GAINESVILLE REGIONAL UTILITIES

2025 TEN-YEAR SITE PLAN

GRU℠
More than Energy

Submitted to:

The Florida Public Service Commission

April 1, 2025

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INTRODUCTION

The 2025 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 2025 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 transmission service to the City of Alachua (Alachua) and Seminole Electric Cooperative (Seminole). GRU's distribution system served its retail territory of approximately 124 square miles and an average of 104,510 customers during 2024. 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 section. The present Summer Net Continuous Capacity is 640.2 MW and the Winter Net Continuous Capacity is 672.9 MW. Currently, the System's energy is produced by three fossil fuel steam turbines[1], one of which is part of a combined cycle unit; a biomass-fueled steam turbine; five combustion turbines, three of which are simple cycle, one which can generate in either simple or combined cycle mode, and one which provides distributed generation; and an internal combustion engine which also provides distributed generation.

The System has three primary generating plant sites: Deerhaven (DH), Deerhaven Renewable (DHR), and John R. Kelly (JRK). These sites are shown on Figure 1.1.

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1 One steam turbine, JRK steam turbine FS08.2, operates only in combined cycle with JRK combustion turbine GT044. As GT04 is fossil fueled, the steam created by the heat recovery steam generator into which it exhausts when in combined cycle mode is produced by fossil fuel. Therefore FS08.2 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for FS08.2.

1.1.1 Generating Units[2]

1.1.1.1 Simple Cycle Steam and Combined Cycle Units. The System has two simple cycle steam turbines and one combined cycle steam turbine powered by fossil fuels[3]. The System also consists of a biomass-fueled simple cycle steam turbine. The two simple cycle fossil-fueled steam turbines comprise 49% of the System's Net Summer Continuous Capacity and produced 38% of the electric energy supplied by the System in 2024. The combined cycle unit, which includes a heat recovery steam generator (HRSG), a steam turbine/generator, and combustion turbine/generator, comprises 18% of the System's Net Summer Continuous Capacity and produced 42% of the electric energy supplied by the System in 2024. Deerhaven FS02 (232 MW), JRK CC1 (112 MW), and DHR (103 MW) are used for base load purposes, while Deerhaven FS01 (76 MW) has more commonly been used for intermediate loading. DHR comprises 16% of the System’s Net Summer Continuous Capacity and produced 13% of the electric energy supplied by the System in 2024.

1.1.1.2 Simple Cycle Combustion Gas Turbines. The System's four industrial combustion turbines that operate only in simple cycle comprise 18% of the System's Summer Net generating capacity and produced 2% of the electric energy supplied by the System in 2024. Three of these simple cycle combustion turbines are utilized for peaking purposes only as their energy conversion efficiencies are considerably lower than steam or combined cycle units. However, simple cycle combustion turbines are advantageous in that they can be started and placed online quickly. The fourth combustion turbine operates to serve load as part of a combined heat and power facility at the South Energy Center, further described in Section 1.4. The combustion turbine mentioned in 1.1.1.1 that is used the majority of the time in combined cycle can also be operated in simple cycle to provide for peaking power.

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2 All MW ratings are Summer Net continuous capacity unless otherwise stated.

3 One steam turbine, JRK steam turbine FS08.2, operates only in combined cycle with JRK combustion turbine GT044. As GT04 is fossil fueled, the steam created by the heat recovery steam generator into which it exhausts when in combined cycle mode is produced by fossil fuel. Therefore FS08.2 is indirectly driven by fossil fuel. No capability exists to directly burn fossil fuel to produce steam for FS08.2.

1.1.1.3 Reciprocating Internal Combustion Engine. The System operates a 7.4 MW natural gas-fired internal combustion engine at the South Energy Center. The engine is used in a combined heat and power application, where the engine's waste heat is captured to make steam and hot water for an academic medical campus.

1.1.1.4 Environmental Considerations. Deerhaven FS02 has an Air Quality Control System, consisting of low NO_x burners to reduce NO_x; a dry recirculating flue gas desulfurization unit to reduce acid gases, sulfur dioxide (SO_2) and mercury; and a fabric filter baghouse to reduce particulates. The Deerhaven Renewable (biomass) unit uses a fabric filter baghouse to reduce particulates; and an SCR to reduce NO_x. Both the Deerhaven and Deerhaven Renewable Plant Sites operate with zero liquid discharge to surface waters.

1.1.2 Generating Plant Sites

The locations of the System's primary 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 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 combustion turbines, associated cooling facilities, fuel storage, pumping equipment, transmission equipment, coal unloading facilities, and coal storage facilities.

1.1.2.3 Deerhaven Renewable Plant. The Deerhaven Renewable biomass-fueled generation facility is located northwest of the Deerhaven Generating Station. GRU purchased this 103 MW generating unit in November 2017. The facility consists of one steam turbine, the associated cooling facilities, and biomass unloading and storage facilities.

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 three primary generating stations,
2) GRU's eleven distribution substations,
3) One 230 kV and one 69 kV intertie with Duke Energy Florida (DEF),
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 geographical locations of the System's transmission lines.

1.2.2 Transmission Lines

The present transmission network consists of the following:

Line	Circuit Miles	Conductor
138 kV double circuit	80.08	795 MCM ACSR 26/7
138 kV single circuit	16.86	1192 MCM ACSR 45/7
138 kV single circuit	20.61	795 MCM ACSR 26/7
230 kV single circuit	2.53	795 MCM ACSR 26/7
Total	120.08	

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 or fault conditions that may occur.

1.2.3 State Interconnections

The System is currently interconnected with DEF and FPL at four separate points. The System interconnects with DEF'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 DEF's Idylwild Substation with two separate lines 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 also evaluating increasing transmission capacity with DEF and/or FPL. The timing, cost, and feasibility of this transmission upgrade is currently being assessed.

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

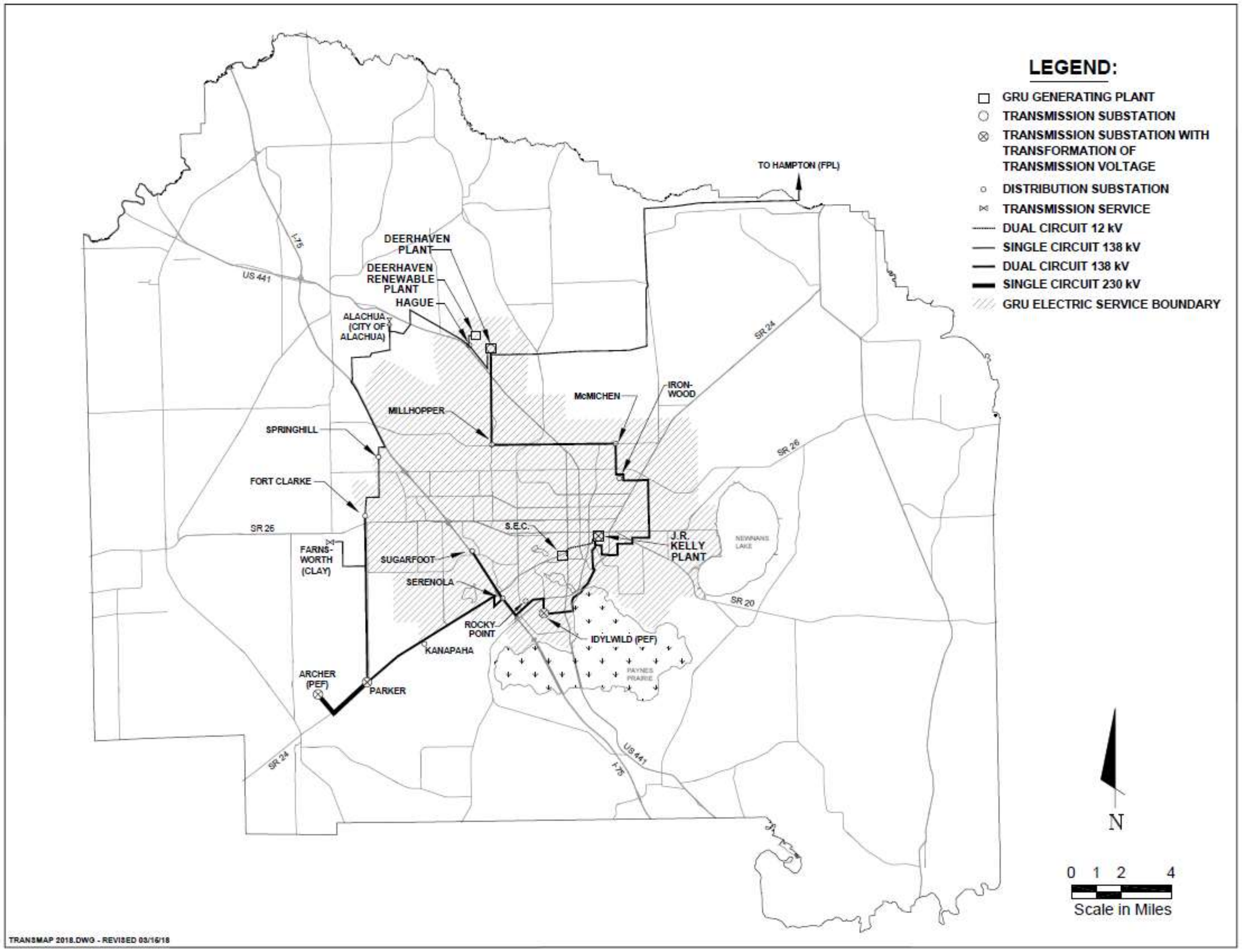
The seven loop-fed distribution substations are connected to the 138 kV bulk power transmission network with feeds that prevent the outage of a single transmission line from causing any outages in the distribution system. Ironwood, Kanapaha, Rocky Point, and Springhill are served by a single tap to the 138 kV network which would require distribution switching to restore customer power if the single transmission line tapped experienced an outage. GRU serves its retail customers through a 12.47 kV distribution network. The System has three Power Delivery Substations (PDS) with single 33.6 MVA transformers that are directly radial-tapped to the looped 138 kV system. The Springhill Substation consists of one 33.3 MVA transformer served by a loop-fed SEECO pole-mounted switch. Ft. Clarke substation has a 22.4 MVA and a 28 MVA transformer. Kelly West Substation has a 56 MVA and a 33.6 MVA transformer. Millhopper Substation has two 33.6 MVA transformers and one 44MVA transformer. Sugarfoot Substation has three 44 MVA transformers. Serenola has two 44MVA transformers. Finally, the McMichen Substation has two transformers at 44MVA and 33MVA respectively. Under normal peak conditions, the system’s substation transformers are loaded in the range of 50% to 75% of their capacity.

1.4 DISTRIBUTED GENERATION

The South Energy Center (SEC), a combined heat and power plant, has served the UF Health South Campus since February 2009. The SEC houses a 3.8 MW natural gas-fired turbine and a 7.4 MW natural gas-fired reciprocating internal combustion engine which are capable of supplying 100% of the UF Health Cancer, Heart and Vascular, and Neuromedicine hospitals' electric and thermal needs. The SEC provides electricity, chilled water, steam, heating hot water, and the storage and delivery of medical gases to the hospitals. The unique design is at least 65% 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 energy output is not totally utilized by the UF Health South Campus.

Figure 1.1

Gainesville Regional Utilities Electric Facilities



Schedule 1
EXISTING GENERATING FACILITIES (as of January 1, 2025)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				Primary Fuel		Alternate Fuel		Alt. Fuel Storage	Commercial In-Service	Expected Retirement	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Type	Trans.	Type	Trans.	(Days)	Month/Year	Month/Year	Summer MW	Winter MW	Summer MW	Winter MW	Status
J. R. Kelly		Alachua County									**114.0**	**127.4**	**112.0**	**125.4**	
	FS08.2	Sec. 4, T10S, R20E	CA	WH	PL	DFO	TK		[5/01; 5/21]	12/2051	41.5	41.5	41.0	41.0	OP
	GT04	(GRU)	CT	NG	PL	DFO	TK		5/01	12/2051	72.5	85.9	71.0	84.4	OP
Deerhaven		Alachua County									**439.5**	**459.0**	**414.0**	**433.0**	
	FS02	Secs. 26,27,35	ST	NG	PL	BIT	RR		10/81	12/2036*	251.0	251.0	232.0	232.0	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	12/2027*	81.0	81.0	76.0	76.0	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	12/2046	71.5	81.0	71.0	81.0	OP
	GT02		GT	NG	PL	DFO	TK		8/76	12/2031	18.0	23.0	17.5	22.0	OP
	GT01		GT	NG	PL	DFO	TK		7/76	12/2031	18.0	23.0	17.5	22.0	OP
South Energy Center		Alachua County									**11.2**	**11.5**	**11.2**	**11.5**	
	GT01 (*)	Sec. 10, T10S, R20E	GT	NG	PL				5/09	12/2039	3.8	4.1	3.8	4.1	OP
	IC02 (*)	(GRU)	IC	NG	PL				12/17	12/2047	7.4	7.4	7.4	7.4	OP
Deerhaven Renewable		Alachua County													
	DHR	Sec. 26, T08, R19 (GRU)	ST	WDS	TK				12/13	12/2043	**114.0**	**114.0**	**103.0**	**103.0**	OP
System Total													**640.2**	**672.9**	

Unit Type
CA = Combined Cycle - Steam Part
CT = Combined Cycle - CT Part
GT = Gas Turbine
ST = Steam Turbine
IC = Internal Combustion Engine

Fuel Type
BIT = Bituminous Coal
DFO = Distillate Fuel Oil
NG = Natural Gas
RFO = Residual Fuel Oil
WH = Waste Heat
WDS = Wood Waste Solids

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

Status
OP = Operational

Notes
* = these units are being evaluated for refurbishment, and their retirement dates may be deferred

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 2015-2034. Energy sales and number of customers are tabulated in Schedules 2.1, 2.2, and 2.3. Schedule 3.1 gives the summer peak demand forecast by reporting category. Schedule 3.2 presents the winter peak demand forecast by reporting category. Schedule 3.3 presents net energy for load 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 2024. 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. Historical estimates used in this forecast were taken from Florida Estimates of Population 2024. Population projections used in this forecast were based on projections included in BEBR Bulletin 198.

(3) Historical weather data was used to fit regression models. The forecast assumes normal weather conditions. Heating degree days and cooling degree days as reported to NOAA by the Gainesville Municipal Airport

station were compiled from 1984-2024. The median values from 2015-2024 were used in this forecast.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2017, using the Personal Consumption Expenditures Price Index, published by the U.S. Bureau of Economic Analysis. Inflation is assumed to average approximately 2.25% 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 Woods & Poole Economics, Inc.

(6) Historical estimates of household size were obtained from BEBR Bulletin 200 (December 2024), and projections were held constant at the 2024 level through the forecast horizon.

(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 Woods & Poole Economics, Inc.

(8) Retail electric prices for each billing rate category were assumed to increase at a nominal rate of approximately 2.5% 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 1980-2024. GRU's involvement with DSM is described in more detail later in this section.

(10) Separate forecasts of solar net metering impacts and electric vehicle charging impacts were incorporated into this forecast for each customer rate classification. The overall impacts of these uses, net of impacts through 2024, results in progressively increasing energy usage in the later years of the forecast.

11) GRU does not have any firm wholesale agreements with other utilities. All customer, sales and load projections included in this forecast represent retail activity only.

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 2025 through 2034. Separate energy sales forecasts were developed for each of the following customer segments: residential, general service non-demand, general service demand, large power, and outdoor lighting. 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)[4]. 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, an index measuring building envelope efficiency, heating degree days, and cooling degree days. The form of this equation is as follows:

$$RESAVUSE = -14978 - 20.0\,(RESPR17) + 26756\,(COOL\_INDX) + 1.10\,(HDD) + 0.36\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use per Customer
RESPR17	=	Residential Price, Dollars per 1000 kWh
COOL_INDX	=	Building Shell Cooling Efficiency Index
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

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

Adjusted R^2	=	0.8541
DF (error)	=	23 (period of study, 1997-2024)
t - statistics:		
Intercept	=	-2.40
RESPR17	=	-3.29
COOL_INDX	=	4.85
HDD	=	3.21
CDD	=	1.05

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

RESCUS = 22111 + 238.0 (POP)

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
Adjusted R^2	=	0.9783
DF (error)	=	8 (period of study, 2015-2024)
t - statistics:		
Intercept	=	6.75
POP	=	20.16

The product of forecasted values of average usage per customer 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 billing 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. As a result, a significant proportion of current GSD customers have voluntarily elected this rate category. The forecast assumes that additional GSN customers will opt into 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 and the price of electricity. The specifications of this model are as follows:

GSNAVUSE= 35.37 – 0.0068 (OPTDCUS) – 0.0880 (GSNPR17)

Where:

GSNAVUSE	=	Average Annual Energy Usage per GSN Customer
OPTDCUS	=	Optional GSD Customers
GSNPR17	=	Delivered Electricity Price
Adjusted R^2	=	0.9198
DF (error)	=	25 (period of study, 1997-2024)
t - statistics:		
Intercept	=	25.25
OPTDCUS	=	-6.53
GSNPR17	=	-7.85

The number of general service non-demand customers was projected using an equation specifying customers as a function of Alachua County population and the addition of a group of individually metered cable amplifiers that were previously bulk metered in 2008. The specifications of the general service non-demand customer model are as follows:

GSNCUS	=	*2249.8 + 26.2 (POP) + 1.15 (COXTRAN)*
Where:		
GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
COXTRAN	=	Cable TV Meters
Adjusted R^2	=	0.9660
DF (error)	=	17 (period of study, 2004-2024)
t - statistics:		
Intercept	=	5.70
POP	=	15.97
COXTRAN	=	5.49

Forecasted energy sales to general service non-demand customers were derived from the product of projected number of customers and the projected average annual usage 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, electric price, and an indicator variable representing a change in eligibility criteria for the general service large demand rate category beginning in 2013. Average energy use projections for general service demand customers result from the following model:

GSDAVUSE=		*680.4 – 0.041 (OPTDCUS) – 1.32 (GSNPR17) + 40.5 (POLICY)*
Where:		
GSDAVUSE	=	Average Annual Energy Use by GSD Customers
OPTDCUS	=	Optional GSD Customers
GSNPR17	=	Delivered Electricity Price
POLICY	=	Eligibility Indicator Variable
Adjusted R^2	=	0.6605
DF (error)	=	26 (period of study, 1995-2024)
t - statistics:		
Intercept	=	27.58
OPTDCUS	=	-1.30
GSNPR17	=	-6.70
POLICY	=	2.65

The annual average number of customers was projected using a linear trend analysis of historical data from 2005 – 2024. The forecast adds approximately four new GSD customers per year.

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

2.2.4 General Service Large Demand Sector

The general service large demand customer class currently includes eleven customers that maintain an average monthly billing demand of at least 1,000 kW. Because of this requirement to maintain a minimum average billing demand, there is occasional rate migration between the large power and general service demand classes. The forecast of general service large demand energy sales was developed via analysis of each individual account. Recent historical energy sales were examined for the presence of any trends in usage patterns. This methodology has been described as an heuristic approach. The forecast of usage per customer was held constant through the forecast horizon.

The number of customers in the general service large demand sector is expected to increase by approximately one customer every ten years. Since the timing of any prospective customer addition is not known, fractional increases were included each year providing for a smooth transition of modest load growth. Future forecasts will incorporate known, specific changes within this sector when and if they are identified.

2.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of public streetlights and rental lighting accounts. Outdoor lighting energy sales account for less than one percent of retail energy sales. Outdoor lighting energy sales were forecast to remain constant at current levels through the forecast horizon.

2.2.6 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, general service large demand, and outdoor lighting. 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 was 0.97. Historical delivered efficiencies from 2000 through 2024 were examined to make this determination. The impact of energy savings from conservation programs, solar net metering, and electric vehicle charging 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. A second methodology for projecting peak demands was utilized in the forecasts for this TYSP. Regression equations were developed for summer and winter peak demand, where retail net energy for load and minimum temperature (winter) and maximum temperature (summer) were the explanatory variables. The results from this methodology were combined in a manner such that results from the load factor methodology and results from the regression methodology were equally weighted. GRU is monitoring whether the relationship between energy and demand is changing in recent years as behind the meter solar distributed generation and electric vehicle charging become more commonplace.

2.3 ENERGY SOURCES AND FUEL REQUIREMENTS

2.3.1 Fuels Used by the System

Presently, the System is capable of using coal, woody biomass, natural gas, residual oil, and distillate oil to satisfy its fuel requirements. The System has historically relied upon coal to fulfill much of its fuel requirements. However, with lower natural gas prices, and subsequent fuel switching, natural gas has become the largest portion of generation fuel. Because the System participates in interchange sales and purchases, and because fuel prices constantly change, actual consumption of these fuels will likely differ from the requirements indicated in Schedule 5.

2.3.2 Purchased Power Agreements

2.3.2.1 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 is purchasing solar energy from approximately 250 privately-owned systems distributed throughout GRU's service territory. Each FIT system has an individual contract with a 20-year term. Approximately 18.6 MW of solar generation were constructed under the Solar FIT 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 2024.

The effectiveness of historical measures is reflected in usage data. Over the past 10 years, residential usage per customer has declined 0.19% per year and non-residential usage per customer has declined 0.86% per year.

DSM direct services currently available to the System's residential customers include energy and water surveys, allowances for whole house energy efficiency improvements under the Low-income Energy Efficiency Program Plus (LEEP^{plus}), and natural gas rebates for new construction and conversions in existing homes for water heating, central heating, clothes drying and cooking appliances.

The System continues to offer standardized interconnection procedures for both residential and non-residential customers who install photovoltaic solar systems on their homes or businesses.

GRU has also produced numerous factsheets, publications, and videos which are available at no charge to customers and which assist them in making informed decisions regarding their consumption.

2.4.2 Demand-Side Management Methodology and Results

Energy and demand savings resulting from DSM program implementation have been estimated using a combination of techniques, including engineering calculations, pre and post billing analysis, and measurement and verification for specific measures. Known interactions between measures and programs were accounted for where possible. From 1980 through 2024, GRU estimates that utility-sponsored DSM programs reduced energy sales by 221 GWh and lowered summer peak demand by 44 MW. In the forecast period, DSM-related savings are projected to be very small relative to system load due to the scaling back of programs in this and future years' budgets.

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 improved the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. In specific areas, feeders have been installed underground using 1000 MCM underground cable and most if not all new distribution feeder installations must be underground. GRU adds capacitors on its distribution feeders where necessary to support a high system-wide power factor. GRU conducted a Cable Restoration Project, where direct-buried underground primary cables installed prior to 1985 were injected with a solution that restored the insulation of the cable and extends the cable's useful life. Efforts have been made to increase segmentation of feeders by adding more fusing stages, which reduces the number of customers behind any one device. GRU expends great effort in hardening its overhead distribution facilities, increasing basic insulation levels everywhere feasible, using thicker poles, installing animal guards and rebuilding circuits using vertical construction with greater phase spacing. Since 2022, GRU energized two new main feeders that improved reliability by increasing the ability to switch loads under contingency. Efforts in distribution automation have included adding reclosers and automated switches, which decrease outage times by enabling GRU's system operators to remotely switch customers to adjacent feeders when outages occur. GRU has a vegetation management program targeting feeders on a three-to-four-year rotational basis as well as a wood pole inspection program that follows an eight-year inspection cycle.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU relies on natural gas and biomass as primary fuels used to meet its generation needs. Both heavy and light fuel oils as well as coal are used as backup for natural gas-fired generation, although in practice they are rarely used. GRU consults a number of reputable sources such as EIA, S&P Global Platts, Platts Gas Daily, Coaldesk, and the NYMEX futures market when assessing expected future fuel commodity 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 CSX rail, and natural gas is transported over the Florida Gas Transmission (FGT) Company pipeline system.

2.5.1 Coal

Coal was used to generate approximately 0.1% of the energy produced by the system in 2024. Thus far, GRU has purchased low sulfur and medium sulfur, high BTU eastern coal for use in FS02. In 2009, FS02 was retrofitted with an air quality control system, which was added as a means of complying with new environmental regulations. Following this retrofit, FS02 can utilize coals with up to approximately 2.9% sulfur content. Given the impact of impending environmental regulations on coal generating units, reduced demand, and depressed prompt prices for Central Appalachian (CAPP) coal, GRU has continued to purchase relatively high-quality Eastern coal whenever it enters the market. GRU does not anticipate any near-term coal purchases due to the system only using coal for emergencies, the system having a relatively high coal inventory, and natural gas having lower forecasted prices than coal for much of the foreseeable future.

In addition to the commodity price of coal and rail transport expense, GRU's all-in price of coal also incorporates the cost of environmental commodities (pebble lime) used during the combustion of coal to comply with environmental regulations as well as expenses associated with railcar maintenance, disposal of combustion products, and diesel for pile maintenance.

In 2021, the System completed a dual-fuel upgrade on Deerhaven Unit 2 to allow the boiler to be able to operate both on natural gas and coal. As natural gas prices are forecasted to remain relatively low compared to coal over most of the 10-year horizon, coal consumption is forecasted to be relatively small. However, if natural gas prices increase beyond coal prices, the unit may switch its fuel source back to coal if coal supply is readily available. Otherwise, coal will be the back-up/emergency fuel for the unit when natural gas is unavailable.

2.5.2 Natural Gas

GRU procures natural gas for power generation and for distribution by its Local Distribution Company (LDC). In 2024, GRU purchased approximately 19 million MMBTU for use by both systems. GRU power plants used 88% of the total purchased for GRU during 2024, while the LDC used the remaining 12%. Natural gas was used to produce approximately 82% of the energy produced by GRU's electric generating units during calendar year 2024.

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, FGT's fuel charge, FGT's usage (transportation) charge, FGT's reservation (capacity) charge, and basis adjustments. Fuel commodity cost projections were based on closing NYMEX natural gas futures prices for the Henry Hub.

2.5.3 Biomass

GRU procures woody biomass consisting mainly of forest residue from logging operations and urban wood waste from within a 75-100-mile radius of the plant. The major portion of biomass fuel is secured by contracts of varying lengths with the remainder purchased on a spot basis to take advantage of opportunity fuel. The forecast of biomass prices is based on contract prices escalated by forecasts of the Producer Price Index for diesel and the Consumer Price Index. Biomass was used to generate approximately 13% of the total energy produced by the system in calendar year 2024.

In addition to the delivered commodity price of woody biomass, GRU's all-in price of biomass fuel also incorporates the cost of environmental commodities (ammonia) required for combustion of biomass to comply with environmental regulations as well as expenses associated with disposal of combustion products and diesel for pile maintenance.

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
2015	198,129	2.36	799	83,953	9,519	784	10,663	73,533
2016	199,085	2.36	822	84,358	9,747	784	10,790	72,684
2017	203,196	2.36	806	86,100	9,362	775	11,132	69,579
2018	202,429	2.34	834	86,508	9,640	796	11,161	71,307
2019	202,827	2.33	837	87,050	9,621	800	11,264	71,043
2020	204,183	2.31	850	88,391	9,620	752	11,313	66,490
2021	208,252	2.32	839	89,764	9,342	759	11,342	66,928
2022	208,222	2.32	840	89,751	9,358	762	11,289	67,475
2023	214,155	2.32	844	92,308	9,147	782	11,546	67,726
2024	215,686	2.32	870	92,968	9,354	773	11,530	67,022
2025	217,316	2.32	873	93,671	9,320	776	11,621	66,759
2026	218,899	2.32	879	94,353	9,314	779	11,709	66,489
2027	220,434	2.32	885	95,015	9,312	781	11,795	66,234
2028	221,923	2.32	891	95,656	9,313	784	11,879	65,994
2029	223,364	2.32	897	96,278	9,316	787	11,959	65,768
2030	224,758	2.32	903	96,879	9,322	789	12,037	65,557
2031	226,105	2.32	909	97,459	9,331	792	12,113	65,360
2032	227,405	2.32	916	98,019	9,343	794	12,186	65,178
2033	228,658	2.32	922	98,559	9,358	797	12,256	65,011
2034	229,863	2.32	929	99,079	9,376	799	12,323	64,859

* 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
2015	157	12	12,928	0	25	0	1,765
2016	165	13	12,758	0	25	0	1,796
2017	168	13	12,738	0	25	0	1,774
2018	175	12	14,177	0	25	0	1,830
2019	170	10	16,450	0	23	0	1,830
2020	168	10	16,406	0	20	0	1,790
2021	175	11	15,875	0	18	0	1,791
2022	179	11	15,938	0	16	0	1,797
2023	169	11	15,756	0	16	0	1,811
2024	177	12	15,273	0	16	0	1,836
2025	177	11	15,988	0	16	0	1,842
2026	179	11	15,994	0	16	0	1,853
2027	181	11	16,000	0	16	0	1,863
2028	182	11	16,007	0	16	0	1,873
2029	184	12	16,015	0	16	0	1,884
2030	186	12	16,024	0	16	0	1,894
2031	188	12	16,033	0	16	0	1,905
2032	189	12	16,043	0	16	0	1,915
2033	191	12	16,054	0	16	0	1,926
2034	193	12	16,066	0	16	0	1,937

** Industrial includes General Service Large Demand Rate Class

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

(1) Year	(2) Sales For Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers	(6) Total Number of Customers
2015	214	45	2,024	0	94,628
2016	221	37	2,054	0	95,161
2017	220	37	2,031	0	97,245
2018	222	27	2,079	0	97,681
2019	134	36	2,000	0	98,324
2020	134	53	1,977	0	99,714
2021	135	26	1,952	0	101,117
2022	31	67	1,895	0	101,051
2023	0	36	1,847	0	103,865
2024	0	67	1,903	0	104,510
2025	0	57	1,899	0	105,303
2026	0	57	1,910	0	106,073
2027	0	58	1,921	0	106,821
2028	0	58	1,931	0	107,546
2029	0	58	1,942	0	108,249
2030	0	59	1,953	0	108,928
2031	0	59	1,964	0	109,584
2032	0	60	1,975	0	110,217
2033	0	60	1,986	0	110,827
2034	0	60	1,997	0	111,414

Schedule 3.1
History and Forecast of Summer Peak Demand - MW

(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
2015	464	37	384	0	0	27	0	16	421
2016	471	38	390	0	0	27	0	16	428
2017	461	38	380	0	0	27	0	16	418
2018	452	37	371	0	0	28	0	16	408
2019	473	28	401	0	0	28	0	16	429
2020	469	28	397	0	0	28	0	16	425
2021	466	29	393	0	0	28	0	16	422
2022	452	0	408	0	0	28	0	16	408
2023	453	0	409	0	0	28	0	16	409
2024	449	0	405	0	0	28	0	16	405
2025	450	0	406	0	0	28	0	16	406
2026	452	0	408	0	0	28	0	16	408
2027	454	0	410	0	0	28	0	16	410
2028	456	0	412	0	0	28	0	16	412
2029	459	0	415	0	0	28	0	16	415
2030	461	0	417	0	0	28	0	16	417
2031	463	0	419	0	0	28	0	16	419
2032	467	0	422	0	0	29	0	16	422
2033	469	0	424	0	0	29	0	16	424
2034	471	0	426	0	0	29	0	16	426

Schedule 3.2
History and Forecast of Winter Peak Demand - MW

(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
2015 / 2016	412	35	313	0	0	51	0	13	348
2016 / 2017	397	33	300	0	0	51	0	13	333
2017 / 2018	475	38	372	0	0	52	0	13	410
2018 / 2019	398	24	309	0	0	52	0	13	333
2019 / 2020	403	23	315	0	0	52	0	13	338
2020 / 2021	413	25	323	0	0	52	0	13	348
2021 / 2022	420	25	330	0	0	52	0	13	355
2022 / 2023	375	0	309	0	0	53	0	13	309
2023 / 2024	362	0	296	0	0	53	0	13	296
2024 / 2025	416	0	350	0	0	53	0	13	350
2025 / 2026	402	0	336	0	0	53	0	13	336
2026 / 2027	404	0	338	0	0	53	0	13	338
2027 / 2028	406	0	340	0	0	53	0	13	340
2028 / 2029	408	0	342	0	0	53	0	13	342
2029 / 2030	411	0	344	0	0	54	0	13	344
2030 / 2031	413	0	346	0	0	54	0	13	346
2031 / 2032	415	0	348	0	0	54	0	13	348
2032 / 2033	417	0	350	0	0	54	0	13	350
2033 / 2034	419	0	352	0	0	54	0	13	352
2034 / 2035	421	0	354	0	0	54	0	13	354

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	Comm./Ind. Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2015	2,241	147	70	1,765	214	45	2,024	55%
2016	2,271	147	70	1,796	221	37	2,054	55%
2017	2,249	148	70	1,774	220	37	2,031	55%
2018	2,297	148	70	1,830	222	27	2,079	58%
2019	2,219	149	70	1,830	134	36	2,000	53%
2020	2,197	150	70	1,790	134	53	1,977	53%
2021	2,172	150	70	1,791	135	26	1,952	53%
2022	2,116	151	70	1,797	31	67	1,895	53%
2023	2,068	151	70	1,811	0	36	1,847	52%
2024	2,125	152	70	1,836	0	67	1,903	53%
2025	2,121	152	70	1,842	0	57	1,899	53%
2026	2,133	153	70	1,853	0	57	1,910	53%
2027	2,144	153	70	1,863	0	58	1,921	53%
2028	2,154	153	70	1,873	0	58	1,931	53%
2029	2,166	154	70	1,884	0	58	1,942	53%
2030	2,177	154	70	1,894	0	59	1,953	53%
2031	2,188	154	70	1,905	0	59	1,964	54%
2032	2,200	155	70	1,915	0	60	1,975	53%
2033	2,211	155	70	1,926	0	60	1,986	53%
2034	2,222	155	70	1,937	0	60	1,997	54%

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			
	2023		2024		2025	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	292	135	338	147	339	147
FEB	264	120	295	127	295	128
MAR	292	135	278	135	279	135
APR	340	141	311	138	312	139
MAY	331	156	363	166	365	167
JUN	382	171	398	180	400	180
JUL	402	198	402	194	404	195
AUG	409	207	407	197	409	199
SEP	379	175	382	180	384	181
OCT	311	149	332	155	334	155
NOV	255	127	272	132	274	133
DEC	254	132	294	141	296	142

Schedule 5
FUEL REQUIREMENTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				ACTUAL										
FUEL REQUIREMENTS			UNITS	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	NUCLEAR		TRILLION BTU	0	0	0	0	0	0	0	0	0	0	0
(2)	COAL		1000 TON	1	31	29	8	108	118	86	95	126	116	154
	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	8,821	5,988	7,569	6,922	4,631	6,615	6,791	6,729	5,873	5,174	3,098
(12)		CC	1000 MCF	6,711	6,862	5,947	6,757	6,128	5,853	5,626	6,106	5,776	5,799	5,227
(13)		CT	1000 MCF	591	491	531	532	561	536	530	527	538	533	600
(14)		TOTAL:	1000 MCF	16,123	13,341	14,047	14,211	11,320	13,004	12,947	13,362	12,187	11,506	8,925
(15)	OTHER (specify)		1000 Tons Biomass	365	481	485	499	512	378	499	444	553	647	855

Schedule 6.1
ENERGY SOURCES (GWH)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0	0	0	0	0	0	0	0	0	0	0
(2)	NUCLEAR Replacement Power		GWh	0	0	0	0	0	0	0	0	0	0	0
(3)	COAL		GWh	2	63	57	16	213	238	177	197	259	238	316
	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	717	480	604	560	395	564	583	576	485	428	250
(13)		CC	GWh	807	852	738	840	760	726	696	756	716	718	651
(14)		CT	GWh	38	48	53	53	54	53	53	53	54	54	58
(15)		TOTAL:	GWh	1562	1380	1395	1453	1209	1343	1332	1385	1255	1200	959
(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		GWh	253	343	373	369	365	274	361	322	426	496	654
(19)	GEOTHERMAL		GWh	0	0	0	0	0	0	0	0	0	0	0
(20)	HYDRO		GWh	0	0	0	0	0	0	0	0	0	0	0
(21)	LANDFILL GAS	PPA	GWh	0	0	0	0	0	0	0	0	0	0	0
(22)	MSW		GWh	0	0	0	0	0	0	0	0	0	0	0
(23)	SOLAR		GWh	0	0	0	0	0	0	0	0	0	0	0
(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	253	343	373	369	365	274	361	322	426	496	654
(27)	Market Purchases (Sales)		GWh	86	113	85	83	144	87	83	60	35	52	68
(28)	NET ENERGY FOR LOAD		GWh	1903	1899	1910	1921	1931	1942	1953	1964	1975	1986	1997

Schedule 6.2
ENERGY SOURCES (%)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	ENERGY SOURCES		UNITS	ACTUAL 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(2)	NUCLEAR Replacement Power		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(3)	COAL		GWh	0.1%	3.3%	3.0%	0.8%	11.0%	12.3%	9.1%	10.0%	13.1%	12.0%	15.8%
	RESIDUAL													
(4)		STEAM	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(5)		CC	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(6)		CT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(7)		TOTAL:	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	DISTILLATE													
(8)		STEAM	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(9)		CC	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(10)		CT	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(11)		TOTAL:	GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	NATURAL GAS													
(12)		STEAM	GWh	37.7%	25.3%	31.6%	29.2%	20.5%	29.0%	29.9%	29.3%	24.6%	21.6%	12.5%
(13)		CC	GWh	42.4%	44.9%	38.6%	43.7%	39.4%	37.4%	35.6%	38.5%	36.3%	36.2%	32.6%
(14)		CT	GWh	2.0%	2.5%	2.8%	2.8%	2.8%	2.7%	2.7%	2.7%	2.7%	2.7%	2.9%
(15)		TOTAL:	GWh	82.1%	72.7%	73.0%	75.6%	62.6%	69.2%	68.2%	70.5%	63.5%	60.4%	48.0%
(16)	NUG		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(17)	BIOFUELS		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(18)	BIOMASS		GWh	13.3%	18.1%	19.5%	19.2%	18.9%	14.1%	18.5%	16.4%	21.6%	25.0%	32.7%
(19)	GEOTHERMAL		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(20)	HYDRO		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(21)	LANDFILL GAS		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(22)	MSW		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(23)	SOLAR		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(24)	WIND		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(25)	OTHER RENEWABLE		GWh	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
(26)	Total Renewable		GWh	13.3%	18.1%	19.5%	19.2%	18.9%	14.1%	18.5%	16.4%	21.6%	25.0%	32.7%
(27)	Market Purchases (Sales)		GWh	4.5%	6.0%	4.5%	4.3%	7.5%	4.5%	4.2%	3.1%	1.8%	2.6%	3.4%
(28)	NET ENERGY FOR LOAD		GWh	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

Deerhaven fossil steam unit #1, combustion turbines #1 and #2, and fossil steam unit #2 and are currently scheduled for retirement in 2027, 2031, and 2036, respectively, and these scheduled changes to the System's generation mix are tabulated in Schedule 8. However, fossil steam units #1 and #2 will undergo assessment for refurbishment, and their retirement dates may be deferred.

3.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

GRU uses a planning criterion of 15% capacity reserve margin (required for emergency power 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 in excess of 15% over the next ten years.

3.3 GENERATION ADDITIONS

GRU is evaluating adding flexible gas generation at the Deerhaven site. This quick-starting and quick-ramping generation addition would allow GRU to quickly respond to contingency events, to balance intermittent renewable resources, and to participate more extensively in economical power purchases and sales.

3.4 DISTRIBUTION SYSTEM ADDITIONS

The Rocky Point, Kanapaha, and Ironwood compact power delivery systems (PDS) utilize single 33 MVA class transformers that are radial-tapped to the System's looped 138 kV system. These three radial-tapped substations all have remote controlled motor-operated tie reclosers to remotely switch distribution load in a matter of minutes. The Springhill Substation consists of one 33 MVA class transformer served by a loop-fed pole-mounted switch. Each PDS consists of one (or more) 138/12.47 kV, 33 MVA class, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new PDS's to existing 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	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
2015	533	106	0	0	639	421	218	51.7%	0	218	51.7%
2016	525	106	0	0	631	428	203	47.4%	0	203	47.4%
2017	521	106	0	0	627	418	209	49.9%	0	209	49.9%
2018	631	4	0	0	635	408	227	55.6%	0	227	55.6%
2019	631	4	0	0	635	429	206	48.0%	0	206	48.0%
2020	631	4	0	0	635	425	210	49.4%	0	210	49.4%
2021	631	4	0	0	635	422	213	50.4%	0	213	50.4%
2022	634	4	0	0	638	408	230	56.3%	0	230	56.3%
2023	640	4	0	0	644	409	235	57.4%	0	235	57.4%
2024	640	0	0	0	640	405	235	58.1%	0	235	58.1%
2025	640	0	0	0	640	406	234	57.7%	0	234	57.7%
2026	640	0	0	0	640	408	232	56.9%	0	232	56.9%
2027	640	0	0	0	640	410	230	56.1%	0	230	56.1%
2028	564	0	0	0	564	412	152	36.9%	0	152	36.9%
2029	564	0	0	0	564	415	149	36.0%	0	149	36.0%
2030	564	0	0	0	564	417	147	35.3%	0	147	35.3%
2031	564	0	0	0	564	419	145	34.7%	0	145	34.7%
2032	529	0	0	0	529	422	107	25.4%	0	107	25.4%
2033	529	0	0	0	529	424	105	24.8%	0	105	24.8%
2034	529	0	0	0	529	426	103	24.2%	0	103	24.2%

(1) Details of planned changes to installed capacity from 2025-2034 are reflected in Schedule 8.

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	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
2015/16	550	106	0	0	656	348	308	88.4%	0	308	88.4%
2016/17	554	106	0	0	660	333	327	98.1%	0	327	98.1%
2017/18	659	4	0	0	663	410	253	61.7%	0	253	61.7%
2018/19	659	4	0	0	663	333	330	99.1%	0	330	99.1%
2019/20	661	4	0	0	664	338	326	96.5%	0	326	96.5%
2020/21	661	4	0	0	664	348	316	90.9%	0	316	90.9%
2021/22	666	4	0	0	669	355	314	88.5%	0	314	88.5%
2022/23	666	4	0	0	669	309	360	116.6%	0	360	116.6%
2023/24	673	0	0	0	673	337	336	99.7%	0	336	99.7%
2024/25	673	0	0	0	673	350	323	92.3%	0	323	92.3%
2025/26	673	0	0	0	673	336	337	100.3%	0	337	100.3%
2026/27	673	0	0	0	673	338	335	99.1%	0	335	99.1%
2027/28	597	0	0	0	597	340	257	75.6%	0	257	75.6%
2028/29	597	0	0	0	597	342	255	74.5%	0	255	74.5%
2029/30	597	0	0	0	597	344	253	73.5%	0	253	73.5%
2030/31	597	0	0	0	597	346	251	72.5%	0	251	72.5%
2031/32	553	0	0	0	553	348	205	58.9%	0	205	58.9%
2032/33	553	0	0	0	553	350	203	58.0%	0	203	58.0%
2033/34	553	0	0	0	553	352	201	57.1%	0	201	57.1%
2034/35	549	0	0	0	549	354	195	55.1%	0	195	55.1%

(1) Details of planned changes to installed capacity from 2025-2034 are reflected in Schedule 8.

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
Deerhaven	FS01	Alachua County	ST	NG	RFO	PL	TK		8/1972	12/2027	-81.0	-81.0	-76.0	-76.0	RT
	FS02	Secs. 26, 27, 35,	ST	NG	BIT	PL	RR		10/1981	12/2036	-251.0	-251.0	-232.0	-232.0	RT
	GT01	T8S, R19E	GT	NG	PL	DFO	TK		7/1976	12/2031	-18.0	-23.0	-17.5	-22.0	RT
	GT02	(GRU)	GT	NG	PL	DFO	TK		8/1976	12/2031	-18.0	-23.0	-17.5	-22.0	RT

Unit Type
ST = Steam Turbine

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

Transportation Method
PL = Pipeline
TK = Truck

Status
RT = Generating unit retired or scheduled for retirement

4. ENVIRONMENTAL AND LAND USE INFORMATION

4.1 DESCRIPTION OF POTENTIAL SITES FOR NEW GENERATING FACILITIES

GRU is evaluating adding flexible natural gas-fueled generation at its Deerhaven site.

4.2 DESCRIPTION OF PREFERRED SITES FOR NEW GENERATING FACILITIES

Any additional system generation is expected to be sited at the existing Deerhaven site. Evaluation of the need for future generation is in progress.

4.2.1 Land Use and Environmental Features

The location of Deerhaven Generating Station is indicated on Figures 1.1 (see Section 1) and 4.1. The existing land use of the certified portion of the Deerhaven 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 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. Water for potable use is supplied via the City's potable water system. Groundwater is 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 or ground waters. GRU uses a brine concentrator/spray dryer and off-site disposal of solid wastewater treatment by-products.

4.2.2 Air Emissions

Any generation technology installed at the Deerhaven site will meet all applicable standards for all pollutants regulated for the category of emissions unit.

Figure 4.1

Deerhaven Generating Site