GRU More than Energy

GAINESVILLE REGIONAL UTILITIES

STRATEGIC PLANNING

March 30, 2009

090000-OT

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

Dear Ms. Cole:

In accordance with Section 186.801, Florida Statutes and Rule 25-22.071, Florida Administrative Code, Gainesville Regional Utilities hereby submits 25 copies of its 2009 Ten Year Site Plan for your review. Should you have any questions regarding this Ten Year Site Plan, please contact me at (352) 393-1272.

Sincerely,

Ed Regan, P.E.
Assistant General Manager
Strategic Utility Planning

Enclosures

File: PSC - Ten Year Site Plan

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GAINESVILLE REGIONAL UTILITIES

2009 TEN-YEAR SITE PLAN

GRU℠
More than Energy™

Submitted to:

The Florida Public Service Commission

April 2009

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INTRODUCTION

The 2009 Ten-Year Site Plan for Gainesville Regional Utilities (GRU) is submitted to the Florida Public Service Commission pursuant to Section 186.801, Florida Statutes. The contents of this report conform to information requirements listed in Form PSC/EAG 43, as specified by Rule 25-22.072, Florida Administrative Code. The four sections of the 2009 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 Clay Electric Cooperative (Clay). These wholesale contracts will terminate after December 31, 2010 and December 31, 2012 respectively, unless renewed. GRU's distribution system serves its retail territory of approximately 124 square miles and 92,795 customers (2008 average). 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 610 MW and the winter net capability is 630 MW[1]. Currently, the System's energy is produced by three fossil fuel steam turbines, six simple-cycle combustion turbines, one combined-cycle unit, and a 1.4079% ownership share of the Crystal River 3 (CR3) nuclear unit operated by Progress Energy Florida (PEF).

The System has two primary generating plant sites -- Deerhaven and John R. Kelly (JRK). Each site comprises both steam-turbine and gas-turbine generating units. The JRK station also utilizes a combined cycle unit.

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

1.1.1 Generating Units

1.1.1.1 Steam Turbines. The System's three operational simple-cycle steam turbines are powered by fossil fuels and CR3 is nuclear powered. The fossil fueled steam turbines comprise 54.8% of the System's net summer capability and produced 84.6% of the electric energy supplied by the System in 2008. These units range in size from 23.2 MW to 228.4 MW. The combined-cycle unit, which includes a heat recovery steam generator/turbine and combustion turbine set, comprises 18.4% of the System's net summer capability and produced 8.5% of the electric energy supplied by the System in 2008. The System's 11.6 MW share of CR3 comprises 1.9% of the System's net summer capability and produced 5.7% of total electric energy in 2008. The System's share of CR3 will increase to 11.981 MW in 2010, and to 13.911 MW in 2012 as the result of capacity upgrades planned by PEF. Deerhaven Unit 2 and CR3 are used for base load purposes, while JRK Unit 7, JRK CC1, and Deerhaven Unit 1 are used for intermediate loading.

1.1.1.2 Gas Turbines. The System's six industrial gas turbines make up 24.9% of the System's summer generating capability and produced 1.3% of the electric energy supplied by the System in 2008. These simple-cycle combustion turbines are utilized for peaking purposes only because their energy conversion efficiencies are considerably lower than steam units. As a result, they yield higher operating costs and are consequently unsuitable for base load operation. Gas turbines are advantageous in that they can be started and placed on line 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 Internal Combustion (Piston/Diesel). The two reciprocating internal combustion engines operated by the System at the Southwest Landfill were decommissioned in 2008 due to a diminished fuel supply.

1.1.1.4 Environmental Considerations. All of the System's steam turbines, except for Crystal River 3, utilize recirculating cooling towers with a mechanical draft for the cooling of condensed steam. Crystal River 3 uses a once-through cooling system aided by helper towers. Only Deerhaven 2 currently has flue gas cleaning equipment consisting of a "hot-side" electrostatic precipitator. Construction is currently underway on a selective catalytic reduction system to reduce NO_x, and a dry flue gas desulfurization unit with fabric filters, which will reduce SO_2, mercury, and particulates. This equipment will result in a net decrease of 6 MW for Deerhaven 2.

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, one steam turbine, three 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 original site, which was certified pursuant to the Power Plant Siting Act, includes an 1146 acre parcel of partially forested land. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. As amended to include the addition of Deerhaven Unit 2 in 1981, the certified site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats water effluent from both steam units. A potential expansion area, owned by the System and adjacent to the certified Deerhaven plant site, was incorporated into the Gainesville City limits February 12, 2007 (ordinance 0-06-130), consists of an additional 2328 acres, for a total of 3474 acres.

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 nine 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. The load ratings for GRU's transmission lines were developed in Appendix 6.1 of GRU's Long-Range Transmission Planning Study, March 1991. Refer to Figure 1.2 for a one-line diagram of GRU's electric system. The criteria for normal and emergency loading are taken to be:

- Normal loading: conductor temperature not to exceed 100° C (212° F).
- Emergency 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	80.01	795 MCM ACSR
138 kV single circuit	16.30	1192 MCM ACSR
138 kV single circuit	20.91	795 MCM ACSR
230 kV single circuit	2.53	795 MCM ACSR
Total	119.75	

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.

Contingency simulations revealed the system effects of serving peak summer load with assumed outages of both Deerhaven Unit 2 and the Archer 230 kV tie line. The results identified GRU bus voltages that would fall below acceptable levels. This will be addressed by installing two 3-phase, 138kV, 24.6 MVAr capacitor banks: one at the Parker Transmission Substation (May 2009); and another at the McMichen Substation (July 2009).

According to the state system reliability coordinator, who is responsible for the integrity and stability of the entire Florida transmission grid, GRU could plan to import about 250 MW before exceeding the bus voltage standard for reliability with these new capacitor banks.

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 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 a 150 MVA 138/69 kV transformer at the Idylwild Substation. 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 norrnal (Rating A) capacities.

1.3 DISTRIBUTION

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

The six major distribution substations are connected to the 138 kV bulk power transmission network with looped feeds which prevent the outage of a single transmission line from causing major 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.

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.

In 2007 GRU expanded its John R. Kelly Plant generation-transmission-distribution substation configuration to include a third 56 MVA 138/12.47 kV transformer located on the south side of the plant (referred to as Kelly West). This expansion has enhanced reliability by reassigning load to a point on the system not directly tied to the generator buses of the plant. The additional transformer capacity will allow for load growth in Gainesville's downtown area.

1.4 WHOLESALE ENERGY

The System provides full requirements wholesale electric service to Clay Electric Cooperative (Clay) through a contract between GRU and Seminole Electric Cooperative (Seminole), of which Clay is a member. The System began the 138 kV service at Clay's Farnsworth Substation in February 1975. This substation is supplied through a 2.37 mile radial line connected to the System's transmission facilities at Parker Road near SW 24th Avenue.

The System also 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 City of Alachua and GRU agreed to extend the original contract that expired on December 31, 2008 for two years.

Wholesale sales to Clay and the City of Alachua have been included as native load for purposes of projecting GRU's needs for generating capacity and associated reserve margins. This forms a conservative basis for planning purposes in the event these contracts are renewed. Schedules 7.1 and 7.2 at the end of Section 3 summarize GRU's reserve margins.

1.5 DISTRIBUTED GENERATION

Construction of the South Energy Center was completed in February of 2009. The South Energy Center will provide multiple onsite utility services to the new Shands at UF Cancer Hospital. The new facility houses a 4.1 MW (summer rating) natural gas-fired turbine capable of supplying 100% of the hospital's electric and thermal needs. The South Energy Center will provide electricity, chilled water, steam and 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. Commercial operation of the South Energy Center is expected to begin in May of 2009.

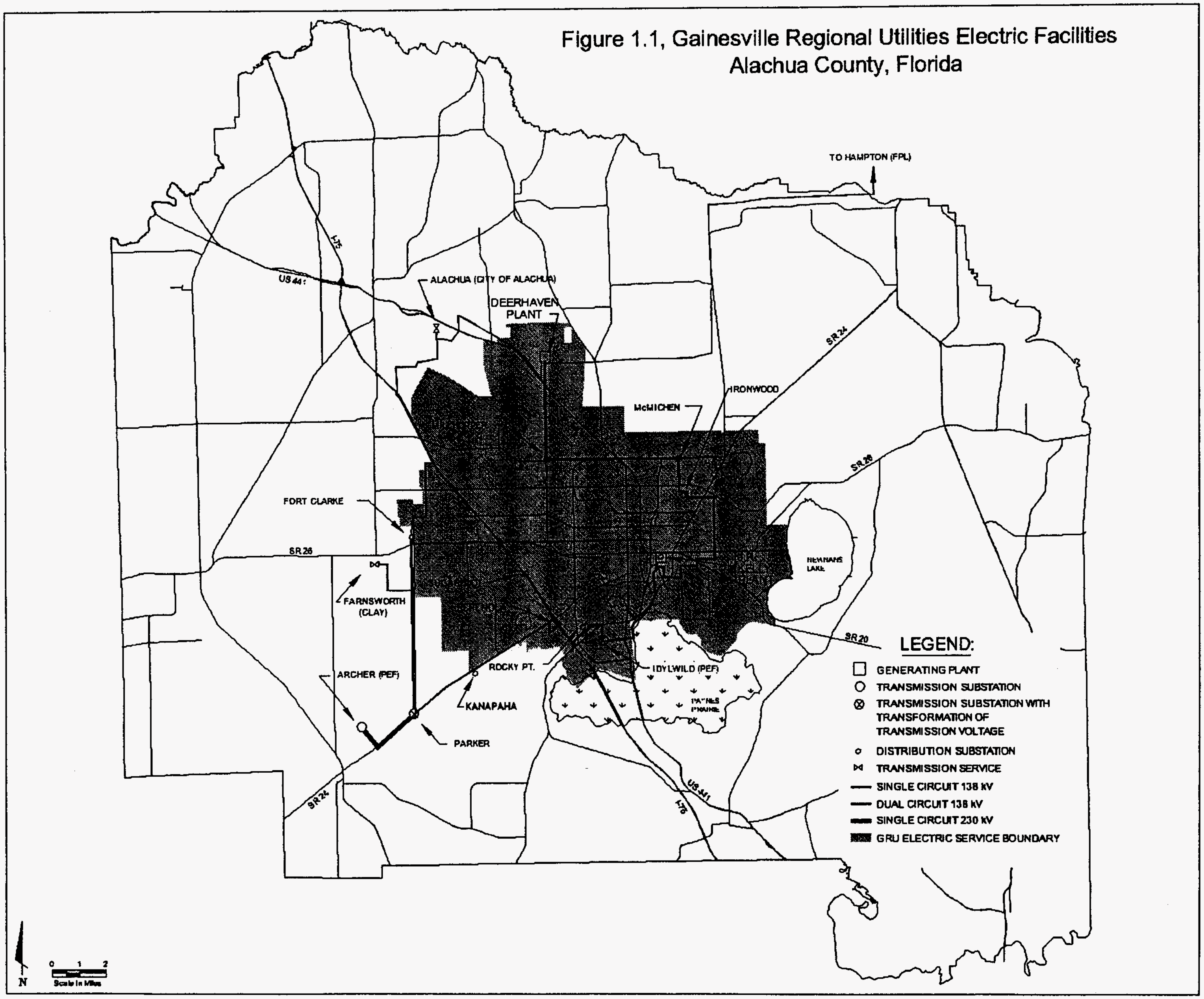
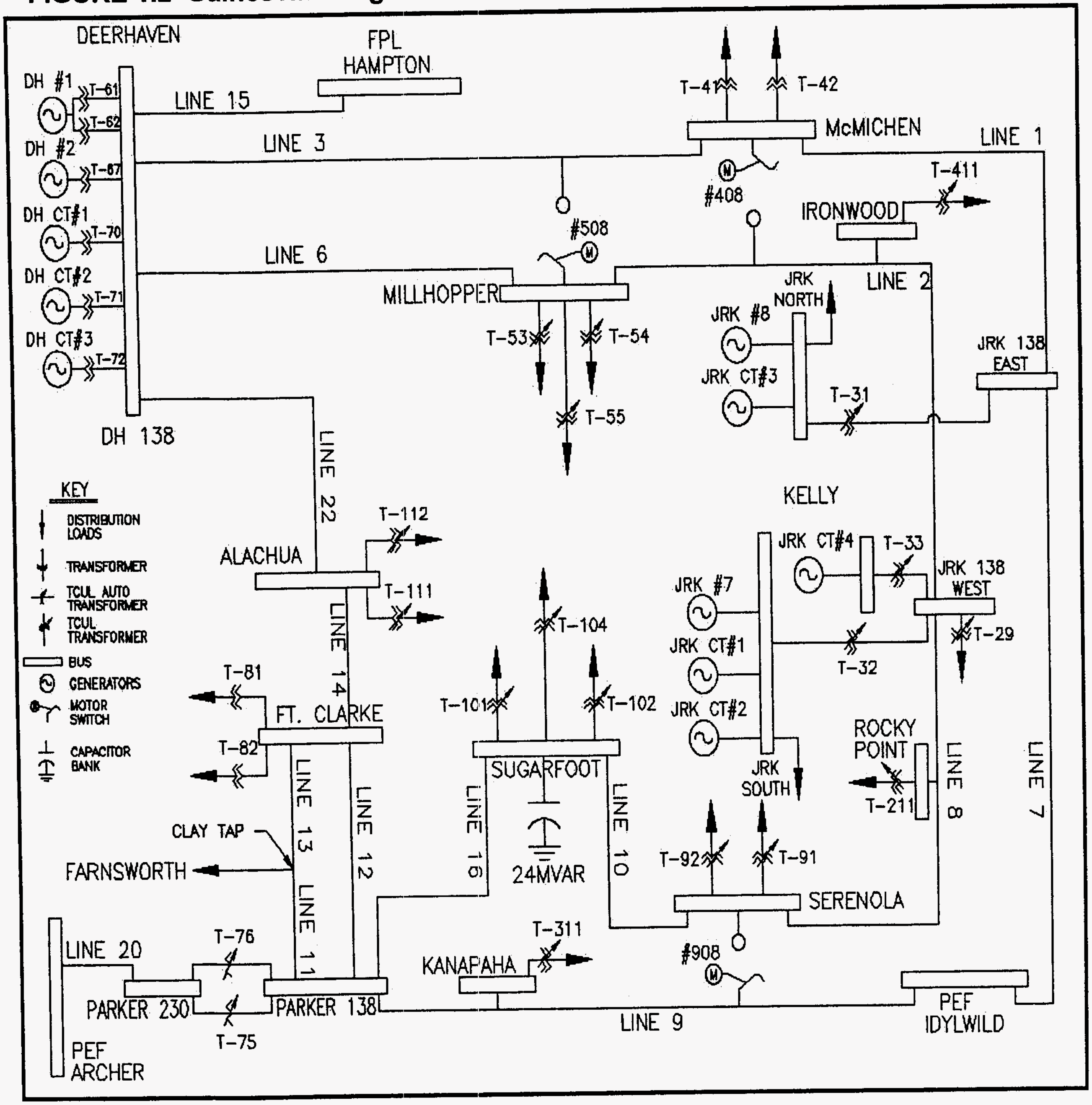


Figure 1.1, Gainesville Regional Utilities Electric Facilities
Alachua County, Florida

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



Schedule 1
EXISTING GENERATING FACILITIES

(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									**180.00**	**189.00**	**177.20**	**186.20**	
	FS08	Sec. 4, T10S, R20E	CA	WH	PL				[4/65 ; 5/01]	2051	38.00	38.00	37.00	37.00	OP
	FS07	(GRU)	ST	NG	PL	RFO	TK		8/61	10/13	24.00	24.00	23.20	23.20	OP
	GT04		CT	NG	PL	DFO	TK		5/01	2051	76.00	82.00	75.00	81.00	OP
	GT03		GT	NG	PL	DFO	TK		5/69	05/19	14.00	15.00	14.00	15.00	OP
	GT02		GT	NG	PL	DFO	TK		9/68	09/18	14.00	15.00	14.00	15.00	OP
	GT01		GT	NG	PL	DFO	TK		2/68	02/18	14.00	15.00	14.00	15.00	OP
Deerhaven		Alachua County									**437.00**	**447.00**	**421.40**	**432.40**	
	FS02	Secs. 26,27,35	ST	BIT	RR				10/81	2031	235.00	235.00	228.40	228.40	OP
	FS01	T8S, R19E	ST	NG	PL	RFO	TK		8/72	08/22	88.00	88.00	83.00	83.00	OP
	GT03	(GRU)	GT	NG	PL	DFO	TK		1/96	2046	76.00	82.00	75.00	81.00	OP
	GT02		GT	NG	PL	DFO	TK		8/76	2026	19.00	21.00	17.50	20.00	OP
	GT01		GT	NG	PL	DFO	TK		7/76	2026	19.00	21.00	17.50	20.00	OP
Crystal River (818/815)	3	Citrus County Sec. 33, T17S, R16E (PEF)	ST	NUC	TK				3/77	2037	**12.24**	**12.42**	**11.60**	**11.89**	OP
System Total													**610.20**	**630.49**	

Unit Type
CA = Combined Cycle Steam Part
CT = Combined Cycle Combustion Turbine Part
GT = Gas Turbine
ST = Steam Turbine

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

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

Status
OP = Operational

TABLE 1.1

TRANSMISSION LINE RATINGS
SUMMER POWER FLOW LIMITS

Line Number	Description	Normal 100°C (MVA)	Limiting Device	8-Hour 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	Switch	186.0	Switch
12	Parker - Ft. Clarke	236.2	Conductor	282.0	Conductor
13	Clay Tap - Ft. Clarke	143.6	Switch	186.0	Switch
14	Ft. Clarke - Alachua	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
20	Parker-Archer(T75,T76)	224.0	Transformers	300.0	Transformers
22	Alachua - Deerhaven	287.3	Switch	356.0	Conductor
xx	Clay Tap - Farnsworth	236.2	Conductor	282.0	Conductor
xx	Idylwild – PEF	150.0[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.

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
Transformers T75 & T76 normal limits are based on a 65 °C temperature rise rating.

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]	168.0 MVA	20
McMichen	44.8 MVA	6
Millhopper	100.8 MVA	10
Serenola	67.2 MVA	8
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 6 distribution feeders fed from a single, loop-fed 56 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 1999-2018. 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 net energy requirements for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy shown in Schedule 6.1 are given in Schedule 6.2. The quantities of fuel expected to be used to generate the energy requirements shown in Schedule 6.1 are given by fuel type in Schedule 5.

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 2008. 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 obtained from the Florida Population Studies, March 2008 (Bulletin No. 150), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(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 1984-2008.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 2008, 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 provided historical estimates of total income and per capita income for Alachua County. Forecast values of per capita income for Alachua County were obtained from Global Insight.

(6) Historical estimates of household size were obtained from BEBR, and projected levels were estimated from a logarithmic trend.

(7) The Florida Agency for Workforce Innovation and the U.S. Department of Labor provided historical estimates of non-agricultural employment in Alachua County. Forecast values of non-agricultural employment were obtained from Global Insight.

(8) GRU's corporate model was the basis for projections of the average price of 1,000 kWh of electricity for all customer classes. The price of electricity is expected to slightly outpace inflation over the forecast horizon.

(9) Estimates of energy and demand reductions resulting from planned demand-side management programs (DSM) were subtracted from all retail forecasts. GRU's involvement with DSM is described in more detail later in this section.

(10) The City of Alachua will generate (via generation entitlement shares of PEF and FPL nuclear units) approximately 8,077 MWh (6 %) of its annual energy requirements.

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 2009 through 2018. 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, sales to Clay, and sales to Alachua. Separate forecasts of number of customers were developed for residential, general service non-demand, general service demand and large power retail rate classifications. The basis for these independent forecasts originated with the development of least-squares regression models. All modeling was performed in-house using the Statistical Analysis System (SAS)[3]. The following text describes the regression equations utilized to forecast energy sales and number of customers.

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 household income in Alachua County, residential price of electricity, heating degree days, and cooling degree days. The form of this equation is as follows:

$$RESAVUSE = 7890 + 0.026\,(HHY08) - 19.42\,(RESPR08) + 0.73\,(HDD) + 0.94\,(CDD)$$

Where:

RESAVUSE	=	Average Annual Residential Energy Use Per Customer
HHY08	=	Average Household Income
RESPR08	=	Residential Price, Dollars per 1000 kWh
HDD	=	Annual Heating Degree Days
CDD	=	Annual Cooling Degree Days

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

Adjusted R^2	=	0.8093
DF (error)	=	32 (period of study, 1971-2008)
t - statistics:		
Intercept	=	5.03
HHY08	=	2.36
RESPR08	=	-5.10
HDD	=	3.07
CDD	=	3.45

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, the historical series of Clay customer transfers, and an indicator variable for customer counts recorded under the billing system used prior to 1992. The residential customer model specifications are:

$$RESCUS = 99588 + 287.8\,(POP) - 40779\,(HHSize) + 0.90\,(CLYRCus) - 976\,(OldSys)$$

Where:

RESCUS	=	Number of Residential Customers
POP	=	Alachua County Population (thousands)
HHSize	=	Number of Persons per Household
CLYRCus	=	Clay Customer Transfers
OldSys	=	Older Billing System (1978-1991)
Adjusted R^2	=	0.9992
DF (error)	=	25 (period of study, 1978-2008)
t - statistics:		
Intercept	=	9.63
POP	=	30.34
HHSize	=	-11.15
CLYRCus	=	5.09

OldSys = -2.37

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 and have good load factors. Since 1990, 428 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 and cooling degree days. The specifications of this model are as follows:

GSNAVUSE = *23.51 – 0.012 (OPTDCus) + 0.0016 (CDD)*

Where:

GSNAVUSE = Average annual energy usage by GSN customers

OPTDCus = Cumulative number of Optional Demand Customers

CDD = Annual Cooling Degree Days

Adjusted R^2 = 0.8521

DF (error) = 26 (period of study, 1979-2008) t - statistics:

Intercept	=	11.25
OPTDCus	=	-12.13
CDD	=	2.11

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

$$GSNCUS = -5345 + 60.0(POP) + 2.81(CLYNCus) - 3.15(OptDCus)$$

Where:

GSNCUS	=	Number of General Service Non-Demand Customers
POP	=	Alachua County Population (thousands)
CLYNCus	=	Clay Non-Demand Transfer Customers
OptDCus	=	Optional Demand Customers
Adjusted R^2	=	0.9947
DF (error)	=	26 (period of study, 1978-2008)

t - statistics:

Intercept	=	-8.56
POP	=	15.28
CLYNCus	=	2.27
OptDCus	=	-4.82

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

$$GSDAVUSE = 326.2 + 0.0081\,(PCY08) - 0.22\,(OPTDCust)$$

Where:

GSDAVUSE	=	Average annual energy use by GSD Customers
PCY08	=	Per Capita Income in Alachua County
OPTDCust	=	Cumulative number of Optional Demand Customers
Adjusted R^2	=	0.6934
DF (error)	=	26 (period of study, 1979-2008)
t - statistics:		
Intercept	=	12.19
PCY08	=	7.64
OPTDCust	=	-7.63

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

$$GSDCUS = -437.9 + 5.37(POP) + 19.65(CLYDCus) + 0.48(OptDCus)$$

Where:

GSDCUS	=	Number of General Service Demand Customers
POP	=	Alachua County Population (thousands)
CLYDCus	=	Clay Demand Transfer Customers
OptDCus	=	Optional Demand Customers
Adjusted R^2	=	0.9958
DF (error)	=	26 (period of study, 1978-2008)
t - statistics:		
Intercept	=	-5.74
POP	=	11.38
CLYDCus	=	4.40
OptDCus	=	6.28

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 1976 through 2008. The model developed to project average use by large power customers includes Alachua County nonagricultural employment and large power price of electricity as independent variables. Energy use per customer has been observed to increase over time, presumably due to the periodic expansion or increased utilization of existing facilities. This growth is measured in the model by local employment levels. The specifications of the large power average use model are as follows:

$$LPAVUSE = 7549 + 31.6\,(NONAG) - 13.8\,(LPPR08)$$

Where:

LPAVUSE = Average Annual Energy Consumption (MWh per Year)

NONAG = Alachua County Nonagricultural Employment (000's)

LPPR08 = Average Price for 1,000 kWh in the Large Power Sector

Adjusted R^2 = 0.8994

DF (error) = 30 (period of study, 1976-2008)

t - statistics:

INTERCEPT = 6.61

NONAG = 5.43

LPPR08 = -2.10

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 are 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 approximately 1.3% of total energy sales. Outdoor lighting energy sales were forecast using a model which specified lighting energy as a function of the natural log of the number of residential customers. The specifications of this model are as follows:

$$LGTMWH = -287291 + 27878\,(LNRESCUS)$$

Where:

LGTMWH = Outdoor Lighting Energy Sales

LNRESCUS = Number of Residential Customers (natural log)

Adjusted R^2 = 0.9918

DF (error) = 13 (period of study, 1994-2008) t - statistics:

Intercept	=	-38.25
RESCUS	=	41.28

2.2.6 Wholesale Energy Sales

As previously described, the System provides control area services to two wholesale customers: Clay Electric Cooperative (Clay) at the Farnsworth Substation; and the City of Alachua (Alachua) at the Alachua No. 1 Substation, and at the Hague Point of Service. Approximately 6% of Alachua's 2008 energy requirements were met through generation entitlements of nuclear generating units operated by PEF and FPL. These wholesale delivery points serve an urban area that is either included in, or adjacent to the Gainesville urban area. These loads are considered part of the System's native load for facilities planning through the forecast horizon. GRU provides other utilities services in the same geographic areas served by Clay and Alachua, and continued electrical service will avoid duplicating facilities. Furthermore, the populations served by Clay and Alachua benefit from services provided by the City of Gainesville, which are in part supported by transfers from the System.

Clay-Farnsworth net energy requirements were modeled with an equation in which Alachua County population was the independent variable. Output from this model was adjusted to account for the history of load that has been transferred between GRU and Clay-Farnsworth, yielding energy sales to Clay. Historical boundary adjustments between Clay and GRU have reduced the duplication of facilities in both companies' service areas. The form of the Clay-Farnsworth net energy requirements equation is as follows:

$$CLYNEL = -53730 + 578.3\ (POP)$$

Where:

CLYNEL	=	Farnsworth Substation Net Energy (MWh)
POP	=	Alachua County Population (000's)
Adjusted R^2	=	0.9420
DF (error)	=	17 (period of study, 1990-2008)
t - statistics:		
Intercept	=	-7.38
POP	=	17.13

Net energy requirements for Alachua were estimated using a model in which City of Alachua population was the independent variable. BEBR provided historical estimates of City of Alachua Population. This variable was projected from a trend analysis of the component populations within Alachua County. The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALANEL = -61514 + 22693\,(ALAPOP)$$

Where:

ALANEL	=	City of Alachua Net Energy (MWh)
ALAPOP	=	City of Alachua Population (000's)
Adjusted R^2	=	0.9846
DF (error)	=	25 (period of study, 1982-2008)
t - statistics:		
Intercept	=	-19.33
ALAPOP	=	40.77

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

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, sales to Clay, and sales to Alachua. Net energy for load was then forecast by applying a delivered efficiency factor for the System to total energy sales. The projected delivered efficiency factor used in this forecast is 0.96. 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 net energy for load.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load. Winter peak demands are projected to occur in January of each year, and summer peak demands are projected to occur in August of each year, although historical data suggests the summer peak is nearly as likely to occur in July. The average ratio of the most recent 25 years' monthly net energy for load for January and August, as a portion of annual net energy for load, was applied to projected annual net energy for load to obtain estimates of January and August net energy for load over the forecast horizon. The medians of the past 25 years' load factors for January and August were applied to January and August net energy for load 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, natural gas, and a small percentage of nuclear fuel to satisfy its fuel requirements. Since the completion of the Deerhaven 2 coal-fired unit, the System has relied upon coal to fulfill much of its fuel requirements. 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. These projections are based on a fuel price forecast prepared in 2008.

2.3.2 Methodology for Projecting Fuel Use

The fuel use projections were produced using the Electric Generation Expansion Analysis System (EGEAS) developed under Electric Power Research Institute guidance. Ng Engineering provides support, maintenance, and training for the EGEAS software. This is the same software the System uses to perform long-range integrated resource planning. EGEAS has the ability to model each of the System's generating units as well as optimize the selection of new capacity and technologies (see Section 3), and include the effects of environmental limits, dual fuel units, reliability constraints, and maintenance schedules. The production modeling process uses a load-duration curve convolution and conjoint probability model to simulate optimal hourly dispatch of the System's generating resources.

The input data to this model includes:

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

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

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

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 has entered into a 15-year contract to receive 3 MW of landfill gas fueled capacity at the Marion County Baseline Landfill, from G2 Energy Marion, LLC. The generation facility began commercial operation on January 1, 2009. G2 expects to complete a capacity expansion of 0.8 MW by December 2009, 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. Extensions of this contract are subject to negotiation. An additional 25 MW baseload capacity was contracted from January 1, 2009 through December 31, 2010, and another additional 25 MW of baseload capacity was contracted for March through August of 2009 and 2010.

2.3.3.3 Biomass RFP for PPA. GRU is negotiating a 25-year purchase power agreement with American Renewables for 100 MW of biomass capacity to be online before January 1, 2014. GRU anticipates reselling approximately 50 MW of capacity from this unit for up to 10 years.

2.3.3.4 Inglis Hydro. GRU is negotiating with Inglis Hydroelectric, LLC for about 2 MW of hydro power located in Levy County near the Inglis locks of the Cross Florida Barge Canal. The anticipated in-service date is mid 2013.

2.3.3.5 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 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 the equivalent of a 1.5% base rate increase. This limit translates to an annual capacity stop-loss to purchase 4 MW.

GRU has received applications to fully build out this capacity in the first two years of the program, and applications are continuing to be aquired.

2.4 DEMAND-SIDE MANAGEMENT

2.4.1 Demand-Side Management Program History and Current Status

Demand and energy forecasts and generation expansion plans outlined in this Ten Year Site Plan include impacts from GRU's Demand-Side Management (DSM) programs. The System forecast reflects the incremental impacts of DSM measures, net of cumulative impacts from 1980 through 2008. DSM programs are available for all retail customers, including commercial and industrial customers, and are designed to effectively reduce and control the growth rates of electric consumption and weather sensitive peak demands.

DSM direct services currently available to the System's residential customers, or expected to be implemented during 2009, include energy audits and low income household whole house energy efficiency improvements. GRU also offers rebates and other financial incentives for the promotion of:

- high efficiency central air conditioning
- high efficiency room air conditioning
- central air conditioner maintenance
- reflective roof coating for mobile homes
- solar water heating
- solar photovoltaic systems
- natural gas in new construction
- Home Performance with the federal Energy Star program
- Energy Star building practices of the EPA
- Green Building practices
- 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
- energy efficiency low-interest loans
- natural gas for displacement of electric in water heating, space heating, and space cooling in existing structures.

Energy audits are available to the System's non-residential customers. In addition GRU offers rebates and other considerations for the promotion of:

- solar water heating
- solar photovoltaic
- natural gas for water heating and space heating
- vending machine motion sensors
- efficient exit lighting
- customized business rebates for energy efficiency retrofits

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.

Grants and voluntary customer contributions have made several renewable projects possible within GRU's service area. A combination of customer contributions and State and Federal grants allowed GRU to add its 10 kW photovoltaic array at the Electric System Control Center in 1996. GRU secured grant funding through the Department of Community Affairs' PV for Schools

Educational Enhancement Program for PV systems that were installed at two middle schools in 2003. And currently, the GRUGreen^{sm} program gives customers the opportunity to invest in renewable energy resources including landfill gas, solar, and wind energy credits through contributions on their monthly bill.

GRU has also 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: Passive Solar Design-Factors for North Central Florida, a booklet which provides detailed solar and environmental data for passive solar designs in this area; Solar Guidebook, a brochure which explains common applications of solar energy in Gainesville; and The Energy Book, a guide to conserving energy at home.

2.4.2 Future Demand-Side Management Programs

GRU continues to monitor the potential for additional DSM efforts including programs addressing thermal storage, district chilled water cooling, window shading, additional energy efficiency in low-income households and demand response. GRU continues to review the efforts of conservation leaders in the industry, and has conducted fact finding trips to California, Texas, Vermont and New York to maximize these efforts. GRU plans to continue to expand its DSM programs as a way to cost-effectively meet customer needs and hedge against potential future carbon tax and trade programs.

2.4.3 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 has contracted with a consultant to perform a measurement and verification analysis of several of the conservation programs implemented over the past two years. Results from this study will aid 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 2009-2018 is expected to provide an additional 49 MW of summer peak reduction and 123 GWh of annual energy savings by the year 2018. A history and projection of total DSM program achievements from 1980-2018 is shown in Table 2.1.

2.4.4 Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) is a nine-member citizen group that is charged with formulating recommendations to the Gainesville City Commission concerning national, state and local energy-related issues. The GEAC offers advice and guidance on energy management studies and consumer awareness programs.

GEAC has contributed to several significant policy changes, including helping to establish a residential energy audit program, creating inverted-block and time-of-use electric rates, and making solar a generation priority for the City of Gainesville. GEAC was instrumental in the development and installation of a 10 kilowatt PV system at the System Control Center. GEAC has strongly supported the EPA's Energy Star program, and has helped GRU earn EPA's 1998 Utility Ally of the Year award. As a long-range load reduction strategy, GEAC contributed to the development of a Green Builder program for existing multi-family dwellings, which account for approximately 35% of GRU's total residential load. GEAC also supported GRU's IRP efforts through their sponsorship of community workshops and review of the IRP.

2.4.5 Supply Side Programs

Prior to the addition of Deerhaven Unit 2 in 1982, the System was relying on oil and natural gas for over 90% of native load energy requirements. In 2008, oil-fired generation comprised 0.5% of total net generation, natural gas-fired generation contributed 19.7%, nuclear fuel contributed 5.7%, and coal-fired generation provided 74.1% of total net generation. Deerhaven 2 is also contributing to reduced oil use by other utilities by offering coal-generated energy on the Florida energy market. The PV system at the System Control Center provides slightly more than 10 kilowatts of capacity at solar noon on clear days.

The System has several programs to improve the adequacy and reliability of the transmission and distribution systems, which will also result in decreased energy losses. These include the installation of distribution capacitors, purchase of high-efficiency distribution transformers, and the reconductoring of the feeder system.

2.4.5.1 Transformers. GRU has been purchasing overhead and underground transformers with a higher efficiency than the NEMA TP-1 Standard for the past 18 years. Higher efficiency means less kW losses or power lost due the design of the transformer. Since 1988, there have been 18,073 high-efficiency transformers installed on GRU's distribution system. A study was initiated to compare the kW losses of GRU's transformer design to a design based on NEMA TP-1 Efficiency Standard for Transformers. The results of this investigation showed that relative to the standard design, GRU experienced these savings:

Average Annual Demand Loss Savings	2.8 MW
Average Annual Energy Saved	24,900 MWh

Peak Demand Savings	6.2 MW

2.4.5.2 Reconductoring. GRU has been continuously improving the feeder system by reconductoring feeders from 4/0 Copper to 795 MCM aluminum overhead conductor. Also, in specific areas the feeders have been installed underground using 1000 MCM underground cable. Following is a comparison of the resistance for the types of conductors used on GRU's electric distribution system:

795 MCM Aluminum Overhead Conductor	0.13 ohms/mile
1000 MCM Aluminum Underground Cable	0.13 ohms/mile
4/0 Copper Overhead Conductor	0.31 ohms/mile

Calculations with average loading on the conductors show the total savings due to moving from 4/0 copper to an aluminum conductor (795 or 1000 MCM):

Average Annual Demand Savings	2.4 MW
Average Annual Energy Saved	21,000 MWh
Peak Demand Savings	7.9 MW

2.4.5.3 Capacitors. GRU strives to maintain an average power factor of 0.98 by adding capacitors where necessary on each distribution feeder. Without these capacitors the average uncorrected power factor would be 0.92.

The percentage of loss reduction can be calculated as shown:

$\%$ Loss Reduction=$[1-(\text{Uncorrected pf}/\text{Corrected pf})^2] \times 100$

$\%$ Loss Reduction=$[1-(0.92/0.98)^2] \times 100$

$\%$ Loss Reduction = 11.9

In general, overall system losses have stabilized near 4% of net generation as reflected in the forecasted relationship of total energy sales to net energy for load.

In general, overall system losses have stabilized near 4% of net generation as reflected in the forecasted relationship of total energy sales to net energy for load.

2.5 FUEL PRICE FORECAST ASSUMPTIONS

GRU consults a variety of reputable sources to compile projections of fuel prices for fuels currently used and those that are evaluated for potential future use. Oil prices are obtained from the Annual Energy Outlook 2009 (AEO2009), published in March 2009 by the U.S. Department of Energy's Energy Information Administration (EIA). Natural gas price projections are derived from several forecasts published by the PIRA Energy Group. Coal prices are projected in the near term based on knowledge of contractual agreements with suppliers. These prices are projected to the out years by applying growth rates for U.S. coal prices provided in AEO2009. Projected prices for nuclear fuel were provided by PEF. Any price forecasts that are provided in constant-year (real) dollars are translated to nominal dollars using the projected Gross Domestic Product – Implicit Price Deflator from AEO2009. Fuel prices are analyzed in two parts: the cost of the fuel (commodity), and the cost of transporting the fuel to GRU's generating stations. The external forecasts typically address the commodity prices, and GRU's specific transportation costs are included to derive delivered prices. A summary of historical and projected fuel prices is provided in Table 2.2.

2.5.1 Oil

GRU relies on No. 6 Oil (residual) and No. 2 Oil (distillate or diesel) as back-up fuels for natural gas fired generation. These fuels are delivered to GRU generating stations by truck. Forecast prices for these two types of oil are derived directly from AEO2009.

During calendar year 2008, distillate fuel oil was used to produce 0.07% of GRU's total net generation. Distillate fuel oil is expected to be the most expensive fuel available to GRU. During calendar year 2008, residual fuel oil was used to produce 0.44% of GRU's total net generation. The quantity of fuel oils used by GRU is expected to remain low.

2.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity, comprising 74.1% of total net generation during calendar year 2008. GRU purchases low-sulfur (0.7%), high Btu eastern coal for use in Deerhaven Unit 2. In 2009, Deerhaven Unit 2 will begin operating following the retrofit of an air quality control system, which is being added as a means of complying with new environmental regulations. Deerhaven Unit 2 will be able to utilize coals with up to approximately 1.7% sulfur content following the retrofit, therefore GRU also projects prices for both low and medium sulfur coals for evaluation in Deerhaven Unit 2 following the air quality control retrofit.

Projected prices for coal used by Deerhaven Unit 2 through 2011 were based on GRU's contractual options with its coal suppliers. Projected prices beyond 2011 were escalated using growth rates for U.S. coal prices from AEO2009. GRU has a contract with CSXT for delivery of coal to the Deerhaven plant site through 2019.

2.5.3 Natural Gas

GRU procures natural gas for power generation and for distribution by a Local Distribution Company (LDC). In 2008, GRU purchased approximately 6.1 million MMBtu for use by both systems. GRU power plants used 65% of the total purchased for GRU during 2008, while the LDC used the remaining 35%.

GRU purchases natural gas via arrangements with producers and marketers connected with the Florida Gas Transmission (FGT) interstate pipeline. GRU's delivered cost of natural gas includes the commodity component, Florida Gas

Transmission's (FGT) fuel charge, FGT's usage (transportation) charge, FGT's reservation (capacity) charge, and basis adjustments.

Prices for 2009 and 2010 were projected in-house using anticipated impacts from risk management activities, commodity costs, and other pricing impacts including transportation costs. Delivered prices from 2011 through 2018 represent the sum of GRU's anticipated transportation costs and commondity prices from PIRA Energy Group's October 2008 long-term Henry Hub forecast.

2.5.4 Nuclear Fuel

GRU's nuclear fuel price forecast includes a component for fuel and a component for fuel disposal. The projection for the price of the fuel component is based on Progress Energy Florida's (PEF) forecast of nuclear fuel prices. The projection for the cost of fuel disposal is based on a trend analysis of actual costs to GRU.

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
1999	161,203	2.35	763	68,543	11,137	648	8,095	80,036
2000	164,932	2.34	788	70,335	11,202	674	8,368	80,490
2001	169,269	2.34	803	72,391	11,092	697	8,603	80,986
2002	172,149	2.33	851	73,827	11,527	721	8,778	82,112
2003	173,148	2.33	854	74,456	11,467	726	8,959	81,090
2004	178,642	2.32	878	77,021	11,398	739	9,225	80,143
2005	180,830	2.31	888	78,164	11,358	752	9,378	80,199
2006	183,248	2.31	877	79,407	11,047	746	9,565	78,042
2007	186,764	2.30	878	81,128	10,817	778	9,793	79,398
2008	188,945	2.30	820	82,271	9,969	773	10,508	73,538
2009	190,515	2.29	824	83,147	9,908	756	10,579	71,480
2010	192,016	2.29	823	83,993	9,795	754	10,699	70,485
2011	194,169	2.28	827	85,124	9,719	761	10,885	69,945
2012	196,511	2.28	834	86,338	9,654	771	11,091	69,544
2013	198,769	2.27	840	87,516	9,599	782	11,290	69,280
2014	200,905	2.27	847	88,641	9,552	793	11,478	69,130
2015	202,924	2.26	853	89,715	9,512	805	11,655	69,103
2016	204,800	2.26	859	90,726	9,471	816	11,819	69,066
2017	206,577	2.25	865	91,693	9,434	827	11,974	69,070
2018	208,277	2.25	871	92,626	9,401	838	12,121	69,163

* 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 **						
Year	GWh	Average Number of Customers	Average MWh per Customer	Railroads and Railways GWh	Street and Highway Lighting GWh	Other Sales to Public Authorities GWh	Total Sales to Ultimate Consumers GWh
1999	173	17	10,188	0	22	0	1,606
2000	172	17	10,114	0	22	0	1,656
2001	173	17	10,162	0	23	0	1,696
2002	178	18	10,178	0	24	0	1,774
2003	181	19	9,591	0	24	0	1,786
2004	188	18	10,444	0	25	0	1,830
2005	189	18	10,477	0	25	0	1,854
2006	200	20	10,093	0	25	0	1,849
2007	196	18	10,891	0	26	0	1,877
2008	184	16	11,497	0	26	0	1,803
2009	159	11	14,431	0	27	0	1,766
2010	157	11	14,277	0	27	0	1,761
2011	157	11	14,312	0	28	0	1,773
2012	158	11	14,405	0	28	0	1,791
2013	160	11	14,538	0	28	0	1,810
2014	161	11	14,649	0	29	0	1,830
2015	162	11	14,761	0	29	0	1,849
2016	163	11	14,854	0	29	0	1,867
2017	164	11	14,934	0	30	0	1,886
2018	165	11	15,022	0	30	0	1,904

** Industrial includes Large Power Rate Class

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

(1) Year	(2) Sales For Resale GWh	(3) Utility Use and Losses GWh	(4) Net Energy for Load GWh	(5) Other Customers	(6) Total Number of Customers
1999	109	83	1,798	0	76,655
2000	120	93	1,868	0	78,720
2001	125	62	1,882	0	81,011
2002	142	92	2,008	0	82,623
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	198	81	2,045	0	93,737
2010	201	82	2,044	0	94,703
2011	205	83	2,061	0	96,020
2012	210	84	2,085	0	97,440
2013	215	85	2,110	0	98,817
2014	219	86	2,135	0	100,130
2015	224	87	2,160	0	101,381
2016	227	89	2,183	0	102,556
2017	231	88	2,205	0	103,678
2018	235	89	2,228	0	104,759

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
1999	439	26	393	0	0	12	0	8	419
2000	446	28	397	0	0	13	0	8	425
2001	430	28	381	0	0	13	0	8	409
2002	454	32	401	0	0	13	0	8	433
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	507	44	437	0	0	16	0	10	481
2008	487	43	414	0	0	18	0	12	457
2009	475	45	396	0	0	20	0	14	441
2010	478	46	393	0	0	23	0	16	439
2011	485	47	394	0	0	26	0	18	441
2012	492	48	395	0	0	28	0	21	443
2013	500	49	396	0	0	31	0	24	445
2014	508	50	398	0	0	34	0	26	448
2015	516	51	399	0	0	37	0	29	450
2016	523	52	401	0	0	39	0	31	453
2017	532	53	404	0	0	42	0	33	457
2018	539	54	406	0	0	44	0	35	460

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

(1) Winter	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1999 / 2000	380	27	310	0	0	36	0	7	337
2000 / 2001	408	33	331	0	0	37	0	7	364
2001 / 2002	416	33	336	0	0	39	0	8	369
2002 / 2003	442	37	357	0	0	40	0	8	394
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	412	38	324	0	0	42	0	8	362
2007 / 2008	411	40	321	0	0	42	0	8	361
2008 / 2009	471	45	376	0	0	42	0	8	421
2009 / 2010	409	45	314	0	0	42	0	8	359
2010 / 2011	412	46	316	0	0	42	0	8	362
2011 / 2012	416	47	319	0	0	42	0	8	366
2012 / 2013	421	48	323	0	0	42	0	8	371
2013 / 2014	425	49	326	0	0	42	0	8	375
2014 / 2015	430	50	330	0	0	42	0	8	380
2015 / 2016	434	51	333	0	0	42	0	8	384
2016 / 2017	437	52	335	0	0	42	0	8	387
2017 / 2018	441	53	338	0	0	42	0	8	391
2018 / 2019	445	54	341	0	0	42	0	8	395

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 %
1999	1,887	67	22	1,606	109	83	1,798	49%
2000	1,961	70	23	1,655	120	93	1,868	50%
2001	1,979	74	23	1,695	125	62	1,882	53%
2002	2,110	78	24	1,774	142	92	2,008	53%
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	98	33	1,877	186	59	2,122	50%
2008	2,230	108	43	1,804	196	79	2,079	52%
2009	2,209	115	49	1,765	198	82	2,045	53%
2010	2,219	121	54	1,761	201	82	2,044	53%
2011	2,249	128	60	1,774	205	82	2,061	53%
2012	2,285	134	66	1,791	210	84	2,085	54%
2013	2,323	141	72	1,810	215	85	2,110	54%
2014	2,360	147	78	1,830	219	86	2,135	54%
2015	2,398	154	84	1,850	224	86	2,160	55%
2016	2,433	160	90	1,869	227	87	2,183	55%
2017	2,467	166	96	1,886	231	88	2,205	55%
2018	2,503	173	102	1,904	235	89	2,228	55%

Schedule 4

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL 2008		FORECAST 2009		FORECAST 2010	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
JAN	*361*	*162*	*420*	*161*	359	158
FEB	*319*	*142*	*421*	137	331	137
MAR	*273*	*147*	293	144	293	144
APR	*324*	*156*	326	147	326	147
MAY	*406*	*187*	390	177	389	177
JUN	*449*	*200*	424	194	424	193
JUL	*431*	*209*	437	210	437	210
AUG	*457*	*209*	441	214	439	214
SEP	*432*	*200*	419	196	419	196
OCT	*345*	*166*	360	167	360	167
NOV	*337*	*150*	314	145	314	145
DEC	*340*	*151*	337	156	336	156

Schedule 5
FUEL REQUIREMENTS
As of January 1, 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
	FUEL REQUIREMENTS		UNITS	ACTUAL 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
(1)	NUCLEAR		TRILLION BTU	1.011	1.059	1.094	0.968	1.270	1.149	1.270	1.149	1.270	1.149	1.270
(2)	COAL		1000 TON	550.410	456.424	462.534	518.122	504.654	448.138	526.404	548.563	549.501	562.157	554.082
	RESIDUAL													
(3)		STEAM	1000 BBL	14.499	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(4)		CC	1000 BBL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(5)		CT	1000 BBL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(6)		TOTAL:	1000 BBL	14.499	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(7)		STEAM	1000 BBL	0.074	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(8)		CC	1000 BBL	1.062	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CT	1000 BBL	1.871	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		TOTAL:	1000 BBL	3.007	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	NATURAL GAS													
(11)		STEAM	1000 MCF	2,239.919	131.459	80.086	186.163	215.865	34.472	109.691	78.927	73.054	69.455	83.687
(12)		CC	1000 MCF	1,310.994	2,283.106	1,355.691	2,184.140	2,051.867	973.657	2,117.528	2,016.030	2,136.495	2,102.704	2,280.569
(13)		CT	1000 MCF	303.268	796.529	520.008	959.886	882.923	313.255	849.063	779.940	671.840	754.448	733.355
(14)		TOTAL:	1000 MCF	3,854.181	3,211.094	1,955.785	3,330.189	3,150.655	1,321.384	3,076.282	2,874.897	2,881.389	2,926.607	3,097.611
(15)	Landfill Gas		1000 MCF	0.264	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

Schedule 6.1
ENERGY SOURCES (GWH)
As of January 1, 2009

(1)	(2) ENERGY SOURCES	(3)	(4) UNITS	(5) ACTUAL 2008	(6) 2009	(7) 2010	(8) 2011	(9) 2012	(10) 2013	(11) 2014	(12) 2015	(13) 2016	(14) 2017	(15) 2018
(1)	ANNUAL FIRM INTERCHANGE (INTER-REGION)		GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(2)	NUCLEAR		GWh	98.554	100.832	104.188	92.220	120.972	109.439	120.972	109.439	120.972	109.439	120.972
(3)	COAL		GWh	1,277.016	1,054.260	1,048.342	1,192.942	1,197.177	1,049.275	1,264.761	1,321.026	1,323.310	1,353.841	1,335.281
	RESIDUAL													
(4)		STEAM	GWh	7.567	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(5)		CC	GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(6)		CT	GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(7)		TOTAL:	GWh	7.567	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	DISTILLATE													
(8)		STEAM	GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(9)		CC	GWh	0.537	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(10)		CT	GWh	0.626	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(11)		TOTAL:	GWh	1.163	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	NATURAL GAS													
(12)		STEAM	GWh	173.161	11.006	6.672	15.530	17.991	2.898	9.082	6.393	5.932	5.642	6.799
(13)		CC	GWh	145.343	229.804	133.580	228.573	216.442	89.126	213.289	197.424	209.286	206.695	231.480
(14)		CT	GWh	20.936	63.873	46.943	74.378	73.365	32.367	67.699	62.876	57.649	60.324	61.017
(15)		TOTAL:	GWh	339.440	304.683	187.195	318.481	307.798	124.391	290.070	266.693	272.867	272.661	299.296
(16)	NUG		GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(17)	BIOFUELS		GWh	0.000	0.000	0.000	0.000	0.000	394.312	393.192	394.512	394.826	395.522	396.060
(18)	BIOMASS	ppa	GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(19)	GEOTHERMAL		GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(20)	HYDRO	ppa	GWh	0.000	0.000	0.000	0.000	0.000	11.050	11.050	11.050	11.050	11.050	11.050
(21)	LANDFILL GAS	ppa	GWh	0.000	23.146	29.319	29.319	29.319	29.319	29.319	29.319	29.319	29.319	29.319
(22)	MSW		GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(23)	SOLAR	FIT-PV	GWh	0.000	5.490	10.980	16.470	19.215	21.960	24.705	27.450	30.195	32.940	35.685
(24)	WIND		GWh	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(25)	OTHER RENEWABLE	LFG-SWLF	GWh	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(26)	Total Renewable		GWh	0.003	28.636	40.299	45.789	48.534	456.641	458.266	462.331	465.390	468.831	472.114
(27)	Purchased Energy		GWh	428.109	556.880	663.601	411.942	410.321	369.973	0.594	0.620	0.585	0.627	0.654
(28)	Energy Sales		GWh	72.903	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(29)	NET ENERGY FOR LOAD		GWh	2,078.949	2,045.291	2,043.625	2,061.374	2,084.802	2,109.719	2,134.663	2,160.109	2,183.124	2,205.399	2,228.317

Schedule 6.2
ENERGY SOURCES (%)
As of January 1, 2009

(1)	(2) ENERGY SOURCES	(3)	(4) UNITS	(5) ACTUAL 2008	(6) 2009	(7) 2010	(8) 2011	(9) 2012	(10) 2013	(11) 2014	(12) 2015	(13) 2016	(14) 2017	(15) 2018
(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		GWh	4.74%	4.93%	5.10%	4.47%	5.80%	5.19%	5.67%	5.07%	5.54%	4.96%	5.43%
(3)	COAL		GWh	61.43%	51.55%	51.30%	57.87%	57.42%	49.74%	59.25%	61.16%	60.62%	61.39%	59.92%
	RESIDUAL													
(4)		STEAM	GWh	0.36%	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	0.36%	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	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(10)		CT	GWh	0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(11)		TOTAL:	GWh	0.06%	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	8.33%	0.54%	0.33%	0.75%	0.86%	0.14%	0.43%	0.30%	0.27%	0.26%	0.31%
(13)		CC	GWh	6.99%	11.24%	6.54%	11.09%	10.38%	4.22%	9.99%	9.14%	9.59%	9.37%	10.39%
(14)		CT	GWh	1.01%	3.12%	2.30%	3.61%	3.52%	1.53%	3.17%	2.91%	2.64%	2.74%	2.74%
(15)		TOTAL:	GWh	16.33%	14.90%	9.16%	15.45%	14.76%	5.90%	13.59%	12.35%	12.50%	12.36%	13.43%
(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%	18.69%	18.42%	18.26%	18.09%	17.93%	17.77%
(18)	BIOMASS	ppa	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(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	ppa	GWh	0.00%	0.00%	0.00%	0.00%	0.00%	0.52%	0.52%	0.51%	0.51%	0.50%	0.50%
(21)	LANDFILL GAS	ppa	GWh	0.00%	1.13%	1.43%	1.42%	1.41%	1.39%	1.37%	1.36%	1.34%	1.33%	1.32%
(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	0.00%	0.27%	0.54%	0.80%	0.92%	1.04%	1.16%	1.27%	1.38%	1.49%	1.60%
(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	0.000144%	1.40%	1.97%	2.22%	2.33%	21.64%	21.47%	21.40%	21.32%	21.26%	21.19%
(27)	Purchased Energy		GWh	20.59%	27.23%	32.47%	19.98%	19.68%	17.54%	0.03%	0.03%	0.03%	0.03%	0.03%
(28)	Energy Sales		GWh	3.51%	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	Summer kW
1980	254	168
1981	575	370
1982	1,054	674
1983	2,356	1,212
1984	8,024	2,801
1985	16,315	4,619
1986	25,416	7,018
1987	30,279	8,318
1988	34,922	9,539
1989	38,824	10,554
1990	43,661	11,753
1991	48,997	12,936
1992	54,898	14,317
1993	61,356	15,752
1994	66,725	16,871
1995	72,057	18,022
1996	75,894	18,577
1997	79,998	19,066
1998	84,017	19,541
1999	88,631	20,055
2000	93,132	20,654
2001	97,428	21,185
2002	102,159	21,720
2003	106,277	22,222
2004	109,441	22,676
2005	113,182	23,405
2006	116,544	24,078
2007	130,872	26,511
2008	151,347	30,139
2009	163,647	34,339
2010	175,947	38,939
2011	188,247	43,939
2012	200,547	49,339
2013	212,847	54,939
2014	225,147	60,639
2015	237,447	66,439
2016	249,792	70,739
2017	262,137	75,039
2018	274,483	79,339

TABLE 2.2

DELIVERED FUEL PRICES
$/MMBtu

Year	Residual Fuel Oil	Distillate Fuel Oil	Natural Gas	Compliance Coal (1)	Performance Coal (2)	Nuclear
1999	2.79	3.47	2.86	1.66		0.44
2000	4.52	5.99	4.53	1.62		0.38
2001	4.15	6.53	4.94	1.88		0.38
2002	4.58	5.69	3.95	2.06		0.38
2003	4.87	6.59	5.97	2.04		0.43
2004	5.17	5.17	6.40	2.03		0.41
2005	7.15	18.67	9.15	2.38		0.45
2006	8.07	15.24	8.68	3.00		0.45
2007	7.68	16.35	8.52	2.94		0.40
2008	7.60	13.74	10.57	3.87		0.42
2009	8.35	15.24	6.57	3.86		0.48
2010	12.97	14.91	6.76		3.31	0.65
2011	14.68	16.68	8.49		3.43	0.66
2012	16.53	18.46	8.84		3.53	0.83
2013	17.65	19.44	9.04		3.61	0.85
2014	19.80	21.74	9.43		3.73	0.92
2015	20.90	22.97	9.95		3.83	0.93
2016	21.60	23.83	10.46		3.88	0.96
2017	22.02	24.44	11.08		3.94	0.96
2018	22.87	25.39	11.90		4.04	0.95

(1) Compliance coal has an average heat content 12,800 Btu/lb and a sulfur content of approximately 0.7%.
(2) Performance coal has an average heat content 12,500 Btu/lb and a sulfur content of approximately 1.25%.

3. FORECAST OF FACILITIES REQUIREMENTS

3.1 GENERATION RETIREMENTS

The System plans to retire one generating unit within the next 10 years. The John R. Kelly steam unit #7 (JRK #7) (23 MW) is presently scheduled to be retired in October 2013.

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 Figure 3.1) and System winter peak demands in Schedule 7.2 (and Figure 3.2). 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

Due to new EPA regulations promulgated in March 2005, the retrofit of our Deerhaven #2 Air Quality Control System (AQCS) is proceeding as one means of complying with the new regulations. The upgraded AQCS will consist of a selective catalytic reduction (SCR) system and a dry flue gas desulfurization system (FGD) which will include a baghouse (BH). It is expected that the SCR and the FGD/BH will be operational following the 2009 spring maintenance outage.

The GRU South Energy Center located at the new Shands Healthcare Cancer Hospital (4.1 MW combustion turbine) was recently completed and will begin commercial operation in early summer 2009. Characteristics of the combustion turbine are summarized in Schedule 8 at the end of this section.

As part owner in the Crystal River 3 nuclear unit, GRU will benefit from three uprates of the unit's capacity approved by the Nuclear Regulatory Commission (NRC). GRU's share (1.4079%) of the uprates (first 11 MW in 2008, second 28 MW in 2009, and 140 MW in 2011) will net the System 2.5 MW of additional base load capacity.

Eleven responses to GRU's "Request for Proposals" (RFP) for a biomass fueled facility in the 30-100 MW range were received on December 15, 2007. Addendum Two has been issued to solicit binding proposals from the top three proposals from the initial RFP. The responses to Addendum Two were received April 11, 2008 and included biomass fueled capacity and energy through a purchase power agreement (PPA), with an option to buy the plant at a later date. The proposed biomass facility will be owned and operated by American Renewables. This facility is planned to have a net capacity of 100 MW and will be designed to use clean woody fuels including forest residuals and tree thinnings.

3.4 DISTRIBUTION SYSTEM ADDITIONS

Up to five new, identical, mini-power delivery substations (PDS) were planned for the GRU system back in 1999. Three of the five; Rocky Point, Kanapaha, and Ironwood were installed by 2003. A fourth PDS is planned for spring 2010. The location for this PDS, which will be known as Springhill, will be a parcel owned by GRU west of Interstate 75 and north of 39th Avenue along our existing 138 kV transmission line. A fifth PDS is being considered for addition to the System no earlier than 2013. The location of this proposed fifth PDS would be in the northern part of the service territory near U.S. Highway 441. 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.

Each PDS will consist of one (or more) 138/12.47 kV, 33.6 MVA, wye-wye substation transformer with a maximum of eight distribution circuits. The proximity of these new 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

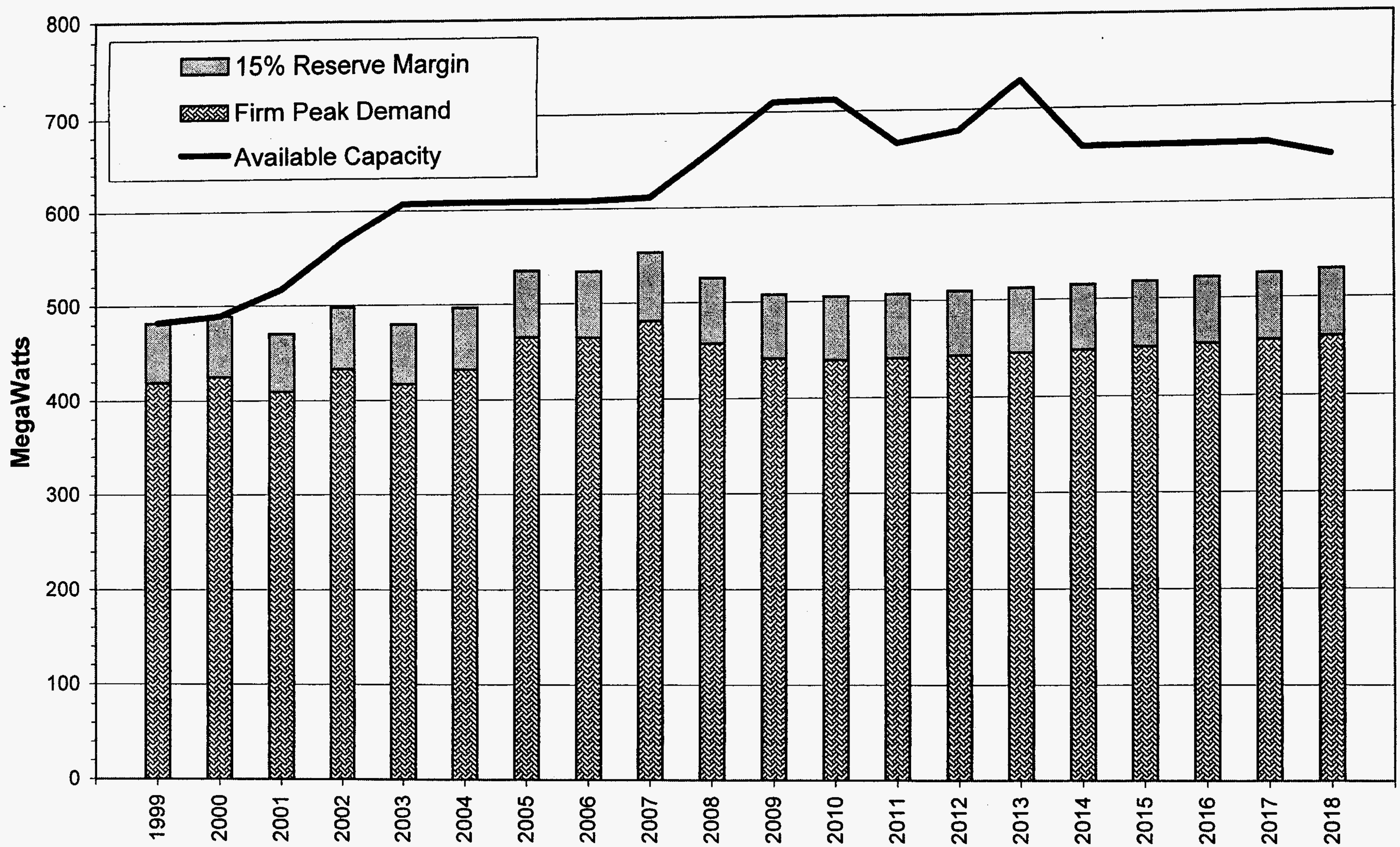
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity (2)	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available (3)	System Firm Summer Peak Demand (1)	Reserve Margin before Maintenance		Scheduled Maintenance	Reserve Margin after Maintenance (1)	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
1999	547	32	97	0	482	419	63	15.0%	14	49	11.7%
2000	547	0	58	0	489	425	64	15.1%	0	64	15.1%
2001	610	0	93	0	517	409	108	26.4%	0	108	26.4%
2002	610	0	43	0	567	433	134	30.9%	0	134	30.9%
2003	610	0	3	0	607	417	190	45.6%	0	190	45.6%
2004	611	0	3	0	608	432	176	40.7%	0	176	40.7%
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	27.0%	0	130	27.0%
2008	610	49	0	0	659	457	202	44.2%	0	202	44.2%
2009	608	105	0	0	710	441	269	60.9%	0	269	60.9%
2010	608	110	0	0	712	439	273	62.3%	0	273	62.3%
2011	608	65	0	0	665	441	224	50.9%	0	224	50.9%
2012	620	67	0	0	678	443	235	53.0%	0	235	53.0%
2013	620	121	0	0	730	445	285	64.0%	0	285	64.0%
2014	597	74	0	0	659	448	211	47.2%	0	211	47.2%
2015	597	76	0	0	660	450	210	46.6%	0	210	46.6%
2016	597	78	0	0	660	453	207	45.6%	0	207	45.6%
2017	597	80	0	0	661	457	204	44.8%	0	204	44.8%
2018	583	82	0	0	648	460	188	40.8%	0	188	40.8%

(1) System Peak demands shown in this table reflect continued service to partial and full requirements wholesale customers. In the event these contracts are not renewed, reserve margins shown in this table will increase significantly.

(2) Details of planned changes to installed capacity from 2009-2018 are reflected in Schedule 8.

(3) The coincidence factor used for Summer photovoltaic capacity is 35%.

Figure 3.1
Summer Peak Demand and Resources



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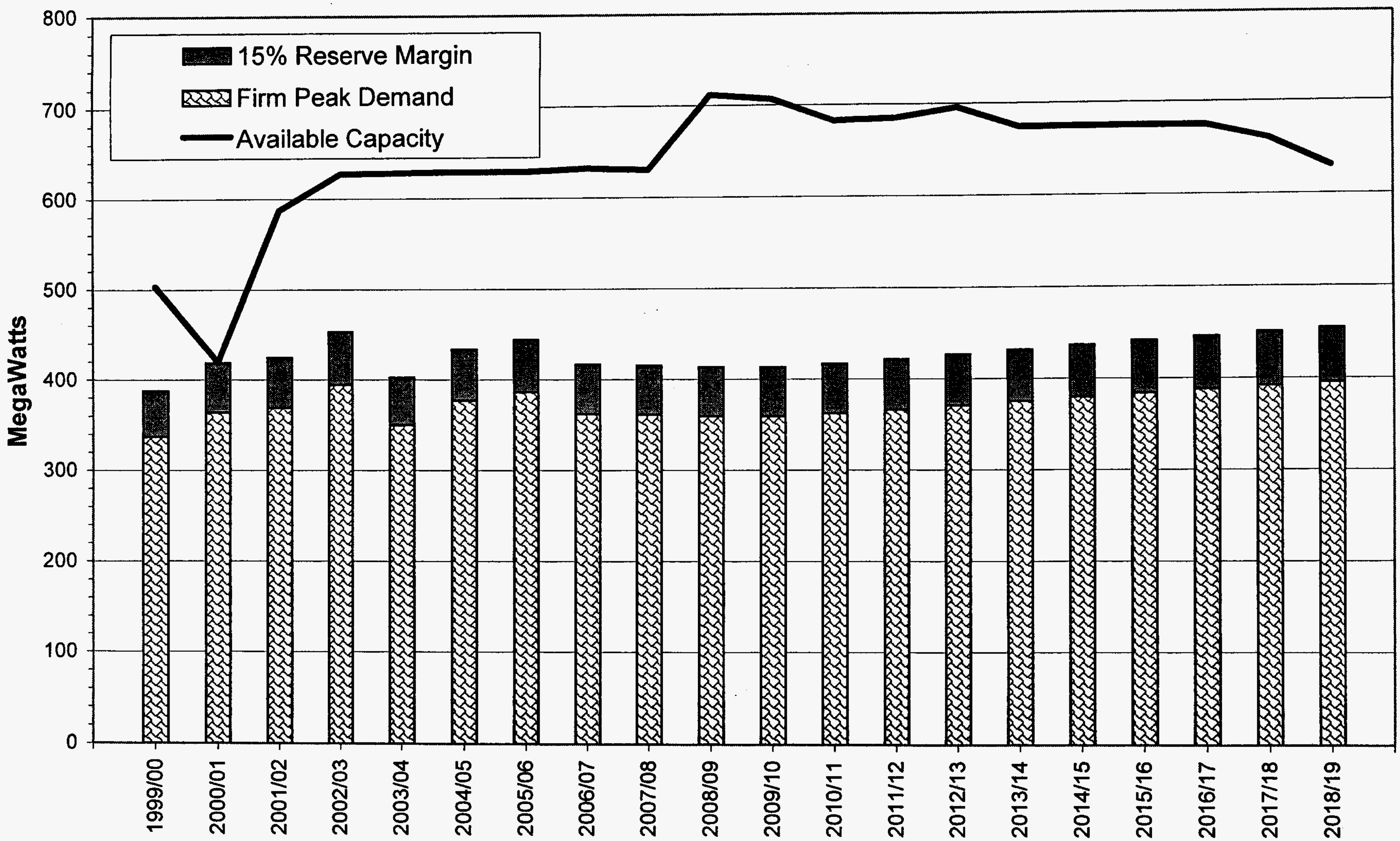
Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(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
1999/00	561	0	58	0	503	337	166	49.3%	0	166	49.3%
2000/01	512	0	93	0	419	364	55	15.1%	0	55	15.1%
2001/02	630	0	43	0	587	369	218	59.1%	0	218	59.1%
2002/03	630	0	3	0	627	394	233	59.1%	0	233	59.1%
2003/04	631	0	3	0	628	350	278	79.4%	0	278	79.4%
2004/05	632	0	3	0	629	377	252	66.8%	0	252	66.8%
2005/06	632	0	3	0	629	386	243	63.0%	0	243	63.0%
2006/07	632	0	0	0	632	362	270	74.6%	0	270	74.6%
2007/08	630	0	0	0	630	361	269	74.5%	0	269	74.5%
2008/09	635	76	0	0	711	359	352	98.0%	0	352	98.0%
2009/10	629	81	0	0	707	359	347	96.8%	0	347	96.8%
2010/11	629	61	0	0	682	362	320	88.4%	0	320	88.4%
2011/12	631	65	0	0	685	366	318	87.0%	0	318	87.0%
2012/13	640	69	0	0	696	371	325	87.8%	0	325	87.8%
2013/14	617	72	0	0	674	375	299	79.8%	0	299	79.8%
2014/15	617	74	0	0	674	380	295	77.7%	0	295	77.7%
2015/16	617	76	0	0	675	384	291	75.9%	0	291	75.9%
2016/17	617	78	0	0	675	387	287	74.1%	0	287	74.1%
2017/18	602	80	0	0	660	391	268	68.6%	0	268	68.6%
2018/19	572	82	0	0	630	395	235	59.5%	0	235	59.5%

(1) System Peak demands shown in this table reflect continued service to partial and full requirements wholesale customers. In the event these contracts are not renewed, reserve margins shown in this table will increase significantly.
(2) Details of planned changes to installed capacity from 2009-2018 are reflected in Schedule 8.
(3) The coincidence factor used for Winter photovoltaic capacity is 9.3%.

Figure 3.2
Winter Peak Demand and Resources



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)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gross Capability		Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo/Yr	In-Service Mo/Yr	Retire Mo/Yr	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Status
DEERHAVEN	FS02	Alachua County Secs. 26,27 35 T8S, R19E	ST	BIT		RR		Jan-07	May-09		0	0	-6.3	-6.3	D
DEERHAVEN	FS02	Alachua County Secs. 26,27 35 T8S, R19E	ST	BIT		RR		Sep-09	May-12		0	0	9.1	9.1	A
SOUTH ENERGY CENTER (Distributed generation)	GT1	Alachua County Sec. 10, T10S, R20E	GT	NG		PL		Apr-07	May-09		4.5	4.5	4.1	4.1	V
CRYSTAL RIVER	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			Jan-10				0.386	0.396	A
CRYSTAL RIVER	3	Citrus County Sec. 33, T17S, R16E	ST	NUC		TK			Jan-12				1.930	1.978	A
J. R. KELLY	FS07	Alachua County Sec. 4, T10S, R20E	ST	NG	RFO	PL	TK			Oct-13	-24	-24	-23.2	-23.2	RT

Unit Type
GT = Combustion (gas) Turbine
ST = Steam Turbine

Fuel Type
BIT = Bituminus Coal
NG = Natural Gas
NUC = Nuclear
RFO = Residual Fuel Oil

Transportation Method
PL = Pipeline
RR = Railroad
TK = Truck

Status
A = Generating unit capability increased
D = Generating unit capability decreased
RT = Existing generator scheduled for retirement
V = Under construction, more than 50% complete

Schedule 9
Description of Proposed Facility Under Discussion

(1)	Plant Name and Unit Number:	GRU Energy Center (Distributed Generation)	
(2a)	Net Capacity		
	a. Summer	4.1	MW
	b. Winter	4.1	MW
(2a)	Gross Capacity		
	a. Summer	4.5	MW
	b. Winter	4.5	MW
(3)	Technology Type:	Combustion Turbine (Solar)	
(4)	Anticipated Construction Timing		
	a. Field construction start-date:	4/1/2007	
	b. Commercial in-service date:	5/1/2009	
(5)	Fuel		
	a. Primary Fuel (by Heat Input)	Natural Gas	
	b. Alternate Fuel	na	
(6)	Air Pollution Control Strategy:	Low NOx Burners	
(7)	Cooling Method:	air cooled	
(8)	Total Site Area (ft^2):	50,000	
(9)	Construction Status:	Approved	
(10)	Certification Status:	Not Certified	
(11)	Status with Federal Agencies:	Air Permit issued 7/25/07	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	3.0%	
	Forced Outage Factor (FOF):	6.0%	
	Equivalent Availability Factor (EAF):	95.0%	
	Resulting Capacity Factor (CF)	90.0%	
	Average Net Operating Heat Rate (ANOHR):	10,100	
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (2009$/kW)	930.49	
	Direct Construction Cost ($2009/kW):	0.00	
	Escalation ($2009/kW)	28.75	
	Escalation:	3.00%	
	Fixed O&M ($2009/kW-Yr):	0.00	
	Variable O&M ($2009/MWh):	15.33	

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 potential generating facility (resulting from GRU's "Request for Proposals for Biomass-fueled Generation Facility") is planned to be located on land leased from GRU on the northwest portion of the existing Deerhaven plant site. The Deerhaven site is shown in Figure 1.1 and Figure 4.1, located north of Gainesville off U.S. Highway 441. The Deerhaven site is preferred for the proposed 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 and power delivery; as well as fuel, water and combustion product management facilities. The preferred location of the proposed biomass facility is shown on Figure 4.1.

4.2.1 Land Use and Environmental Features

The location of the Deerhaven Generating Station ("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, combustion product, and forest management). The areas acquired since 2002 have been annexed into the City of Gainesville. The current zoning remains County Agricultural, but a land use change application has been filed with the City of Gainesville. Eventually, the site will be zoned (city) Pubic Services with conservation areas. Surrounding land uses are primarily rural or agricultural with some low-density residential development. The Deerhaven site encompasses approximately 3474 acres.

The Site is located in the Suwannee River Water Management District. A small increase in water quantities for potable uses is projected. It is estimated that industrial water usage associated with the new unit could be as much as two million gallons per day (MGD). The groundwater allocation in the existing Site Certification would be sufficient to accommodate the requirements of the site in the future with the proposed new unit. Water for potable use will be supplied via the City's potable water system. Groundwater will continue to be extracted from the Floridian aquifer. A significant amount of reclaimed water from GRU's Main St. and/or Kanapaha wastewater treatment plants may be made available to the site to supply industrial process and cooling water needs. 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. It is expected that this practice would continue with the addition of a new unit. Other water conservation measures may be identified during the design of the project.

4.2.2 Air Emissions

The proposed generation technology would necessarily meet all applicable standards for all criteria pollutants.

4.3 STATUS OF APPLICATION FOR SITE CERTIFICATION

American Renewables will be applying for site certification for the planned 100 MW biomass generating facility located on land that is part of the Deerhaven site.

Figure 4.1

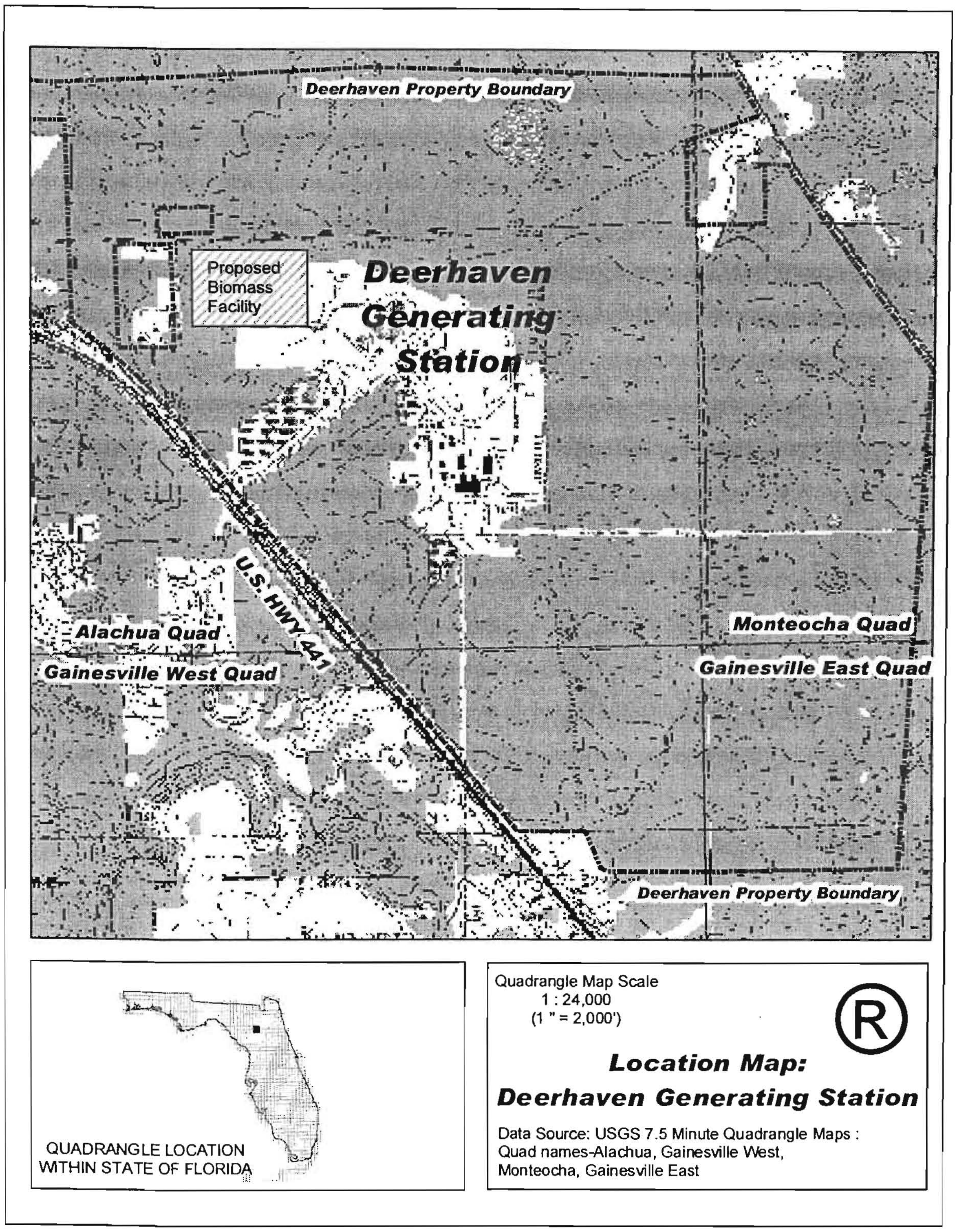
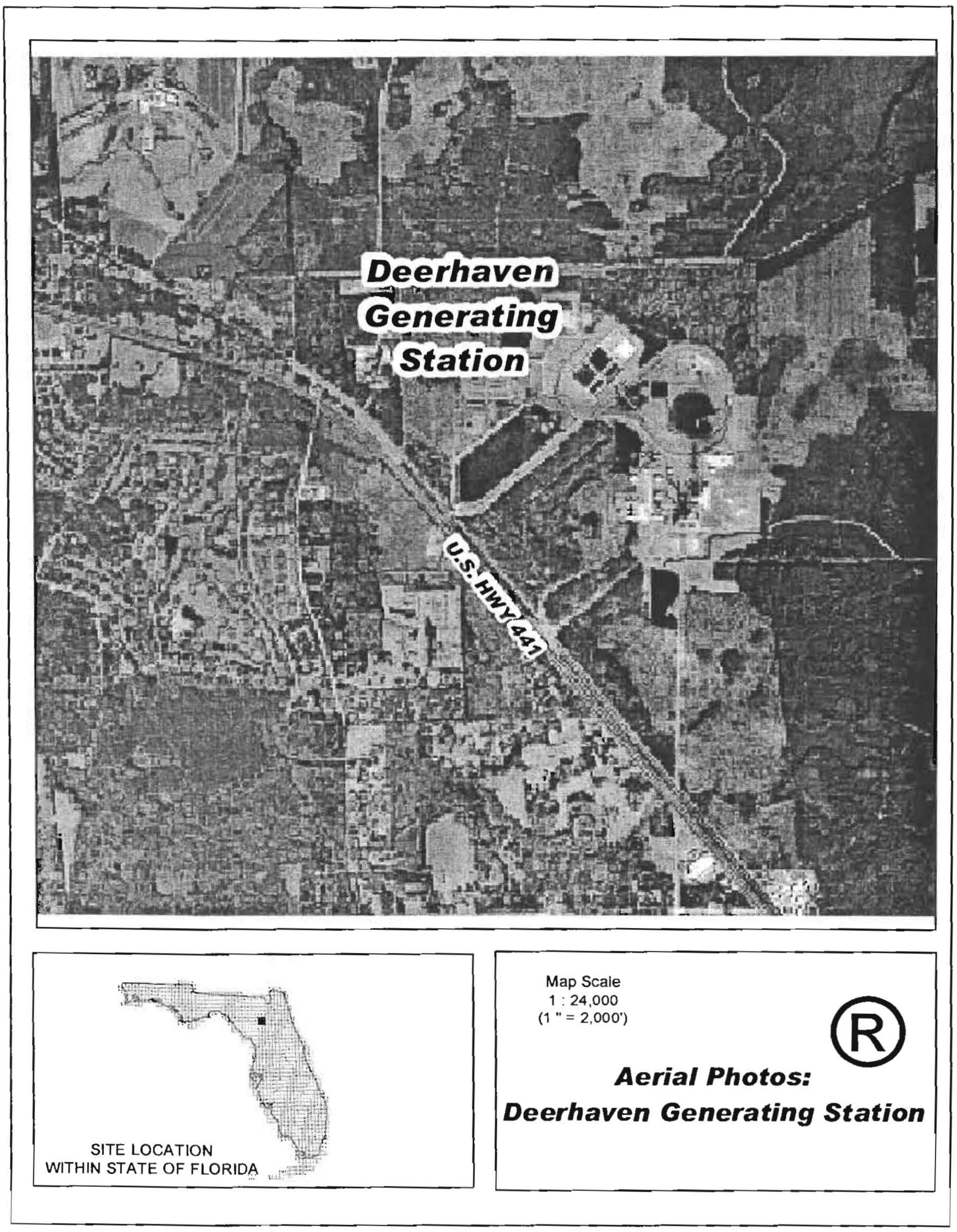

Deerhaven Property Boundary
Proposed Biomass Facility
Deerhaven Generating Station
U.S. HWY 441
Alachua Quad
Gainesville West Quad
Monteocha Quad
Gainesville East Quad
Deerhaven Property Boundary
QUADRANGLE LOCATION WITHIN STATE OF FLORIDA
Quadrangle Map Scale
1 : 24,000
(1 " = 2,000')
Location Map:
Deerhaven Generating Station
Data Source: USGS 7.5 Minute Quadrangle Maps :
Quad names-Alachua, Gainesville West,
Monteocha, Gainesville East

Figure 4.2


Deerhaven
Generating
Station
U.S. HWY 441
SITE LOCATION
WITHIN STATE OF FLORIDA
Map Scale
1 : 24,000
(1 " = 2,000')
Aerial Photos:
Deerhaven Generating Station