0	161	56%
1994 /95	459	0	33	0	426	314	112	36%	0	112	36%
1995 /96	540	0	33	0	507	345	162	47%	0	162	47%
1996 /97	540	18	43	0	515	284	231	81%	0	231	81%
1997 /98	540	30	23	0	547	282	265	94%	0	265	94%
1998 /99	563	31	88	0	506	317	189	60%	0	189	60%
1999 /00	563	0	3	0	560	330	230	70%	0	230	70%
2000 /01	623	0	3	0	620	341	279	82%	0	279	82%
2001 /02	623	0	3	0	620	351	269	77%	0	269	77%
2002 /03	623	0	3	0	620	359	261	73%	0	261	73%
2003 /04	623	0	0	0	623	370	253	68%	0	253	68%
2004 /05	623	0	0	0	623	379	244	64%	0	244	64%
2005 /06	623	0	0	0	623	389	234	60%	0	234	60%
2006 /07	623	0	0	0	623	400	223	56%	0	223	56%
2007 /08	623	0	0	0	623	410	213	52%	0	213	52%

(1) GRU provides reserve margin backup for 3 MW Schedule D contract with the City of Starke.

Schedule 8

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
J. R. Kelly	8	12-001	ST	NG	FO6	PL	TK		4/65	11/00	(50,000)	(49,500)	(49,500)	RP [1]
	8	(Alachua Co.,	CW	WH				11/00	2/01		50,000	40,000	40,000	RP [2]
	4	Section 4, Township	CT	NG	FO2	PL	TK	1/00	2/01		96,140	70,000	70,000	L [3]
		10 S, Range 20E)												
		(GRU)												

Unit Type
ST = Steam
CT = Combined Cycle - Combustion Turbine Portion
CW = Combined Cycle - Steam Turbine - Waste Heat Boiler Only

Fuel Type
NG = Natural Gas
FO6 = Fuel Oil #6 (Residual)
FO2 = Fuel Oil #2 (Distillate)
WH = Waste Heat

Transportation Method
PL = Pipe Line
TK = Truck

Status
RP = Proposed for repowering
L = Regulatory approval pending. Not under construction.

Notes: (1) Will be taken out of service about November 2000 to begin conversion to heat recovery steam source.
(2) To be on line as a Combined-Cycle, February 2001, part of J.R. Kelly CC Unit 1.
(3) GE 7EA CT will be Waste Heat Source for J.R. Kelly Unit 8, part of J.R. Kelly CC Unit 1.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number:	J.R. Kelly CC1
(2) Capacity	
a. Summer:	110 MW (nominal)
b. Winter:	110 MW (nominal)
(3) Technology Type:	Combined-Cycle
(4) Anticipated Construction Timing	
a. Field construction start-date:	January, 2000
b. Commercial in-service date:	February, 2001
(5) Fuel	
a. Primary fuel:	Natural Gas
b. Alternate fuel:	Fuel Oil #2 (Distillate)
(6) Air Pollution Control Strategy:	Dry Low NOx Burners Water Injection Fuel Specification
(7) Cooling Method:	Closed-Loop Cooling Tower
(8) Total Site Area:	32,000 square feet
(9) Construction Status:	In-Progress
(10) Certification Status:	Not Applicable
(11) Status with Federal Agencies:	Pending
(12) Projected Unit Performance Data	
Planned Outage Factor (POF):	5.75%
Forced Outage Factor (FOF):	1.32%
Equivalent Availability Factor (EAF):	83.61%
Resulting Capacity Factor (%):	52%
Average Net Operating Heat Rate (ANOHR):	7,880 Btu/kWh
(13) Projected Unit Financial Data	
Book Life (Years):	30
Total Installed Cost (In-Service Year $/kW):	$374.50
Direct Contruction Cost ($/kW):	$68.18
AFUDC Amount ($/kW):	$10.70
Escalation:	3.00%
Fixed O&M ($/kW-Yr):	$12.80
Variable O&M ($/MWh):	$2.90
K Factor:	n/a

5. ENVIRONMENTAL AND LAND USE INFORMATION

5.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Not applicable.

5.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

Gainesville Regional Utilities is planning a repowering project at its existing John R. Kelly Generating Station located at 605 SE 3rd Street in downtown Gainesville. This site has been used for power generation since 1912.

The project will entail repowering of the existing Unit 8 turbine-generator with a new simple cycle combustion turbine and a heat recovery steam generator. The 110 MW (nominal) unit will operate in a combined cycle mode and will be fired with either natural gas (primary fuel) or distillate oil (backup fuel). The new combined cycle unit is projected to be in commercial service by spring 2001.

<u>Land Use and Environmenal Features</u>

a. The location of the John R. Kelly Generating Station ("Site") is indicated on Figure 1.
b. The general layout of the proposed combined cycle unit on the Site is indicated on Figure 2.
c. Figure 3 provides a photographic depiction of the land use and cover of the existing site and adjacent areas.
d. The existing land use of the site is industrial; surrounding land uses are primarily residential to the north and east, mixed residential/commercial to the west and industrial to the south.
e. The site and surrounding areas are highly urbanized and provide little habitat

area with the exception of a large wooded parcel of land to the southwest of the site. Sweetwater Branch, a drainage creek for a large portion of downtown Gainesville, flows through the Site in a concrete culvert that becomes an open channel prior to the creek leaving the Site.

f. Not applicable.

g. The City of Gainesville's Generalized Future Land Use Map is provided in Figure 4. It should be noted that there are plans to convert a portion of the large industrial area south of Depot Avenue and east of South Main Street to a regional stormwater collection/treatment and passive recreation facility.

h. This site was selected because it provided for the optimal integration of new and existing generating equipment to meet GRU's future generation needs.

i. The site is located in the St. John's River Water Management District. The entire District has been designated a water resource caution area. The only surface water resource on the site and adjacent areas is Sweetwater Branch.

j. There are no notable geologic features on this site or adjacent areas.

k. No water will be required for industrial processing. No increase in water quantities for potable uses is projected. Cooling water quantities will depend on the operating capacities of the steam generating units. The water allocation in the existing consumptive use permit should be sufficient to accommodate the requirements of the Site in the future. The combined cycle unit will utilize water injection for controlling nitrogen oxide (NOx) emissions only while firing distillate fuel oil. Hence, quantities will depend on the use of this fuel.

l. Water for potable use and for the NOx control system will be supplied via the City's potable water system. Cooling water will be supplied by an on-site Floridan well.

m. Not applicable.

n. Cooling tower blowdown, low-volume waste and stormwater will continue to be discharged to Sweetwater Branch pursuant to the facility's NPDES permit. No new discharges are projected.

o. The new unit will utilize existing fuel oil delivery and storage facilities. No new facilities will be required. Several existing bulk residual fuel oil tank systems will be retired because of the reduced usage of this fuel at the Site.

Air and Noise Emissions

p. The new unit will be equipped with dry low-NOx combustors and water injection for NOx control while firing natural gas and distillate fuel oil, respectively. Low sulfur, low nitrogen distillate fuel oil will displace the use of residual fuel oil in existing Unit 8 and result in lower sulfur dioxide and particulate matter emission rates while firing fuel oil.

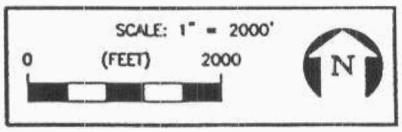
q. The new unit will be equipped with noise abatement equipment including silencers and an acoustic barrier wall. The predicted noise impact is insignificant.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.

Figure 1

QUADRANGLE LOCATION
STATE OF FLORIDA



FACILITY LOCATION MAP

Source: USGS Quad, Gainesville East, FL, 1988.

SITE LAYOUT

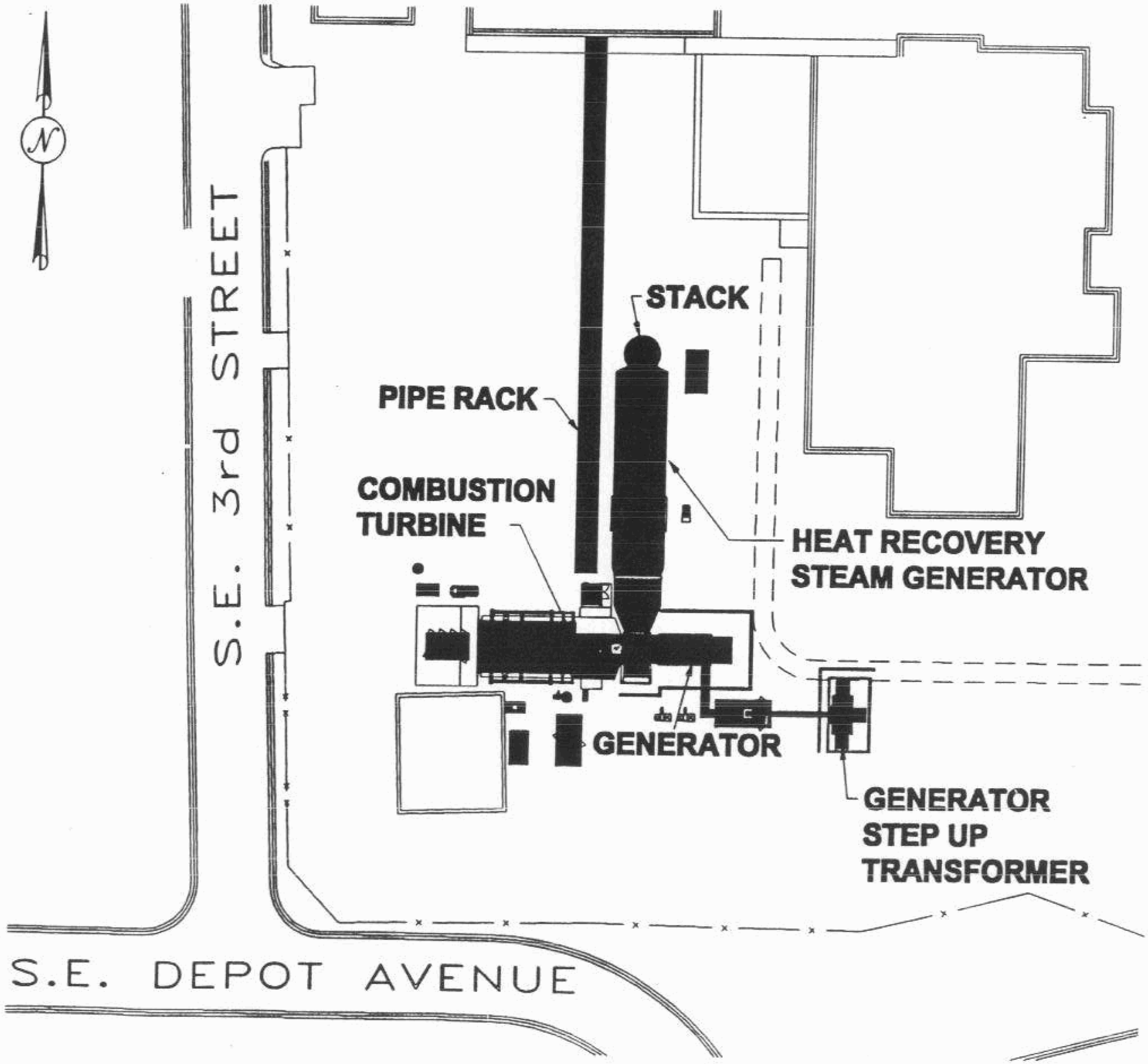
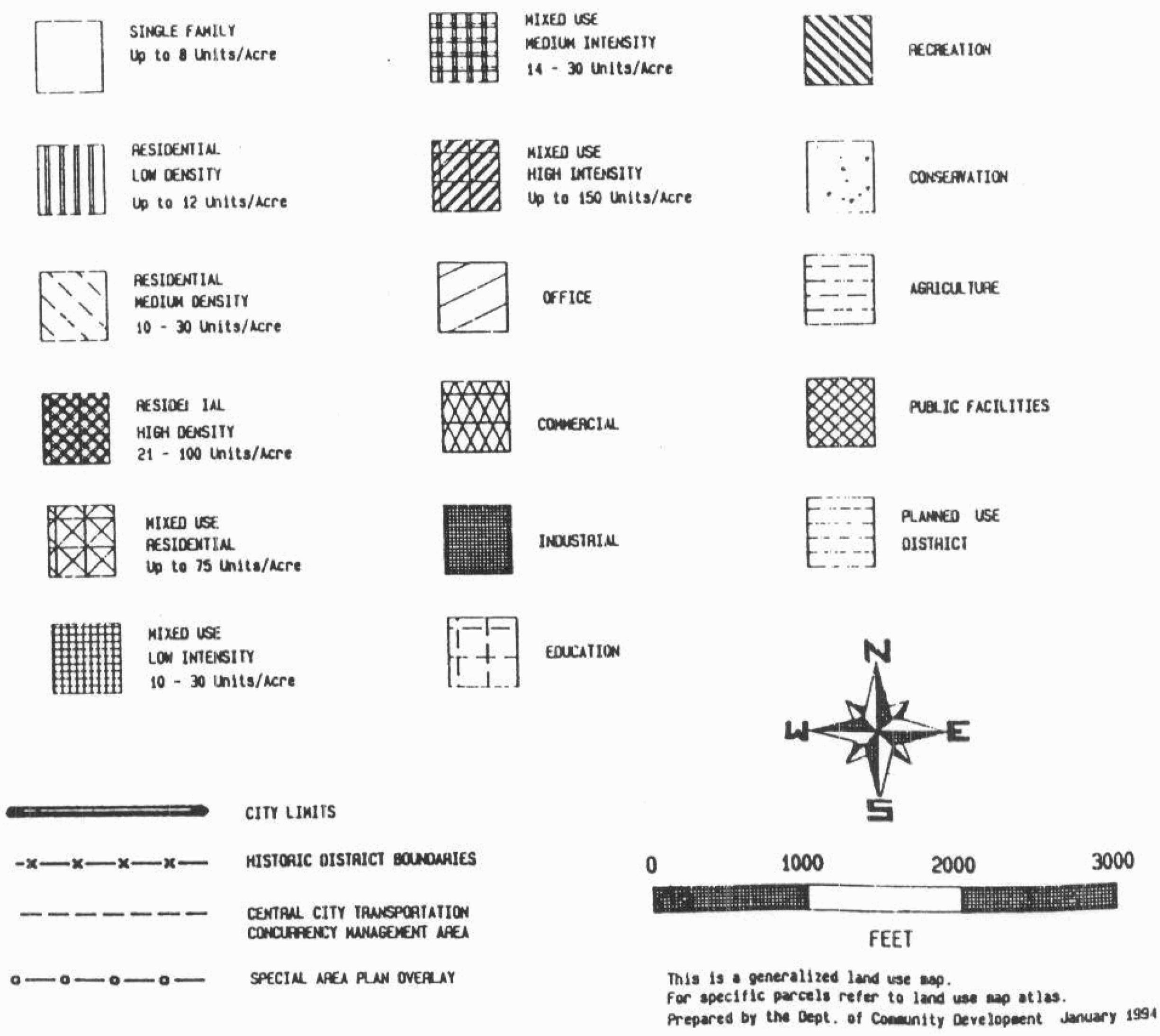


Figure 2

Figure 3

Figure 4.1

CITY OF GAINESVILLE
GENERALIZED FUTURE LAND USE MAP
1991-2001 COMPREHENSIVE PLAN



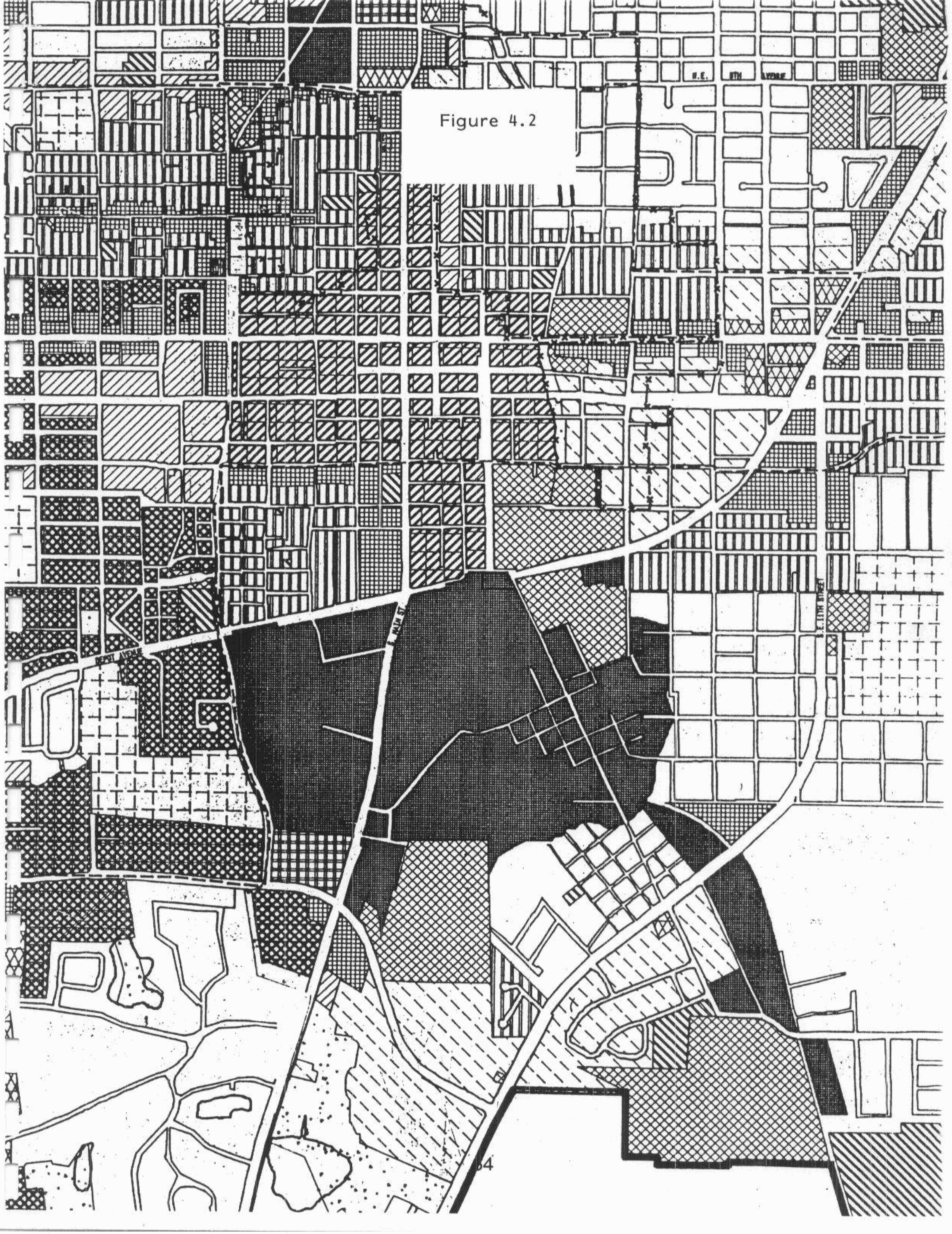


Figure 4.2