ORIGINAL

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

April 1, 2002

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 5 copies of its 2002 Ten Year Site Plan for your review. GRU will copy separately the reviewing agencies named in the correspondence from FRCC dated March 15, 2002. 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,

N. Todd Kamhoot for ER

Ed Regan
Strategic Planning Director

Enclosures

File: PSC - Ten Year Site Plan

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GAINESVILLE REGIONAL UTILITIES

2002 TEN-YEAR SITE PLAN

Submitted to:

The Florida Public Service Commission

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1. INTRODUCTION

The 2002 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 five sections of the 2002 Ten-Year Site Plan are:

- Introduction
- Description of Existing Facilities
- Forecast of Electric Energy and Demand Requirements
- Forecast of Facilities Requirements
- Environmental and Land Use Information

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 425 megawatts on July 20, 2000. The repowering of J. R. Kelly Unit 8 to a 110 megawatt combined-cycle unit was recently completed and increased net summer capability to 610 megawatts. The new JRK CC1 provides benefit to the system in improved operating efficiency; reduced emission rates; reduced total emissions; and participation in the redevelopment of downtown Gainesville, while increasing system capacity at a time when the reserve margin for Peninsular Florida is relatively tight.

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 80,587 customers (December, 2001). 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. GRU's combined cycle unit, which is a combination of a gas turbine, a heat recovery steam generator (to capture the waste heat from the gas turbine and generate steam), and a steam turbine, is located at the John R. Kelly Station.

The present summer net capability is 610 MW and the winter net capability is 629 MW[1]. Currently, the System's energy is produced by three fossil fuel steam turbines, six simple-cycle combustion turbines, one combined-cycle unit, and a 1.4% ownership share of the Crystal River 3 nuclear unit, which is operated by Florida Power Corporation (FPC).

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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.

2.1.1 Generating Units

2.1.1.1 Steam Turbines. The System's three operational steam turbines are powered by fossil fuels and Crystal River 3 is nuclear powered. The fossil fueled steam turbines comprise 54.8% of the System's net summer capability and produced 84.0% of the electric energy supplied by the System in 2001. These units range in size from 23.2 MW to 228.4 MW. The recently installed combined-cycle unit comprises 18.4% of the System's net summer capability and produced 8.2% of the electric energy supplied by the System in 2001. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 1.8% of the System's net summer capability.

Both Deerhaven 2 and Crystal River 3 are used for base load purposes, while Kelly 7 and Kelly CC1 and Deerhaven 1 are used for intermediate loading.

2.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 25.1% 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 one combined cycle, one steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

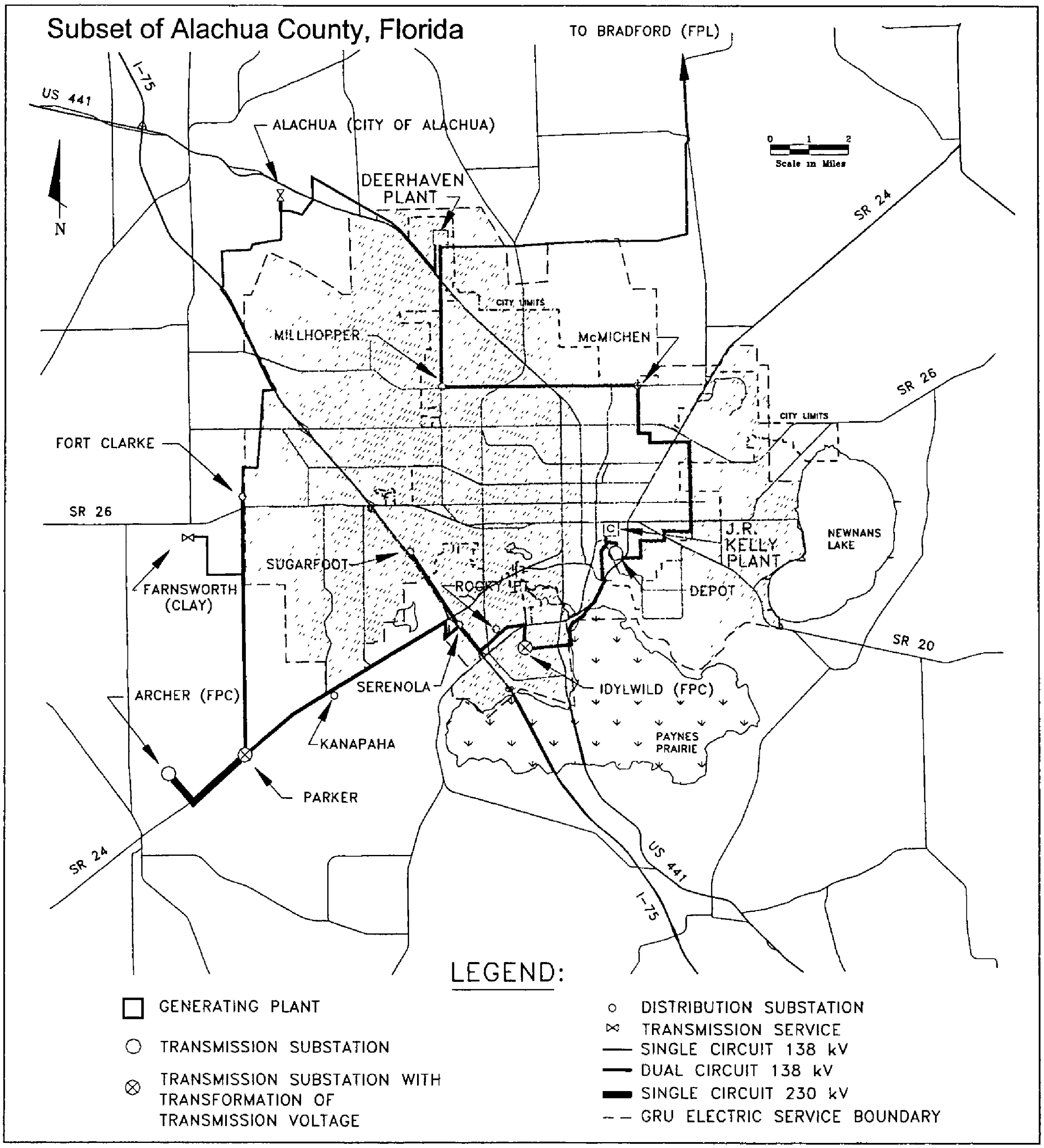

Figure 2.1, Gainesville Regional Utilities Electric Facilities

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. A buffer/expansion area of 1,153 acres was added to the East side of Deerhaven Station. 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 eight 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 and two minor distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Sugarfoot, Rocky Point and Kanapaha substations, respectively. The locations of these substations are shown on Figure 2.1.

Six of GRU's distribution substations are connected to the 138 kV bulk power transmission network with dual feeds, while Rocky Point and Kanapaha are served by a single tap to the 138 kV network. This prevents the outage of a single transmission line from causing major outages in the distribution system. 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, Kanapaha, was brought on-line in 2002 to serve the growing load in the area of State Road 24 and SW 91st Terrace and to provide backup support for the Serenola, Sugarfoot, and Fort Clarke substations. McMichen, Serenola, Ft. Clarke, and Kelly substations currently consist of two transformers of equal size allowing these stations to be loaded under normal conditions 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),

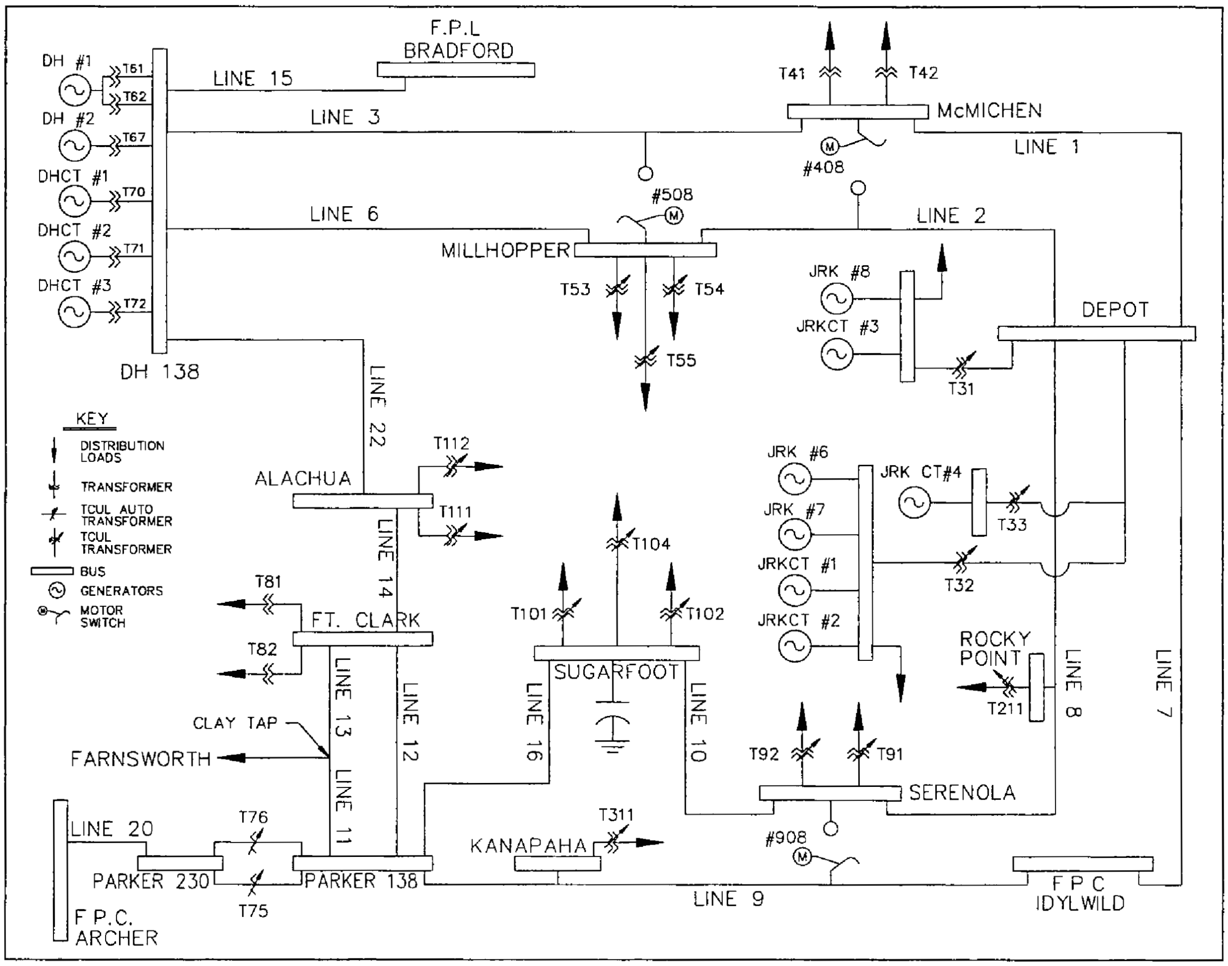

FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.

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 90% 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. This agreement was assigned to the FMPA in 1998 when Starke became an "All Requirements" member of FMPA.

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 through 2002.

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 from December 17, 2001 through March 15, 2002.

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	10
McMichen	44.8 MVA	6
J. R. Kelly[2]	112.0 MVA	18
Kanapaha	33.6 MVA	1
Rocky Point	33.6 MVA	3
Serenola	67.2 MVA	8
Sugarfoot	100.8 MVA	8
Ft. Clarke	44.8 MVA	4

[2] J. R. Kelly is a generating station as well as a distribution substation. The CT portion (75 MW) of JRK CC 1 is connected directly to the 138 kV distribution line from Depot Transmission Substation to J. R. Kelly Distribution Substation/Generation Station and the steam portion is connected to the substation bus along with the remaining generation capacity at J. R. Kelly Station (102 MW).

Schedule 1

EXISTING GENERATING FACILITIES
(As of December 31, 2001)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
								Alt.							
								Fuel	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Primary Fuel		Alternate Fuel		Storage	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	MW	MW	MW	MW	Status
J. R. Kelly		12-001											177	186	
		(Alachua Co.,													
	FS08	Section 4, Township	CA	WH	PL				(4/65)/(5/01)	Unknown	38	38	37	37	OP
	FS07	10 S, Range 20E)	ST	NG	PL	RFO	TK		8/61	Unknown	24	24	23	23	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	Unknown	76	82	75	81	OP
	GT03		GT	NG	PL	DFO	TK		5/69	Unknown	14	15	14	15	OP
	GT02		GT	NG	PL	DFO	TK		9/68	Unknown	14	15	14	15	OP
	GT01		GT	NG	PL	DFO	TK		2/68	Unknown	14	15	14	15	OP
Deerhaven		12-001									451	461	422	432	
		(Alachua Co., Sections													
	FS02	26,27,35, Township	ST	BIT	RR				10/81	Unknown	249	249	228	228	OP
	FS01	8 S, Range 19 E)	ST	NG	PL	RFO	TK		8/72	Unknown	88	88	83	83	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	Unknown	76	82	75	81	OP
	GT02		GT	NG	PL	DFO	TK		8/76	Unknown	19	21	18	20	OP
	GT01		GT	NG	PL	DFO	TK		7/76	Unknown	19	21	18	20	OP
Crystal River	3	12-017	ST	NUC	TK				3/77	Unknown	11	11	11	11	OP
(818/815)		(Citrus Co.,													
		Section 33, Township													
		17 S, Range 16 E)													
		(FPC)													
System Total													610	629	

<u>Unit Type</u>
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine

<u>Fuel Type</u>
NG = Natural Gas
BIT = Bituminous Coal
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil
WH = Waste Heat

<u>Transportation Method</u>
PL = Pipe Line
RR = Railroad
TK = Truck

<u>Status</u>
OP = Operational

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 1992-2011. 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 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 2000. 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, February 2000 (Bulletin No. 126), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida. Projections from Bulletin No. 126 were trued to Census 2000 population estimates.

(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 (1984-2000).

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 1998, 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 be 3% per year for each year of the forecast.

(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 2000.

(6) The Florida Long Term Economic Forecast 2000 and Florida Population Studies, Bulletin 125, were used to estimate and project the number of persons per household (household size) in Alachua County.

(7) The Florida Long Term Economic Forecast 2000 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 prices. If revenue from present pricing is insufficient, pricing changes are programmed in and become GRU's official pricing program plan. Programmed price increases from the model for all retail customer 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. 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 (10%) 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 2002 through 2011. 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:

$$RESAVUSE = 4790.2 + 0.07\,(HHY98) - 10.98\,(RESPR98) + 0.68\,(HDD) + 0.91\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use
HHY98	=	Average Household Income
RESPR98	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

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

Adjusted R^2	=	0.8890
DF (error)	=	25
t - statistics:		
Intercept	=	3.99
HHY98	=	6.98
RESPR98	=	-2.41
HDD	=	3.88
CDD	=	4.66

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, lagged one year. The residential customer model specifications are:

$$RESCUS = -25598 + 431.9\,(LAGPOP)$$

Where:

RESCUS	=	Number of Residential Customers
LAGPOP	=	Alachua County Population (thousands), lagged one year
Adjusted R^2	=	0.9958
DF (error)	=	21
t - statistics:		
Intercept	=	-24.00
LAGPOP	=	71.89

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 (GSN) customer class includes non-residential customers with maximum annual demands less than 50 kilowatts (kW). In 1990, GRU began offering GSN customers the option to enter the General Service Demand (GSD) class. This option offers potential benefit to GSN customers that use high amounts of energy, and 210 customers have elected to voluntarily transfer to the GSD class since 1990. Regression models were tested, but an insufficient amount of the variation in historical usage was fit. Average use by GSN customers was projected to remain constant at 26,348 kWh per customer per year. This figure represents median usage since GRU began offering the optional GSD rate in 1990.

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

$$GNDCUS = -4708.0 + 57.75\,(LAGPOP)$$

Where:

GNDCUS = Number of General Service Non-Demand Customers

LAGPOP = Alachua County Population (thousands), lagged on year

Adjusted R^2 = 0.9850

DF (error) = 21

t - statistics:

Intercept = -17.45

LAGPOP = 38.00

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:

$$DEMAVUSE = 389.67 + 0.0070\,(PCY98)$$

Where:

DEMAVUSE	=	Average Annual Energy Use for General Service Demand Customers (MWh per Year)
PCY98	=	Per Capita Income in Alachua County
Adjusted R^2	=	0.7826
DF (error)	=	20
t - statistics:		
Intercept	=	23.99
PCY98	=	8.75

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

$$DEMCUS = -466.71 + 5.69\,(LAGPOP)$$

Where:

DEMCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands), lagged one year

Adjusted R^2	=	0.9699
DF (error)	=	20
t - statistics:		
Intercept	=	-11.93
POP	=	26.05

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 17 customers with billing demands of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1976 through 2000. 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 periodic expansion of existing facilities. This growth is measured in the model by local employment levels. The specifications of the large power average use model are as follows:

$$LPAVUSE = 10211 + 19.13\,(NONAG) - 39.81\,(LPPR98)$$

Where:

LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
NONAG	=	Alachua County Nonagricultural Employment (000's)
LPPR98	=	Average Price for 1,000 kWh in the Large Power Sector
Adjusted R^2	=	0.8965
DF (error)	=	22

t - statistics:

INTERCEPT	=	5.68
NONAG	=	1.97
LPPR98	=	-3.00

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. Outdoor lighting energy sales account for less than 1.5% of total energy sales. Outdoor lighting energy sales were forecast using a model which specified lighting energy as a function of the number of residential customers. The specifications of this model are as follows:

LGTMWH = -7841.5 + 0.43 (RESCUS)

Where:

LGTMWH	=	Outdoor Lighting Energy Sales
RESCUS	=	Number of Residential Customers
Adjusted R^2	=	0.9527
DF (error)	=	9

t - statistics:

Intercept	=	-4.12
RESCUS	=	14.22

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 10% of Alachua's 2001 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:

$$CLYMWH = -21274 + 17.83\,(COY98)$$

Where:

CLYMWH	=	Megawatt-Hour Sales to Clay
COY98	=	Total Personal Income (Alachua County)
Adjusted R^2	=	0.9340
DF (error)	=	19
t - statistics:		
Intercept	=	-5.18
COY98	=	16.85

Net energy requirements for Alachua were estimated using a model in which City of Alachua total income and cooling degree days were the independent variables. City of Alachua total income is 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	=	*-32442 + 0.60 (ALAY98) + 7.29 (CDD)*
Where:		
ALANEL	=	Net Energy Requirements of Alachua
ALAY98	=	City of Alachua Total Income
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9697
DF (error)	=	18
t - statistics:		
Intercept	=	-3.56
ALAPOP	=	25.25
CDD	=	2.39

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 was determined from an analysis of observed historical values from 1984 through 2000, and is projected to be approximately 95%.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load. Winter peak demands are projected to occur in January of each year, and summer peak demands are projected to occur in July of each year, although historical data suggests the summer peak is nearly as likely to occur in August. The average ratio of the most recent 17 years' monthly net energy for load for January and

July, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and July net energy for load over the forecast horizon. The medians of the past 17 years' load factors for January and July were applied to January and July 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 nearly equal for January and February. Likewise, the historical data indicates that summer peak demands are likely to be nearly 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 4% to 6% of net generation. Post 1984 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. 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 Programs

Demand and energy forecasts and generation expansion plans outlined in this Ten Year Site Plan include impacts from GRU's Demand-Side Management (DSM) programs. The System forecast reflects historical program implementations recorded from 1980 through 2001, as well as projected program implementations scheduled through 2011. GRU's DSM programs were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU. DSM programs are available for all retail 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 residential conservation efforts: energy audits; low income household weatherization and natural gas extension; promotion of natural gas in residential construction; promotion of natural gas for displacement of electric water heating, space heating and space cooling in existing structures; and promotion of solar water heating. GRU offers the following conservation services to its non-residential customers: energy audits; lighting efficiency and maintenance services; and promotion of natural gas for water heating, space cooling and dehumidification.

GRU continues to monitor the potential for additional conservation efforts including programs addressing high-efficiency air conditioning, heat recovery, duct leakage, heat pipes, reflective roof coatings, thermal storage and window shading. GRU is also developing a 10 kW photovoltaic project at the Gainesville Regional Airport to promote the use of renewable energy. This project will be funded through voluntary customer contributions, avoided utility costs and grant funding.

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 energy usage of DSM program participants and non-participants. The methodology upon which existing DSM programs 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 8 MW of summer peak reduction, 18 MW of winter peak reduction and 65 GWh of annual energy savings by the year 2011. 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 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. The GEAC has strongly supported the EPA's Energy Star program, and helped GRU earn EPA's 1998 Utility Ally of the Year award. Current GEAC activities include development of a Green Builder program for existing multi-family dwellings as a long-range load reduction strategy. Multi-family dwellings represent approximately 35% of GRU's total residential load.

3.4.3 Supply Side Programs

Deerhaven 2 is also contributing to reduced oil use by other utilities through the Florida energy market. 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 2001, oil-fired generation comprised 2.1% of total net generation, natural gas-fired generation contributed 22.5%, nuclear fuel contributed 4.7%, and coal-fired generation provided 70.7% of total net generation. The PV system at ESCC provides slightly more than 10 kilowatts of capacity at solar noon on clear days. The proposed landfill gas to energy (LFGTE) project could provide approximately 2.4 MW of capacity on a continuous basis.

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 near 5% 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 2002 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 2001. 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 five 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.

The price of crude oil increased about 60% from 1999 to 2000, but dropped approximately 22% from 2000 to 2001. Over the next 10 years, the price of No.2 oil delivered to GRU is expected to increase 3.5% 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 4.6% 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 sulfur compliance coal, which is presently used by the System; pulverized coal for flue gas desulfurization; 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 desulfurization 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 0.5% for low sulphur compliance coal, pulverized coal for flue gas desulphurization, and fluidized bed compatible coal from 2001 through 2010.

3.5.3 Natural Gas

Natural gas is expected to experience a higher rate of growth in demand than other fuels. Following a period of low and stable prices through 1999, gas prices climbed rapidly in 2000 and peaked in 2001. Currently, gas prices appear to be lowering to more stable levels.

GRU 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 transportation charge; and FGT's reservation charge.

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

Based on the above factors, the price of natural gas delivered to GRU is expected to increase at an annual rate of 4.5% from 2002 through 2011.

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 4.0% 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
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	164,503	2.40	763	68,543	11,137	648	8,095	80,036
2000	168,804	2.40	788	70,335	11,202	674	8,368	80,490
2001	173,738	2.40	803	72,391	11,092	697	8,603	80,986
2002	175,749	2.40	833	73,229	11,378	713	8,794	81,058
2003	179,273	2.40	855	74,697	11,445	731	9,009	81,179
2004	182,694	2.40	876	76,123	11,505	749	9,219	81,293
2005	186,218	2.40	899	77,591	11,582	769	9,434	81,492
2006	189,639	2.40	922	79,016	11,664	789	9,644	81,770
2007	192,956	2.40	942	80,398	11,723	808	9,847	82,058
2008	196,273	2.40	963	81,781	11,772	827	10,050	82,261
2009	199,590	2.40	983	83,163	11,817	845	10,252	82,404
2010	202,907	2.40	1,003	84,545	11,861	863	10,455	82,543
2011	206,224	2.40	1,020	85,927	11,872	881	10,658	82,611

* 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 **				Street and	Other Sales	Total Sales
		Average	Average	Railroads	Highway	to Public	to Ultimate
		Number of	MWh per	and Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Customer	GWh	GWh	GWh	GWh
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	173	17	10,188	0	22	0	1,606
2000	172	17	10,114	0	22	0	1,656
2001	173	17	10,162	0	23	0	1,696
2002	177	17	10,417	0	24	0	1,747
2003	180	17	10,566	0	24	0	1,790
2004	182	17	10,696	0	25	0	1,832
2005	184	17	10,825	0	25	0	1,877
2006	185	17	10,901	0	26	0	1,922
2007	186	17	10,951	0	27	0	1,963
2008	187	17	10,993	0	27	0	2,003
2009	188	17	11,033	0	28	0	2,043
2010	188	17	11,070	0	28	0	2,082
2011	189	17	11,110	0	29	0	2,118

** Industrial represents Large Power Rate Class.

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales For Resale GWh	Utility Use and Losses GWh	Net Energy for Load GWh	Other Customers	Total Number of Customers
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	83	1,798	0	76,655
2000	120	93	1,868	0	78,720
2001	125	62	1,882	0	81,011
2002	129	98	1,974	0	82,039
2003	134	101	2,025	0	83,723
2004	139	103	2,074	0	85,358
2005	82	103	2,062	0	87,042
2006	86	105	2,112	0	88,677
2007	89	108	2,160	0	90,262
2008	92	110	2,205	0	91,847
2009	94	112	2,250	0	93,432
2010	97	114	2,294	0	95,017
2011	100	117	2,335	0	96,602

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
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	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	438	28	397	0	0	7	0	6	425
2001	423	28	381	0	0	7	0	7	409
2002	445	30	402	0	0	7	0	6	432
2003	456	31	413	0	0	6	0	6	444
2004	466	32	423	0	0	6	0	5	455
2005	464	18	435	0	0	6	0	5	453
2006	474	19	445	0	0	6	0	4	464
2007	485	20	455	0	0	6	0	4	475
2008	494	20	465	0	0	6	0	3	485
2009	503	21	474	0	0	6	0	2	495
2010	513	21	485	0	0	5	0	2	506
2011	523	22	493	0	0	6	0	2	515

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

(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
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	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	423	28	381	0	0	7	0	7	409
2002	449	30	406	0	0	7	0	6	436
2003	463	32	419	0	0	6	0	6	451
2004	477	33	433	0	0	6	0	5	466
2005	478	19	448	0	0	6	0	5	467
2006	492	20	462	0	0	6	0	4	482
2007	507	21	476	0	0	6	0	4	497
2008	521	22	490	0	0	6	0	3	512
2009	534	23	503	0	0	6	0	2	526
2010	547	24	516	0	0	5	0	2	540
2011	562	25	529	0	0	6	0	2	554

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

(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
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	411	26	370	0	0	8	0	7	396
1999	434	26	393	0	0	8	0	7	419
2000	440	28	397	0	0	8	0	7	425
2001	423	28	381	0	0	7	0	7	409
2002	442	29	400	0	0	7	0	6	429
2003	449	30	407	0	0	6	0	6	437
2004	456	31	414	0	0	6	0	5	445
2005	451	17	423	0	0	6	0	5	440
2006	458	18	430	0	0	6	0	4	448
2007	466	18	438	0	0	6	0	4	456
2008	472	19	444	0	0	6	0	3	463
2009	477	19	450	0	0	6	0	2	469
2010	482	20	455	0	0	5	0	2	475
2011	489	20	461	0	0	6	0	2	481

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Winter	(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
1992 / 1993	290	22	237	0	0	25	0	6	259
1993 / 1994	319	23	262	0	0	27	0	7	285
1994 / 1995	350	25	289	0	0	29	0	7	314
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	401	33	336	0	0	27	0	6	369
2002 / 2003	388	31	326	0	0	26	0	5	357
2003 / 2004	397	32	335	0	0	25	0	5	367
2004 / 2005	394	18	348	0	0	24	0	4	366
2005 / 2006	403	19	358	0	0	23	0	3	377
2006 / 2007	411	20	367	0	0	21	0	3	387
2007 / 2008	418	21	376	0	0	19	0	2	397
2008 / 2009	426	21	386	0	0	18	0	1	407
2009 / 2010	434	22	395	0	0	16	0	1	417
2010 / 2011	441	23	400	0	0	17	0	1	423
2011 / 2012	449	23	407	0	0	18	0	1	430

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

(1) Winter	(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
1992 / 1993	290	22	237	0	0	25	0	6	259
1993 / 1994	319	23	262	0	0	27	0	7	285
1994 / 1995	350	25	289	0	0	29	0	7	314
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	401	33	336	0	0	27	0	6	369
2002 / 2003	394	32	331	0	0	26	0	5	363
2003 / 2004	407	34	342	0	0	26	0	5	376
2004 / 2005	407	19	359	0	0	25	0	4	378
2005 / 2006	419	20	372	0	0	24	0	3	392
2006 / 2007	431	21	385	0	0	22	0	3	406
2007 / 2008	442	22	398	0	0	20	0	2	420
2008 / 2009	454	23	411	0	0	19	0	1	434
2009 / 2010	465	24	423	0	0	17	0	1	447
2010 / 2011	476	25	432	0	0	18	0	1	457
2011 / 2012	489	26	442	0	0	20	0	1	468

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

(1) Winter	(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
1992 / 1993	290	22	237	0	0	25	0	6	259
1993 / 1994	319	23	262	0	0	27	0	7	285
1994 / 1995	350	25	289	0	0	29	0	7	314
1995 / 1996	381	28	317	0	0	29	0	7	345
1996 / 1997	343	26	280	0	0	30	0	7	306
1997 / 1998	319	23	259	0	0	30	0	7	282
1998 / 1999	389	28	323	0	0	31	0	7	351
1999 / 2000	373	27	310	0	0	29	0	7	337
2000 / 2001	398	33	331	0	0	28	0	6	364
2001 / 2002	401	33	336	0	0	27	0	6	369
2002 / 2003	382	30	321	0	0	26	0	5	351
2003 / 2004	387	31	327	0	0	24	0	5	358
2004 / 2005	382	18	337	0	0	23	0	4	355
2005 / 2006	388	18	345	0	0	22	0	3	363
2006 / 2007	393	19	351	0	0	20	0	3	370
2007 / 2008	397	19	358	0	0	18	0	2	377
2008 / 2009	402	19	365	0	0	17	0	1	384
2009 / 2010	406	20	370	0	0	15	0	1	390
2010 / 2011	410	20	373	0	0	16	0	1	393
2011 / 2012	415	21	376	0	0	17	0	1	397

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 %
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	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,044	51	19	1,746	129	99	1,974	52.16%
2003	2,094	52	17	1,790	134	101	2,025	52.06%
2004	2,143	53	16	1,831	139	104	2,074	52.03%
2005	2,131	54	15	1,877	82	103	2,062	51.96%
2006	2,180	55	13	1,921	86	105	2,112	51.96%
2007	2,226	55	11	1,963	89	108	2,160	51.91%
2008	2,269	55	9	2,003	92	110	2,205	51.90%
2009	2,313	55	8	2,043	94	113	2,250	51.89%
2010	2,356	55	7	2,083	97	114	2,294	51.75%
2011	2,400	58	7	2,119	100	116	2,335	51.76%

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

(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 %
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	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,062	51	19	1,761	132	99	1,992	52.16%
2003	2,131	53	17	1,820	138	103	2,061	52.05%
2004	2,199	54	16	1,877	145	107	2,129	52.04%
2005	2,203	56	16	1,939	86	106	2,131	51.98%
2006	2,271	57	14	2,000	91	109	2,200	51.89%
2007	2,338	58	12	2,059	95	114	2,268	51.88%
2008	2,401	58	10	2,117	99	117	2,333	51.81%
2009	2,466	59	9	2,175	103	120	2,398	51.85%
2010	2,529	59	8	2,233	107	122	2,462	51.76%
2011	2,595	63	8	2,286	112	126	2,524	51.73%

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

(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 %
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	1,847	47	21	1,595	108	76	1,779	51.28%
1999	1,869	50	21	1,606	109	83	1,798	48.99%
2000	1,939	50	21	1,656	120	93	1,868	50.19%
2001	1,953	50	20	1,696	125	62	1,882	52.54%
2002	2,027	51	19	1,734	126	97	1,957	52.20%
2003	2,061	51	17	1,763	130	100	1,993	52.06%
2004	2,095	52	16	1,793	133	101	2,027	52.00%
2005	2,068	52	15	1,823	78	100	2,001	52.03%
2006	2,101	53	13	1,852	81	102	2,035	51.97%
2007	2,130	53	11	1,880	83	103	2,066	51.95%
2008	2,155	52	9	1,905	85	104	2,094	51.85%
2009	2,181	52	8	1,928	87	106	2,121	51.85%
2010	2,205	51	7	1,950	89	108	2,147	51.82%
2011	2,228	54	6	1,969	91	108	2,168	51.78%

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL		FORECAST			
	2001		2002		2003	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	364	160	347	152	357	156
FEB	285	122	344	133	353	136
MAR	259	130	289	139	297	143
APR	298	141	312	140	321	144
MAY	363	165	373	169	383	174
JUN	386	176	418	187	429	192
JUL	389	192	432	204	444	209
AUG	409	206	428	207	439	212
SEP	367	169	406	190	417	195
OCT	334	149	354	160	363	164
NOV	267	131	307	141	315	144
DEC	280	141	336	153	345	156

Schedule 5
FUEL REQUIREMENTS
As Of JANUARY 1, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				ACTUAL	ACTUAL										
	FUEL REQUIREMENTS		UNITS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	NUCLEAR		TRILLION BTU	1	1	1	1	1	1	1	1	1	1	1	1
(2)	COAL		1000 TON	572	574	591	563	570	580	589	598	591	604	603	607
	RESIDUAL														
(3)		STEAM	1000 BBL	96	70	0	0	0	0	0	0	0	0	0	0
(4)		CC	1000 BBL	0	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	0
(6)		TOTAL:	1000 BBL	96	70	0	0	0	0	0	0	0	0	0	0
	DISTILLATE														
(7)		STEAM	1000 BBL	1	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	7	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	2	7	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	3	14	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS														
(11)		STEAM	1000 MCF	3,488	2,677	1,438	1,206	1,289	1,076	1,125	1,283	1,488	1,617	1,690	1,831
(12)		CC	1000 MCF	0	1,425	4,012	3,716	3,597	3,795	3,865	3,959	3,998	4,151	4,171	4,126
(13)		CT	1000 MCF	1,336	810	647	676	873	475	530	645	930	748	1,129	1,463
(14)		TOTAL:	1000 MCF	4,824	4,912	6,097	5,598	5,759	5,346	5,520	5,887	6,416	6,516	6,990	7,420
(15)	OTHER (SPECIFY)		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0	0

Schedule 5, 6-1, 6-2 xls

Schedule 6.1
ENERGY SOURCES (GWH)
As Of JANUARY 1, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				ACTUAL	ACTUAL										
	ENERGY SOURCES		UNITS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR		GWH	101	92	82	71	82	71	82	71	82	71	82	71
(3)	COAL		GWH	1,379	1,384	1,486	1,406	1,426	1,451	1,476	1,501	1,487	1,520	1,520	1,536
	RESIDUAL														
(4)		STEAM	GWH	54	36	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)		TOTAL:	GWH	54	36	0	0	0	0	0	0	0	0	0	0
	DISTILLATE														
(8)		STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)		CC	GWH	0	3	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWH	0	2	0	0	0	0	0	0	0	0	0	0
(11)		TOTAL:	GWH	0	5	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS														
(12)		STEAM	GWH	296	223	125	103	111	93	97	111	129	141	147	159
(13)		CC	GWH	0	158	456	406	389	413	420	433	439	463	463	461
(14)		CT	GWH	100	59	46	51	66	34	37	44	68	55	82	108
(15)		TOTAL:	GWH	396	440	627	560	566	540	554	588	636	659	692	728
(16)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(17)	HYDRO		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(18)	OTHER (NET INTRA-REGION INTERCHANGE)		GWH	-62	-75	-221	-12	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWH	1,868	1,882	1,974	2,025	2,074	2,062	2,112	2,160	2,205	2,250	2,294	2,335

Schedule 5, 6-1, 6-2 xls

Schedule 6.2
ENERGY SOURCES (%)
As Of JANUARY 1, 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				ACTUAL	ACTUAL										
	ENERGY SOURCES		UNITS	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	ANNUAL FIRM INTER-REGION INTERCHANGE		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(2)	NUCLEAR		%	5%	5%	4%	4%	4%	3%	4%	3%	4%	3%	4%	3%
(3)	COAL		%	74%	74%	75%	69%	69%	70%	70%	69%	67%	68%	66%	66%
	RESIDUAL														
(4)		STEAM	%	3%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(5)		CC	%	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%
(7)		TOTAL:	%	3%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	DISTILLATE														
(8)		STEAM	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(10)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		TOTAL:	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	NATURAL GAS														
(12)		STEAM	%	16%	12%	6%	5%	5%	5%	5%	5%	6%	6%	6%	7%
(13)		CC	%	0%	8%	23%	20%	19%	20%	20%	20%	20%	21%	20%	20%
(14)		CT	%	5%	3%	2%	3%	3%	2%	2%	2%	3%	2%	4%	5%
(15)		TOTAL:	%	21%	23%	32%	28%	27%	26%	26%	27%	29%	29%	30%	31%
(16)	NUG		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(17)	HYDRO		%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(18)	OTHER (SPECIFY)		%	-3%	-4%	-11%	-1%	0%	0%	0%	0%	0%	0%	0%	0%
(19)	NET ENERGY FOR LOAD		%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

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 capacity addition was a repowering of JRK Unit 8 (49.5 MW) to a combined cycle unit (JRK CC1, 110 MW) at the J.R. Kelly Station. It began commercial operation on May 3, 2001.

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: 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 net present value of revenue requirements, considering the net present value of the optimization time frame.

GRU is evaluating the economic feasibility of developing a landfill gas to energy (LFGTE) project at the Alachua County Southwest Landfill and wheeling the power over the Florida Power Corporation distribution network from the landfill to the Archer substation where GRU connects to the FPC system. This LFGTE project, if feasible, could provide up to 2.4 MW of green power on a continuous basis during the first year of operation. The generation capacity of the LFGTE system will diminish through time as the landfill gas production rate slows.

4.1.2 Green Pricing

GRU is developing a green pricing program to sell green energy produced at the Southwest landfill to interested customers. GRU plans to market the output in discrete blocks of energy to residential and commercial customers.

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 installing a new 10 kW PV system at the Gainesville Regional Airport. This project will be supported by voluntary customer contributions, avoided utility costs and grant funding.

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. Summer reserve margins are forecast to be at least 18% (of peak demand) through 2011.

4.3 DISTRIBUTION SYSTEM ADDITIONS

Four new identical mini-power delivery substations (PDS) are planned for the GRU system. The first, Rocky Point, located near the intersection of SW Williston Road and SW 23rd Terrace in Gainesville, was installed the summer of 2000. The second, Kanapaha, is located in the 8800 block of SW Archer Road and was installed spring of 2002. The third, Ironwood, to be located at 1800 NE 31st Avenue is planned for March 2003. The fourth and last of this series to be located within the transmission right-of-way one-half mile north of NW 39th Avenue is planned for 2005. This last PDS will require the modification of the transmission structures. These new PDSs have been planned in response to heavy loading on the existing substations, with more major load development planned for GRU's service territory.

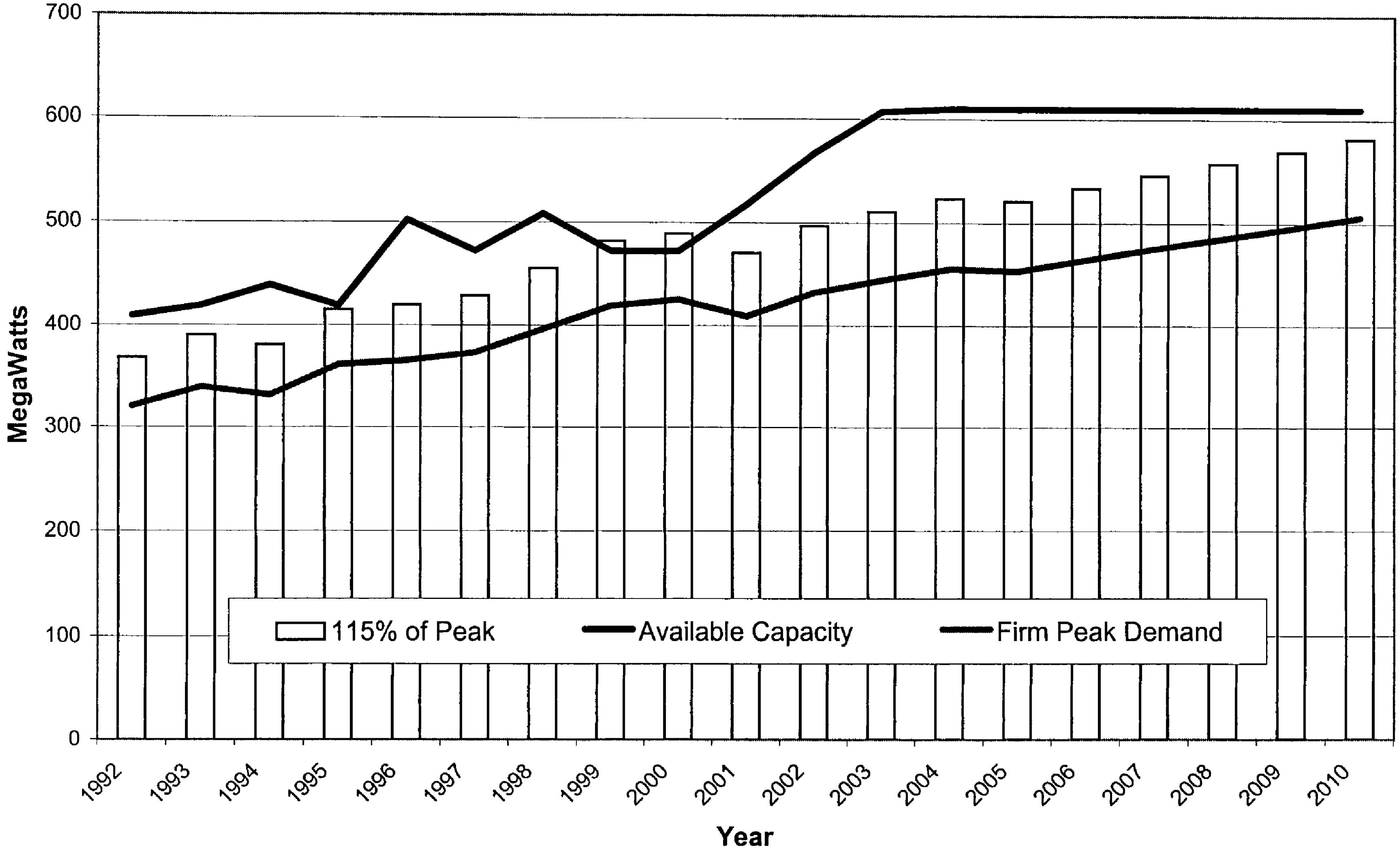
Each PDS will consist of one or more 138-12.47 KV, 33.6 MVA, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new PDSs to other, existing adjacent area substations will allow for backup in the event of a substation transformer failure.

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
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	419	53	13%	14	39	9%
2000	550	0	78	0	472	425	47	11%	0	47	11%
2001	610	0	93	0	517	409	108	26%	0	108	26%
2002	610	0	43	0	567	432	135	31%	0	135	31%
2003	610	0	3	0	607	444	163	37%	0	163	37%
2004	610	0	0	0	610	455	155	34%	0	155	34%
2005	610	0	0	0	610	453	157	35%	0	157	35%
2006	610	0	0	0	610	464	146	31%	0	146	31%
2007	610	0	0	0	610	475	135	28%	0	135	28%
2008	610	0	0	0	610	485	125	26%	0	125	26%
2009	610	0	0	0	610	495	115	23%	0	115	23%
2010	610	0	0	0	610	506	104	21%	0	104	21%
2011	610	0	0	0	610	515	95	18%	0	95	18%

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

Gainesville Regional Utilities
Summer Peak Demand and Generation Capacity

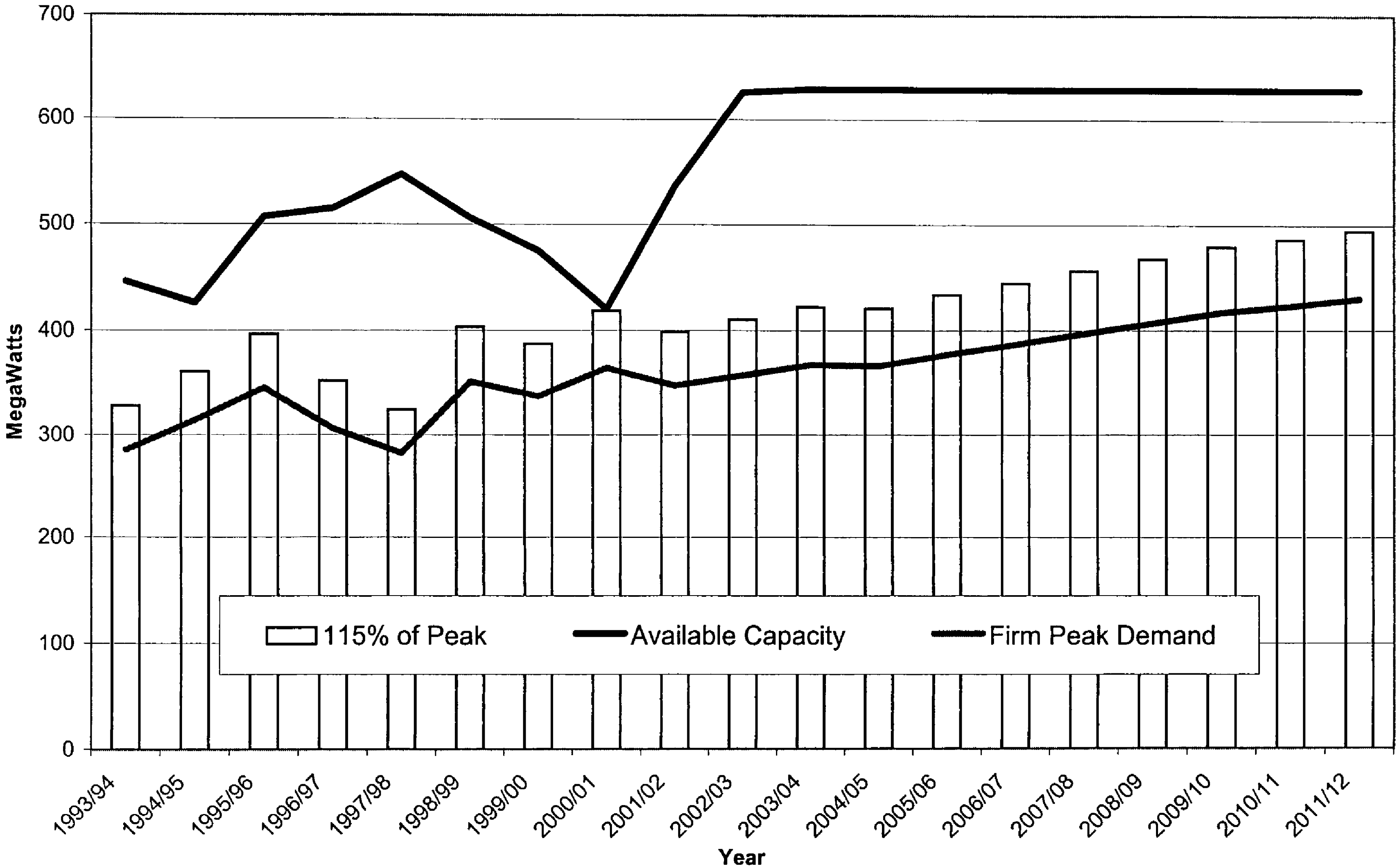


Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(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
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	306	209	68%	0	209	68%
1997/98	540	30	23	0	547	282	265	94%	0	265	94%
1998/99	563	31	88	0	506	351	155	44%	0	155	44%
1999/00	563	0	88	0	475	337	138	41%	15	123	36%
2000/01	513	0	93	0	420	364	56	15%	0	56	15%
2001/02	629	0	93	0	536	347	189	54%	0	189	54%
2002/03	629	0	3	0	626	357	269	75%	0	269	75%
2003/04	629	0	0	0	629	367	262	71%	0	262	71%
2004/05	629	0	0	0	629	366	263	72%	0	263	72%
2005/06	629	0	0	0	629	377	252	67%	0	252	67%
2006/07	629	0	0	0	629	387	242	63%	0	242	63%
2007/08	629	0	0	0	629	397	232	58%	0	232	58%
2008/09	629	0	0	0	629	407	222	55%	0	222	55%
2009/10	629	0	0	0	629	417	212	51%	0	212	51%
2010/11	629	0	0	0	629	423	206	49%	0	206	49%
2011/12	629	0	0	0	629	430	199	46%	0	199	46%

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

Gainesville Regional Utilities
Winter Peak Demand and Generation Capacity



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)	(16)
								Const.	Commercial	Expected	Gross Capability		Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Summer	Winter	Summer	Winter	
Plant Name	No,	Location	Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	(MW)	(MW)	(MW)	(MW)	Status

no planned additions at this time

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

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

Transportation Method
PL = Pipe Line
TK = Truck

Status
FC = Existing generator, planned for conversion to another energy source.
V = Under construction, more than 50% complete.
TS = Construction complete, but not yet in commercial operation.

5. ENVIRONMENTAL AND LAND USE INFORMATION

5.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

There are no new generating facilities planned.

5.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

Not applicable.

5.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Not applicable.