ORIGINAL

GRU

# Gainesville Regional Utilities

# 1998 Ten Year Site Plan

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CAF ____
CMU ____
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**Submitted to:**

**The Public Service Commission**

**April 1, 1998**

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# GAINESVILLE REGIONAL UTILITIES

## 1998 TEN-YEAR SITE PLAN

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# 2. DESCRIPTION OF EXISTING FACILITIES

The City of Gainesville owns a fully integrated electric power production, transmission, and distribution system (herein referred to as "the System"). GRU is the City of Gainesville enterprise arm that has the responsibility to operate and maintain the System. In addition to retail electric service, GRU also provides wholesale electric service to the City of Alachua (Alachua) and to Clay Electric Cooperative, Inc. (Clay). GRU's distribution system serves approximately 130 square miles and 73,176 customers (December, 1997). The general locations of GRU electric facilities and the electric system service area are shown in Figure 2.1.

On July 21, 1986, the System executed a 15-year territorial agreement with Clay which established a service boundary between the two utilities in the unincorporated areas of the County in order to clearly delineate areas to be served by the System and those areas to be served by Clay. Additionally, the agreement provided for the transfer of certain customers and associated electric distribution facilities from Clay to the System and from the System to Clay. This agreement significantly reduced the duplication of distribution facilities in the area served by the System. All transfers specifically stipulated to by this agreement concluded in June of 1993.

## 2.1 GENERATION

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

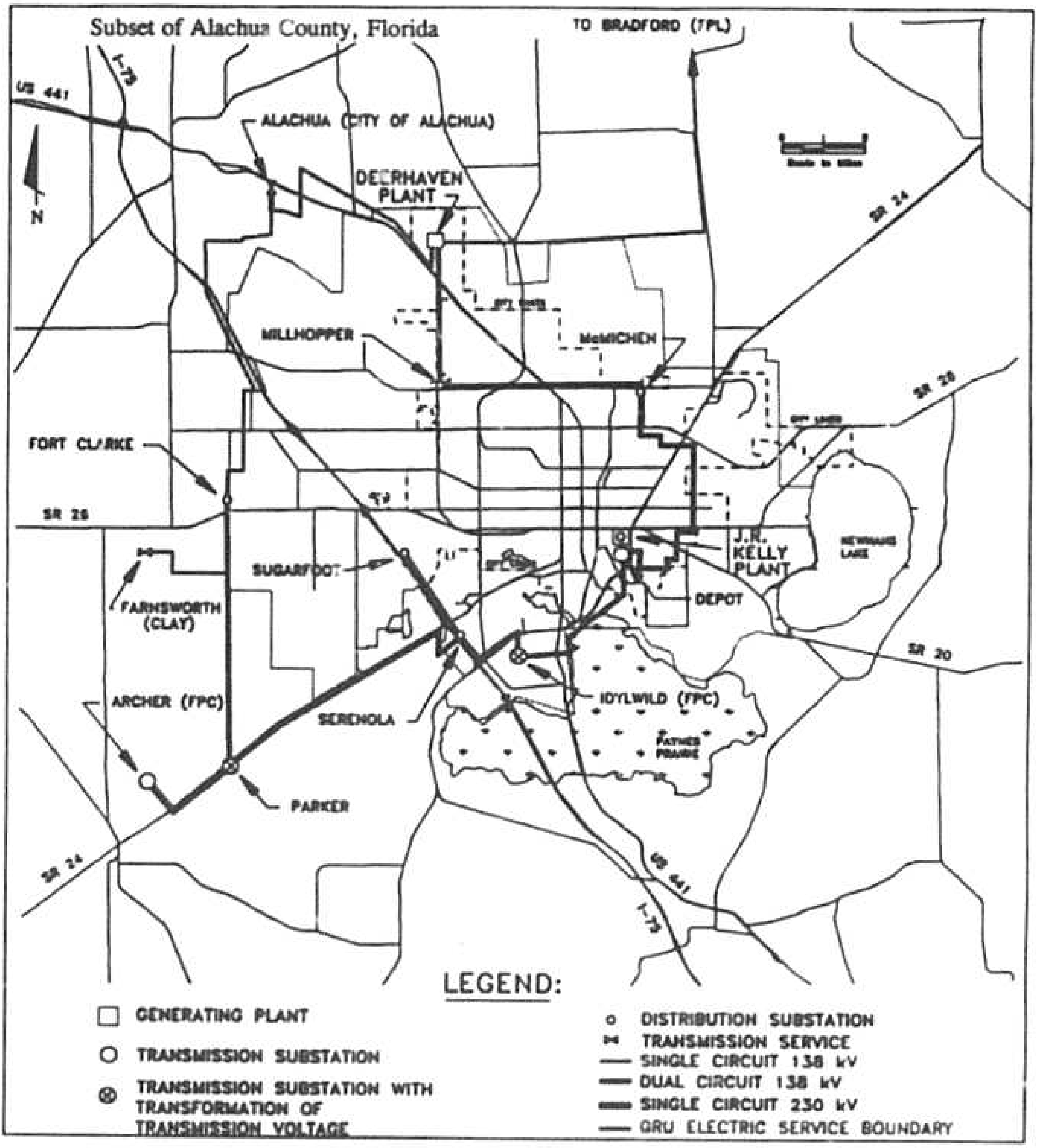


**FIGURE 2.1 Gainesville Regional Electric Facilities.**

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

### 2.1.1 Generating Units

**2.1.1.1 Steam Turbines.** Three of the System's four operational steam turbines are powered by fossil fuels, and Crystal River 3 is nuclear powered. John R. Kelly (Kelly) 6, a fossil steam turbine, was placed in cold standby in August, 1989 and is no longer considered operational for planning purposes. The fossil fueled steam turbines comprise 70.1% of the System's net summer capability and produced 96.9% of the electric energy supplied by the System in 1997. These units range in size from 23.2 MW to 228.4 MW. The System's 11.0 MW share of Crystal River 3 nuclear unit comprises 2.0% of the System's net summer capability.

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

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

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

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

### 2.1.2 Generating Plant Sites

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

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

**2.1.2.2 Deerhaven Plant.** The Deerhaven Station is located six miles northwest of Gainesville. The site is a 1,116 acre parcel of partially forested land. The facility consists of two steam turbines, three gas turbines, and the associated cooling facilities, fuel storage, pumping equipment and transmission equipment. January 26, 1996 GRU placed its third gas turbine in service at the Deerhaven Station. With the addition of Deerhaven 2 in 1981, the site now includes coal unloading and storage facilities and a zero discharge water treatment plant, which treats water effluent from both steam units.

## 2.2 TRANSMISSION

### 2.2.1 The Transmission Network

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

1) GRU's two generating stations,

2) GRU's six distribution substations,

3) Three interties with Florida Power Corporation,

4) An intertie with Florida Power and Light Company,

5) An interconnection with Clay at Farnsworth Substation, and

6) An interconnection with the City of Alachua at Alachua No. 1 Substation

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

### 2.2.2 Transmission Lines

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

- Normal loading: conductor temperature not to exceed 100° C (212° F).
- Emergency loading: conductor temperature not to exceed 125° C (257° F).

The present transmission network consists of the following:

| Line | Circuit Miles | Conductor |
|---|---|---|
| 138 KV double circuit | 80.87 | 795 MCM ACSR |
| 138 KV single circuit | 16.47 | 1192 MCM ACSR |
| 138 KV single circuit | 31.97 | 795 MCM ACSR |
| 230 KV single circuit | 2.51 | 795 MCM ACSR |
| Total | 131.82 | |

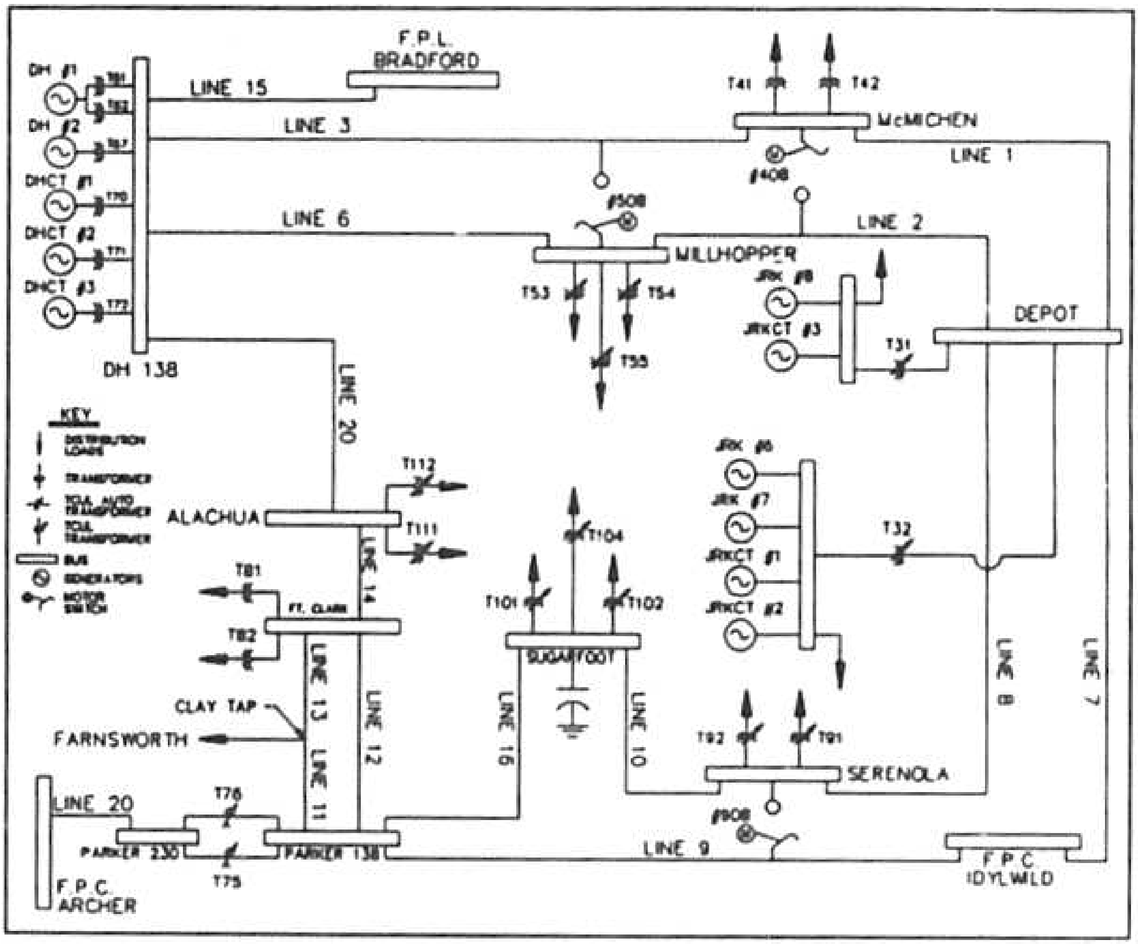


**FIGURE 2.2 Gainesville Regional Utilities Electric System One-Line Diagram.**

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

Reliability contingencies:

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

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

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

### 2.2.3 State Interconnections

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

## 2.3 DISTRIBUTION

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

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

The last substation added by GRU, Sugarfoot, was brought on-line in 1986 to serve the growing load in the area of State Road 26 and Interstate Highway I-75. McMichen, Serenola, Ft. Clarke, and Kelly Substations currently consist of two transformers of equal size allowing these stations to be loaded under normal conditions to 80 percent of the capabilities shown in Table 2.2. Millhopper and Sugarfoot Substations currently consist of three transformers of equal size allowing both of these substations to be loaded under normal conditions to 100 percent of the capability shown in Table 2.2.

## 2.4 WHOLESALE ENERGY

The System provides wholesale electric service to Clay Electric Cooperative (Clay) through a contract between GRU and Seminole Electric Cooperative (Seminole), of which Clay is a member. The System began the 138 kV service at Clay's Farnsworth Substation in February 1975. This substation is supplied through a 2.4 mile radial line connected to the System's transmission facilities.

The System also provides wholesale electric service to the City of Alachua at two points of service. The Alachua No. 1 Substation is supplied with GRU's looped 138 kV transmission system. Approximately 400 residences and a few commercial customers within Alachua's city limits are served by a 12.47 kV distribution circuit, known as the Hague point of service. The System provides approximately 87% (1997) of Alachua's energy requirements with the remainder being supplied by Alachua's generation entitlements from the Crystal River 3 and St. Lucie 2 nuclear units. Energy supplied to Alachua by these nuclear units is wheeled over GRU's transmission network, with GRU providing generation backup in the event of outages of these nuclear units.

## 2.5 EXPORT COMMITMENTS

GRU has a Schedule D firm interchange service commitment with the City of Starke (Starke). The agreement with Starke is non-unit specific and provides for the sale of 3 MW of System capacity. This agreement was renewed January 1, 1994 and continues through 2003, with optional three year extensions available indefinitely and allows Starke the option to expand the capacity commitment to 5 MW.

GRU has a Schedule D firm interchange service commitment with the Florida Municipal Power Agency (FMPA). The agreement with FMPA is unit specific with Deerhaven Unit #2 (DH2) and provides for the sale of 20 MW of DH2 capacity for 1998, and 10 MW of DH2 capacity for 1999. This sale schedule is contemplated herein and is consistent with GRU's needs for generating capacity and associated reserve margins. Table 2.3 contains a summary of GRU's export commitments.

GRU has a peaking capacity and energy schedule D contract with PECO Energy Company to provide 50 MW during June, July, August, and September of 1998 and 47 MW during the same summer months of 1999.

Schedule 1

EXISTING GENERATING FACILITIES
(As of December 31, 1997)

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

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

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

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

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

Notes: (1) GRU reevaluated the capabilities of the System's steam units under 5% throttle over pressure.
(2) JRK Unit 6 was placed in cold standby in August, 1989.

## TABLE 2.1

## SUMMER POWER FLOW LIMITS

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

## TABLE 2.2

## CURRENT SUBSTATION TRANSFORMATION AND CIRCUITS

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

## TABLE 2.3

## SUMMARY of SCHEDULE D SERVICE COMMITMENTS

| Year | Starke D | FMPA D | PECO Peaking[1] D | Total D |
|---|---|---|---|---|
| 1998 | 3. | 20. | 50. | 73. |
| 1999 | 3. | 10.[2] | 47. | 60. |
| 2000 | 3. | | | 3. |
| 2001 | 3. | | | 3. |
| 2002 | 3. | | | 3. |
| 2003 | 3. | | | 3. |
| 2004 | | | | |
| 2005 | | | | |
| 2006 | | | | |
| 2007 | | | | |

Definitions:

Schedule D: Firm interchange service.

Notes:

(1) Peaking capacity and energy sale for June, July, August, and September.
(2) Decreased to 10 MW starting 1/1/99, with service ending 1/1/2000.

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

# 3. FORECAST OF ELECTRIC ENERGY AND DEMAND REQUIREMENTS

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

The accompanying tables provide historical and forecast information for calendar years ending December 31, for 1988-2007. Energy consumption and customer information are presented in Schedules 2.1, 2.2 and 2.3. Schedules 3.1, 3.1H and 3.1L present components of summer peak demand for the base case, high band and low band forecasts, respectfully. Schedules 3.2, 3.2H and 3.2L present the components of winter peak demand for each forecast scenario. Schedules 3.3, 3.3H and 3.3L similarly present components of net energy for load. Short-term monthly retail load data is presented in Schedule 4. Projected net energy requirements for the System, by method of generation, are shown in Schedule 6.1. The percentage breakdowns of energy shown in Schedule 6.1 are given in Schedule 6.2. The quantities of fuel that are expected to be used to generate the energy requirements shown in Schedule 6.1 are given by fuel type in Schedule 5.

## 3.1 FORECAST ASSUMPTIONS AND DATA SOURCES

(1) All regression analyses were based on annual data. Historical data were assimilated for calendar years 1970 through 1996. System data, such as net energy for load, seasonal peak demands, customer counts and energy sales, were obtained from GRU records and sources.

(2) Estimates and projections of Alachua County population were obtained from the Florida Population Studies, February, 1997 (Bulletin No. 117), published by the Bureau of Economic and Business Research (BEBR) at the University of Florida.

(3) Normal weather conditions were assumed. Normal heating degree day and cooling degree day projections are thirteen-year medians from 1984 through 1996 for the Gainesville Municipal Airport weather station.

(4) All income and price figures were adjusted for inflation, and indexed to a base year of 1986, using a price index developed to represent inflationary trends in Alachua County. After reviewing several reputable projections of national-level macroeconomic indicators, an assumption for the projected rate of inflation for Alachua County was developed at 3.5% per year throughout the forecast horizon.

(5) The U. S. Department of Commerce provided historical estimates of total income and per capita income for Alachua County. The BEBR projected income levels for Alachua County in The Florida Long Term Economic Forecast, April 1996.

(6) The Florida Long Term Economic Forecast and Florida Population Studies, Bulletin 116, were used to estimate and project the number of persons per household (household size) in Alachua County.

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

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

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

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

## 3.2 DOCUMENTATION OF CUSTOMER, ENERGY AND SEASONAL PEAK DEMAND FORECASTS

Number of customers, energy sales and seasonal peak demands were forecast from 1998 through 2007. Energy sales were disaggregated into billing related customer classes: residential, general service non-demand, general service demand, large power, lighting, sales to Clay, and sales to Alachua. Separate energy sales forecasts were developed for each of these sectors, and customer forecasts were developed for each of the retail revenue classes. The basis for these independent forecasts originated with the development of econometric models utilizing least squares regression. All modeling was performed in-house using the Statistical Analysis System (SAS)[3].

The following text describes the regression equations selected to formulate energy sales and customer projections for each customer class.

### 3.2.1 Residential Sector

Linear regression was employed to develop a model which explained a statistically significant amount of the historical variation in the average annual energy usage per residential customer.

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

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

$$RESAVUSE = 5014.5 + 0.11\,(HHY86) - 16.57\,(RESPR86) + 0.65\,(HDD) + 0.82\,(CDD)$$

Where:

| | | |
|---|---|---|
| RESAVUSE | = | Average Annual Residential Energy Consumption |
| HHY86 | = | Average Household Income |
| RESPR86 | = | Residential Price for 1000 kWh |
| HDD | = | Annual Heating Degree Days |
| CDD | = | Annual Cooling Degree Days |

Adjusted $R^2$ = 0.8588

Degrees of Freedom: 21

t - statistics:

Intercept = 4.00

HHY86 = 6.80

RESPR86 = -2.42

HDD = 3.59

CDD = 3.69

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:

$$RESCUS = -30574 + 451.91\,(POP)$$

Where:

| | | |
|---|---|---|
| RESCUS | = | Number of Residential Customers |
| POP | = | Alachua County Population (thousands) |

Adjusted $R^2$ = 0.9966

Degrees of Freedom: 17

t - statistics:

Intercept = -28.28

POP = 72.73

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

### 3.2.2 General Service Non-Demand Sector

The general service non-demand customer class includes non-residential customers with maximum annual demands generally less than 50 kilowatts (kW). Average annual energy use per general service non-demand customer has exhibited neither an increasing nor decreasing trend over the last 18 years. From 1979 through 1996, average annual consumption has ranged from a low of 26,165 kWh per year (1992) to a high of 28,968 kWh per year (1990). No significant correlations between average use and economic data or average use and weather data were identified. For this reason, average use was projected to remain constant at 27,681 kWh (the median of the last 18 years' observed values) per customer per year.

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

$$GNDCUS = -4745.94 + 57.21\ (POP)$$

Where:

GNDCUS = Number of General Service Non-Demand Customers

POP = Alachua County Population (thousands)

Adjusted $R^2$ = 0.9735

Degrees of Freedom: 13

t - statistics:

Intercept = -10.48

POP = 22.72

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

### 3.2.3 General Service Demand Sector

The general service demand customer rate class includes non-residential customers with established annual maximum demands generally of at least 50 kW but less than 1,000 kW. The annual average number of customers was projected based on the results of a regression model in which Alachua County population was the independent variable. Average annual energy use per customer was projected using an equation specifying average use as a function of real per capita income for residents of Alachua County. A significant number of the customers in this sector are large retailers such as department stores and grocery stores, whose business activity is related to income levels of area residents.

The specifications of the general service demand customer model are as follows:

$$DEMCUS = -907.9 + 8.15\ (POP)$$

Where:

DEMCUS = Number of General Service Demand Customers

POP = Alachua County Population (thousands)

Adjusted $R^2$ = 0.9904

Degrees of Freedom: 13

t - statistics:

Intercept = -23.55

POP = 38.03

Average energy use projections for general service demand customers result from the following model:

*DEMAVUSE* = *381.0 + 0.01 (PCY86)*

Where:

DEMAVUSE = Average Annual Energy Consumption for General Service Demand Customers (MWh per Year)

PCY86 = Real Per Capita Income in Alachua County

Adjusted $R^2$ = 0.7583

Degrees of Freedom: 16

t - statistics:

Intercept = 19.01

PCY86 = 7.37

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

### 3.2.4 Large Power Sector

The large power rate class includes 15 customers with billing demands of at least 1,000 kW. Analyses of large power customer average annual energy consumption were based on historical observations from 1976 through 1996. Average annual energy consumption per large power customer was modeled using an equation in which nonagricultural employment in Alachua County and the average price paid for 1,000 kWh in the large power sector were independent variables.

The specifications of the large power average use model are as follows:

$$LPAVUSE = 10455 + 19.54\,(NONAG) - 61.89\,(LPPR86)$$

Where:

LPAVUSE = Average Annual Energy Consumption per Large Power Customer (MWh per Year)

NONAG = Alachua County Nonagricultural Employment (000's)

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

Adjusted $R^2$ = 0.8579

Degrees of Freedom: 18

t - statistics:

INTERCEPT = 5.56

CONONAG = 1.94

LPPR86 = -3.04

No new large power customers are included explicitly in the forecast presented in this report. However, expansions of existing facilities in GRU's service area are expected to lead to increased sales in this sector. These anticipated sales increases are projected to be correlated to the expected growth in local employment. Expansion of existing demand customers' facilities will be monitored where load growth indicates the potential for a rate classification change to large power.

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

### 3.2.5 Outdoor Lighting Sector

The outdoor lighting sector consists of street light, traffic light, and outdoor rental light accounts. Lighting energy sales are projected by applying one third of the forecasted growth rate in the number of residential customers to actual 1996 outdoor lighting energy sales. Adjustments to lighting inventories in recent years have produced an erratic and unreliable time series of historical lighting sales. To date, this has precluded modeling of outdoor lighting energy sales as a function of economic or weather data.

### 3.2.6 Wholesale Energy Sales

The System presently serves two wholesale customers: Clay Electric Cooperative, Inc. (Clay) at the Farnsworth Substation and, the City of Alachua at the Alachua No. 1 Substation and at the Hague Point of Service. Approximately 13% of Alachua's energy requirements were provided by Alachua's generation entitlement shares of nuclear generating units operated by Florida Power Corporation and Florida Power and Light during 1997.

Each wholesale delivery point serves an urban area that is either included in, or adjacent to the Gainesville Urban Area. Regression equations were developed to forecast energy sales to these two customers. For Clay's Farnsworth Substation, a model was developed in which total county income was used as the independent variable. Net energy requirements for Alachua were estimated using a model in which the total City of Alachua income was the independent variable. This variable represents the product of City of Alachua population and Alachua County per capita income. Population projections were developed by modeling City of Alachua population as a function of Alachua County population.

The form of the model used to develop the forecast of sales to Clay is as follows:

$$CLYMWH = -24693 + 28.52\ (COY86)$$

Where:

CLYMWH = Megawatt-Hour Sales to Clay

COY86 = Real Total Personal Income (Alachua County)

Adjusted $R^2$ = 0.9458

Degrees of Freedom: 15

t - statistics:

Intercept = -6.10

COY86 = 16.74

The model used to develop projections of sales to the City of Alachua is of the following form:

$$ALANEL = -5764.2 + 0.78\,(ALAY86)$$

Where:

ALANEL = Net Energy Requirements of Alachua

ALAY86 = City of Alachua Total Income

Adjusted $R^2$ = 0.9685

Degrees of Freedom: 15

t - statistics:

Intercept = -2.65

ALAPOP = 22.19

To obtain a final forecast of the System's sales to Alachua, an annual reduction of 8,077 MWh was made to projections of net energy requirements of Alachua, reflecting the City of Alachua's nuclear generation entitlements.

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

To obtain a total system energy sales forecast, the energy sales projections for each customer class (residential, general service non-demand, general service demand, large power, lighting, sales to Clay, and sales to Alachua were aggregated, then adjusted for projected impacts from demand side management programs' net effects, after 1996. The projected "delivered efficiency" factor for the System was applied to total energy sales to develop projections of net energy for load. The projected "delivered efficiency" factor (0.9401) was the median of total energy sales divided by net energy for load from 1982 through 1996.

The forecasts of seasonal peak demands were derived from forecasts of annual net energy for load and assumed that the winter peak will occur in January of each year and the summer peak will occur in August of each year. The average ratio of the most recent 15 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 15 years' load factors for January and August were applied to January and August net energy for load projections, yielding seasonal peak demand projections. Load data has converged over time to a point that winter peak demands are forecast to be equal for January and February. Likewise, the data indicates that summer peak demands are likely to be equal in July and August. Adjustments to seasonal peak demands were included explicitly to account for impacts from demand side management programs.

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

### 3.2.8 Low Band and High Band Forecast Scenarios

Alternative scenarios to the base case forecast (high band and low band) were developed by varying projections of one independent variable in each revenue class for which a forecast was developed. The fundamental variable which was varied to band the base case forecast was the series of population projections for Alachua County. High and low forecast scenarios were derived from the same equations used to develop the base case forecasts. The low band and high band population scenarios were set to approximately equal the midpoints of the BEBR low-to-medium and medium-to-high population projections, respectively.

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

## 3.3 DOCUMENTATION OF ENERGY SOURCES AND FUEL REQUIREMENTS

### 3.3.1 Fuels Used by System

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

### 3.3.2 Methodology

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

The input data to this model includes:

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

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

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

The output of this model includes:

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

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

## 3.4 DEMAND-SIDE MANAGEMENT

### 3.4.1 Demand-Side Management Plan

Demand and energy forecasts and generation expansion plans outlined in this Ten Year Site Plan are consistent with GRU's 1990 Energy Conservation Plan and GRU's 1996

Demand-Side Management Plan. The System forecast reflects historical program implementations recorded under both plans and projected program implementations scheduled in the 1996 DSM Plan. Both plans address a similar array of DSM measures and both plans were designed for the purpose of conserving the resources utilized by the System in a manner most cost effective to the customers of GRU.

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

GRU is presently active in the following conservation efforts: residential and commercial energy audits; low income household weatherization; promotion of natural gas in residential construction; promotion of natural gas for displacement of electric water heating and space heating in existing structures; commercial lighting efficiency and maintenance services; customer conservation education and information programs; the Trade Alliance Program, which offers a series of workshops providing technical assistance to builders, contractors, installers and codes officials covering topics such as: *Building An Energy Efficient Home* and *Duct System Installation And Sealing Techniques*; and the Business Partners Program, which offers a series of workshops pertaining to energy and power conservation in the commercial and industrial sectors. GRU plans to begin commercial customer rebate programs for thermal energy storage and heat recovery this year, and a rebate program for gas-fired cooling systems started in 1997. GRU participated in the FDCA Solar Weatherization Assistance Program in 1996, and began a solar water heater rebate program in 1997. A green-pricing program to allow customers an opportunity to have a grid-connected photovoltaic system installed on their rooftop is planned for this year, pending receipt of Grant funds from UPVG.

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

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

Projected penetration rates were based on historical levels of program implementations and tied to escalation rates paralleling service area population growth. For example, the number of residential energy audits and commercial energy audits was projected to grow at a rate of two percent per year from actual 1995 levels.

DSM program implementations are expected to provide 25 MW of summer peak reduction, 28 MW of winter peak reduction and 98 GWh of annual energy savings by the year 2007. These figures represent cumulative impacts of programs since 1980. The System's projections of energy sales and peak demands reflect the effects of these DSM programs.

### 3.4.2 Gainesville Energy Advisory Committee

The Gainesville Energy Advisory Committee (GEAC) is a ten-member citizen group that is charged with formulating recommendations to the Gainesville City Commission concerning national, state and local energy-related issues. The GEAC offers advice and guidance on energy management studies and consumer awareness programs. The GEAC's efforts have resulted in numerous contributions, accomplishments, and achievements for the City of Gainesville. Specifi[illegible], the GEAC helped establish a residential energy audit program in 1979. The GEAC was initially involved in the ratemaking process in 1980 which ultimately lead to the approval of an inverted block residential rate and a voluntary residential time-of-use rate. The GEAC recognized *Solar Month* in October of 1991 by sponsoring a seminar to foster the viability of solar energy as an alternative to conventional means of energy supply. Representatives from Sandia National Laboratories, the Florida Solar Energy Center, FPC, and GRU gave presentations on various solar projects and technologies. A recommendation from GEAC followed the Solar Day Seminars for GRU to investigate offering its citizen-ratepayers the option of contributing to photovoltaic power production through monthly donations on their utility bills. GRU staff investigated PV technologies and determined that there was an opportunity for a cost-effective application within the System at its Electric System Control Center. A description of this project is provided in Chapter 4. GRU solicited public input on the planned solar water heater rebate and green-pricing programs through the GEAC, and the committee in turn formally supported both programs.

### 3.4.3 Supply Side Programs

Deerhaven 2 is also contributing to reduced oil use by other utilities through the Florida Energy Broker. Prior to the addition of Deerhaven Unit 2 in 1982, the System was relying on oil and natural gas for over 90% of native load energy requirements. In 1997, oil-fired generation comprised 0.7% of total net generation, natural gas-fired generation contributed 20.1%, nuclear fuel made zero contribution, and coal-fired generation provided 79.2% of total net generation.

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

## 3.5 FUEL PRICE FORECAST ASSUMPTIONS

Forecast prices for each type of fossil fuel analyzed by GRU were generally developed in two parts. Short-term monthly forecasts extending through 1998 were developed in-house by GRU's Fuels Department staff. Long-term fuel price forecasts were developed based upon forecasts of the U.S. Department of Energy's Energy Information Administration (EIA) as published in the Annual Energy Outlook 1997. In essence, the end-point of the GRU short-term forecasts became the starting point for the long-term forecasts, subject to adjustment such that escalation rates within the long term forecasts were consistent with those in EIA forecasts. EIA's real price projections were converted to "nominal" by application of EIA's forecast Implicit Price Deflator. Fossil fuel transportation costs were forecast separately from fuel commodity costs. Forecast fuel commodity costs and transportation costs were aggregated to develop forecast delivered fuel costs. The following documentation describes GRU's fuel price forecasts by fuel type.

### 3.5.1 Oil

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

Based on the above factors, the price of No.2 oil delivered to GRU is expected to increase 4.0% annually while the actual volume of oil used remains small. Based on the above factors, the price of No.6 oil delivered to GRU is expected to increase 3.91% annually while the actual volume of oil used remains small.

### 3.5.2 Coal

Coal is the primary fuel used by GRU to generate electricity. Abundant U.S. supplies of coal will limit the price increases of this fuel to moderate levels. In addition to a forecast for the low sulphur compliance coal presently being burned by GRU, this forecast also includes long-term forecasts for two other types of coal (flue gas desulphurization and fluidized bed compatible coal). Resource planning needs make the additional coal forecasts necessary.

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

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

Based on the above factors, the price for coal delivered to GRU is expected to increase at an average annual rate of 1.74%, 1.60%, and 1.80% for low sulphur compliance, flue gas desulphurization, and fluidized bed compatible coal, respectively.

### 3.5.3 Natural Gas

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

GRU's natural gas is purchased cooperatively by Florida Gas Utility (FGU) of which GRU is a member. The starting point for GRU's gas cost is known as FGU's weighted average cost of gas (WACOG). The sum of the following components make up GRU's delivered cost of natural gas: the WACOG; Florida Gas Transmission's (FGT) fuel charge; FGT's demand or usage charge, per million Btu; the Market Value of Gas Transportation (MVGT, for firm transportation); and, FGU's broker or service charge.

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

Transportation charges were projected by applying EIA's forecast Implicit Price Deflator to the actual 1996 FGT usage charge. These same factors were applied to FGU's broker charge. MVGT costs were adjusted such that they approximated FGT's tariff charges for Firm Transportation Service by the year 2000, the time at which excess transportation capacity is expected to diminish as the pipeline becomes fully subscribed. (The MVGT is believed to be depressed currently because of the amount of excess pipeline capacity available.) After 2000, MVGT costs are expected to escalate at the rate of the Implicit Price Deflator as forecast by EIA.

Based on the above factors, the price of natural gas delivered to GRU is expected to increase at an annual rate of 4.24%.

### 3.5.4 Nuclear Fuel

GRU's nuclear fuel price fc ecast is based on Florida Power Corporation's (FPC) forecast of nuclear fuel prices. The FPC forecast projects the price of nuclear fuel to increase approximately 0.18% per year through the forecast horizon.

**Schedule 2.1**
**History and Forecast of Energy Consumption and Number of Customers by Customer Class**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|
| | RURAL AND RESIDENTIAL | | | | | COMMERCIAL * | | |
| Year | Service Area Population | Persons per Household | GWh | Average Number of Customers | Average kWh per Customer | GWh | Average Number of Customers | Average kWh per Customer |
| 1988 | 122,350 | 2.42 | 534 | 50,558 | 10,565 | 436 | 6,059 | 72,011 |
| 1989 | 125,537 | 2.41 | 562 | 52,090 | 10,782 | 458 | 6,250 | 73,353 |
| 1990 | 129,432 | 2.40 | 594 | 53,930 | 11,023 | 481 | 6,394 | 75,240 |
| 1991 | 131,873 | 2.39 | 602 | 55,177 | 10,906 | 491 | 6,527 | 75,222 |
| 1992 | 135,678 | 2.39 | 610 | 56,769 | 10,739 | 507 | 6,730 | 75,284 |
| 1993 | 141,163 | 2.39 | 637 | 59,064 | 10,778 | 524 | 6,998 | 74,624 |
| 1994 | 145,460 | 2.39 | 649 | 60,862 | 10,670 | 558 | 7,059 | 79,024 |
| 1995 | 148,491 | 2.39 | 704 | 62,130 | 11,329 | 590 | 7,305 | 80,767 |
| 1996 | 151,591 | 2.39 | 718 | 63,427 | 11,313 | 594 | 7,539 | 78,813 |
| 1997 | 155,713 | 2.39 | 705 | 65,152 | 10,817 | 598 | 7,750 | 77,193 |
| 1998 | 158,287 | 2.39 | 740 | 66,229 | 11,166 | 633 | 7,944 | 79,666 |
| 1999 | 161,636 | 2.39 | 755 | 67,630 | 11,157 | 650 | 8,146 | 79,829 |
| 2000 | 164,984 | 2.39 | 772 | 69,031 | 11,181 | 667 | 8,349 | 79,946 |
| 2001 | 168,225 | 2.39 | 790 | 70,387 | 11,217 | 686 | 8,545 | 80,279 |
| 2002 | 171,463 | 2.39 | 806 | 71,742 | 11,241 | 705 | 8,741 | 80,622 |
| 2003 | 174,704 | 2.39 | 823 | 73,098 | 11,252 | 724 | 8,937 | 80,964 |
| 2004 | 177,945 | 2.39 | 838 | 74,454 | 11,254 | 742 | 9,133 | 81,260 |
| 2005 | 181,076 | 2.39 | 853 | 75,764 | 11,257 | 760 | 9,323 | 81,568 |
| 2006 | 184,209 | 2.39 | 869 | 77,075 | 11,269 | 779 | 9,512 | 81,886 |
| 2007 | 187,340 | 2.39 | 884 | 78,385 | 11,282 | 798 | 9,702 | 82,264 |

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

## Schedule 2.2
## History and Forecast of Energy Consumption and Number of Customers by Customer Class

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|
| | INDUSTRIAL ** | | | | | | |
| Year | GWh | Average Number of Customers | Average MWh per Customer | Railroads and Railways GWh | Street and Highway Lighting GWh | Other Sales to Public Authorities GWh | Total Sales to Ultimate Consumers GWh |
| 1988 | 117 | 14 | 8,561 | 0 | 16 | 0 | 1,103 |
| 1989 | 120 | 13 | 9,023 | 0 | 16 | 0 | 1,156 |
| 1990 | 126 | 14 | 9,024 | 0 | 16 | 0 | 1,218 |
| 1991 | 128 | 14 | 9,392 | 0 | 16 | 0 | 1,237 |
| 1992 | 128 | 13 | 9,853 | 0 | 16 | 0 | 1,261 |
| 1993 | 132 | 13 | 10,121 | 0 | 16 | 0 | 1,308 |
| 1994 | 134 | 13 | 10,344 | 0 | 18 | 0 | 1,359 |
| 1995 | 137 | 13 | 10,521 | 0 | 18 | 0 | 1,449 |
| 1996 | 148 | 15 | 9,893 | 0 | 19 | 0 | 1,479 |
| 1997 | 151 | 15 | 10,059 | 0 | 21 | 0 | 1,475 |
| 1998 | 154 | 15 | 10,289 | 0 | 20 | 0 | 1,546 |
| 1999 | 157 | 15 | 10,467 | 0 | 20 | 0 | 1,582 |
| 2000 | 160 | 15 | 10,634 | 0 | 20 | 0 | 1,619 |
| 2001 | 162 | 15 | 10,793 | 0 | 20 | 0 | 1,657 |
| 2002 | 164 | 15 | 10,939 | 0 | 20 | 0 | 1,695 |
| 2003 | 166 | 15 | 11,041 | 0 | 20 | 0 | 1,732 |
| 2004 | 167 | 15 | 11,142 | 0 | 20 | 0 | 1,767 |
| 2005 | 169 | 15 | 11,2[illegible]8 | 0 | 20 | 0 | 1,802 |
| 2006 | 170 | 15 | 11,333 | 0 | 21 | 0 | 1,838 |
| 2007 | 171 | 15 | 11,428 | 0 | 21 | 0 | 1,874 |

** Industrial represents Large Power Rate Class

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

| (1) Year | (2) Sales For Resale GWh | (3) Utility Use and Losses GWh | (4) Net Energy for Load GWh | (5) Other Customers | (6) Total Number of Customers |
|---|---|---|---|---|---|
| 1988 | 67 | 75 | 1,246 | 0 | 56,631 |
| 1989 | 76 | 91 | 1,323 | 0 | 58,353 |
| 1990 | 85 | 60 | 1,363 | 0 | 60,338 |
| 1991 | 90 | 85 | 1,411 | 0 | 61,718 |
| 1992 | 93 | 70 | 1,424 | 0 | 63,512 |
| 1993 | 94 | 100 | 1,502 | 0 | 66,075 |
| 1994 | 91 | 69 | 1,519 | 0 | 67,934 |
| 1995 | 101 | 97 | 1,648 | 0 | 69,448 |
| 1996 | 105 | 75 | 1,659 | 0 | 70,981 |
| 1997 | 104 | 82 | 1,661 | 0 | 72,917 |
| 1998 | 104 | 105 | 1,755 | 0 | 74,188 |
| 1999 | 107 | 108 | 1,796 | 0 | 75,791 |
| 2000 | 109 | 110 | 1,838 | 0 | 77,395 |
| 2001 | 113 | 113 | 1,884 | 0 | 78,947 |
| 2002 | 117 | 116 | 1,928 | 0 | 80,498 |
| 2003 | 121 | 118 | 1,971 | 0 | 82,050 |
| 2004 | 126 | 121 | 2,014 | 0 | 83,602 |
| 2005 | 130 | 123 | 2,055 | 0 | 85,102 |
| 2006 | 134 | 126 | 2,097 | 0 | 86,602 |
| 2007 | 138 | 128 | 2,141 | 0 | 88,102 |

**Schedule 3.1**
**History and Forecast of Summer Peak Demand**
**Base Case**

| (1) Year | (2) Total | (3) Wholesale | (4) Retail | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 1988 | 291 | 16 | 266 | 0 | 0 | 7 | 0 | 2 | 282 |
| 1989 | 307 | 21 | 275 | 0 | 0 | 8 | 0 | 3 | 296 |
| 1990 | 317 | 21 | 284 | 0 | 0 | 8 | 0 | 4 | 305 |
| 1991 | 310 | 21 | 276 | 0 | 0 | 9 | 0 | 4 | 297 |
| 1992 | 334 | 23 | 297 | 0 | 0 | 9 | 0 | 5 | 320 |
| 1993 | 355 | 23 | 316 | 0 | 0 | 10 | 0 | 6 | 339 |
| 1994 | 347 | 21 | 310 | 0 | 0 | 9 | 0 | 7 | 331 |
| 1995 | 377 | 24 | 337 | 0 | 0 | 9 | 0 | 7 | 361 |
| 1996 | 380 | 24 | 341 | 0 | 0 | 8 | 0 | 7 | 365 |
| 1997 | 389 | 24 | 349 | 0 | 0 | 8 | 0 | 8 | 373 |
| 1998 | 400 | 24 | 358 | 0 | 0 | 9 | 0 | 9 | 382 |
| 1999 | 409 | 25 | 366 | 0 | 0 | 9 | 0 | 9 | 391 |
| 2000 | 419 | 25 | 375 | 0 | 0 | 9 | 0 | 10 | 400 |
| 2001 | 428 | 26 | 384 | 0 | 0 | 8 | 0 | 10 | 410 |
| 2002 | 439 | 27 | 393 | 0 | 0 | 9 | 0 | 10 | 420 |
| 2003 | 449 | 28 | 401 | 0 | 0 | 10 | 0 | 10 | 429 |
| 2004 | 459 | 29 | 409 | 0 | 0 | 10 | 0 | 11 | 438 |
| 2005 | 469 | 30 | 417 | 0 | 0 | 11 | 0 | 11 | 447 |
| 2006 | 479 | 31 | 424 | 0 | 0 | 13 | 0 | 11 | 455 |
| 2007 | 489 | 32 | 432 | 0 | 0 | 14 | 0 | 11 | 464 |



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

| (1) Year | (2) Total | (3) Wholesale | (4) Retail | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 1988 | 291 | 16 | 266 | 0 | 0 | 7 | 0 | 2 | 282 |
| 1989 | 307 | 21 | 275 | 0 | 0 | 8 | 0 | 3 | 296 |
| 1990 | 317 | 21 | 284 | 0 | 0 | 8 | 0 | 4 | 305 |
| 1991 | 310 | 21 | 276 | 0 | 0 | 9 | 0 | 4 | 297 |
| 1992 | 334 | 23 | 297 | 0 | 0 | 9 | 0 | 5 | 320 |
| 1993 | 355 | 23 | 316 | 0 | 0 | 10 | 0 | 6 | 339 |
| 1994 | 347 | 21 | 310 | 0 | 0 | 9 | 0 | 7 | 331 |
| 1995 | 377 | 24 | 337 | 0 | 0 | 9 | 0 | 7 | 361 |
| 1996 | 380 | 24 | 341 | 0 | 0 | 8 | 0 | 7 | 365 |
| 1997 | 389 | 24 | 349 | 0 | 0 | 8 | 0 | 8 | 373 |
| 1998 | 408 | 25 | 365 | 0 | 0 | 9 | 0 | 9 | 390 |
| 1999 | 422 | 26 | 378 | 0 | 0 | 9 | 0 | 9 | 404 |
| 2000 | 437 | 27 | 391 | 0 | 0 | 9 | 0 | 10 | 418 |
| 2001 | 451 | 28 | 405 | 0 | 0 | 8 | 0 | 10 | 433 |
| 2002 | 466 | 29 | 418 | 0 | 0 | 9 | 0 | 10 | 447 |
| 2003 | 483 | 31 | 430 | 0 | 0 | 11 | 0 | 11 | 461 |
| 2004 | 498 | 32 | 443 | 0 | 0 | 11 | 0 | 12 | 475 |
| 2005 | 513 | 33 | 456 | 0 | 0 | 12 | 0 | 12 | 489 |
| 2006 | 529 | 35 | 468 | 0 | 0 | 14 | 0 | 12 | 503 |
| 2007 | 544 | 36 | 481 | 0 | 0 | 15 | 0 | 12 | 517 |



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

| (1) Year | (2) Total | (3) Wholesale | (4) Retail | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 1988 | 291 | 16 | 266 | 0 | 0 | 7 | 0 | 2 | 282 |
| 1989 | 307 | 21 | 275 | 0 | 0 | 8 | 0 | 3 | 296 |
| 1990 | 317 | 21 | 284 | 0 | 0 | 8 | 0 | 4 | 305 |
| 1991 | 310 | 21 | 276 | 0 | 0 | 9 | 0 | 4 | 297 |
| 1992 | 334 | 23 | 297 | 0 | 0 | 9 | 0 | 5 | 320 |
| 1993 | 355 | 23 | 316 | 0 | 0 | 10 | 0 | 6 | 339 |
| 1994 | 347 | 21 | 310 | 0 | 0 | 9 | 0 | 7 | 331 |
| 1995 | 377 | 24 | 337 | 0 | 0 | 9 | 0 | 7 | 361 |
| 1996 | 380 | 24 | 341 | 0 | 0 | 8 | 0 | 7 | 365 |
| 1997 | 389 | 24 | 349 | 0 | 0 | 8 | 0 | 8 | 373 |
| 1998 | 392 | 23 | 351 | 0 | 0 | 9 | 0 | 9 | 374 |
| 1999 | 397 | 24 | 355 | 0 | 0 | 9 | 0 | 9 | 379 |
| 2000 | 403 | 24 | 360 | 0 | 0 | 9 | 0 | 10 | 384 |
| 2001 | 408 | 25 | 365 | 0 | 0 | 8 | 0 | 10 | 390 |
| 2002 | 415 | 25 | 371 | 0 | 0 | 9 | 0 | 10 | 396 |
| 2003 | 421 | 26 | 375 | 0 | 0 | 10 | 0 | 10 | 401 |
| 2004 | 424 | 27 | 378 | 0 | 0 | 9 | 0 | 10 | 405 |
| 2005 | 430 | 27 | 383 | 0 | 0 | 10 | 0 | 10 | 410 |
| 2006 | 436 | 28 | 386 | 0 | 0 | 12 | 0 | 10 | 414 |
| 2007 | 441 | 28 | 390 | 0 | 0 | 13 | 0 | 10 | 418 |



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**Schedule 3.2**
**History and Forecast of Winter Peak Demand**
**Base Case**

| (1) Year | (2) Total | (3) Wholesale | (4) Retail | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 1988 | 276 | 19 | 241 | 0 | 0 | 14 | 0 | 2 | 260 |
| 1989 | 280 | 25 | 237 | 0 | 0 | 15 | 0 | 3 | 262 |
| 1990 | 246 | 20 | 205 | 0 | 0 | 17 | 0 | 4 | 225 |
| 1991 | 262 | 22 | 216 | 0 | 0 | 20 | 0 | 4 | 238 |
| 1992 | 306 | 25 | 253 | 0 | 0 | 23 | 0 | 5 | 278 |
| 1993 | 290 | 22 | 237 | 0 | 0 | 25 | 0 | 6 | 259 |
| 1994 | 319 | 23 | 262 | 0 | 0 | 27 | 0 | 7 | 285 |
| 1995 | 350 | 25 | 289 | 0 | 0 | 29 | 0 | 7 | 314 |
| 1996 | 381 | 28 | 317 | 0 | 0 | 29 | 0 | 7 | 345 |
| 1997 | 321 | 26 | 258 | 0 | 0 | 30 | 0 | 7 | 284 |
| 1998 | 355 | 25 | 292 | 0 | 0 | 31 | 0 | 7 | 317 |
| 1999 | 363 | 25 | 300 | 0 | 0 | 31 | 0 | 7 | 325 |
| 2000 | 371 | 26 | 309 | 0 | 0 | 29 | 0 | 7 | 335 |
| 2001 | 380 | 27 | 318 | 0 | 0 | 28 | 0 | 7 | 345 |
| 2002 | 389 | 28 | 327 | 0 | 0 | 28 | 0 | 6 | 355 |
| 2003 | 397 | 29 | 335 | 0 | 0 | 27 | 0 | 6 | 364 |
| 2004 | 405 | 30 | 343 | 0 | 0 | 27 | 0 | 5 | 373 |
| 2005 | 413 | 31 | 351 | 0 | 0 | 26 | 0 | 5 | 382 |
| 2006 | 421 | 32 | 360 | 0 | 0 | 25 | 0 | 4 | 392 |
| 2007 | 430 | 33 | 369 | 0 | 0 | 25 | 0 | 3 | 402 |

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

| (1) Year | (2) Total | (3) Wholesale | (4) Retail | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 1988 | 278 | 19 | 241 | 0 | 0 | 14 | 0 | 2 | 260 |
| 1989 | 280 | 25 | 237 | 0 | 0 | 15 | 0 | 3 | 262 |
| 1990 | 246 | 20 | 205 | 0 | 0 | 17 | 0 | 4 | 225 |
| 1991 | 262 | 22 | 216 | 0 | 0 | 20 | 0 | 4 | 238 |
| 1992 | 306 | 25 | 253 | 0 | 0 | 23 | 0 | 5 | 278 |
| 1993 | 290 | 22 | 237 | 0 | 0 | 25 | 0 | 6 | 259 |
| 1994 | 319 | 23 | 262 | 0 | 0 | 27 | 0 | 7 | 285 |
| 1995 | 350 | 25 | 289 | 0 | 0 | 29 | 0 | 7 | 314 |
| 1996 | 381 | 28 | 317 | 0 | 0 | 29 | 0 | 7 | 345 |
| 1997 | 321 | 26 | 258 | 0 | 0 | 30 | 0 | 7 | 284 |
| 1998 | 363 | 25 | 300 | 0 | 0 | 31 | 0 | 7 | 325 |
| 1999 | 375 | 26 | 310 | 0 | 0 | 32 | 0 | 7 | 336 |
| 2000 | 387 | 27 | 323 | 0 | 0 | 30 | 0 | 7 | 350 |
| 2001 | 400 | 29 | 335 | 0 | 0 | 29 | 0 | 7 | 364 |
| 2002 | 413 | 30 | 348 | 0 | 0 | 29 | 0 | 6 | 378 |
| 2003 | 425 | 31 | 360 | 0 | 0 | 28 | 0 | 6 | 391 |
| 2004 | 438 | 33 | 371 | 0 | 0 | 29 | 0 | 5 | 404 |
| 2005 | 451 | 34 | 384 | 0 | 0 | 28 | 0 | 5 | 418 |
| 2006 | 464 | 36 | 397 | 0 | 0 | 27 | 0 | 4 | 433 |
| 2007 | 477 | 37 | 410 | 0 | 0 | 27 | 0 | 3 | 447 |

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

| (1) Year | (2) Total | (3) Wholesale | (4) Retail | (5) Interruptible | (6) Residential Load Management | (7) Residential Conservation | (8) Comm./Ind. Load Management | (9) Comm./Ind. Conservation | (10) Net Firm Demand |
|---|---|---|---|---|---|---|---|---|---|
| 1988 | 276 | 19 | 241 | 0 | 0 | 14 | 0 | 2 | 260 |
| 1989 | 280 | 25 | 237 | 0 | 0 | 15 | 0 | 3 | 262 |
| 1990 | 246 | 20 | 205 | 0 | 0 | 17 | 0 | 4 | 225 |
| 1991 | 262 | 22 | 216 | 0 | 0 | 20 | 0 | 4 | 238 |
| 1992 | 306 | 25 | 253 | 0 | 0 | 23 | 0 | 5 | 278 |
| 1993 | 290 | 22 | 237 | 0 | 0 | 25 | 0 | 6 | 259 |
| 1994 | 319 | 23 | 262 | 0 | 0 | 27 | 0 | 7 | 285 |
| 1995 | 350 | 25 | 289 | 0 | 0 | 29 | 0 | 7 | 314 |
| 1996 | 381 | 28 | 317 | 0 | 0 | 29 | 0 | 7 | 345 |
| 1997 | 321 | 26 | 258 | 0 | 0 | 30 | 0 | 7 | 284 |
| 1998 | 349 | 24 | 287 | 0 | 0 | 31 | 0 | 7 | 311 |
| 1999 | 352 | 24 | 291 | 0 | 0 | 30 | 0 | 7 | 315 |
| 2000 | 356 | 25 | 296 | 0 | 0 | 28 | 0 | 7 | 321 |
| 2001 | 362 | 25 | 303 | 0 | 0 | 27 | 0 | 7 | 328 |
| 2002 | 367 | 26 | 308 | 0 | 0 | 27 | 0 | 6 | 334 |
| 2003 | 372 | 27 | 313 | 0 | 0 | 26 | 0 | 6 | 340 |
| 2004 | 376 | 27 | 318 | 0 | 0 | 26 | 0 | 5 | 345 |
| 2005 | 381 | 28 | 323 | 0 | 0 | 25 | 0 | 5 | 351 |
| 2006 | 384 | 28 | 329 | 0 | 0 | 23 | 0 | 4 | 357 |
| 2007 | 389 | 29 | 334 | 0 | 0 | 23 | 0 | 3 | 363 |

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

| (1) Year | (2) Total | (3) Residential Conservation | (4) Comm./Ind. Conservation | (5) Retail | (6) Wholesale | (7) Utility Use & Losses | (8) Net Energy for Load | (9) Load Factor % |
|---|---|---|---|---|---|---|---|---|
| 1987 | 1182 | 26 | 5 | 1043 | 40 | 68 | 1151 | 48.66% |
| 1988 | 1281 | 28 | 7 | 1104 | 67 | 75 | 1246 | 50.44% |
| 1989 | 1362 | 31 | 8 | 1156 | 76 | 91 | 1323 | 51.02% |
| 1990 | 1407 | 34 | 10 | 1217 | 85 | 61 | 1363 | 51.01% |
| 1991 | 1460 | 37 | 12 | 1236 | 90 | 85 | 1411 | 54.23% |
| 1992 | 1479 | 41 | 14 | 1261 | 93 | 70 | 1424 | 50.80% |
| 1993 | 1563 | 44 | 17 | 1308 | 94 | 100 | 1502 | 50.58% |
| 1994 | 1581 | 44 | 18 | 1359 | 91 | 69 | 1519 | 52.39% |
| 1995 | 1711 | 43 | 20 | 1449 | 101 | 98 | 1648 | 52.11% |
| 1996 | 1722 | 42 | 21 | 1479 | 105 | 75 | 1659 | 51.89% |
| 1997 | 1728 | 45 | 22 | 1475 | 104 | 82 | 1661 | 50.83% |
| 1998 | 1826 | 48 | 23 | 1546 | 104 | 105 | 1755 | 52.45% |
| 1999 | 1871 | 51 | 24 | 1581 | 107 | 108 | 1796 | 52.44% |
| 2000 | 1915 | 52 | 25 | 1619 | 109 | 110 | 1838 | 52.45% |
| 2001 | 1964 | 54 | 26 | 1658 | 113 | 113 | 1884 | 52.46% |
| 2002 | 2010 | 56 | 26 | 1696 | 117 | 115 | 1928 | 52.40% |
| 2003 | 2056 | 59 | 26 | 1732 | 121 | 118 | 1971 | 52.45% |
| 2004 | 2103 | 63 | 26 | 1767 | 126 | 121 | 2014 | 52.49% |
| 2005 | 2148 | 67 | 26 | 1802 | 130 | 123 | 2055 | 52.48% |
| 2006 | 2193 | 70 | 26 | 1838 | 134 | 125 | 2097 | 52.61% |
| 2007 | 2239 | 73 | 25 | 1874 | 138 | 129 | 2141 | 52.67% |

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

| (1) Year | (2) Total | (3) Residential Conservation | (4) Comm./Ind. Conservation | (5) Retail | (6) Wholesale | (7) Utility Use & Losses | (8) Net Energy for Load | (9) Load Factor % |
|---|---|---|---|---|---|---|---|---|
| 1988 | 1281 | 28 | 7 | 1104 | 67 | 75 | 1246 | 50.44% |
| 1989 | 1362 | 31 | 8 | 1156 | 76 | 91 | 1323 | 51.02% |
| 1990 | 1407 | 34 | 10 | 1217 | 85 | 61 | 1363 | 51.01% |
| 1991 | 1460 | 37 | 12 | 1236 | 90 | 85 | 1411 | 54.23% |
| 1992 | 1479 | 41 | 14 | 1261 | 93 | 70 | 1424 | 50.80% |
| 1993 | 1563 | 44 | 17 | 1308 | 94 | 100 | 1502 | 50.58% |
| 1994 | 1581 | 44 | 18 | 1359 | 91 | 69 | 1519 | 52.39% |
| 1995 | 1711 | 43 | 20 | 1449 | 101 | 98 | 1648 | 52.11% |
| 1996 | 1722 | 42 | 21 | 1479 | 105 | 75 | 1659 | 51.89% |
| 1997 | 1728 | 45 | 22 | 1475 | 104 | 82 | 1661 | 50.83% |
| 1998 | 1868 | 49 | 23 | 1582 | 106 | 108 | 1796 | 52.57% |
| 1999 | 1934 | 52 | 25 | 1635 | 111 | 111 | 1857 | 52.47% |
| 2000 | 2000 | 54 | 26 | 1690 | 115 | 115 | 1920 | 52.43% |
| 2001 | 2071 | 56 | 27 | 1748 | 121 | 119 | 1988 | 52.41% |
| 2002 | 2140 | 58 | 27 | 1805 | 127 | 123 | 2055 | 52.48% |
| 2003 | 2209 | 62 | 27 | 1861 | 132 | 127 | 2120 | 52.50% |
| 2004 | 2280 | 67 | 28 | 1916 | 138 | 131 | 2185 | 52.51% |
| 2005 | 2349 | 71 | 28 | 1971 | 144 | 135 | 2250 | 52.53% |
| 2006 | 2419 | 75 | 28 | 2027 | 150 | 139 | 2316 | 52.56% |
| 2007 | 2489 | 79 | 27 | 2084 | 156 | 143 | 2383 | 52.62% |

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

| (1) Year | (2) Total | (3) Residential Conservation | (4) Comm./Ind. Conservation | (5) Retail | (6) Wholesale | (7) Utility Use & Losses | (8) Net Energy for Load | (9) Load Factor % |
|---|---|---|---|---|---|---|---|---|
| 1988 | 1281 | 28 | 7 | 1104 | 67 | 75 | 1246 | 50.44% |
| 1989 | 1362 | 31 | 8 | 1156 | 76 | 91 | 1323 | 51.02% |
| 1990 | 1407 | 34 | 10 | 1217 | 85 | 61 | 1363 | 51.01% |
| 1991 | 1460 | 37 | 12 | 1236 | 90 | 85 | 1411 | 54.23% |
| 1992 | 1479 | 41 | 14 | 1261 | 93 | 70 | 1424 | 50.80% |
| 1993 | 1563 | 44 | 17 | 1308 | 94 | 100 | 1502 | 50.58% |
| 1994 | 1581 | 44 | 18 | 1359 | 91 | 69 | 1519 | 52.39% |
| 1995 | 1711 | 43 | 20 | 1449 | 101 | 98 | 1648 | 52.11% |
| 1996 | 1722 | 42 | 21 | 1479 | 105 | 75 | 1659 | 51.89% |
| 1997 | 1728 | 45 | 22 | 1475 | 104 | 82 | 1661 | 50.83% |
| 1998 | 1789 | 47 | 23 | 1515 | 101 | 103 | 1719 | 52.47% |
| 1999 | 1816 | 50 | 24 | 1535 | 103 | 104 | 1742 | 52.47% |
| 2000 | 1840 | 51 | 24 | 1555 | 104 | 106 | 1765 | 52.47% |
| 2001 | 1869 | 52 | 25 | 1578 | 107 | 107 | 1792 | 52.45% |
| 2002 | 1896 | 54 | 25 | 1599 | 109 | 109 | 1817 | 52.38% |
| 2003 | 1922 | 56 | 25 | 1619 | 112 | 110 | 1841 | 52.41% |
| 2004 | 1948 | 60 | 25 | 1637 | 115 | 111 | 1863 | 52.51% |
| 2005 | 1973 | 63 | 25 | 1655 | 117 | 113 | 1885 | 52.48% |
| 2006 | 1997 | 66 | 24 | 1673 | 120 | 114 | 1907 | 52.58% |
| 2007 | 2020 | 68 | 23 | 1692 | 122 | 115 | 1929 | 52.68% |



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## Schedule 4

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

| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| | ACTUAL | | FORECAST | | | |
| | 1997 | | 1998 | | 1999 | |
| Month | Peak Demand (MW) | NEL (GWh) | Peak Demand (MW) | NEL (GWh) | Peak Demand (MW) | NEL (GWh) |
| JAN | 284 | 127 | 317 | 138 | 325 | 141 |
| FEB | 239 | 107 | 317 | 119 | 325 | 122 |
| MAR | 259 | 123 | 265 | 124 | 271 | 127 |
| APR | 252 | 117 | 276 | 123 | 283 | 126 |
| MAY | 307 | 139 | 326 | 148 | 333 | 151 |
| JUN | 341 | 149 | 370 | 166 | 379 | 170 |
| JUL | 366 | 173 | 381 | 180 | 390 | 185 |
| AUG | 373 | 177 | 382 | 184 | 391 | 188 |
| SEP | 353 | 169 | 362 | 168 | 371 | 172 |
| OCT | 305 | 136 | 315 | 142 | 323 | 146 |
| NOV | 234 | 115 | 275 | 126 | 281 | 129 |
| DEC | 282 | 130 | 299 | 136 | 306 | 139 |

Schedule 5
Fuel Requirements

| (1) | (2) Fuel Type | (3) | (4) Units | (5) Actual 1996 | (6) Actual 1997 | (7) 1998 | (8) 1999 | (9) 2000 | (10) 2001 | (11) 2002 | (12) 2003 | (13) 2004 | (14) 2005 | (15) 2006 | (16) 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | NUCLEAR | | Btu x 10^12 | 0.4 | 0.0 | 0.7 | 0.9 | 0.7 | 0.9 | 0.7 | 0.9 | 0.7 | 0.9 | 0.7 | 0.9 |
| (2) | COAL | Total | 1000 Tons | 555 | 584 | 545 | 550 | 552 | 556 | 567 | 562 | 577 | 580 | 586 | 590 |
| (3) | RESIDUAL (1) | Total | 1000 bbl | 28 | 24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (4) | | Steam | 1000 bbl | 28 | 24 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (5) | | CC (2) | 1000 bbl | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (6) | | CT (3) | 1000 bbl | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (7) | | Diesel | 1000 bbl | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (8) | DISTILLATE (4) | Total | 1000 bbl | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (9) | | Steam | 1000 bbl | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (10) | | CC (2) | 1000 bbl | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (11) | | CT (3) | 1000 bbl | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (12) | | Diesel | 1000 bbl | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (13) | NATURAL GAS | Total | cf x 10^6 | 4,286 | 4,268 | 3,777 | 3,869 | 3,528 | 3,632 | 3,812 | 4,140 | 4,005 | 4,125 | 5,545 | 5,838 |
| (14) | | Steam | cf x 10^6 | 3,782 | 3,552 | 2,546 | 2,563 | 2,407 | 2,523 | 2,626 | 2,868 | 2,735 | 2,827 | 3,624 | 3,715 |
| (15) | | CC (2) | cf x 10^6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (16) | | CT (3) | cf x 10^6 | 504 | 716 | 1,231 | 1,306 | 1,121 | 1,109 | 1,186 | 1,272 | 1,271 | 1,298 | 1,921 | 2,123 |
| (17) | Other (Specify) | | Btu x 10^12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

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

Schedule 6.1
Energy Sources

| (1) | (2) CAPABILITY/FUEL TYPE | (3) | (4) | (5) Actual 1996 | (6) Actual 1997 | (7) 1998 | (8) 1999 | (9) 2000 | (10) 2001 | (11) 2002 | (12) 2003 | (13) 2004 | (14) 2005 | (15) 2006 | (16) 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Annual Firm Interchange | (1)(2) | GWh | (125) | (171) | (153) | (103) | (21) | (21) | (21) | (21) | 0 | 0 | 0 | 0 |
| (2) | NUCLEAR | | GWh | 29 | 0 | 71 | 82 | 71 | 82 | 71 | 82 | 71 | 82 | 71 | 82 |
| | Coal | | GWh | 1,354 | 1,413 | 1,433 | 1,446 | 1,450 | 1,464 | 1,494 | 1,485 | 1,524 | 1,533 | 1,552 | 1,561 |
| (3) | Residual | Total | GWh | 16 | 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (4) | | Steam | GWh | 16 | 13 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (5) | | CC | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (6) | | CT | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (7) | | Diesel | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (8) | Distillate | Total | GWh | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (9) | | Steam | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (10) | | CC | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (11) | | CT | GWh | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (12) | | Diesel | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (13) | Natural Gas | Total | GWh | 351 | 358 | 325 | 332 | 302 | 311 | 326 | 354 | 342 | 351 | 475 | 498 |
| (14) | | Steam | GWh | 315 | 303 | 231 | 233 | 219 | 230 | 240 | 264 | 251 | 260 | 333 | 341 |
| (15) | | CC | GWh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (16) | | CT | GWh | 36 | 55 | 94 | 98 | 83 | 81 | 86 | 90 | 90 | 91 | 142 | 156 |
| (17) | Non-Firm Interchange | | GWh | 33 | 48 | 79 | 39 | 36 | 48 | 58 | 71 | 78 | 89 | 0 | 0 |
| (18) | Net Energy for Load | | | 1,659 | 1,661 | 1,755 | 1,796 | 1,838 | 1,884 | 1,928 | 1,971 | 2,014 | 2,055 | 2,097 | 2,141 |

Notes:

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



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Schedule 6.2
Energy Sources

| (1) | (2) CAPABILITY/FUEL TYPE | (3) | (4) | (5) Actual 1996 | (6) Actual 1997 | (7) 1998 | (8) 1999 | (9) 2000 | (10) 2001 | (11) 2002 | (12) 2003 | (13) 2004 | (14) 2005 | (15) 2006 | (16) 2007 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (1) | Annual Firm Interchange | (1)(2) | GWh | -7.5% | -10.3% | -8.7% | -5.7% | -1.1% | -1.1% | -1.1% | -1.1% | 0.0% | 0.0% | 0.0% | 0.0% |
| (2) | NUCLEAR | | GWh | 1.7% | 0.0% | 4.0% | 4.5% | 3.6% | 4.3% | 3.7% | 4.1% | 3.5% | 4.0% | 3.4% | 3.8% |
| | Coal | | GWh | 81.6% | 85.1% | 81.7% | 80.5% | 78.9% | 77.7% | 77.5% | 75.3% | 75.7% | 74.6% | 74.0% | 72.9% |
| (3) | Residual | Total | GWh | 1.0% | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (4) | | Steam | GWh | 1.0% | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (5) | | CC | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (6) | | CT | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (7) | | Diesel | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (8) | Distillate | Total | GWh | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (9) | | Steam | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (10) | | CC | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (11) | | CT | GWh | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (12) | | Diesel | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (13) | Natural Gas | Total | GWh | 21.2% | 21.6% | 18.5% | 18.5% | 16.4% | 16.5% | 16.9% | 18.0% | 17.0% | 17.1% | 22.6% | 23.3% |
| (14) | | Steam | GWh | 19.0% | 18.2% | 13.2% | 13.0% | 11.9% | 12.2% | 12.5% | 13.4% | 12.5% | 12.7% | 15.9% | 15.9% |
| (15) | | CC | GWh | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| (16) | | CT | GWh | 2.2% | 3.3% | 5.3% | 5.5% | 4.5% | 4.3% | 4.4% | 4.6% | 4.5% | 4.4% | 6.8% | 7.3% |
| (17) | Non-Firm Interchange | | GWh | 2.0% | 2.9% | 4.5% | 2.2% | 1.9% | 2.5% | 3.0% | 3.6% | 3.9% | 4.3% | 0.0% | 0.0% |
| (18) | Net Energy for Load | | | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

Notes:

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

# 4. FORECAST OF FACILITIES REQUIREMENTS

## 4.1 GENERATION RETIREMENTS AND ADDITIONS

### 4.1.1 Least-Cost Planning Selection

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

GRU is engaged in an integrated least-cost planning study for the purpose of determining the best plan for serving our customers well into the next century. This process is expected to take several months and will involve: several RFPs to discover unknown options from other Utilities and Power Marketers; multiple sensitivities using combinations of high/base/low/constant differential fuel price forecasts and high/base/low load and energy forecasts; combinations of investors/purchase/partnership/sole ownership of new generating facilities, reconfiguring/repowering existing facilities; and, as well as, continuing to evaluate and refine, as necessary, existing conservation and load control options. The modeling tools used for the least-cost planning will be the EGEAS model described in Chapter 3 and EXPAN which uses analytical, probabilistic, and graphical tools and provides enhanced expansion plan analysis. GRU will use the criteria of 15% operating reserve margin as set by the Public Service Commission in Docket No. 960214-EU August 20, 1996. The optimization is based on lowest NPV of revenue requirements, considering both the NPV of the optimization time frame and a thirty year end-effects period. Although the study in not complete at this time the preliminary results of the base case analysis indicate the reserve margin of 15% is being met, therefore, no capacity additions are included. At this time, Schedules 9 & 10 are not applicable and have not been included.

Based upon the load and energy forecasts included with this document GRU has identified a possible need for capacity options as early as 2005 for the high band forecast. Schedules 8 L/B/H provide a listing of proposed generic changes to the System's generation facilities.

Prior to deciding to construct Deerhaven CT3, a request was issued by Utility Purchasing on March 23, 1995 for Non-Binding Power Supply Proposals. The RFP was sent out to validate prior studies which concluded that the addition of a third combustion turbine generating unit at our Deerhaven Station was the most cost-effective option for serving our customers future energy needs. The ten proposals received were evaluated based on predetermined evaluation criteria. The findings of that RFP process were that the best option for The System was to proceed with the installation of a gas-fired General Electric 7EA Combustion Turbine. However, the highest ranked offer, which was tended by LG&E POWER MARKETING INC. ("LPM"), a California corporation, was potentially advantageous in a long-term analysis, even though for the short-term, LPM's offer was not beneficial. Negotiations continued with LPM to try to find common ground where both the System and LPM could benefit from a power purchase contract. As of November, 1995 staff was able to negotiate a mutually beneficial agreement. Under the terms of the power purchase agreement, the System would be able to import financially firm peaking power from LPM at very attractive prices.

### 4.1.2 Green Pricing

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

The Gainesville City Commission has authorized GRU to proceed with offering a new PV program, pending approval/receipt of Grant funds from UPVG. This green-pricing program will allow customers an opportunity to have a grid-connected photovoltaic system installed on their rooftop and is planned for this year.

### 4.1.3 PV-10 Photovoltaic Project

The 10 kW Photovoltaic System at the Electric System Dispatch Center went on line December 31, 1996 and was dedicated on January 11, 1997, to the Citizens who donated to the project. Figure 4.1 is an aerial photo of the completed PV-10 project. On June 24, 1997 a lightning strike close to the Electric System Dispatch Center destroyed several of the thyristors and a couple of the control circuits in the UPS to which the PV system was interfaced. Due to the sensitive nature of the equipment powered by the UPS the PV system was not reconnected to the repaired UPS. The original intent to interface a PV system with an existing UPS was shown to work for six months.

The 10 kW Photovoltaic System will be placed back on line through three new inverters connected to the building's three phase bus. This reconfiguration has been designed and will be accomplished by the end of April, 1998.

## 4.2 RESERVE MARGIN AND SCHEDULED MAINTENANCE

Available generating capacities are compared with System summer peak demands in Schedule 7.1 and System winter peak demands in Schedule 7.2 Lower unit operating efficiencies and higher peak demands in summer result in lower reserve margins during the summer season than in winter. A minimum reserve margin of 25% of peak demand is expected in 1998 and decreases to 19% in 2007.

FIGURE 4.1 AERIAL PHOTO OF THE COMPLETED PV-10 PROJECT AT THE ELECTRIC SYSTEM CONTROL CENTER.

**Schedule 7.1**
**Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Installed Capacity | Firm Capacity Import | Firm Capacity Export | QF | Total Capacity Available | System Firm Summer Peak Demand | Reserve Margin before Maintenance | | Scheduled Maintenance | Reserve Margin after Maintenance | |
| Year | MW | MW | MW | MW | MW | MW | MW | % of Peak | MW | MW | % of Peak |
| 1998 | 550 | 0 | 73 | 0 | 477 | 382 | 95 | 25% | 0 | 95 | 25% |
| 1999 | 550 | 0 | 60 | 0 | 490 | 391 | 99 | 25% | 0 | 99 | 25% |
| 2000 | 550 | 0 | 3 | 0 | 547 | 400 | 147 | 37% | 0 | 147 | 37% |
| 2001 | 550 | 0 | 3 | 0 | 547 | 410 | 137 | 33% | 0 | 137 | 33% |
| 2002 | 550 | 0 | 3 | 0 | 547 | 420 | 127 | 30% | 0 | 127 | 30% |
| 2003 | 550 | 0 | 3 | 0 | 547 | 429 | 118 | 28% | 0 | 118 | 28% |
| 2004 | 550 | 0 | 0 | 0 | 550 | 438 | 112 | 26% | 0 | 112 | 26% |
| 2005 | 550 | 0 | 0 | 0 | 550 | 447 | 103 | 23% | 0 | 103 | 23% |
| 2006 | 550 | 0 | 0 | 0 | 550 | 455 | 95 | 21% | 0 | 95 | 21% |
| 2007 | 550 | 0 | 0 | 0 | 550 | 464 | 86 | 19% | 0 | 86 | 19% |

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

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total Installed Capacity | Firm Capacity Import | Firm Capacity Export | QF | Total Capacity Available | System Firm Winter Peak Demand | Reserve Margin before Maintenance | | Scheduled Maintenance | Reserve Margin after Maintenance | |
| Year | MW | MW | MW | MW | MW | MW | MW | % of Peak | MW | MW | % of Peak |
| 1997 /98 | 563 | 0 | 23 | 0 | 540 | 317 | 223 | 70% | 0 | 223 | 70% |
| 1998 /99 | 563 | 0 | 13 | 0 | 550 | 325 | 225 | 69% | 0 | 225 | 69% |
| 1999 /00 | 563 | 0 | 3 | 0 | 560 | 335 | 225 | 67% | 0 | 225 | 67% |
| 2000 /01 | 563 | 0 | 3 | 0 | 560 | 345 | 215 | 62% | 0 | 215 | 62% |
| 2001 /02 | 563 | 0 | 3 | 0 | 560 | 355 | 205 | 58% | 0 | 205 | 58% |
| 2002 /03 | 563 | 0 | 3 | 0 | 560 | 364 | 196 | 54% | 0 | 196 | 54% |
| 2003 /04 | 563 | 0 | 0 | 0 | 563 | 373 | 190 | 51% | 0 | 190 | 51% |
| 2004 /05 | 563 | 0 | 0 | 0 | 563 | 382 | 181 | 47% | 0 | 181 | 47% |
| 2005 /06 | 563 | 0 | 0 | 0 | 563 | 392 | 171 | 44% | 0 | 171 | 44% |
| 2006 /07 | 563 | 0 | 0 | 0 | 563 | 402 | 161 | 40% | 0 | 161 | 40% |



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Schedule 8B

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
Base Demand & Energy Case

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fuel | | Fuel Transport | | Const. | Commercial | Expected | Gen. Max. | Net Capability | | |
| Plant Name | Unit No. | Location | Unit Type | Pri. | Alt. | Pri. | Alt. | Start Mo/Yr | In-Service Mo/Yr | Retirement Mo/Yr | Nameplate kW | Summer MW | Winter MW | Status |

No planned or prospective facilities.



**Unit Type**
GT = Gas Turbine
NP = Nuclear Pow...
ST = Steam

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

**Transportation Method**
PL = Pipe Line
TK = Truck

**Status**
P = Planned, but not authorized by utility.

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Schedule 8H

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
High Demand & Energy Case

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Fuel | | Fuel Transport | | | | | | Net Capability | | |
| Plant Name | Unit No. | Location | Unit Type | Pri. | Alt. | Pri. | Alt. | Const. Start Mo/Yr | Commercial In-Service Mo/Yr | Expected Retirement Mo/Yr | Gen. Max. Nameplate kW | Summer MW | Winter MW | Status |
| Prospective | X | Unknown | CC | Unk | Unk | Unk | Unk | Unk | 1/2005 | Unk | 110,000 | 110 | 110 | P |

**Unit Type**
GT = Gas Turbine
NP = Nuclear Power
ST = Steam
CC = Combined Cycle

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

**Transportation Method**
PL = Pipe Line
TK = Truck

**Status**
P = Planned, but not authorized by utility.



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Schedule 8L

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES
Low Demand & Energy Case

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Const. | Commercial | Expected | Gen. Max. | Net Capability | | |
| | Unit | | Unit | Fuel | | Fuel Transport | | Start | In-Service | Retirement | Nameplate | Summer | Winter | |
| Plant Name | No. | Location | Type | Pri. | Alt. | Pri. | Alt. | Mo/Yr | Mo/Yr | Mo/Yr | kW | MW | MW | Status |

No planned or prospective facilities.

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

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

Transportation Method
PL = Pipe Line
TK = Truck

Status
P = Planned, but not authorized by utility.

# 5. SITE DESCRIPTION AND IMPACT ANALYSIS

## 5.1 DISCLOSURE OF POTENTIAL SITES

There are no new facilities planned for the next ten years.

## 5.2 SPECIFICATION OF PROPOSED TRANSMISSION LINES

There are no new facilities planned for the next ten years.

# 6. ENVIRONMENTAL CONSIDERATIONS FOR PROPOSED FACILITY SITTINGS

## 6.1 AIR RESOURCES

There are no new facilities planned for the next ten years.

## 6.2 WATER RESOURCES

There are no new facilities planned for the next ten years.

## 6.3 NOISE

There are no new facilities planned for the next ten years.

## 6.4 WASTE

There are no new facilities planned for the next ten years.

## 6.5 FUEL DELIVERY AND STORAGE

There are no new facilities planned for the next ten years.

## 6.6 ECOLOGICAL RESOURCES

There are no new facilities planned for the next ten years.

## 6.7 CULTURAL RESOURCES

There are no new facilities planned for the next ten years.