GRU[SM]
More than Energy[TM]

GAINESVILLE REGIONAL UTILITIES

March 29, 2013

Ann Cole, Clerk
Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

130000-OT

Dear Ms. Cole:

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071(1), Florida Administrative Code, Gainesville Regional Utilities hereby submits 25 copies of its 2013 Ten Year Site Plan for your review. An unbound, single-sided copy is also included for scanning. Should you have any questions regarding this Ten Year Site Plan, please contact me at (352) 393-1280.

Sincerely,

Todd Kamhoot

Todd Kamhoot
Utility Analyst
Finance

Enclosures

File: PSC - Ten Year Site Plan

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GAINESVILLE REGIONAL UTILITIES

2013 TEN-YEAR SITE PLAN

GRU100

100 YEARS of SERVICE | 1912-2012

Submitted to:

The Florida Public Service Commission

April 1, 2013

Table of Contents

INTRODUCTION

The 2013 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/RAD 043-E, as specified by Rule 25-22.072, Florida Administrative Code. The four sections of the 2013 Ten-Year Site Plan are:

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

Gainesville Regional Utilities (GRU) is a municipal electric, natural gas, water, wastewater, and telecommunications utility system, owned and operated by the City of Gainesville, Florida. 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 481 Megawatts on August 8, 2007.

1. DESCRIPTION OF EXISTING FACILITIES

Gainesville Regional Utilities (GRU) operates a fully vertically-integrated electric power production, transmission, and distribution system (herein referred to as "the System"), and is wholly owned by the City of Gainesville. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and transmission service to Seminole Electric Cooperative (Seminole). GRU's distribution system serves its retail territory of approximately 124 square miles and an average of 92,556 customers during 2012. The general locations of GRU electric facilities and the electric system service area are shown in Figure 1.1.

1.1 GENERATION

The existing generating facilities operated by GRU are tabulated in Schedule 1 at the end of this chapter. The present summer net capability is 598 MW and the winter net capability is 618 MW. Currently, the System's energy is produced by (i) four fossil fuel steam turbines[1], one of which is part of a combined cycle unit, (ii) seven combustion turbines, six of which are simple cycle and one of which can generate in either simple or combined-cycle unit mode, (iii) and distributed generation. Due to the extended outage during all of 2012 and the announced retirement of Crystal River 3 nuclear unit by Duke Energy Corporation in February 2013, GRU is not including any capacity associated with its 1.4079% ownership share of CR3 in this Ten Year Site Plan. GRU received 106,431 MWh of replacement power from Progress Energy Florida during 2012, but this energy is not included as generation by the System in the computation of statistics reported in this Ten Year Site Plan.

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1 One steam turbine, JRK steam turbine (ST) 8, operates only in combined cycle with JRK combustion turbine (CT) 4. As CT4 is fossil fueled, the steam created by the heat recovery steam generator (HRSG) into which it exhausts when in combined cycle mode is produced by fossil fuel. Therefore ST8 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for ST8.

The System has two primary generating plant sites -- Deerhaven and John R. Kelly (JRK). Each site is comprised of both steam-turbine and gas-turbine generating units. The JRK station is the site of the steam turbine and combustion turbine that can be operated in combined cycle.

1.1.1 Generating Units

1.1.1.1 Simple-Cycle Steam and Combined Cycle Units. The System's four operational simple-cycle steam turbines are powered by fossil fuels. The three simple cycle fossil fueled steam turbines comprise 55.3% of the System's net summer capability and produced 63.4% of the electric energy supplied by the System in 2012. These units range in size from 23.2 MW to 232 MW. The combined-cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 18.7% of the System's net summer capability and produced 34.1% of the electric energy supplied by the System in 2012. Deerhaven Unit 2 and JRK CC1 are typically used for base load purposes, while JRK Unit 7 and Deerhaven Unit 1 are more commonly used for intermediate loading.

1.1.1.2 Simple Cycle Gas Turbines. The System's six industrial gas turbines that operate only in simple cycle comprise 26% of the System's summer generating capability and produced 2.5% of the electric energy supplied by the System in 2012. These simple-cycle combustion turbines are utilized for peaking purposes only. Their energy conversion efficiencies are considerably lower than steam units. Simple cycle combustion turbines are advantageous in that they can be started and placed on line quickly. 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.

1.1.1.3 Environmental Considerations. All of the System's steam turbines utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. Only Deerhaven 2 currently has an Air Quality Control System (AQCS) consisting of a “hot-side” electrostatic precipitator for the removal of fly ash, a selective catalytic reduction system (SCR) to reduce NO_x, a dry recirculating flue gas desulfurization unit to reduce sulfur dioxide (SO_2) and mercury (Hg), and a fabric filter baghouse to reduce particulates. The Deerhaven site operates with zero liquid discharge (ZLD) to surface waters.

1.1.2 Generating Plant Sites

The locations of the System's generating plant sites are shown on Figure 1.1.

1.1.2.1 John R. Kelly Plant. The Kelly Station is located in southeast Gainesville near the downtown business district and consists of one combined cycle unit, one conventional steam turbine, three simple-cycle gas turbines, and the associated cooling facilities, fuel storage, pumping equipment, transmission and distribution equipment.

1.1.2.2 Deerhaven Plant. The Deerhaven Station is located six miles northwest of Gainesville. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. Deerhaven Unit 2 is coal fired and the site includes the coal unloading and storage facilities. On September 28, 2009 GRU entered into a 47 year lease of approximately 13 acres of property to the Gainesville Renewable Energy Center, LLC. The property is in the northwest corner of the site and will be the location of a 100 MW capacity biomass fueled power generating facility due to come on line in 2013.

1.2 TRANSMISSION

1.2.1 The Transmission Network

GRU's bulk electric power transmission network (System) consists of a 230 kV radial and a 138 kV loop connecting the following:

1) GRU's two generating stations,
2) GRU's ten distribution substations,
3) One 230 kV and two 138 kV interties with Progress Energy Florida (PEF),
4) A 138 kV intertie with Florida Power and Light Company (FPL),
5) A radial interconnection with Clay at Farnsworth Substation, and
6) A loop-fed interconnection with the City of Alachua at Alachua No. 1 Substation.

Refer to Figure 1.1 for line geographical locations and Figure 1.2 for electrical connectivity and line numbers.

1.2.2 Transmission Lines

The ratings for all of GRU's transmission lines are given in Table 1.1, and Figure 1.2 shows 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 8 hour 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	80.08	795 MCM ACSR
138 kV single circuit	16.86	1192 MCM ACSR
138 kV single circuit	20.61	795 MCM ACSR
230 kV single circuit	2.53	795 MCM ACSR
Total	120.08	

Annually, GRU participates in Florida Reliability Coordinating Council, Inc. (FRCC) studies that analyze multi-level contingencies. Contingencies are occurrences that depend on changes or uncertain conditions and, as used here, represent various equipment failures that may occur. All single and two circuits-common pole contingencies have no identifiable problems.

1.2.3 State Interconnections

The System is currently interconnected with PEF and FPL at four separate points. The System interconnects with PEF's Archer Substation via a 230 kV transmission line to the System's Parker Road Substation with 224 MVA of transformation capacity from 230 kV to 138 kV. The System also interconnects with PEF's Idylwild Substation with two separate circuits via their 168 MVA 138/69 kV transformer. The System interconnects with FPL via a 138 kV tie between FPL's Hampton Substation and the System's Deerhaven Substation. This interconnection has a transformation capacity at Bradford Substation of 224 MVA. All listed capacities are based on normal (Rating A) capacities.

The System is planned, operated, and maintained to be in compliance with all FERC, NERC, and FRCC requirements to assure the integrity and reliability of Florida's Bulk Electric System (BES).

1.3 DISTRIBUTION

The System has seven loop-fed and three radial distribution substations connected to the transmission network: Ft. Clarke, Kelly, McMichen, Millhopper, Serenola, Springhill, Sugarfoot, Ironwood, Kanapaha, and Rocky Point substations, respectively. Parker Road is GRU's only 230 kV transmission voltage substation. The locations of these substations are shown on Figure 1.1.

The seven loop fed distribution substations are connected to the 138 kV bulk power transmission network with feeds which prevent the outage of a single transmission line from causing any outages in the distribution system. Ironwood, Kanapaha and Rocky Point are served by a single tap to the 138 kV network which would require distribution switching to restore customer power if the single transmission line tapped experiences an outage. GRU serves its retail customers through a 12.47 kV distribution network. The distribution substations, their present rated transformer capabilities, and the number of circuits for each are listed in Table 1.2. The System has three Power Delivery Substations (PDS) with single 33.6 MVA transformers that are directly radial-tapped to our looped 138 kV system. The new Springhill Substation consists of one 33.3 MVA transformer served by a loop fed SEECO pole mounted switch. Ft. Clarke, Kelly, McMichen, and Serenola substations currently consist of two transformers of basically equal size allowing these stations to be loaded under normal conditions to 80 percent of the capabilities shown in Table 1.2. 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 1.2. One of the two 22.4 MVA transformers at Ft. Clarke has been repaired with rewinding to a 28.0 MVA rating. This makes the normal rating for this substation 50.4 MVA.

1.4 WHOLESALE ENERGY

The System provides full requirements wholesale electric service to the City of Alachua. The Alachua No. 1 Substation is supplied by GRU's looped 138 kV transmission system. The System provides approximately 94% of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the PEF's Crystal River 3 and FPL's St. Lucie 2 nuclear units. Energy supplied to the City of 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. The System began serving the City of Alachua in July 1985 and has provided full requirements wholesale electric service since January 1988. A 10-year extension amendment was approved in 2010 and made effective on January 1, 2011. Wholesale sales to the City of Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins through this planning horizon.

1.5 DISTRIBUTED GENERATION

The South Energy Center, a combined heating and power plant (CHP) began commercial operation in May 2009. The South Energy Center provides multiple onsite utility services to the Shands at UF South Campus hospital. The new facility houses a 3.5 MW (summer rating) natural gas-fired turbine capable of supplying 100% of the hospital's electric and thermal needs. The South Energy Center provides electricity, chilled water, steam, and the storage and delivery of medical gases to the hospital. The unique design is 75% efficient at primary fuel conversion to useful energy and greatly reduces emissions compared to traditional generation. The facility is designed to provide electric power into the GRU distribution system when its capacity is not totally utilized by the hospital.

Figure 1.1
Gainesville Regional Utilities Electric Facilities
Alachua County, Florida

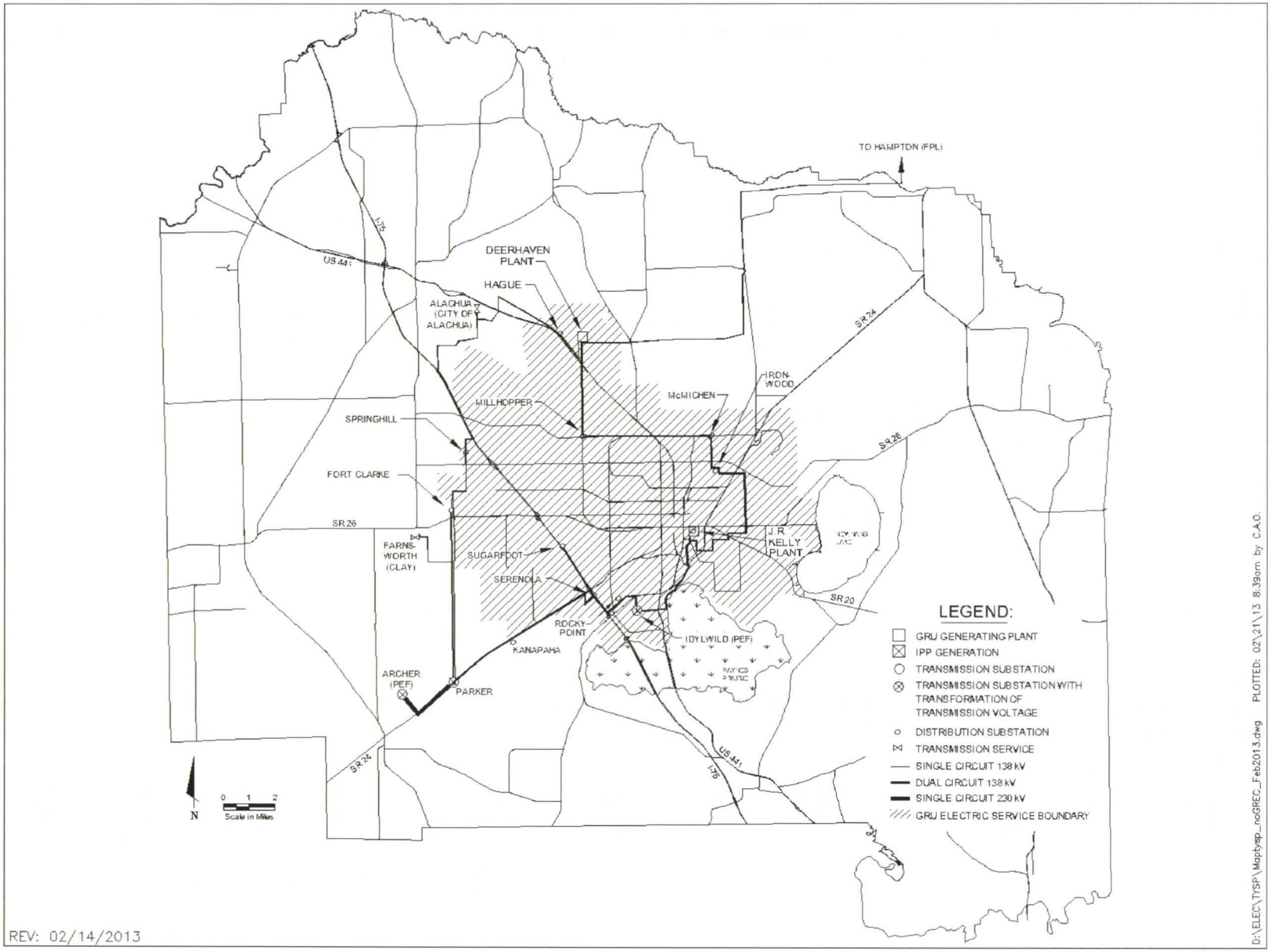
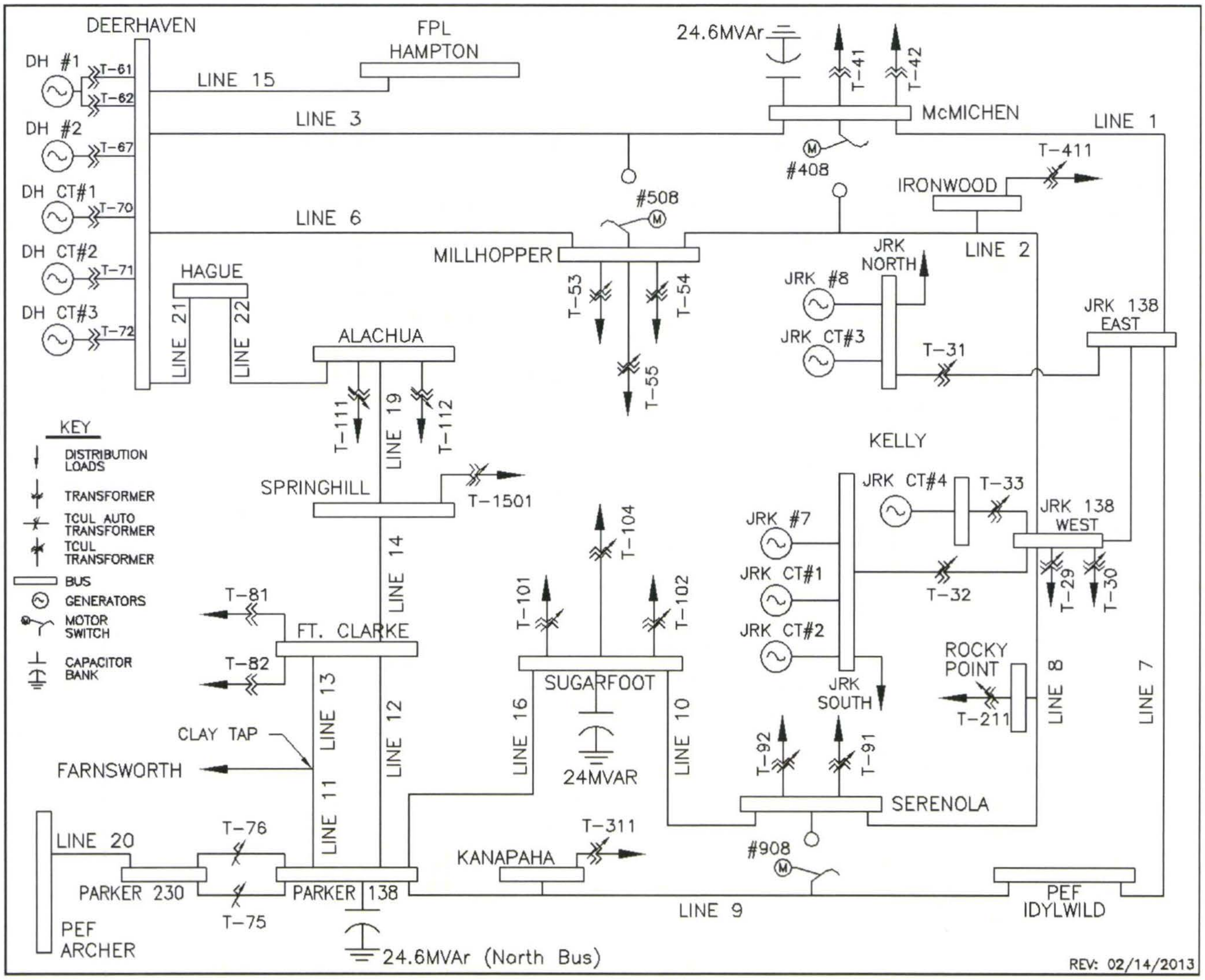


FIGURE 1.2 Gainesville Regional Utilities Electric System One-Line Diagram.



Schedule 1
EXISTING GENERATING FACILITIES (as of January 1, 2013)

(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		Alachua County									**180.0**	**189.0**	**177.2**	**186.2**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL				[4/65 ; 5/01]	2051	38.0	38.0	37.0	37.0	OP
	FS07	(GRU)	ST	NG	PL	RFO	TK		8/61	10/15	24.0	24.0	23.2	23.2	OP
	GT04		CT	NG	PL	DFO	TK		5/01	2051	76.0	82.0	75.0	81.0	OP
	GT03		GT	NG	PL	DFO	TK		5/69	05/19	14.0	15.0	14.0	15.0	OP
	GT02		GT	NG	PL	DFO	TK		9/68	09/18	14.0	15.0	14.0	15.0	OP
	GT01		GT	NG	PL	DFO	TK		2/68	02/18	14.0	15.0	14.0	15.0	OP
Deerhaven		Alachua County									**449.0**	**459.0**	**417.0**	**428.0**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	255.0	255.0	232.0	232.0	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	08/22	80.0	80.0	75.0	75.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76.0	82.0	75.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19.0	21.0	17.5	20.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19.0	21.0	17.5	20.0	OP
South Energy Center Distributed Generation	GT1	Alachua County SEC. 10, T10S, R20E	GT	NG		PL			5/09		**4.5**	**4.5**	**4.1**	**4.1**	OP
System Total													**598**	**618**	

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

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

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

<u>Status</u>
OP = Operational

TABLE 1.1

TRANSMISSION LINE RATINGS
SUMMER POWER FLOW LIMITS

Line Number	Description	Normal 100°C (MVA)	Limiting Device	Emergency 125°C (MVA)	Limiting Device
1	McMichen - Depot East	236.2	Conductor	282.0	Conductor
2	Millhopper- Depot West	236.2	Conductor	282.0	Conductor
3	Deerhaven - McMichen	236.2	Conductor	282.0	Conductor
6	Deerhaven - Millhopper	236.2	Conductor	282.0	Conductor
7	Depot East - Idylwild	236.2	Conductor	282.0	Conductor
8	Depot West - Serenola	236.2	Conductor	282.0	Conductor
9	Idylwild - Parker	236.2	Conductor	236.2	Conductor
10	Serenola - Sugarfoot	236.2	Conductor	282.0	Conductor
11	Parker - Clay Tap	143.6	Conductor	282.0	Conductor
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	143.6	Conductor	186.0	Conductor
14	Ft. Clarke - Springhill	287.3	Switch	356.0	Conductor
15	Deerhaven - Hampton	224.0[1]	Transformers	270.0	Transformers
16	Sugarfoot - Parker	236.2	Conductor	282.0	Conductor
17	Clay Tap – Farnsworth	236.2	Conductor	282.0	Conductor
19	Springhill - Alachua	300.0	Conductor	356.0	Conductor
20	Parker-Archer(T75,T76)	224.0	Transformers[3]	300.0	Transformers[3]
21	Deerhaven – GREC	287.3	Switch	356.0	Conductor
22	Alachua - Deerhaven	300.0	Conductor	356.0	Conductor
xx	Idylwild – PEF	168.0[2]	Transformer	168.0[2]	Transformer

1) These two transformers are located at the FPL Bradford Substation and are the limiting elements in the Normal and Emergency ratings for this intertie.

2) This transformer, along with the entire Idylwild Substation, is owned and maintained by PEF.

3) Transformers T75 & T76 normal limits are based on a 65° C temperature rise rating, and the emergency rating is 140% loading for two hours.

Assumptions:

100 °C for normal conductor operation
125 °C for emergency 8 hour conductor operation
40 °C ambient air temperature
2 ft/sec wind speed

TABLE 1.2

SUBSTATION TRANSFORMATION AND CIRCUITS

Distribution Substation	Normal Transformer Rated Capability	Current Number of Circuits
Ft. Clarke	50.4 MVA	4
J.R. Kelly[2]	201.6 MVA	21
McMichen	44.8 MVA	6
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
Springhill	33.3 MVA	2
Sugarfoot	100.8 MVA	9
Ironwood	33.6 MVA	3
Kanapaha	33.6 MVA	3
Rocky Point	33.6 MVA	3

Transmission Substation	Normal Transformer Rated Capability	Number of Circuits
Parker	224 MVA	5
Deerhaven	No transformations- All 138 kV circuits	4

2 J.R. Kelly is a generating station as well as 2 distribution substations. One substation has 14 distribution feeders directly fed from the 2- 12.47 kV generator buses with connection to the 138 kV loop by 2- 56 MVA transformers. The other substation (Kelly West) has 10 distribution feeders fed from one 56 MVA transformer and one 33.6 MVA transformer.

2. FORECAST OF ELECTRIC ENERGY AND DEMAND REQUIREMENTS

Section 2 includes documentation of GRU's forecast of number of customers, energy sales and seasonal peak demands; 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 2003-2022. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2 and 2.3. Schedule 3.1 gives summer peak demand for the base case forecast by reporting category. Schedule 3.2 presents winter peak demand for the base case forecast by reporting category. Schedule 3.3 presents net energy for load for the base case forecast by reporting category. Short-term monthly load data is presented in Schedule 4. Projected sources of energy for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy sources 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.

2.1 FORECAST ASSUMPTIONS AND DATA SOURCES

(1) All regression analyses were based on annual data. Historical data was compiled for calendar years 1970 through 2012. System data, such as net energy for load, seasonal peak demands, customer counts and energy sales, was obtained from GRU records and sources.

(2) Estimates and projections of Alachua County population were based on population data published by The Bureau of Economic and Business Research at the University of Florida. Population projections were based on BEBR Bulletin 162 – revised (March 2012), and Estimates of Population by County and City in Florida: April 1, 2012 (November 2012).

(3) Historical weather data was used to fit regression models. The forecast assumes normal weather conditions. Normal heating degree days and cooling degree days equal the mean of data reported to NOAA by the Gainesville Municipal Airport station from 1984-2012.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2012, using the U.S. Consumer Price Index for All Urban Consumers from the U.S. Department of Labor, Bureau of Labor Statistics. Inflation is assumed to average approximately 2.5% per year for each year of the forecast.

(5) The U.S. Department of Commerce, Bureau of Economic Analysis, provided historical estimates of total personal income. Forecast values of total personal income were obtained from Global Insight.

(6) Historical estimates of household size were obtained from BEBR Bulletin 164, and projections were estimated from a logarithmic trend of historical estimates.

(7) The U.S. Department of Labor, Bureau of Labor Statistics, provided historical estimates of non-farm employment. Forecast values of non-farm employment were obtained from Global Insight.

(8) Retail electric prices for each billing rate category were assumed to increase at a nominal rate of approximately 2.7% per year. Prices are expressed in dollars per 1,000 kWh.

(9) Estimates of energy and demand reductions resulting from planned demand-side management programs (DSM) were subtracted from all retail forecasts. GRU has been involved in formal conservation efforts since 1980. The forecast reduces energy sales and seasonal demands by the projected conservation impacts, net of cumulative impacts from 1980-2012. GRU's involvement with DSM is described in more detail later in this section.

(10) Sales to The City of Alachua were assumed to continue through the duration of this forecast. The agreement to serve Alachua was recently renewed through December 2020. Alachua's ownership in PEF and FPL nuclear units supplied approximately 6% of its annual energy requirements in 2012.

2.2 FORECASTS OF NUMBER OF CUSTOMERS, ENERGY SALES AND SEASONAL PEAK DEMANDS

Number of customers, energy sales and seasonal peak demands were forecast from 2013 through 2022. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand, general service demand, large power, outdoor lighting, and sales to the City of 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)[1]. The following text describes the regression equations utilized to forecast energy sales and number of customers.

2.2.1 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 residential price of electricity and heating degree days. The form of this equation is as follows:

$$RESAVUSE = 15232 - 47.93\,(RESPR12) + 1.06\,(HDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use per Customer
RESPR12	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days

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

Adjusted R^2	=	0.8433
DF (error)	=	17 (period of study, 1993-2012)
t - statistics:		
Intercept	=	25.10
RESPR12	=	-9.95
HDD	=	3.81

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 number of persons per household, and the historical series of customers transferred from Clay Electric Cooperative, Inc. to GRU. The residential customer model specifications are:

RESCUS = *244023 + 268.8 (POP) – 101540 (HHSIZE) + 1.66 (CLYRCUS)*

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
HHSIZE	=	Number of Persons per Household
CLYRCUS	=	Clay Residential Customer Transfers
Adjusted R^2	=	0.9953
DF (error)	=	16 (period of study, 1993-2012)
t - statistics:		
Intercept	=	2.55
POP	=	5.72
HHSize	=	-2.73
CLYRCus	=	2.95

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

2.2.2 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 elect the General Service Demand (GSD) rate classification. This option offers potential benefit to GSN customers that use high amounts of energy relative to their billing demands. Since 1990, 579 customers have elected to transfer to the GSD rate class. The forecast assumes that additional GSN customers will voluntarily elect the GSD classification, but at a more modest pace than has been observed historically. A regression model was developed to project average annual energy use by GSN customers. The model includes as independent variables, the cumulative number of optional demand customers, per capita income, and cooling degree days. The specifications of this model are as follows:

$$GSNAVUSE = 14.77 - 0.019\,(OPTDCUS) + 0.0003\,(MSAPCY12) + 0.0019\,(CDD)$$

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
MSAPCY12	=	Per Capita Income
CDD	=	Annual Cooling Degree Days
Adjusted R^2	=	0.9519
DF (error)	=	16 (period of study, 1993-2012)

t - statistics:

Intercept	=	3.62
OPTDCUS	=	-11.33
MSAPCY12	=	2.85
CDD	=	2.24

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population, the cumulative number of optional demand customers, and the addition of a group of individually metered cable amplifiers that were previously bulk metered. The specifications of the general service non-demand customer model are as follows:

GSNCUS = *-3830 + 53.2 (POP) – 1.06 (OPTDCUS) + 1.08 (COXTRAN)*

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
OPTDCUS	=	Optional GSD Customers
COXTRAN	=	Cable TV Meters
Adjusted R^2	=	0.9927
DF (error)	=	16 (period of study, 1993-2012)

t - statistics:

Intercept	=	-4.68
POP	=	12.47
OPTDCUS	=	-1.80
COXTRAN	=	4.55

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.

2.2.3 General Service Demand Sector

The general service demand customer class includes non-residential customers with average billing 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 the cumulative number of optional demand customers, non-farm employment, and cooling degree days. Average energy use projections for general service demand customers result from the following model:

$$GSDAVUSE = 413.1 - 0.17\,(OPTDCUS) + 0.64\,(MSA\_NF) + 0.029\,(CDD)$$

Where:

GSDAVUSE	=	Average Annual Energy Use by GSD Customers
OPTDCUS	=	Optional GSD Customers
MSA_NF	=	Non-Farm Employment
CDD	=	Cooling Degree Days
Adjusted R^2	=	0.9385
DF (error)	=	16 (period of study, 1993-2012)
t - statistics:		
Intercept	=	8.06
OPTDCUS	=	-12.74
MSA_NF	=	2.05
CDD	=	2.55

The annual average number of customers was projected using a regression model that includes Alachua County population, and the cumulative number of optional demand customers as independent variables. The specifications of the general service demand customer model are as follows:

$$GSDCUS = -644.5 + 6.81\,(POP) + 0.41\,(OPTDCUS)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
OPTDCUS	=	Optional GSD Customers
Adjusted R^2	=	0.9908
DF (error)	=	17 (period of study, 1993-2012)
t - statistics:		
Intercept	=	-4.11
POP	=	8.49
OPTDCUS	=	4.75

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.

2.2.4 Large Power Sector

The large power customer class currently includes eleven customers that maintain an average monthly billing demand of at least 1,000 kW. Analyses of average annual energy use were based on historical observations from 1993 through 2012. The model developed to project average use by large power customers includes per capita income and an indicator variable representing a policy change defining eligibility for this rate category. Energy use per customer has been observed to increase slightly over time, presumably due to the periodic expansion or increased utilization of existing facilities. This growth is measured in the model by per capita income. The specifications of the large power average use model are as follows:

$$LPAVUSE = 8078 + 0.068\,(MSAPCY12) + 3340\,(Policy)$$

Where:

LPAVUSE	=	Average Annual Energy Consumption (MWh per Year)
MSAPCY12	=	Gainesville MSA Per Capita Income
Policy	=	Indicator Variable for Policy Change in 2009
Adjusted R^2	=	0.9342
DF (error)	=	17 (period of study, 1993-2012)
t - statistics:		
INTERCEPT	=	7.48
MSAPCY12	=	2.08
Policy	=	13.79

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, which is projected to remain constant at eleven.

2.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of streetlight, traffic light, and rental light accounts. Outdoor lighting energy sales account for less than 1.4% of total energy sales. A model to forecast outdoor lighting energy sales was developed that specified lighting energy as a function of the natural log of the number of residential customers. However, energy sales to the lighting sector were held constant at current levels in this forecast, and the model was not used.

2.2.6 Wholesale Energy Sales

The System provides full requirements wholesale electric service to the City of Alachua. Approximately 6% of Alachua's 2012 energy requirements were met through generation entitlements of nuclear generating units operated by PEF and FPL. The agreement to provide wholesale power to Alachua was recently renewed, effective from 2011 through 2020. Energy sales to the City of Alachua are considered part of the System's native load for facilities planning through the forecast horizon.

Energy Sales to Alachua were estimated using a model including City of Alachua population and heating degree days as the independent variables. BEBR provided historical estimates of City of Alachua Population. This variable was projected from a trend analysis of the component municipal an unincorporated populations within Alachua County. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALAMWh = -55100 + 18790\,(ALAPOP) + 8.65\,(HDD)$$

Where:

ALAMWh	=	Energy Sales to the City of Alachua (MWh)
ALAPOP	=	City of Alachua Population (000's)
HDD	=	Heating Degree Days
Adjusted R^2	=	0.9690
DF (error)	=	16 (period of study, 1994-2012)
t - statistics:		
Intercept	=	-7.19
ALAPOP	=	23.37
HDD	=	1.74

2.2.7 Total System Sales, Net Energy for Load, Seasonal Peak Demands and Conservation 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, and sales to Alachua. Net energy for load (NEL) was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor used in this forecast is 0.9547. Historical delivered efficiencies were examined from the past 25 years to make this determination. The impact of energy savings from conservation programs was accounted for in energy sales to each customer class, prior to calculating NEL.

The forecasts of seasonal peak demands were derived from forecasts of annual NEL. Winter peak demands are expected to occur in January of each year, and summer peak demands are expected to occur in August. The average ratio of the most recent 25 years' monthly NEL for January and August, as a portion of annual NEL, was applied to projected annual NEL to obtain estimates of January and August NEL over the forecast horizon. The medians of the past 25 years' load factors for January and August were applied to January and August NEL projections, yielding seasonal peak demand projections. Forecast seasonal peak demands include the net impacts from planned conservation programs.

2.3 ENERGY SOURCES AND FUEL REQUIREMENTS

2.3.1 Fuels Used by System

Presently, the system is capable of using coal, residual oil, distillate oil and natural gas 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. To the extent that the System participates in interchange sales and purchases, actual consumption of these fuels will likely differ from the base case requirements indicated in Schedule 5.

2.3.2 Methodology for Projecting Fuel Use

The fuel use projections were produced using the GenTrader® program developed by Power Costs, Inc. (PCI), 3550 West Robinson, Suite 200, Norman, Oklahoma 73072. PCI provides support, maintenance, and training for the GenTrader® software. GenTrader® has the ability to model each of the System's generating units, as well as purchase options from the energy market, on an hour-by-hour basis and includes the effects of environmental limits, dual-fuel units, reliability constraints, maintenance schedules, startup time and startup fuel, and minimum down time for forced outages.

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, and maintenance schedules for each generating unit in the System;

(3) Purchase power & energy options from the market.

The output of this model includes:

(1) Monthly and yearly operating fuel expenses by fuel type and unit; and

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

2.3.3 Purchased Power Agreements

2.3.3.1 G2 Energy Baseline Landfill Gas. GRU entered a 15-year contract with G2 Energy Marion, LLC and began receiving 3 MW of landfill gas fueled capacity in January 2009. G2 completed a capacity expansion of 0.8 MW in May 2010, bringing net output to 3.8 MW.

2.3.3.2 Progress Energy 50 MW. GRU negotiated a contract with Progress Energy Florida (PEF) for 50 MW of base load capacity. This contract began January 1, 2009 and continues through December 31, 2013.

2.3.3.3 Gainesville Renewable Energy Center. The Gainesville Renewable Energy Center (GREC) is a planned 100 MW biomass unit to be built and owned by American Renewables. GRU will purchase all of the output of this unit and anticipates reselling a portion of the output over time. During 2010, GREC received a Determination of Need from the FPSC; Site Certification from the State Siting Board ; and the air construction permit from the Florida Department of Environmental Protection. Construction has begun, and the unit is expected to be online by December 2013.

2.3.3.4 Solar Feed-In Tariff. In March of 2009 GRU became the first utility in the United States to offer a European-style solar feed-in tariff (FIT). Under this program, GRU agrees to purchase 100% of the solar power produced from any qualified private generator at a fixed rate for a contract term of 20 years. The FIT rate has built-in subsidy to incentivize the installation of solar in the community and help create a strong solar marketplace. GRU's FIT costs are recovered through fuel adjustment charges, and have been limited to 4 MW of installed capacity per year. Through the end of 2012, approximately 14.1 MW has been constructed under the Solar FIT program. The amount of capacity available for any given calendar year will be the combination of the 4 MW originally allotted under each year, plus any unassigned and unused capacity from the previous year, unless otherwise noted.

The exact capacity available to the public each annual period will be announced before the annual application period, along with currently approved tariff rates for the program.

2.4 DEMAND-SIDE MANAGEMENT

2.4.1 Demand-Side Management Programs

Demand and energy forecasts outlined in this Ten Year Site Plan include impacts from GRU's Demand-Side Management (DSM) programs. The System forecast reflects the incremental impacts of DSM measures, net of cumulative impacts from 1980 through 2012. DSM programs are available for all residential and non-residential customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

DSM direct services currently available to the System's residential customers, or expected to be implemented during 2013, include energy audits and low income household whole house energy efficiency improvements. GRU also offers rebates and other financial incentives for the promotion of:

- super-efficient central air conditioning
- solar water heating
- solar photovoltaic systems
- natural gas in new construction
- Home Performance with the federal Energy Star program
- heating/cooling duct repair
- variable speed pool pumps
- energy efficiency for low-income households
- attic and raised-floor insulation
- removing second refrigerators from homes and recycling the materials
- compact fluorescent light bulbs

- natural gas for displacement of electric in water heating, space heating, and space cooling in existing structures
- home energy reports to compare household energy consumption to that of neighbors
- heat pump water heaters
- energy-efficient windows, window film, and solar shades

Energy audits are available to the System's non-residential customers. GRU administers a customized business rebate program that incorporates many of the measures described above as residential programs. The rebate award is based on the calculated demand and energy reduction tailored for each non-residential participant.

The System continues to offer standardized interconnection procedures and compensation for excess energy production for both residential and non-residential customers who install distributed resources and offers rebates to residential customers for the installation of photovoltaic generation. The solar feed-in tariff has replaced photovoltaic rebates as the incentive for non-residential customers to implement distributed solar generation.

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

2.4.2 Demand-Side Management Methodology and Results

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 under current conditions, 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 where possible. Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth. GRU contracted with a consultant to perform a measurement and verification analysis of several of the conservation programs implemented in recent years. Results from this study aided GRU in both determining which programs are most effective and in quantifying the energy and demand savings achieved by these measures.

The implementation of DSM programs planned for 2013-2022 is expected to provide an additional 17 MW of summer peak reduction and 80 GWh of annual energy savings by the year 2022. A history and projection of total DSM program achievements from 1980-2022 is shown in Table 2.1.

2.4.3 Supply Side Programs

The System has undertaken several initiatives to improve the adequacy and reliability of the transmission and distribution systems. GRU purchases overhead and underground transformers that exceed the efficiency specified by the NEMA TP-1 Standard. GRU has been continuously improving the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. In specific areas the feeders have been installed underground using 1000 MCM underground cable. GRU adds capacitors on its distribution feeders where necessary to support a high system-wide power factor. During 2012 and 2013, GRU is conducting a Cable Injection Project, where direct-buried underground primary cables installed prior to 1985 are injected with a solution that rejuvenates the insulation of the cable and extends the cable's useful life. Efforts have been made to increase segmentation of feeders, reducing the number of customers behind any one device by adding more fusing stages. This reduces the number of customers affected by any one outaged device. Recent efforts in distribution automation have added reclosers and automated switches, which decreases outage times by enabling GRU's system operators to remotely switch customers to adjacent feeders when outages occur. There is a discernible trend in System data showing a decrease in losses over the past 20 years.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU relies on coal and natural gas as primary fuels used to meet its generation needs. Fuel oils may be used as a backup for natural gas fired generation, although in practice they are seldom used. Since the operation of CR3 has discontinued, nuclear fuel is no longer part of the System's fuel mix. GRU consults a number of reputable sources such as EIA, PIRA, Argus Coal Daily, and the NYMEX futures market, when assessing expected future commodity fuel prices. Costs associated with transporting coal and natural gas to GRU's generating stations are specific to arrangements with transportation entities. Coal is transported to GRU by rail, and natural gas is transported over the Florida Gas Transmission Company (FGT) pipeline system. A summary of historical and projected delivered coal and natural gas prices is provided in Table 2.2.

2.5.1 Coal

Coal was used to generate approximately 45% of the energy produced by the system in 2012. Thus far, GRU has purchased low sulfur and medium sulfur, high Btu eastern coal for use in Deerhaven Unit 2. In 2009, Deerhaven Unit 2 was retrofitted with an air quality control system, which was added as a means of complying with new environmental regulations. Following this retrofit, Deerhaven Unit 2 is able to utilize coals with up to approximately 1.7% sulfur content with the new control system. Testing has been conducted to verify that the unit is capable of utilizing a blend of central Appalachian coal and Illinois basin coal. The forecast of coal prices is based on a 50/50 blend of low sulfur central Appalachian coal and medium sulfur Indiana basin coal. Pricing of these coals was sourced from Argus Coal Daily publications. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019. A step increase in the delivered coal price is expected in 2020 resulting from higher transportation costs.

2.5.2 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2012, GRU purchased approximately 10.9 million MMBtu for use by both systems. GRU power plants used 82% of the total purchased for GRU during 2012, while the LDC used the remaining 18%. Natural gas was used to produce approximately 55% of the energy produced by GRU's electric generating units.

GRU purchases natural gas via arrangements with producers and marketers connected with the FGT interstate pipeline. GRU's delivered cost of natural gas includes the commodity component, FGT's fuel charge, FGT's usage (transportation) charge, FGT's reservation (capacity) charge, and basis adjustments. Commodity fuel cost projections were based on closing NYMEX natural gas futures prices for the Henry Hub.

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)
			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
2003	173,780	2.33	854	74,456	11,467	726	8,959	81,090
2004	179,613	2.33	878	77,021	11,398	739	9,225	80,143
2005	182,122	2.33	888	78,164	11,358	752	9,378	80,199
2006	184,859	2.33	877	79,407	11,047	746	9,565	78,042
2007	188,704	2.33	878	81,128	10,817	778	9,793	79,398
2008	191,198	2.32	820	82,271	9,969	773	10,508	73,538
2009	191,809	2.32	808	82,605	9,785	778	10,428	74,591
2010	190,177	2.32	851	81,973	10,387	780	10,355	75,304
2011	189,958	2.32	805	81,881	9,829	772	10,373	74,401
2012	190,437	2.32	757	82,128	9,219	750	10,415	72,025
2013	191,902	2.32	788	82,800	9,517	738	10,479	70,380
2014	193,363	2.32	805	83,468	9,643	740	10,594	69,844
2015	194,821	2.32	806	84,135	9,583	743	10,710	69,417
2016	196,279	2.31	808	84,800	9,527	748	10,828	69,085
2017	197,736	2.31	809	85,465	9,471	752	10,945	68,700
2018	199,193	2.31	811	86,128	9,419	756	11,064	68,285
2019	200,651	2.31	814	86,792	9,374	759	11,184	67,875
2020	202,109	2.31	816	87,454	9,330	763	11,305	67,459
2021	203,568	2.31	818	88,117	9,288	766	11,426	67,039
2022	205,028	2.31	821	88,780	9,248	770	11,549	66,700

* Commercial includes General Service Non-Demand and General Service 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
2003	181	19	9,591	0	24	0	1,786
2004	188	18	10,396	0	25	0	1,830
2005	189	18	10,526	0	25	0	1,854
2006	200	20	10,093	0	25	0	1,849
2007	196	18	10,742	0	26	0	1,877
2008	184	16	11,438	0	26	0	1,803
2009	168	12	13,842	0	26	0	1,781
2010	168	12	13,625	0	25	0	1,825
2011	164	11	14,575	0	29	0	1,769
2012	168	13	13,441	0	25	0	1,700
2013	150	11	13,638	0	25	0	1,701
2014	150	11	13,594	0	25	0	1,720
2015	149	11	13,564	0	25	0	1,723
2016	149	11	13,547	0	25	0	1,730
2017	149	11	13,520	0	25	0	1,735
2018	148	11	13,493	0	25	0	1,740
2019	148	11	13,470	0	25	0	1,746
2020	148	11	13,446	0	25	0	1,752
2021	148	11	13,425	0	25	0	1,757
2022	148	11	13,418	0	25	0	1,764

** Industrial includes 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
2003	146	83	2,015	0	83,434
2004	149	70	2,049	0	86,264
2005	163	66	2,082	0	87,560
2006	174	75	2,099	0	88,992
2007	188	57	2,122	0	90,939
2008	196	79	2,079	0	92,795
2009	203	99	2,083	0	93,045
2010	217	99	2,141	0	92,340
2011	201	53	2,024	0	92,265
2012	195	74	1,968	0	92,556
2013	122	86	1,909	0	93,290
2014	125	87	1,932	0	94,073
2015	127	88	1,938	0	94,856
2016	128	88	1,946	0	95,639
2017	129	89	1,953	0	96,421
2018	131	89	1,960	0	97,204
2019	132	89	1,967	0	97,987
2020	134	89	1,975	0	98,770
2021	135	90	1,982	0	99,554
2022	137	90	1,991	0	100,340

Schedule 3.1
History and Forecast of Summer Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2003	439	33	384	0	0	14	0	8	417
2004	455	33	399	0	0	14	0	9	432
2005	489	37	428	0	0	15	0	9	465
2006	488	39	425	0	0	15	0	9	464
2007	508	44	437	0	0	17	0	10	481
2008	487	43	414	0	0	19	0	11	457
2009	498	46	419	0	0	21	0	12	465
2010	505	48	422	0	0	22	0	13	470
2011	484	46	399	0	0	24	0	15	445
2012	456	43	372	0	0	26	0	15	415
2013	455	27	384	0	0	28	0	16	411
2014	462	27	389	0	0	29	0	17	416
2015	464	28	389	0	0	30	0	17	417
2016	468	28	391	0	0	31	0	18	419
2017	471	28	393	0	0	32	0	18	421
2018	475	29	393	0	0	34	0	19	422
2019	478	29	395	0	0	35	0	19	424
2020	481	29	396	0	0	36	0	20	425
2021	484	30	397	0	0	37	0	20	427
2022	486	30	398	0	0	38	0	20	428

Schedule 3.2
History and Forecast of Winter Peak Demand - MW
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Winter	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm./Ind. Load Management	Comm./Ind. Conservation	Net Firm Demand
2003 / 2004	398	31	319	0	0	40	0	8	350
2004 / 2005	426	36	341	0	0	41	0	8	377
2005 / 2006	436	40	346	0	0	42	0	8	386
2006 / 2007	414	38	324	0	0	44	0	8	362
2007 / 2008	417	40	321	0	0	46	0	10	361
2008 / 2009	479	50	371	0	0	47	0	11	421
2009 / 2010	523	55	409	0	0	48	0	11	464
2010 / 2011	471	51	358	0	0	50	0	12	409
2011 / 2012	435	47	324	0	0	51	0	13	371
2012 / 2013	403	26	312	0	0	52	0	13	338
2013 / 2014	409	27	315	0	0	53	0	14	342
2014 / 2015	411	27	316	0	0	54	0	14	343
2015 / 2016	415	28	317	0	0	55	0	15	345
2016 / 2017	418	28	319	0	0	56	0	15	347
2017 / 2018	419	28	320	0	0	56	0	15	348
2018 / 2019	423	29	321	0	0	57	0	16	350
2019 / 2020	424	29	322	0	0	57	0	16	351
2020 / 2021	427	29	324	0	0	58	0	16	353
2021 / 2022	431	30	325	0	0	59	0	17	355
2022 / 2023	433	30	327	0	0	59	0	17	357

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 %
2003	2,121	82	24	1,786	146	83	2,015	55%
2004	2,158	84	25	1,830	149	70	2,049	54%
2005	2,196	88	26	1,854	163	65	2,082	51%
2006	2,215	90	26	1,849	174	76	2,099	52%
2007	2,253	99	32	1,877	186	59	2,122	50%
2008	2,230	110	41	1,804	196	79	2,079	52%
2009	2,249	117	49	1,781	203	99	2,083	51%
2010	2,321	124	56	1,825	217	99	2,141	52%
2011	2,221	134	63	1,770	201	53	2,024	52%
2012	2,179	143	68	1,700	195	73	1,968	54%
2013	2,131	149	73	1,701	122	86	1,909	53%
2014	2,163	153	78	1,719	125	88	1,932	53%
2015	2,177	157	82	1,723	127	88	1,938	53%
2016	2,193	160	87	1,730	128	88	1,946	53%
2017	2,208	164	91	1,736	129	88	1,953	53%
2018	2,223	168	95	1,740	131	89	1,960	53%
2019	2,236	171	98	1,746	132	89	1,967	53%
2020	2,251	174	102	1,751	134	90	1,975	53%
2021	2,264	177	105	1,758	135	89	1,982	53%
2022	2,279	180	108	1,764	137	90	1,991	53%

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			
	2012		2013		2014	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	363	149	338	147	342	149
FEB	371	134	308	129	312	130
MAR	286	145	274	135	277	137
APR	340	150	303	138	307	140
MAY	378	180	365	167	369	169
JUN	393	181	397	181	402	183
JUL	415	205	405	196	410	199
AUG	391	196	411	200	416	202
SEP	375	186	388	183	393	185
OCT	340	162	334	154	338	156
NOV	281	136	276	133	279	135
DEC	276	144	314	146	317	147

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	310	470	309	308	270	256	228	216	235	224	258
	RESIDUAL													
(3)		STEAM	1000 BBL	0	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
(5)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(6)		TOTAL:	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
	DISTILLATE													
(7)		STEAM	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(8)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(9)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
(10)		TOTAL:	1000 BBL	0	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(11)		STEAM	1000 MCF	1340	835	2308	2637	2993	3105	3161	3070	3180	3045	3091
(12)		CC	1000 MCF	4554	4783	959	987	1506	1657	2044	1968	1518	1652	1323
(13)		CT	1000 MCF	235	148	2538	2151	1975	2218	2215	2494	2297	2738	2334
(14)		TOTAL:	1000 MCF	6129	5766	5805	5775	6474	6980	7420	7532	6995	7435	6748
(15)	OTHER (specify)		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0

Schedule 6.1
ENERGY SOURCES (GWH)
As of January 1, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR Replacement Power		GWh	106	111	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	696	1021	682	677	592	560	497	460	494	471	539
	RESIDUAL													
(4)		STEAM	GWh	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
(6)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(7)		TOTAL:	GWh	0	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
(9)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0
(10)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0
(11)		TOTAL:	GWh	0	0	0	0	0	0	0	0	0	0	0
	NATURAL GAS													
(12)		STEAM	GWh	306	65	186	216	243	254	258	249	258	247	250
(13)		CC	GWh	528	584	102	105	169	184	231	222	169	185	147
(14)		CT	GWh	15	11	182	154	146	158	164	184	171	201	174
(15)		TOTAL:	GWh	849	660	470	475	558	596	653	655	598	633	571
(16)	NUG		GWh	0	0	0	0	0	0	0	0	0	0	0
(17)	BIOFUELS		GWh	0	0	0	0	0	0	0	0	0	0	0
(18)	BIOMASS	PPA	GWh	0	0	713	714	718	719	732	774	805	800	803
(19)	GEOTHERMAL		GWh	0	0	0	0	0	0	0	0	0	0	0
(20)	HYDRO	PPA	GWh	0	0	0	0	0	0	0	0	0	0	0
(21)	LANDFILL GAS		GWh	27	32	32	32	32	32	32	32	32	32	32
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR	FIT-PV	GWh	16	29	35	40	46	46	46	46	46	46	46
(24)	WIND		GWh	0	0	0	0	0	0	0	0	0	0	0
(25)	OTHER RENEWABLE		GWh	0	0	0	0	0	0	0	0	0	0	0
(26)	Total Renewable		GWh	43	61	780	786	796	797	810	852	883	878	881
(27)	Purchased Energy		GWh	274	56	0	0	0	0	0	0	0	0	0
(28)	Energy Sales		GWh	0	0	0	0	0	0	0	0	0	0	0
(29)	NET ENERGY FOR LOAD		GWh	1968	1909	1932	1938	1946	1953	1960	1967	1975	1982	1991

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2013

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
	ENERGY SOURCES		UNITS	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(2)	NUCLEAR Replacement Power		GWh	5.39%	5.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(3)	COAL		GWh	35.37%	53.46%	35.29%	34.95%	30.43%	28.68%	25.37%	23.39%	25.02%	23.74%	27.07%
	RESIDUAL													
(4)		STEAM	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)		CC	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(6)		CT	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(7)		TOTAL:	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	DISTILLATE													
(8)		STEAM	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(9)		CC	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	NATURAL GAS													
(12)		STEAM	GWh	15.55%	3.43%	9.62%	11.13%	12.48%	13.01%	13.14%	12.67%	13.06%	12.48%	12.56%
(13)		CC	GWh	26.83%	30.59%	5.29%	5.43%	8.68%	9.42%	11.79%	11.28%	8.56%	9.32%	7.38%
(14)		CT	GWh	0.76%	0.58%	9.41%	7.94%	7.50%	8.09%	8.38%	9.35%	8.67%	10.13%	8.74%
(15)		TOTAL:	GWh	43.14%	34.60%	24.32%	24.50%	28.67%	30.52%	33.31%	33.30%	30.29%	31.93%	28.67%
(16)	NUG		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(17)	BIOFUELS		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(18)	BIOMASS	PPA	GWh	0.00%	0.00%	36.93%	36.84%	36.89%	36.80%	37.33%	39.35%	40.74%	40.39%	40.34%
(19)	GEOTHERMAL		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(20)	HYDRO		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(21)	LANDFILL GAS	PPA	GWh	1.37%	1.68%	1.66%	1.65%	1.64%	1.64%	1.63%	1.63%	1.62%	1.61%	1.61%
(22)	MSW		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(23)	SOLAR	FIT	GWh	0.81%	1.52%	1.81%	2.06%	2.36%	2.36%	2.35%	2.34%	2.33%	2.32%	2.31%
(24)	WIND		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(25)	OTHER RENEWABLE		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(26)	Total Renewable		GWh	2.18%	3.20%	40.40%	40.55%	40.90%	40.80%	41.31%	43.31%	44.69%	44.32%	44.26%
(27)	Purchased Energy		GWh	13.92%	2.93%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(28)	Energy Sales		GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(29)	NET ENERGY FOR LOAD		GWh	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

TABLE 2.1

DEMAND-SIDE MANAGEMENT IMPACTS
Total Program Achievements

Year	MWh	Winter kW	Summer kW
1980	254	168	168
1981	575	370	370
1982	1,054	687	674
1983	2,356	1,339	1,212
1984	8,024	3,074	2,801
1985	16,315	6,719	4,619
1986	25,416	10,470	7,018
1987	30,279	13,287	8,318
1988	34,922	15,918	9,539
1989	38,824	18,251	10,554
1990	43,661	21,033	11,753
1991	48,997	24,204	12,936
1992	54,898	27,574	14,317
1993	61,356	31,434	15,752
1994	66,725	34,803	16,871
1995	72,057	38,117	18,022
1996	75,894	39,121	18,577
1997	79,998	40,256	19,066
1998	84,017	41,351	19,541
1999	88,631	42,599	20,055
2000	93,132	43,742	20,654
2001	97,428	44,873	21,185
2002	102,159	46,121	21,720
2003	106,277	47,213	22,222
2004	109,441	48,028	22,676
2005	113,182	48,893	23,405
2006	116,544	49,619	24,078
2007	130,876	52,029	26,510
2008	151,356	55,609	30,139
2009	165,775	57,272	33,059
2010	180,842	59,756	35,827
2011	196,824	62,277	38,958
2012	211,561	64,210	41,611
2013	221,842	65,669	43,675
2014	230,707	66,965	45,526
2015	239,142	68,193	47,285
2016	247,125	69,354	48,952
2017	254,954	70,470	50,689
2018	262,387	71,525	52,388
2019	269,173	72,500	54,021
2020	275,709	73,429	55,636
2021	282,008	74,313	57,237
2022	288,097	75,160	58,826

TABLE 2.2

DELIVERED FUEL PRICES
$/MMBtu

Year	Coal	Natural Gas
2003	2.04	5.97
2004	2.03	6.40
2005	2.38	9.15
2006	3.00	8.68
2007	2.94	8.37
2008	4.10	10.60
2009	3.96	6.11
2010	3.48	6.64
2011	3.86	5.67
2012	4.03	4.28
2013	3.42	3.80
2014	3.71	4.30
2015	3.91	4.56
2016	4.09	4.72
2017	4.37	4.98
2018	4.67	5.21
2019	4.98	5.49
2020	5.51	5.70
2021	5.87	6.04
2022	6.26	6.44

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

The System plans to retire four generating units within the next 10 years. The John R. Kelly steam unit #7 (JRK #7), 23.2 MW net summer continuous capacity, is presently scheduled to be retired in October 2015. JRK combustion turbines 1, 2, and 3, 14 MW net summer continuous capacity each, are scheduled to be retired in February 2018, September 2018, and May 2019, respectively. These unit retirements are tabulated in Schedule 8.

3.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

GRU uses a planning criterion of 15% capacity reserve margin (suggested for emergency power pricing purposes by Florida Public Service Commission Rule 25-6.035). 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 capacities in summer result in lower reserve margins during the summer season than in winter. In consideration of existing resources, expected future purchases, and savings impacts from conservation programs, GRU expects to maintain a summer reserve margin well in excess of 15% over the next 10 years.

3.3 GENERATION ADDITIONS

No additions to GRU owned generating capacity are scheduled within this ten year planning horizon.

GRU has entered into a 30 year power purchase agreement with the Gainesville Renewable Energy Center for 100 MW net capacity, fueled entirely with biomass. Initial synchronization is scheduled for June 26, 2013 with full commercial operation by the end of 2013.

3.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, identical, mini-power delivery substations (PDS) were planned for the GRU system in 1999. Three of the five - Rocky Point, Kanapaha, and Ironwood - were installed by 2003. A fourth PDS, Springhill, was brought on-line in January 2011. The fifth PDS, known as Northwest Sub, is planned for addition to the System in 2019. This PDS will be located in the 2000 block of NW 53rd Avenue. These new mini-power delivery substations have been planned to redistribute the load from the existing substations as new load centers grow and develop within the System.

The Rocky Point, Kanapaha, and Ironwood PDS utilize single 33.6 MVA transformers that are directly radial-tapped to our looped 138 kV system. The new Springhill Substation consists of one 33.3 MVA transformer served by a loop fed SEECO pole mounted switch. The proximity of these new PDS's 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 (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available (3)	System Firm Summer Peak Demand (1)	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance (1)	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2003	610	0	3	0	607	417	189	45.3%	0	189	45.3%
2004	611	0	3	0	608	432	175	40.5%	0	175	40.5%
2005	611	0	3	0	608	465	143	30.8%	0	143	30.8%
2006	611	0	3	0	608	464	144	31.0%	0	144	31.0%
2007	611	0	0	0	611	481	130	27.1%	0	130	27.1%
2008	610	49	0	0	659	457	202	44.3%	0	202	44.3%
2009	608	101	0	0	709	465	244	52.5%	0	244	52.5%
2010	608	102	0	0	710	470	240	51.1%	0	240	51.1%
2011	608	55	0	0	664	445	219	49.1%	0	219	49.1%
2012	610	57	0	0	667	415	252	60.8%	0	252	60.8%
2013	598	59	0	0	657	411	246	60.0%	0	246	60.0%
2014	598	112	0	0	710	416	294	70.7%	0	294	70.7%
2015	598	113	0	0	711	417	294	70.4%	0	294	70.4%
2016	575	115	0	0	690	419	270	64.5%	0	270	64.5%
2017	575	115	0	0	690	421	269	63.9%	0	269	63.9%
2018	561	115	0	0	676	422	253	60.0%	0	253	60.0%
2019	533	115	0	0	648	424	224	52.8%	0	224	52.8%
2020	533	115	0	0	648	425	222	52.3%	0	222	52.3%
2021	533	115	0	0	648	427	221	51.8%	0	221	51.8%
2022	458	115	0	0	573	428	144	33.7%	0	144	33.7%

(1) System Peak demands shown in this table reflect service to partial and full requirements wholesale customers.
(2) Details of planned changes to installed capacity from 2013-2022 are reflected in Schedule 8.
(3) The coincidence factor used for Summer photovoltaic capacity is 35%.

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 (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available (3)	System Firm Winter Peak Demand (1)	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance (1)	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2003/04	631	0	3	0	628	350	278	79.4%	0	278	79.4%
2004/05	632	0	3	0	629	377	251	66.6%	0	251	66.6%
2005/06	632	0	3	0	629	386	242	62.7%	0	242	62.7%
2006/07	632	0	0	0	632	362	270	74.5%	0	270	74.5%
2007/08	631	0	0	0	631	361	270	74.7%	0	270	74.7%
2008/09	635	76	0	0	711	421	290	68.9%	0	290	68.9%
2009/10	628	76	0	0	705	464	241	51.9%	0	241	51.9%
2010/11	628	53	0	0	681	409	272	66.6%	0	272	66.6%
2011/12	630	53	0	0	683	371	312	84.2%	0	312	84.2%
2012/13	618	54	0	0	672	338	334	99.0%	0	334	99.0%
2013/14	618	105	0	0	724	342	382	111.6%	0	382	111.6%
2014/15	618	106	0	0	724	343	381	110.8%	0	381	110.8%
2015/16	595	106	0	0	701	345	356	103.2%	0	356	103.2%
2016/17	595	107	0	0	702	347	355	102.3%	0	355	102.3%
2017/18	595	107	0	0	702	348	353	101.5%	0	353	101.5%
2018/19	565	107	0	0	672	350	322	92.0%	0	322	92.0%
2019/20	550	107	0	0	657	351	305	86.8%	0	305	86.8%
2020/21	550	107	0	0	657	353	304	86.0%	0	304	86.0%
2021/22	550	107	0	0	657	355	302	85.0%	0	302	85.0%
2022/23	475	107	0	0	582	357	225	63.0%	0	225	63.0%

(1) System Peak demands shown in this table reflect service to partial and full requirements wholesale customers.

(2) Details of planned changes to installed capacity from 2013-2022 are reflected in Schedule 8.

(3) The coincidence factor used for Winter photovoltaic capacity is 9.3%.

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.	Comm.	Expected	Gross Capability		Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retire	Summer	Winter	Summer	Winter	
Plant Name	No.	Location	Type	Pri.	Alt.	Pri.	Alt.	Mo/Yr	Mo/Yr	Mo/Yr	(MW)	(MW)	(MW)	(MW)	Status
Cyrstal River	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			3/1977	1/2013	-13.5	-13.7	-11.8	-12.0	OS
J. R. KELLY	FS07	Alachua County Sec. 4, T10S, R20E	ST	NG	RFO	PL	TK			10/2015	-24.0	-24.0	-23.2	-23.2	RT
J. R. KELLY	GT01	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK			2/2018	-14.0	-15.0	-14.0	-15.0	RT
J. R. KELLY	GT02	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK			9/2018	-14.0	-15.0	-14.0	-15.0	RT
J. R. KELLY	GT03	Alachua County Sec. 4, T10S, R20E	GT	NG	DFO	PL	TK			5/2019	-14.0	-15.0	-14.0	-15.0	RT

Unit Type
ST = Steam Turbine
GT = Gas Turbine

Fuel Type
NG = Natural Gas
NUC = Uranium
RFO = Residual Fuel Oil
DFO = Distillate Fuel Oil

Transportation Method
PL = Pipeline
RR = Railroad
TK = Truck

Status
A = Generating unit capability increased
RT = Existing generator scheduled for retirement
OS = Out of Service

4. ENVIRONMENTAL AND LAND USE INFORMATION

4.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

Currently, there are no new potential generation sites planned.

4.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

The new Gainesville Renewable Energy Center (GREC) biomass-fueled generation facility is currently under construction on land leased from GRU on the northwest portion of the existing Deerhaven Generating Station plant (site). The site is shown in Figure 1.1 and Figure 4.1, located north of Gainesville off U.S. Highway 441. The site is preferred for this project for several major reasons. Since it is an existing power generation site, future development is possible while minimizing impacts to the greenfield (undeveloped) areas. It also has an established access to fuel supply, power delivery, and potable water facilities. The location of the biomass facility is shown on Figure 4.1.

4.2.1 Land Use and Environmental Features

The location of the site is indicated on Figure 1.1 and Figure 4.1, overlain on USGS maps that were originally at a scale of 1 inch : 24,000 feet. Figure 4.2 provides a photographic depiction of the land use and cover of the existing site and adjacent areas. The existing land use of the certified portion of the site is industrial (i.e., electric power generation and transmission and ancillary uses such as fuel storage and conveyance; water withdrawal, combustion product handling and disposal, and forest management). The areas acquired since 2002 have been annexed into the City of Gainesville. The site is a PS, Public Services and Operations District, zoned property. Surrounding land uses are primarily rural or agricultural with some low-density residential development. The Deerhaven site encompasses approximately 3,474 acres.

The Deerhaven Generating Station plant site is located in the Suwannee River Water Management District. A small increase in water quantities for potable uses is projected, with the addition of the biomass facility. It is estimated that industrial processes and cooling water needs associated with the new unit will average 1.4 million gallons per day (MGD). Approximately 400,000 gallons per day of these needs will initially be met using reclaimed water from the City of Alachua. The groundwater allocation in the existing Deerhaven Site Certification will be reduced by 1.4 MGD to accommodate the GREC biomasss unit however, the remaining allocation of 5.1 MGD is sufficient to accommodate the requirements of the GRU portion of the site in the future. Water for potable use will be supplied via the City's potable water system. Groundwater will continue to be extracted from the Floridian aquifer. Process wastewater is currently collected, treated and reused on-site. The site has zero discharge of process wastewater to surface and ground waters, with a brine concentrator and on-site storage of solid water treatment by-products. The new GREC biomass unit will use a wastewater treatment system to also accomplish zero liquid discharge however the solid waste produced will not be stored onsite. Other water conservation measures may be identified during the design of the project.

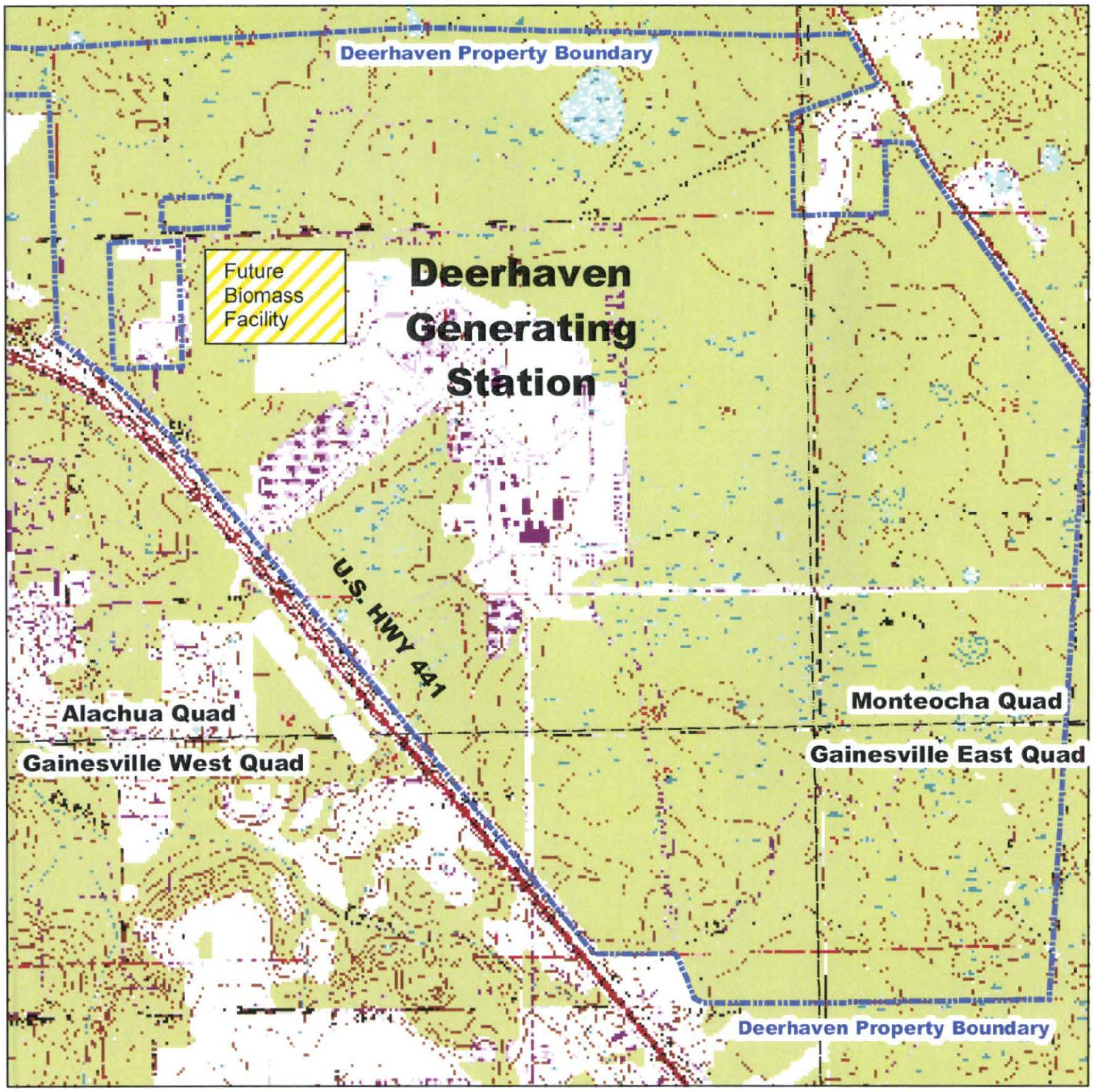
4.2.2 Air Emissions

The proposed generation technology for the biomass unit will necessarily meet all applicable standards for all pollutants regulated for this category of emissions unit.

4.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

Gainesville Renewable Energy Center LLC received unanimous approval for certification under the Power Plant Siting Act on December 7, 2010. The Florida Department of Environmental Protection approved the air construction permit for GREC on December 29, 2010, fulfilling the final regulatory requirement for the biomass facility.

Figure 4.1



Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')

Location Map:
Deerhaven Generating Station

Data Source: USGS 7.5 Minute Quadrangle Maps :
Quad names-Alachua, Gainesville West, Monteocha, Gainesville East

Figure 4.2

SITE LOCATION
WITHIN STATE OF FLORIDA

Map Scale
1 : 24,000
(1 " = 2,000')

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Aerial Photos:
Deerhaven Generating Station