City of Tallahassee
Your Own Utilities

RECEIVED-FPSC
08 APR -4 AM 11:06
COMMISSION
CLERK

April 4, 2008

Ms. Ann Cole, Director
Division of the Commission Clerk
And Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

080000

Dear Ms. Cole:

Attached are twenty-five (25) copies of the City of Tallahassee's 2008 Ten Year Site Plan. If you have any questions, please e-mail me at childsv@talgov.com or call me at 891-3122.

Sincerely,

Venus Childs

Venus Childs
Planning Engineer

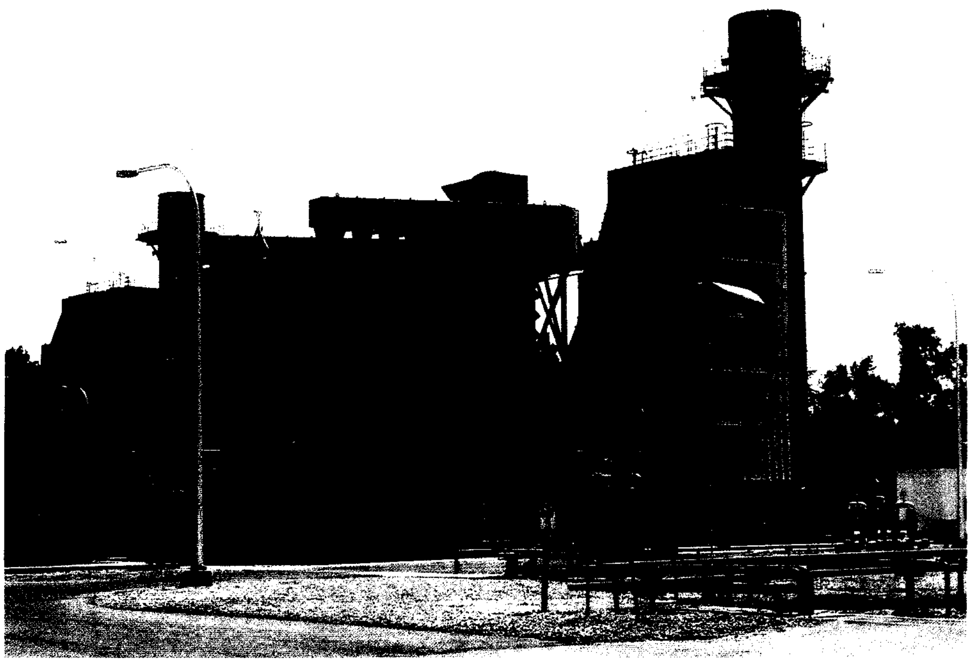
Attachments
cc: KGW
GSB

CMP ____
COM ____
CTR ____
ECR ____
GCL 1
OPC ____
RCA ____
SCR ____
SGA ____
SEC ____
~~OTH~~ CLK 2

DOCUMENT NUMBER-DATE
02620 APR-4 8
FPSC-COMMISSION CLERK

Ten Year Site Plan
2008-2017

City of Tallahassee
Electric Utility



Report Prepared By:
City of Tallahassee Electric Utility
System Planning

City of Tallahassee
Your Own Utilities℠

CITY OF TALLAHASSEE
TEN YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES
2008-2017
TABLE OF CONTENTS

I. Description of Existing Facilities

1.0	Introduction	1
1.1	System Capability	1
1.2	Purchased Power Agreements	2
Figure A	Service Territory Map	3
Table 1.1	FPSC Schedule 1 Existing Generating Facilities	4

II. Forecast of Energy/Demand Requirements and Fuel Utilization

2.0	Introduction	5
2.1	System Demand and Energy Requirements	5
2.1.1	System Load and Energy Forecasts	5
2.1.2	Load Forecast Uncertainty & Sensitivities	7
2.1.3	Energy Efficiency and Demand Side Management Programs	9
2.2	Energy Sources and Fuel Requirements	10
Table 2.1	FPSC Schedule 2.1 History/Forecast of Energy Consumption (Residential and Commercial Classes)	11
Table 2.2	FPSC Schedule 2.2 History/Forecast of Energy Consumption (Industrial and Street Light Classes)	12
Table 2.3	FPSC Schedule 2.3 History/Forecast of Energy Consumption (Utility Use and Net Energy for Load)	13
Figure B1	Energy Consumption by Customer Class (1998-2017)	14
Figure B2	Energy Consumption: Comparison by Customer Class (2008 and 2017)	15
Table 2.4	FPSC Schedule 3.1.1 History/Forecast of Summer Peak Demand – Base Forecast	16
Table 2.5	FPSC Schedule 3.1.2 History/Forecast of Summer Peak Demand – High Forecast	17
Table 2.6	FPSC Schedule 3.1.3 History/Forecast of Summer Peak Demand – Low Forecast	18
Table 2.7	FPSC Schedule 3.2.1 History/Forecast of Winter Peak Demand – Base Forecast	19
Table 2.8	FPSC Schedule 3.2.2 History/Forecast of Winter Peak Demand – High Forecast	20
Table 2.9	FPSC Schedule 3.2.3 History/Forecast of Winter Peak Demand – Low Forecast	21
Table 2.10	FPSC Schedule 3.3.1 History/Forecast of Annual Net Energy for Load – Base Forecast	22
Table 2.11	FPSC Schedule 3.3.2 History/Forecast of Annual Net Energy for Load – High Forecast	23
Table 2.12	FPSC Schedule 3.3.3 History/Forecast of Annual Net Energy for Load – Low Forecast	24
Table 2.13	FPSC Schedule 4 Previous Year Actual and Two Year Forecast Demand/Energy by Month	25
Table 2.14	Load Forecast: Key Explanatory Variables	26
Table 2.15	Load Forecast: Sources of Forecast Model Input Information	27
Figure B3	Banded Summer Peak Load Forecast vs. Supply Resources	28
Table 2.16	Projected DSM Energy Reductions	29
Table 2.17	Projected DSM Seasonal Demand Reductions	30
Table 2.18	FPSC Schedule 5.0 Fuel Requirements	31
Table 2.19	FPSC Schedule 6.1 Energy Sources (GWh)	32
Table 2.20	FPSC Schedule 6.2 Energy Sources (%)	33
Figure B4	Generation by Fuel Type (2008 and 2017)	34

III. Projected Facility Requirements

3.1	Planning Process	35
3.2	Projected Resource Requirements	35
3.2.1	Transmission Limitations	35
3.2.2	Reserve Requirements	36
3.2.3	Near Term Resource Additions	36
3.2.4	Power Supply Diversity	37
3.2.5	Renewable Resources	38
3.2.6	Future Power Supply Resources	39
Figure C	System Peak Demands and Summer Reserve Margins	41
Table 3.1	FPSC Schedule 7.1 Forecast of Capacity, Demand and Scheduled Maintenance at Time of Summer Peak	42
Table 3.2	FPSC Schedule 7.2 Forecast of Capacity, Demand and Scheduled Maintenance at Time of Winter Peak	43
Table 3.3	FPSC Schedule 8 Planned and Prospective Generating Facility Additions and Changes	44
Table 3.4	Generation Expansion Plan	45

IV. Proposed Plant Sites and Transmission Lines

4.1	Proposed Plant Site	46
4.2	Transmission Line Additions/Upgrades	46
Table 4.1	FPSC Schedule 9 Status Report and Specifications of Proposed Generating Facilities – Hopkins 2A Combustion Turbine	49
Table 4.2	FPSC Schedule 9 Status Report and Specifications of Proposed Generating Facilities – Unsited A	50
Table 4.3	FPSC Schedule 9 Status Report and Specifications of Proposed Generating Facilities – Unsited B	51
Figure D1	Hopkins Plant Site	52
Figure D2	Purdom Plant Site	52
Table 4.4	Planned Transmission Projects 2008-2017	53
Table 4.5	FPSC Schedule 10 Status Report and Spec. of Proposed Directly Associated Transmission Lines	54
Table 4.6	FPSC Schedule 10 Status Report and Spec. of Proposed Directly Associated Transmission Lines	55

Appendix A

Existing Generating Unit Operating Performance	A-1
Nominal, Delivered Residual Oil Prices Base Case	A-2
Nominal, Delivered Residual Oil Prices High Case	A-3
Nominal, Delivered Residual Oil Prices Low Case	A-4
Nominal, Delivered Distillate Oil and Natural Gas Prices Base Case	A-5
Nominal, Delivered Distillate Oil and Natural Gas Prices High Case	A-6
Nominal, Delivered Distillate Oil and Natural Gas Prices Low Case	A-7
Nominal, Delivered Coal Prices Base Case	A-8
Nominal, Delivered Coal Prices High Case	A-9
Nominal, Delivered Coal Prices Low Case	A-10
Nominal, Delivered Nuclear Fuel and Firm Purchases	A-11
Financial Assumptions Base Case	A-12
Financial Escalation Assumptions	A-13
Monthly Peak Demands and Date of Occurrence for 2005 – 2007	A-14
Historical and Projected Heating and Cooling Degree Days	A-15
Average Real Retail Price of Electricity	A-16
Loss of Load Probability, Reserve Margin, and Expected Unserved Energy Base Case Load Forecast	A-17

Chapter I

Description of Existing Facilities

1.0 INTRODUCTION

The City of Tallahassee (City) owns, operates, and maintains an electric generation, transmission, and distribution system that supplies electric power in and around the corporate limits of the City. The City was incorporated in 1825 and has operated since 1919 under the same charter. The City began generating its power requirements in 1902 and the City's Electric Department presently serves approximately 112,151 customers located within a 221 square mile service territory (see Figure A). The Electric Department operates three generating stations with a total summer season net generating capacity of 744 megawatts (MW).

The City has two fossil-fueled generating stations, which contain combined cycle (CC), steam and combustion turbine (CT) electric generating facilities. The Sam O. Purdom Generating Station, located in the town of St. Marks, Florida has been in operation since 1952; and the Arvah B. Hopkins Generating Station, located on Geddie Road west of the City, has been in commercial operation since 1970. The City has also been generating electricity at the C.H. Corn Hydroelectric Station, located on Lake Talquin west of Tallahassee, since August of 1985.

1.1 SYSTEM CAPABILITY

The City maintains six points of interconnection with Progress Energy Florida ("Progress", formerly Florida Power Corporation); three at 69 kV, two at 115 kV, and one at 230 kV; and a 230 kV interconnection with Georgia Power Company (a subsidiary of the Southern Company ("Southern")).

As shown in Table 1.1 (Schedule 1), 233 MW of CC generation, 48 MW of steam generation and 20 MW (all net summer ratings) of CT generation facilities are located at the City's Sam O. Purdom Generating Station. The Arvah B. Hopkins Generating Station includes 304 MW of steam generation and 128 MW (net summer ratings) of CT generation facilities.

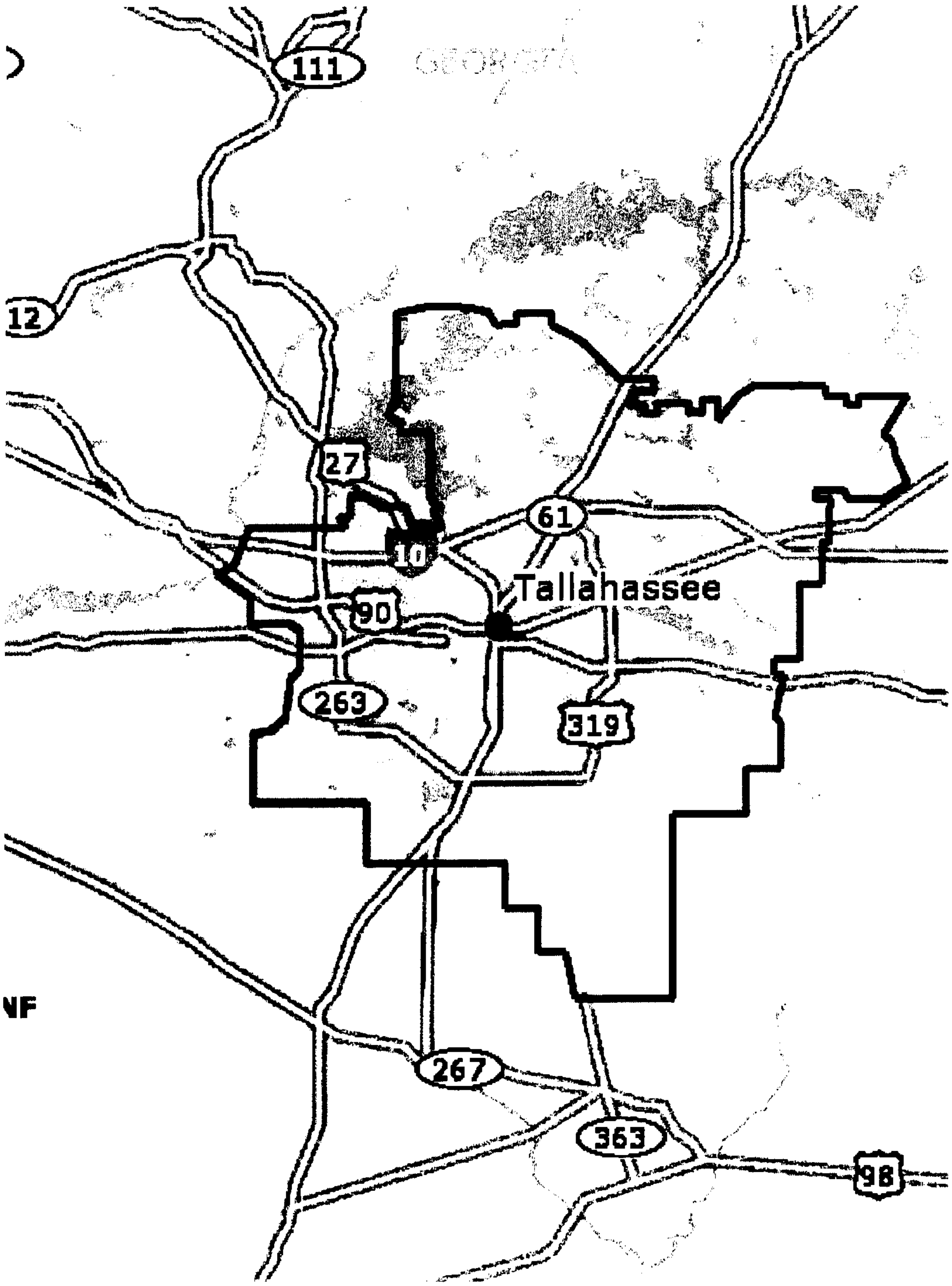
All of the City's available steam generating units at these sites can be fired with natural gas, residual oil or both. The CC and CT units can be fired on either natural gas or diesel oil but cannot burn these fuels concurrently. The total capacity of the three units at the C.H. Corn Hydroelectric Station is 11 MW.

The City's total net summer installed generating capability is 744 MW. The corresponding winter net peak installed generating capability is 795 MW. Table 1.1 contains the details for the individual generating units.

1.2 PURCHASED POWER AGREEMENTS

The City has a long-term firm capacity and energy purchase agreement with Progress for 11.4 MW. The City has also entered into two short-term firm capacity and energy purchase agreements with Southern - one for 25 MW and another for 50 MW - for the duration of the Spring 2008 Hopkins 2 CC repowering outage. These two short-term purchases are scheduled to terminate prior to the anticipated time of the 2008 summer peak.

Figure A – Tallahassee Service Territory



City Of Tallahassee

Schedule 1
Existing Generating Facilities
As of December 31, 2007

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt.				Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel Days	Commercial In-Service	Expected Retirement	Gen. Max. Nameplate	Summer	Winter
Plant	No.	Location	Type	Pri	Alt	Primary	Alternate	Use	Month/Year	Month/Year	(kW)	(MW)	(MW)
Sam O. Purdom	7	Wakulla	ST	NG	FO6	PL	WA	[1, 2]	6/66	3/11	50,000	48	50
	8		CC	NG	FO2	PL	TK	[2, 3]	7/00	12/40	247,743	233	262
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	12/63	3/11	15,000	10	10
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	5/64	3/11	15,000	10	10
											Plant Total	301	332
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK	[1]	5/71	3/16	75,000	76	78
	2		ST	NG	FO6	PL	TK	[1]	10/77	3/22	259,250	228	238
	GT-1		GT	NG	FO2	PL	TK	[3]	2/70	3/15	16,320	12	14
	GT-2		GT	NG	FO2	PL	TK	[3]	9/72	3/17	27,000	24	26
	GT-3		GT	NG	FO2	PL	TK	[3]	9/05	Unknown	60,500	46	48
	GT-4		GT	NG	FO2	PL	TK	[3]	11/05	Unknown	60,500	46	48
											Plant Total	432	452
C. H. Corn Hydro Station	1	Leon/ Gadsden	HY	WAT	WAT	WAT	WAT	NA	9/85	Unknown	4,440	4	4
	2		HY	WAT	WAT	WAT	WAT	NA	8/85	Unknown	4,440	4	4
	3		HY	WAT	WAT	WAT	WAT	NA	1/86	Unknown	3,430	3	3
											Plant Total	11	11
									Total System Capacity as of December 31, 2007			744	795

Notes

[1] The City maintains a minimum residual fuel oil inventory of approximately 19 peak load days between the Purdom and Hopkins sites.

[2] Due to the Purdom facility-wide emissions caps, utilization of liquid fuel at this facility is limited

[3] Historically, sufficient diesel storage has been maintained at Purdom for approximately 30 full load hours of operation for all three CT units and at Hopkins for approximately 8 peak load days of operation for all four CT units. Following the Hopkins 2 CC repowering the City's system-wide target for minimum diesel fuel oil inventory will be approximately 18.5 peak load days. This target will not be attained until storage tank upgrades at the Hopkins site are completed late in 2008.

CHAPTER II

Forecast of Energy/Demand Requirements and Fuel Utilization

2.0 INTRODUCTION

Chapter II includes the City of Tallahassee's forecasts of demand and energy requirements, energy sources and fuel requirements. This chapter also explains the impacts attributable to the Demand Side Management (DSM) plan submitted as a part of the City of Tallahassee's Integrated Resource Planning (IRP) Study completed in December 2006. The City is no longer subject to the requirements of the Florida Energy Efficiency and Conservation Act (FEECA) and, therefore, the FPSC does not set numeric conservation goals for the City. However, the City expects to continue its commitment to conservation and the DSM programs that prove beneficial to the City's ratepayers.

2.1 SYSTEM DEMAND AND ENERGY REQUIREMENTS

Historical and forecast energy consumption and customer information are presented in Tables 2.1, 2.2 and 2.3 (Schedules 2.1, 2.2, and 2.3). Figure B1 shows the historical total sales and forecast trends of energy sales by customer class. Figure B2 shows the percentage of energy sales by customer class for the base year of 2008 and the horizon year of 2017. Tables 2.4 through 2.12 (Schedules 3.1.1 - 3.3.3) contain historical and forecast seasonal peak demands and net energy for load for base, high, and low values. Table 2.13 (Schedule 4) compares actual and two-year forecast peak demand and energy values by month for the 2007 - 2009 period.

2.1.1 SYSTEM LOAD AND ENERGY FORECASTS

The peak demand and energy forecasts contained in this plan are the results of the load and energy forecasting study performed by the City. The forecast is developed utilizing a methodology that the City first employed in 1980, and has updated and revised every one or two years. The methodology consists of thirteen multi-variable linear regression models based on detailed examination of the system's historical growth, usage patterns and population statistics. Several key regression formulas utilize econometric variables.

Table 2.14 lists the econometric-based linear regression forecasting models that are used as predictors. Note that the City uses regression models with the capability of separately predicting commercial customers and consumption by rate sub-class: general service non-demand (GS), general service demand (GSD), and general service large demand (GSLD). These, along with the residential class, represent the major classes of the City's electric customers. In addition to these customer class models, the City's forecasting methodology also incorporates into the demand and energy projections for other customers (interruptible, curtailable, FSU, FAMU, State Capitol and Lighting) and estimated reductions from interruptible and curtailable customers. The key explanatory variables used in each of the models are indicated by an "X" on the table.

Table 2.15 documents the City's internal and external sources for historical and forecast economic, weather and demographic data. These tables summarize the details of the models used to generate the system customer, consumption and seasonal peak load forecasts. In addition to those explanatory variables listed, a component is also included in the models that reflect the acquisition of certain Talquin Electric Cooperative (Talquin) customers over the study period consistent with the territorial agreement negotiated between the City and Talquin and approved by the FPSC.

The customer models are used to predict number of customers by customer class, which in turn serve as input into the customer class consumption models. The customer class consumption models are aggregated to form a total base system sales forecast. The effects of DSM programs and system losses are incorporated in this base forecast to produce the system net energy for load (NEL) requirements.

Since 1992, the City has used two econometric models to separately predict summer and winter peak demand. Table 2.14 also shows the key explanatory variables used in the demand models. The summer peak demand model prediction is based on maximum temperature, air conditioning saturation rates, and total number of customers. The winter peak is dependent upon the minimum temperature on the peak day, electric heating saturation rates, and total number of customers. In light of the actual 2006 and 2007 winter peaks the winter peak demand model was refined resulting in a 2008 winter peak demand forecast that is lower than the projections made in the 2007 winter peak demand forecast.

The most significant input assumptions for the 2008 forecast were the incremental load modifications at Florida State University (FSU), Florida A&M University (FAMU), Tallahassee Memorial Hospital (TMH) and the State Capitol Center. These four customers represent approximately 14% of the City's energy sales. Their incremental additions are highly dependent upon annual economic and budget constraints, which would cause fluctuations in their demand projections if they were projected using a model. Therefore, each entity submits their proposed incremental additions/reductions to the City and these modifications are included as submitted in the load and energy forecast.

The City believes that the inclusion of these incremental additions/reductions, utilizing the five-year average of the actual temperature at the time of seasonal peak demand, the routine update of forecast model coefficients and other minor model refinements have improved the accuracy of its forecast so that they are more consistent with the historical trend of growth in seasonal peak demand and energy consumption.

2.1.2 LOAD FORECAST UNCERTAINTY & SENSITIVITIES

To provide a sound basis for planning, forecasts are derived from projections of the driving variables obtained from reputable sources. However, there is significant uncertainty in the future level of such variables. To the extent that economic, demographic, weather, or other conditions occur that are different from those assumed or provided, the actual load can be expected to vary from the forecast. For various purposes, it is important to understand the amount by which the forecast can be in error and the sources of error.

To capture this uncertainty, the City produces high and low range results that address potential variance in driving population and economic variables from the values assumed in the base case. The base case forecast relies on a set of assumptions about future population and economic activity in Leon County. However, such projections are unlikely to exactly match actual experience.

Population and economic uncertainty tends to result in a deviation from the trend over the long term. Accordingly, separate high and low forecast results were developed to address population and economic uncertainty. These ranges are intended to capture approximately 80% of occurrences (i.e., 1.3 standard deviations). The high and low forecasts shown in this year's report use statistics provided by Woods & Poole Economics, Inc. (Woods & Poole) to develop a range of potential outcomes. Woods & Poole publishes several statistics that define the average amount by which various projections they have provided in the past are different from actual results. The City's load forecasting consultant, R.W. Beck, interpreted these statistics to develop ranges of the trends of economic activity and population representing approximately 80% of potential outcomes. These statistics were then applied to the base case to develop the high and low load forecasts presented in Schedules 3.1.2, 3.1.3, 3.2.2 and 3.2.3.

Sensitivities on the peak demand forecasts are useful in planning for future power supply resource needs. The graph shown in Figure B3 compares summer peak demand (multiplied by 117% for reserve margin requirements) for the three forecast sensitivity cases with reductions from proposed DSM portfolio and the base forecast without proposed DSM reductions against the City's existing and planned power supply resources. This graph allows for the review of the effect of load growth and DSM performance variations on the timing of new resource additions. The highest probability weighting, of course, is placed on the base case assumptions, and the low and high cases are given a smaller likelihood of occurrence.

2.1.3 ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT PROGRAMS

The City currently offers a variety of conservation and DSM programs to its residential and commercial customers, which are listed below:

Residential Programs	Commercial Programs
Low Interest Loan Program	Customized Loan Program
Gas New Construction Rebates	Low Interest Loan Program
Gas Appliance Conversion Rebates	Demonstrations
Information and Audits	Information and Audits
Ceiling Insulation Rebates	Commercial Gas Conversion Rebates
Low Income Ceiling Insulation Rebate	Ceiling Insulation Rebates
Low Income HVAC/water heater repair	Solar Rebates
Energy Star Appliance Rebates	Solar Net Metering Program
High Efficiency HVAC Rebates	
Energy Star New Home Rebates	

The City has a goal to improve the efficiency of customers' end-use of energy resources when such improvements provide a measurable economic and/or environmental benefit to the customers and the City utilities. During the IRP Study the City tested potential DSM measures (conservation, energy efficiency, load management, and demand response) for cost-effectiveness utilizing an integrated approach that is based on projections of total achievable demand and energy reductions and their associated annual costs developed specifically for the City. The measures were combined into bundles affecting similar end uses and /or having similar costs per kWh saved. The City intends to extend the existing DSM program and has begun implementing specific groups of additional measures that achieve the capacity benefit and energy savings projected in the IRP Study.

Energy and demand reductions attributable to the proposed DSM portfolio have been incorporated into the future load and energy forecasts. Tables 2.16 and 2.17 display, respectively, the estimated energy and demand savings associated with the menu of DSM measures. The figures on these tables reflect the cumulative annual impacts of the proposed DSM portfolio on system energy and demand requirements.

2.2 ENERGY SOURCES AND FUEL REQUIREMENTS

Tables 2.18 (Schedule 5), 2.19 (Schedule 6.1), and 2.20 (Schedule 6.2) present the projections of fuel requirements, energy sources by resource/fuel type in gigawatt-hours, and energy sources by resource/fuel type in percent, respectively, for the period 2008-2017. Figure B4 displays the percentage of energy by fuel type in 2008 and 2017.

The City's generation portfolio includes combustion turbine/combined cycle (CC), combustion turbine/simple cycle (CT), conventional steam and hydroelectric units. The City's CC and CT are capable of generating energy using natural gas or distillate fuel oil. Natural gas and residual fuel oil may be burned concurrently in the City's steam units. This mix of generation types coupled with opportunities for firm and economy purchases from neighboring systems provides allows the City to satisfy its total energy requirements consistent with our energy policies that seek to balance the cost of power with the environmental quality of our community.

The projections of fuel requirements and energy sources are taken from the results of computer simulations using Global Energy Decisions, Inc.'s PROSYM production simulation model and are based on the resource plan described in Chapter III.

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	Rural & Residential					Commercial [4]		
Year	Population [1]	Members Per Household	(GWh) [2]	Average No. of Customers [3]	Average kWh Consumption Per Customer	(GWh) [2]	Average No. of Customers [3]	Average kWh Consumption Per Customer
1998	180,725	-	940	75,729	12,413	1,396	15,779	88,472
1999	184,239	-	926	77,357	11,970	1,419	16,183	87,685
2000	186,839	-	971	79,108	12,274	1,471	16,662	88,285
2001	190,575	-	959	80,348	11,936	1,459	16,988	85,884
2002	193,941	-	1,048	81,208	12,905	1,527	16,779	91,007
2003	200,304	-	1,035	82,219	12,588	1,555	17,289	89,942
2004	203,106	-	1,064	85,035	12,512	1,604	17,729	90,473
2005	205,908	-	1,088	89,468	12,161	1,621	18,310	88,531
2006	208,789	-	1,097	92,017	11,922	1,602	18,533	86,440
2007	211,669	-	1,099	93,569	11,745	1,657	18,583	89,168
2008	214,550	-	1,109	95,731	11,585	1,656	18,864	87,786
2009	217,430	-	1,127	97,711	11,534	1,682	19,092	88,100
2010	220,311	-	1,136	99,614	11,404	1,693	19,312	87,666
2011	223,056	-	1,139	101,388	11,234	1,692	19,516	86,698
2012	225,801	-	1,149	103,146	11,140	1,703	19,719	86,363
2013	228,546	-	1,157	104,894	11,030	1,712	19,920	85,944
2014	231,290	-	1,166	106,668	10,931	1,718	20,125	85,366
2015	234,035	-	1,175	108,350	10,844	1,718	20,318	84,556
2016	236,509	-	1,184	109,876	10,776	1,720	20,494	83,927
2017	238,982	-	1,194	111,403	10,718	1,721	20,670	83,261

[1] Population data represents Leon County population served by City of Tallahassee Electric Utility not the general population of Leon County.

[2] Values include DSM Impacts.

[3] Average end-of-month customers for the calendar year. Marked increase in residential customers between 2004 and 2005 due to change in internal customer accounting practices.

[4] As of 2007, due to the structure of the City's billing system, "Commercial" includes General Service Non-Demand, General Service Demand, General Service Large Demand, Interruptible, Curtailable, FSU, FAMU, State Capitol and Lighting.

City Of Tallahassee

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

Base Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial				Street & Highway Lighting (GWh) [2]	Other Sales to Public Authorities (GWh)	Total Sales to Ultimate Consumers (GWh)
Year	(GWh)	Average No. of Customers [1]	Average kWh Consumption Per Customer	Railroads and Railways (GWh)			
1998	-	-	-	-	13	-	2349
1999	-	-	-	-	13	-	2358
2000	-	-	-	-	12	-	2454
2001	-	-	-	-	13	-	2,431
2002	-	-	-	-	13	-	2,588
2003	-	-	-	-	12	-	2,602
2004	-	-	-	-	14	-	2,682
2005	-	-	-	-	14	-	2,724
2006	-	-	-	-	15	-	2,715
2007	-	-	-	-		-	2,756
2008	-	-	-	-		-	2,765
2009	-	-	-	-		-	2,808
2010	-	-	-	-		-	2,829
2011	-	-	-	-		-	2,831
2012	-	-	-	-		-	2,852
2013	-	-	-	-		-	2,869
2014	-	-	-	-		-	2,884
2015	-	-	-	-		-	2,893
2016	-	-	-	-		-	2,904
2017	-	-	-	-		-	2,915

[1] Average end-of-month customers for the calendar year.
[2] As of 2007 Street & Highway Lighting use is included with Commercial on Schedule 2.1.

City Of Tallahassee

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

Base Load Forecast

(1) Year	(2) Sales for Resale (GWh)	(3) Utility Use & Losses (GWh)	(4) Net Energy for Load (GWh)	(5) Other Customers (Average No.)	(6) Total No. of Customers [1]
1998	0	128	2,477		91,508
1999	0	139	2,497		93,540
2000	0	155	2,609		95,770
2001	0	125	2,556		97,335
2002	0	165	2,753		97,987
2003	0	153	2,755		99,508
2004	0	159	2,841		102,764
2005	0	164	2,888		107,778
2006	0	154	2,869		110,549
2007	0	158	2,914		112,151
2008	0	165	2,930		114,595
2009	0	167	2,975		116,803
2010	0	168	2,997		118,925
2011	0	168	2,999		120,904
2012	0	170	3,022		122,865
2013	0	170	3,039		124,814
2014	0	172	3,056		126,793
2015	0	172	3,065		128,668
2016	0	173	3,077		130,371
2017	0	173	3,088		132,074

[1] Average number of customers for the calendar year.

History and Forecast Energy Consumption By Customer Class (Including DSM Impacts)

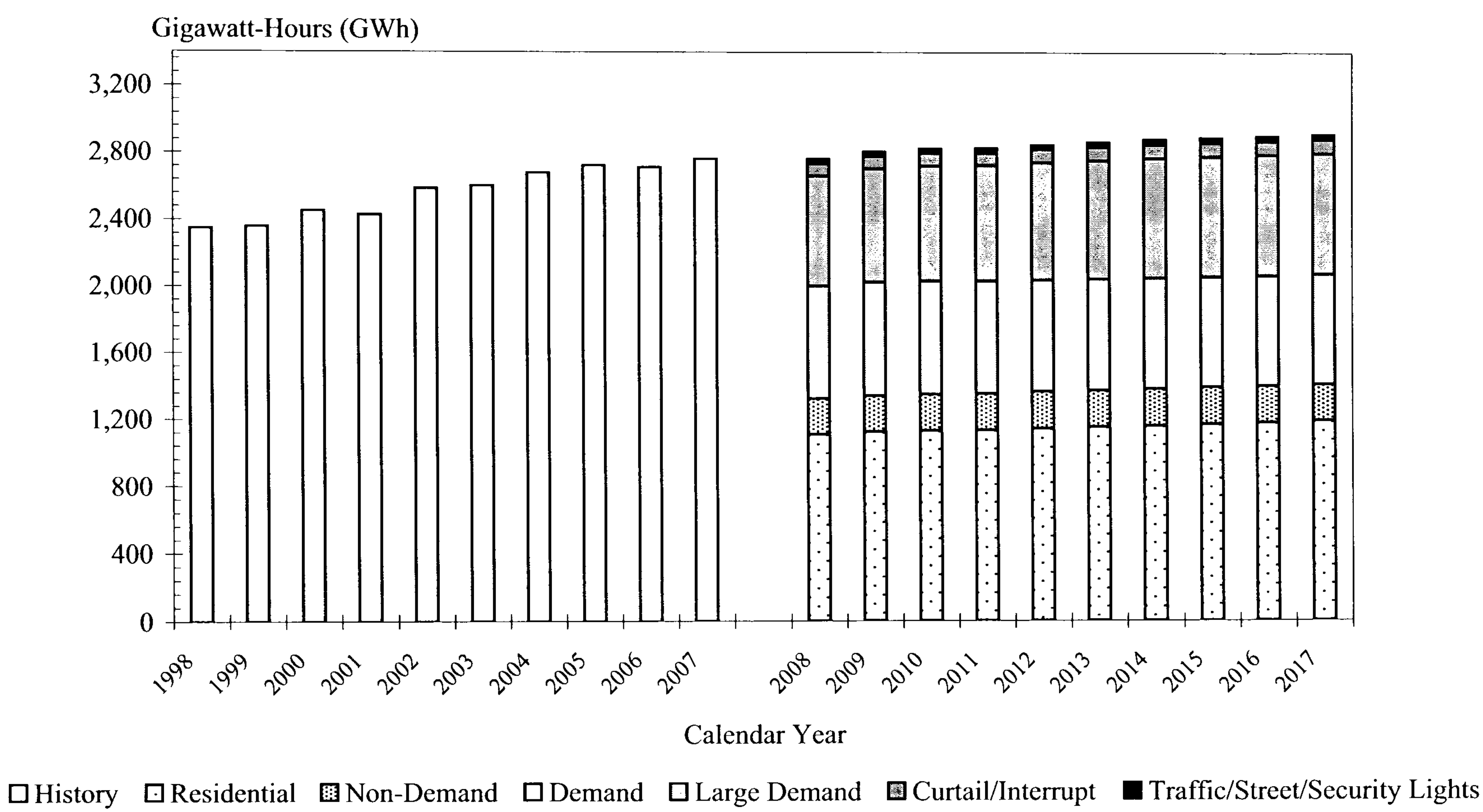
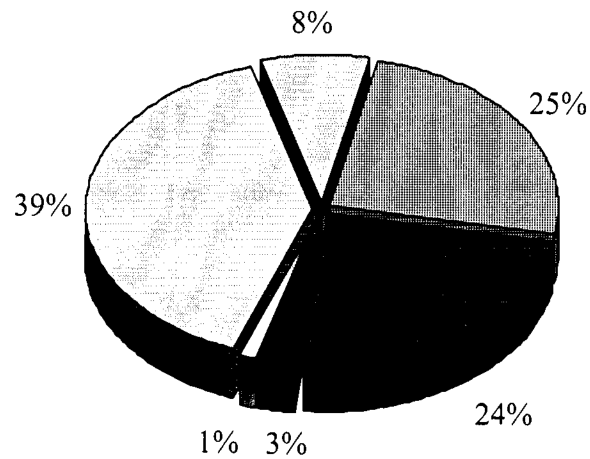


Figure B1

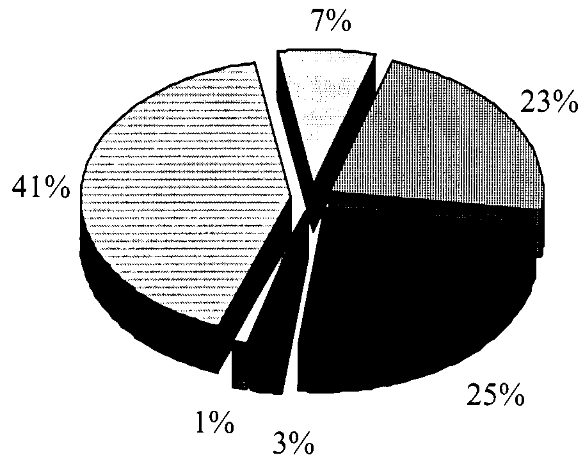
Energy Consumption By Customer Class excluding DSM Impacts

Calendar Year 2008



Total 2008 Sales = 2,772 GWh

Calendar Year 2017



Total 2017 Sales = 3,245 GWh

Residential | Non Demand | Demand
Large Demand | Curtail/Interrupt | Lighting

City Of Tallahassee

Schedule 3.1.1
History and Forecast of Summer Peak Demand
Base Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	622		622			1		0	621
2008	622		622		0	1	0	1	620
2009	638		638		1	3	3	4	627
2010	650		650		4	7	10	9	620
2011	662		662		6	12	16	16	612
2012	674		674		9	16	17	21	611
2013	686		686		10	20	18	26	612
2014	697		697		12	24	18	32	611
2015	708		708		13	28	18	38	611
2016	717		717		15	32	19	42	609
2017	726		726		15	35	20	47	609

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

Table 2.4

City Of Tallahassee

Schedule 3.1.2
History and Forecast of Summer Peak Demand
High Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	622		622			1		0	621
2008	643		643		0	1	0	1	641
2009	664		664		1	3	3	4	653
2010	681		681		4	7	10	9	651
2011	698		698		6	12	16	16	648
2012	716		716		9	16	17	21	653
2013	734		734		10	20	18	26	660
2014	750		750		12	24	18	32	664
2015	767		767		13	28	18	38	670
2016	782		782		15	32	19	42	674
2017	798		798		15	35	20	47	681

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.1.3
History and Forecast of Summer Peak Demand
Low Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1998	530		530						530
1999	526		526						526
2000	550		550						550
2001	520		520						520
2002	581		581						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	622		622			1		0	621
2008	601		601		0	1	0	1	599
2009	612		612		1	3	3	4	601
2010	619		619		4	7	10	9	589
2011	625		625		6	12	16	16	575
2012	632		632		9	16	17	21	569
2013	639		639		10	20	18	26	565
2014	644		644		12	24	18	32	558
2015	649		649		13	28	18	38	552
2016	652		652		15	32	19	42	544
2017	655		655		15	35	20	47	538

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.2.1
History and Forecast of Winter Peak Demand
Base Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1998 -1999	513		513						513
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	531		531			5		0	526
2008 -2009	576		576		1	3	4	3	565
2009 -2010	587		587		4	6	10	8	559
2010 -2011	598		598		6	11	16	14	551
2011 -2012	610		610		9	15	17	18	551
2012 -2013	622		622		10	19	17	23	553
2013 -2014	632		632		12	23	17	28	552
2014 -2015	641		641		15	26	18	32	550
2015 -2016	650		650		15	30	18	37	550
2016 -2017	658		658		15	33	19	41	550
2017 -2018	667		667		15	37	19	45	551

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.2.2
History and Forecast of Winter Peak Demand
High Forecast
(MW)

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2]	(7) Residential Conservation [2], [3]	(8) Comm./Ind Load Management [2]	(9) Comm./Ind Conservation [2], [3]	(10) Net Firm Demand [1]
1998 -1999	513		513						513
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	531		531			5		0	526
2008 -2009	589		589		1	3	4	3	578
2009 -2010	604		604		4	6	10	8	576
2010 -2011	620		620		6	11	16	14	573
2011 -2012	637		637		9	15	17	18	578
2012 -2013	654		654		10	19	17	23	585
2013 -2014	668		668		12	23	17	28	588
2014 -2015	682		682		15	26	18	32	591
2015 -2016	696		696		15	30	18	37	596
2016 -2017	710		710		15	33	19	41	602
2017 -2018	724		724		15	37	19	45	608

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.2.3
History and Forecast of Winter Peak Demand
Low Forecast
(MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management [2]	Residential Conservation [2], [3]	Comm./Ind Load Management [2]	Comm./Ind Conservation [2], [3]	Net Firm Demand [1]
1998 -1999	513		513						513
1999 -2000	497		497						497
2000 -2001	521		521						521
2001 -2002	510		510						510
2002 -2003	590		590						590
2003 -2004	509		509						509
2004 -2005	532		532						532
2005 -2006	537		537						537
2006 -2007	528		528						528
2007 -2008	531		531			5		0	526
2008 -2009	563		563		1	3	4	3	552
2009 -2010	569		569		4	6	10	8	541
2010 -2011	576		576		6	11	16	14	529
2011 -2012	582		582		9	15	17	18	523
2012 -2013	589		589		10	19	17	23	520
2013 -2014	595		595		12	23	17	28	515
2014 -2015	598		598		15	26	18	32	507
2015 -2016	602		602		15	30	18	37	502
2016 -2017	605		605		15	33	19	41	497
2017 -2018	608		608		15	37	19	45	492

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. Reporting year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.3.1
History and Forecast of Annual Net Energy for Load
Base Forecast
(GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,454			2,441		155	2,596	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,724			2,724		164	2,888	55
2006	2,715			2,715		154	2,869	57
2007	2,765	9	0	2,756		158	2,914	54
2008	2,772	3	4	2,765		165	2,930	54
2009	2,836	13	15	2,808		167	2,975	54
2010	2,893	31	33	2,829		168	2,997	55
2011	2,943	53	59	2,831		168	2,999	56
2012	2,998	69	77	2,852		170	3,022	56
2013	3,053	88	96	2,869		170	3,039	57
2014	3,108	106	118	2,884		172	3,056	57
2015	3,157	125	139	2,893		172	3,065	57
2016	3,201	141	156	2,904		173	3,077	58
2017	3,245	157	173	2,915		173	3,088	58

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. Previous year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.3.2
History and Forecast of Annual Net Energy for Load
High Forecast
(GWh)

(1) Year	(2) Total Sales	(3) Residential Conservation [2], [3]	(4) Comm./Ind Conservation [2], [3]	(5) Retail Sales [1]	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load [1]	(9) Load Factor % [1]
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,454			2,441		155	2,596	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,724			2,724		164	2,888	55
2006	2,715			2,715		154	2,869	57
2007	2,765	9	0	2,756		158	2,914	54
2008	2,853	3	4	2,846		170	3,016	54
2009	2,936	13	15	2,908		174	3,081	54
2010	3,012	31	33	2,948		175	3,123	55
2011	3,083	53	59	2,971		177	3,148	55
2012	3,159	69	77	3,013		180	3,193	56
2013	3,237	88	97	3,052		181	3,233	56
2014	3,313	106	118	3,089		183	3,272	56
2015	3,384	125	138	3,121		186	3,307	56
2016	3,453	141	156	3,156		188	3,344	57
2017	3,522	157	174	3,191		190	3,381	57

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. Previous year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 3.3.3
History and Forecast of Annual Net Energy for Load
Low Forecast
(GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total Sales	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
1998	2,349			2,349		128	2,477	53
1999	2,358			2,358		139	2,497	54
2000	2,454			2,441		155	2,596	54
2001	2,431			2,431		125	2,556	56
2002	2,588			2,588		165	2,753	54
2003	2,602			2,602		153	2,755	53
2004	2,682			2,682		159	2,841	57
2005	2,724			2,724		164	2,888	55
2006	2,715			2,715		154	2,869	57
2007	2,765	9	0	2,756		158	2,914	54
2008	2,692	3	4	2,685		159	2,844	54
2009	2,738	13	15	2,710		161	2,871	55
2010	2,775	31	33	2,711		161	2,872	56
2011	2,804	53	59	2,692		160	2,852	57
2012	2,839	69	77	2,693		160	2,853	57
2013	2,872	88	96	2,688		159	2,847	58
2014	2,906	106	118	2,682		160	2,842	58
2015	2,932	125	138	2,669		159	2,828	58
2016	2,953	141	156	2,656		158	2,814	59
2017	2,974	157	174	2,643		157	2,800	59

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. Previous year DSM is actual at peak.
[3] 2007 values reflect incremental increase from 2006.

City Of Tallahassee

Schedule 4
Previous Year and 2-Year Forecast of Retail Peak Demand and Net Energy for Load by Month
City Of Tallahassee

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2007 Actual		**2008 Forecast [1]**		**2009 Forecast [1]**	
Month	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)	Peak Demand (MW)	NEL (GWh)
January	493	226	526	226	565	230
February	504	213	510	210	558	213
March	441	212	490	214	496	217
April	464	212	469	215	474	218
May	497	245	543	246	549	250
June	576	274	596	275	603	279
July	601	295	608	299	615	304
August	621	313	620	310	627	315
September	559	270	579	271	585	275
October	512	240	511	237	517	241
November	398	202	460	206	466	209
December	437	212	540	221	547	224
TOTAL		2,914		2,930		2,975

[1] Peak Demand and NEL include DSM Impacts.

City of Tallahassee, Florida

2008 Electric System Load Forecast

Key Explanatory Variables

Ln. No.	Model Name	Leon County Population	Residential Customers	Total Customers	Cooling Degree Days	Heating Degree Days	Tallahassee Per Capita Taxable Sales	Price of Electricity	State of Florida Population	Minimum Winter Peak day Temp.	Maximum Summer Peak day Temp.	Appliance Saturation	R Squared[1]
1	Residential Customers	X											0.994
2	Residential Consumption		X		X	X	X	X				X	0.927
3	Florida State University Consumption				X				X				0.930
4	State Capitol Consumption				X				X				0.892
5	Florida A&M University Consumption				X				X				0.926
6	Lighting Consumption	X											0.961
7	General Service Non-Demand Customers		X										0.996
8	General Service Demand Customers		X										0.987
9	General Service Non-Demand Consumptioı	X			X	X		X					0.956
10	General Service Demand Consumption	X			X	X							0.979
11	General Service Large Demand Consumption	X			X	X							0.921
12	Summer Peak Demand			X							X	X	0.899
13	Winter Peak Demand			X						X		X	0.654

[1] R Squared, sometimes called the coefficient of determination, is a commonly used measure of goodness of fit of a linear model. If the observations fall on the model regression line, R Squared is 1. If there is no linear relationship between the dependent and independent variable, R Squared is 0. A reasonably good R Squared value could be anywhere from 0.6 to 1.

City of Tallahassee

2008 Electric System Load Forecast

Sources of Forecast Model Input Information

Energy Model Input Data	Source
1. Leon County Population	City Planning Office
2. Talquin Customers Transferred	City Power Engineering
3. Cooling Degree Days	NOAA reports
4. Heating Degree Days	NOAA reports
5. AC Saturation Rate	December 2005 Appliance Saturation Study
6. Heating Saturation Rate	December 2005 Appliance Saturation Study
7. Real Tallahassee Taxable Sales	Department of Revenue
8. Florida Population	Governor's Office of Budget & Planning
9. State Capitol Incremental	Department of Management Services
10. FSU Incremental Additions	FSU Planning Department
11. FAMU Incremental Additions	FAMU Planning Department
12. GSLD Incremental Additions	City Utility Services
13. Other Commercial Customers	Utility Services
14. Tall. Memorial Curtailable	System Planning/ Utilities Accounting.
15. System Peak Historical Data	City System Planning
16. Historical Customer Projections by Class	System Planning & Customer Accounting
17. Historical Customer Class Energy	System Planning & Customer Accounting
18. GDP Forecast	Governor's Planning & Budgeting Office
19. CPI Forecast	Governor's Planning & Budgeting Office
20. Florida Taxable Sales	Governor's Planning & Budgeting Office
21. Interruptible, Traffic Light Sales, & Security Light Additions	System Planning & Customer Accounting
22. Historical Residential Real Price of Electricity	Calculated from Revenues, Kwh sold, and CPI
23. Historical Commercial Real Price Of Electricity	Calculated from Revenues, Kwh sold, and CPI

Banded Summer Peak Load Forecast Vs. Supply Resources
(Load Includes 17% Reserve Margin)

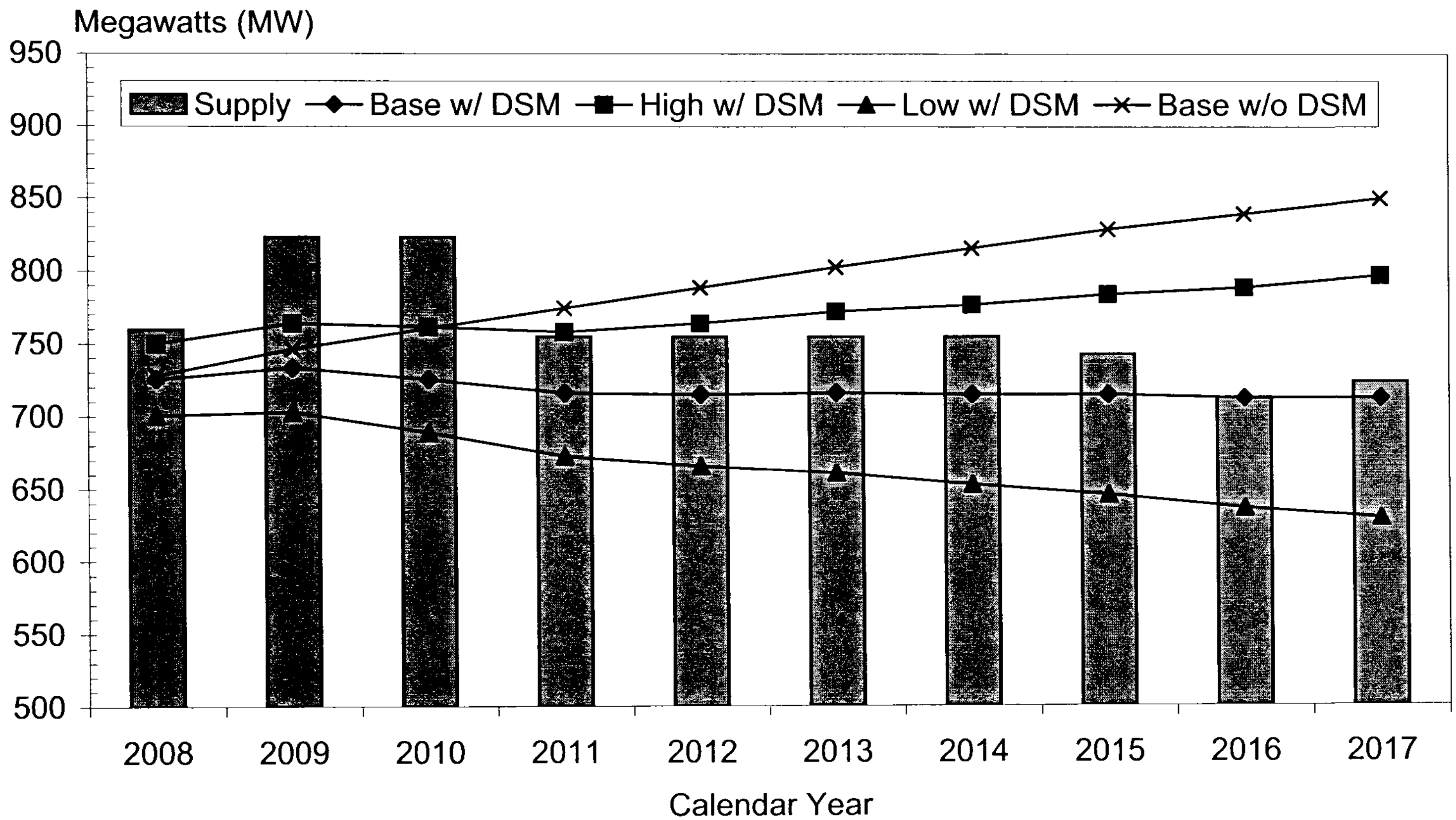


Figure B3

City Of Tallahassee

2008 Electric System Load Forecast

Projected Demand Side Management
Energy Reductions [1]

Calendar Year Basis

Year	Residential Impact (MWh)	Commercial Impact (MWh)	Total Impact (MWh)
2008	3,373	3,746	7,119
2009	14,055	15,608	29,663
2010	32,327	35,898	68,225
2011	56,221	62,431	118,652
2012	73,087	81,161	154,248
2013	92,764	103,012	195,776
2014	112,442	124,863	237,304
2015	132,119	146,713	278,832
2016	148,985	165,443	314,428
2017	165,851	184,173	350,024

[1] Reductions estimated at busbar.

City Of Tallahassee

2008 Electric System Load Forecast

Projected Demand Side Management
Seasonal Demand Reductions [1]

Year		Residential Energy Efficiency Impact		Commercial Energy Efficiency Impact		Residential Demand Response Impact		Commercial Demand Response Impact		Demand Side Management Total	
Summer	Winter	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)	Summer (MW)	Winter (MW)
2008	2008-2009	1	3	1	3	0	1	0	4	2	11
2009	2009-2010	3	6	4	8	1	4	3	10	11	28
2010	2010-2011	7	11	9	14	4	6	10	16	30	47
2011	2011-2012	12	15	16	18	6	9	16	17	50	59
2012	2012-2013	16	19	21	23	9	10	17	17	63	69
2013	2013-2014	20	23	26	28	10	12	18	17	74	80
2014	2014-2015	24	26	32	32	12	15	18	18	86	91
2015	2015-2016	28	30	38	37	13	15	18	18	97	100
2016	2016-2017	32	33	42	41	15	15	19	19	108	108
2017	2017-2018	35	37	47	45	15	15	20	19	117	116

[1] Reductions estimated at busbar.

City Of Tallahassee

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2006	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Nuclear		Billion Btu	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Residual	Total	1000 BBL	194	166	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	194	166	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	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	Total	1000 BBL	7	1	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	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	7	1	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	1000 MCF	19,818	18,865	20,593	22,982	22,897	21,635	20,035	20,091	20,340	20,270	20,354	20,869
(14)		Steam	1000 MCF	6,484	7,499	2,010	301	442	676	780	1,022	630	477	99	0
(15)		CC	1000 MCF	12,416	10,362	16,617	21,776	21,298	19,856	18,594	18,074	19,244	19,332	19,209	19,644
(16)		CT	1000 MCF	918	1,004	1,966	905	1,157	1,103	661	995	466	461	1,046	1,225
(17)		Diesel	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(18)	Other (Specify)		Trillion Btu	0	0	0	0	0	0	0	0	0	0	0	0

City Of Tallahassee

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2006	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Firm Interchange		GWh	100	196	258	117	117	118	118	118	119	119	112	23
(2)	Coal		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(4)	Residual	Total	GWh	110	97	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWh	110	97	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	4	1	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	4	1	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	2,409	2,165	2,613	2,841	2,862	2,611	2,292	2,310	2,328	2,337	2,353	2,456
(15)		Steam	GWh	584	661	176	24	37	58	66	87	53	40	8	0
(16)		CC	GWh	1,734	1,403	2,233	2,727	2,708	2,443	2,159	2,119	2,226	2,249	2,236	2,327
(17)		CT	GWh	91	100	204	89	117	110	67	104	48	48	109	128
(18)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(19)	Hydro		GWh	9	6	18	18	18	18	18	18	18	18	18	18
(20)	Economy Interchange		GWh	236	450	41	0	0	3	1	2	0	0	0	0
(21)	Renewables		GWh	0	0	0	0	0	250	593	591	591	591	593	592
(22)	Net Energy for Load		GWh	2,868	2,914	2,930	2,975	2,997	2,999	3,022	3,039	3,056	3,065	3,077	3,088

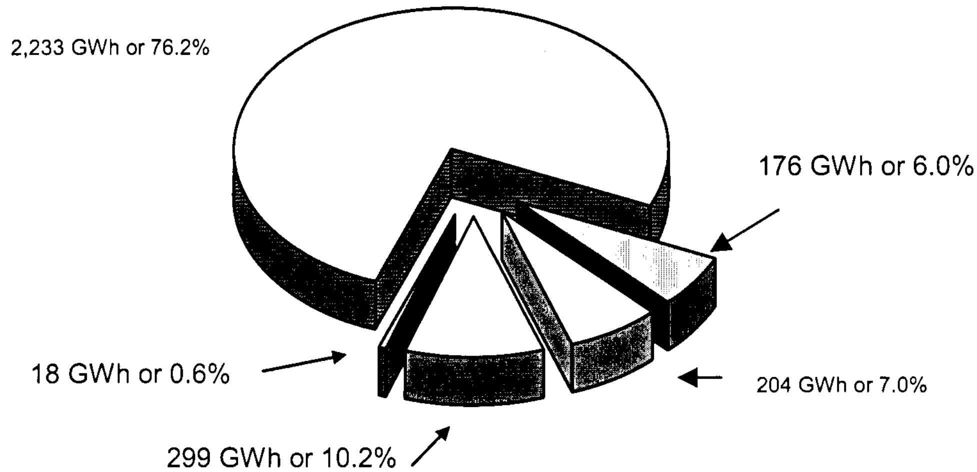
City Of Tallahassee

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	5	6	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2006	Actual 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
(1)	Annual Firm Interchange		%	3.5	6.7	8.8	3.9	3.9	3.9	3.9	3.9	3.9	3.9	3.6	0.7
(2)	Coal		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(3)	Nuclear		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(4)	Residual	Total	%	3.8	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	3.8	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6)		CC	%	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)		CT	%	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)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9)	Distillate	Total	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10)		Steam	%	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)		CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14)	Natural Gas	Total	%	84.0	74.3	89.2	95.5	95.5	87.1	75.8	76.0	76.2	76.2	76.5	79.5
(15)		Steam	%	20.4	22.7	6.0	0.8	1.2	1.9	2.2	2.9	1.7	1.3	0.3	0.0
(16)		CC	%	60.5	48.1	76.2	91.7	90.4	81.5	71.4	69.7	72.8	73.4	72.7	75.4
(17)		CT	%	3.2	3.4	7.0	3.0	3.9	3.7	2.2	3.4	1.6	1.6	3.5	4.1
(18)		Diesel	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(19)	Hydro		%	0.3	0.2	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
(20)	Economy Interchange		%	8.2	15.4	1.4	0.0	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0
(21)	Renewables		GWh	0.0	0.0	0.0	0.0	0.0	8.3	19.6	19.5	19.4	19.3	19.3	19.2
(22)	Net Energy for Load		GWh	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

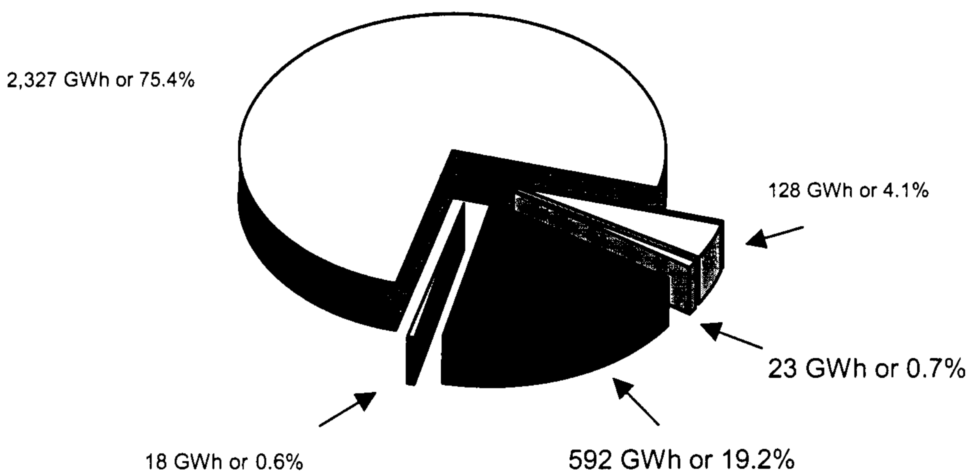
Generation By Resource/Fuel Type

Calendar Year 2008



Total 2007 NEL = 2,930 GWh

Calendar Year 2017



Total 2017 NEL = 3,088

☐ CC - Gas ☐ Steam - Gas ☐ CT/Diesel - Gas ☐ Purch ■ Renewable ☐ Hydro

Chapter III

Projected Facility Requirements

3.1 PLANNING PROCESS

In August 2004 the City issued a task order to Black & Veatch Consultants to conduct a comprehensive integrated resource planning (IRP) study. The purpose of this study was to review future demand-side management (DSM) and power supply options that are consistent with the City's policy objectives. The IRP study was completed in December 2006 and included a detailed analysis of how the DSM and power supply alternatives perform under base and alternative assumptions.

As identified in the 2007 TYSP, the resource plan identified in this IRP study included the City's participation in the Taylor Energy Center (TEC), a proposed coal-fueled power plant to be located near Perry, Florida. Subsequent to the filing of last year's report, the TEC partners decided not to proceed with that project, and the City has adopted a revised resource plan similar to the alternative plan included in the 2007 TYSP report. This revised plan includes the repowering of Hopkins Unit 2 to combined cycle operation, renewable energy purchases, a commitment to an aggressive DSM portfolio and the latter year addition of peaking resources to meet energy demand over the next ten years.

3.2 PROJECTED RESOURCE REQUIREMENTS

3.2.1 TRANSMISSION LIMITATIONS

The City has projected that additional resources will be required during the 2008-2017 Ten Year Site Plan time frame to maintain a reliable electric system. The City's projected transmission import capability is a major determinant of the type, timing and location of future resource additions. The City has worked with its neighboring utilities, Progress and Southern, to plan and maintain, at minimum, sufficient transmission import capability to allow the City to make emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. As has been seen in other parts of the country, there has been little investment in the regional transmission system around Tallahassee. Consequently, the City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future, due in part to this lack of investment in facilities as well as the impact of unscheduled power flow-through on the City's transmission system.

The prospects for significant expansion of the regional transmission system around Tallahassee hinge on (i) the City's ongoing discussions with Progress and Southern, (ii) the Florida Reliability Coordinating Council's (FRCC) regional transmission planning process, (iii) the evolving set of mandatory reliability standards issued by the North American Electric Reliability Corporation (NERC), and (iv) alternative mechanisms envisioned by recent actions of the USDOE regarding key transmission corridors. Unfortunately, none of these efforts is expected to produce substantive improvements to the City's transmission import/export capability in the time frame of the system's short-term resource needs. The City continues to discuss the limitations of the existing transmission grid in the panhandle region with Progress. In consideration of the City's projected transmission import capability reductions and the associated grid limitations, the results of the IRP Study and other internal analysis of options tend to favor local generation alternatives as the means to satisfy future power supply requirements.

3.2.2 Reserve Requirements

The City uses a load reserve margin of 17% in its resource planning studies. This margin was established based in part on loss of load probability (LOLP) analysis of the City's system performed as part of a prior IRP study. The City periodically conducts LOLP analyses to determine if conditions warrant a change in the reserve margin criterion. For the purposes of this year's Ten Year Site Plan reports, the City has determined that the 17% reserve margin remains the appropriate criterion.

3.2.3 Near Term Resource Additions

At their October 17, 2005 meeting the City Commission gave the Electric Utility approval to proceed with the repowering of Hopkins Unit 2 to combined cycle operation.

The repowering will be accomplished by retiring the existing Hopkins Unit 2 boiler and replacing it with a combustion turbine generator (CTG) and a heat recovery steam generator (HRSG). The existing Hopkins 2 steam turbine and generator will be powered by the steam generated in the HRSG. Duct burners will be installed in the HRSG to provide additional peak generating capability. The repowering project will provide additional capacity as well as increased efficiency versus the Hopkins Unit 2 current capabilities. The repowered unit is projected to achieve seasonal net capacities of 296 MW in the summer and 333 MW in the winter. The major equipment has been procured and construction activities commenced in December of 2006. Current plans are for the unit to be ready for commercial operation in June of 2008.

3.2.4 POWER SUPPLY DIVERSITY

Resource diversity, particularly with regard to fuels, has long been a priority concern for the City because of the system's heavy reliance on natural gas as its primary fuel source. This issue has received even greater emphasis in light of the volatility in natural gas prices seen over recent years. The City has attempted to address this concern by implementing an Energy Risk Management (ERM) program in an effort to limit the City's exposure to energy price fluctuations. The ERM program established a organizational structure of interdepartmental committees and working groups and included the adoption of an Energy Risk Management Policy that, among other things, identifies acceptable risk mitigation products to prevent asset value losses, ensure price stability and provide protection against market volatility for fuels and energy to the City's electric and gas utilities and their customers.

Purchase contracts can provide some of the diversity desired in the City's power supply resource portfolio. The IRP Study evaluated both short and long-term purchased power options based on conventional sources as well as power offers based on renewable resources. The City has entered into two purchased power agreements with renewable energy providers, both of which involve the purchase of energy when available from projects developed by private companies but located within the City's electric service territory (see Section 3.2.5 for details on these two purchased power agreements).

As an additional strategy to address the City's lack of power supply diversity, planning staff has investigated options for a significantly enhanced demand-side management (DSM) portfolio. Commitment to this expanded DSM effort (see Section 2.1.3), combined with renewable energy purchases and an increase in customer-sited renewable energy projects (primarily solar panels) are contributing to an improvement in the City's overall resource diversity. However, diversity remains a significant issue for the City, particularly in light of pending federal and state legislation related to climate change and greenhouse gas (GHG) emissions control.

3.2.5 Renewable Resources

As part of its continuing commitment to explore clean energy alternatives, the City has continued to invest in opportunities to develop viable solar photovoltaic (PV) projects as part of our efforts to offer "green power" to our customers. The City believes that offering green power alternatives to its customers is a sound business strategy: it will provide for a measure of supply diversification, reduce dependence on fossil fuels, promote cleaner energy sources, and enhance the City's already strong commitment to protecting the environment and the quality of life in Tallahassee.

Currently the City has a portfolio of 46 kW of solar PV operated and maintained by the Electric Utility, and as of the end of March 2008, an additional 195 kW of solar PV has been installed by customers. The City promotes and encourages environmental responsibility in our community through a variety of programs available to citizens. The commitment to renewable energy sources (and particularly to solar PV) by its customers is made possible through the Go Green Tallahassee initiative, that includes many options related to becoming a greener community such as the City's Solar PV Net Metering offer. Solar PV Net Metering promotes customer investment in renewable energy generation by allowing residential and commercial customers with small to moderate sized PV installations to return excess generated power back to the City at the full retail value.

The City has also investigated other renewable resource alternatives, including solar thermal, biomass and other alternative fuels. This year the City will add 3.8 Million BTU's of solar thermal systems at the following locations: Jack McLean Park Pool, Oak Ridge Elementary School, and Fire Station #1. As reported in previous submissions, the City signed a 30-year PPA with Biomass Gas & Electric (BG&E) for up to 3.3 GWh/year of electricity and 60 million British thermal units (Btu) per hour of synthetic gas produced by BG&E's biomass-fueled synthetic gas production from a 40 MW gasification project. The electric generating facility is to be constructed within the corporate limits of Tallahassee. The target in service date for the facility is June 1, 2010. Although the permitting process has not yet begun for this facility, the City has been advised by the developer that the project remains on schedule. The City will mitigate the risk associated with this emerging technology by (i) having no contractual cost obligations other than to pay for the electric energy actually delivered, and (ii) not counting the purchase as firm capacity until the facility's reliable performance has been demonstrated for a sufficient period.

After the successful completion of the BG&E contract, the City continued its efforts to seek additional energy derived from alternative fuels. Theses efforts lead to a 30-year PPA with Green Power Systems of Jacksonville, Florida for a 40 MW project called "Renewable Fuel Tallahassee" (RFT). The City will purchase up to 3.1 GWh/yr of energy from the project that uses municipal solid waste (MSW) as its primary fuel source. The electric generating facility is to be constructed locally. The target in service date for the facility is October 1, 2010. Permitting activities for the RFT project have not yet begun.

The RFT facility will produce a synthetic gas using the Plasma Arc gasification technology that will be used as fuel for a conventional steam cycle electric generating plant. Currently there is one plant, located in Japan, that is in commercial service using this technology. The City will mitigate the risk associated with this emerging technology by (i) having no contractual cost obligations other than to pay for the electric energy actually delivered, and (ii) not counting the purchase as firm capacity untilthe facility's reliable performance has been demonstrated for a sufficient period.

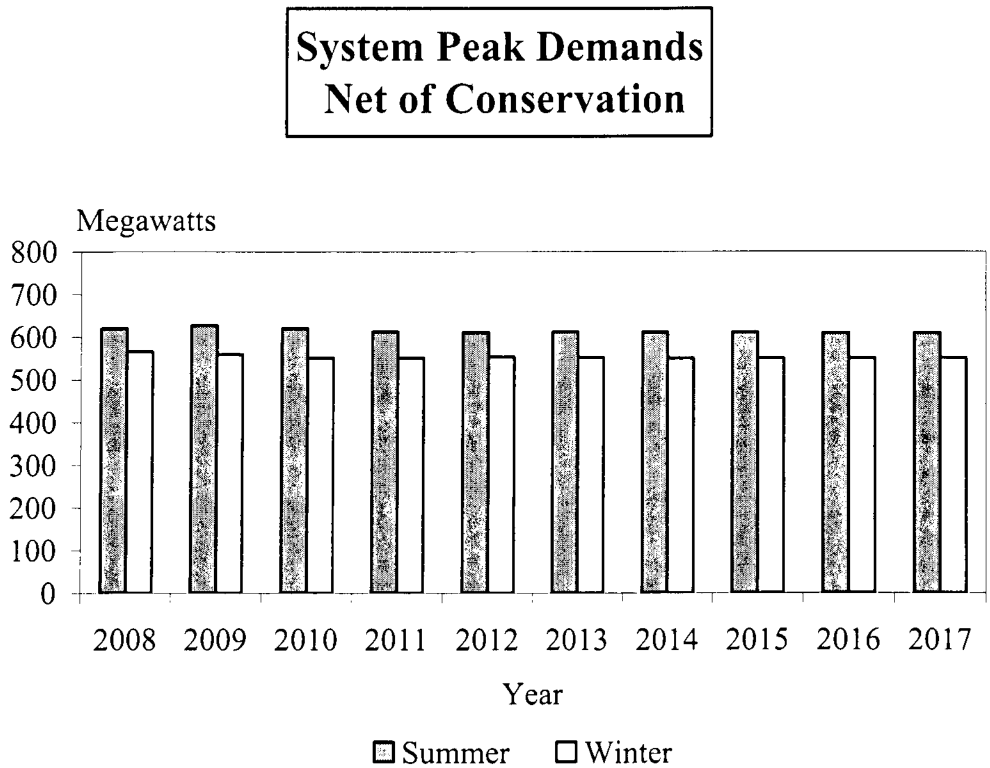
3.2.6 FUTURE POWER SUPPLY RESOURCES

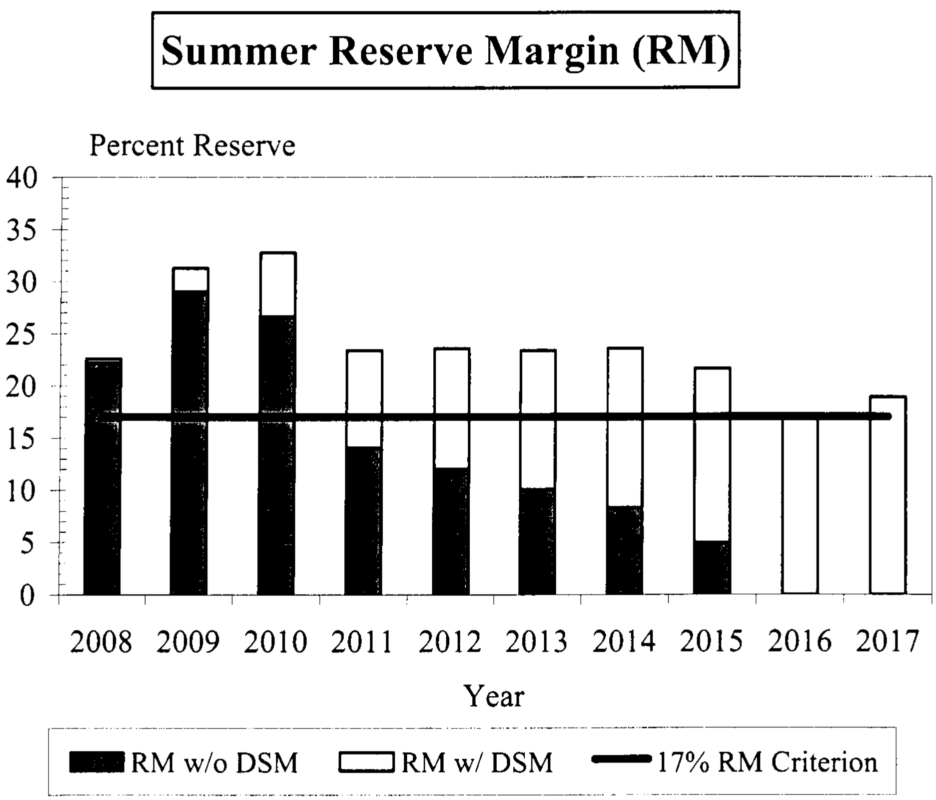
The City's currently proposed resource additions to meet system needs is represented in this report and includes two (2) peaking units in the latter years of the reporting period (2016 & 2017) to maintain the 17% reserve margin coincident with the retirement of some older and less efficient existing resources in those years. The City is currently anticipating these units to be LM 6000 gas turbines (summer rating of 46 MW), but future IRP studies may identify a different technology.

This resource plan is dependent on the expected performance of the aggressive DSM portfolio described in Section 2.1.3 of this report, and does not count the two renewable energy purchase agreements toward meeting the City's planning reserve requirement. Under these base conditions, the City has sufficient reserves to meet its planning reserve requirements until 2016. If only 50% of the DSM target is achieved, the City would require no more than 10 MW to meet its planning reserve requirements until 2014. Based on this assessment, the City's resource plan is adequate and robust enough to withstand variations in net demand without triggering an emergency addition of capacity in the near term.

The proposed renewable energy purchases offer an additional level of flexibility to meet capacity requirements during the 2008-2017 reporting period. If both the BG&E and RFT transactions can be considered as firm capacity and 100% effectiveness of the DSM portfolio is achieved, the City would need no additional resources to meet planning reserve requirements through 2020. The City continues to monitor closely the performance of the DSM portfolio, and will be evaluating the proposed renewable energy purchases to determine if these transactions can be included in future reserve calculations.

Tables 3.1 and 3.2 (Schedules 7.1 and 7.2) provide information on the resources and reserve margins during the next ten years for the City's system. The City has specified its planned capacity additions, retirements and changes on Table 3.3 (Schedule 8). These capacity resources have been incorporated into the City's dispatch simulation model in order to provide information related to fuel consumption and energy mix (see Tables 2.18, 2.19 and 2.20). Figure C compares seasonal net peak load and the system reserve margin based on summer peak load requirements. Table 3.4 provides the City's generation expansion plan. The additional supply capacity required to maintain the City's 17% reserve margin criterion is included in the "Resource Additions" column.


System Peak Demands
Net of Conservation
Megawatts
800
700
600
500
400
300
200
100
0
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
Summer
Winter


Summer Reserve Margin (RM)
Percent Reserve
40
35
30
25
20
15
10
5
0
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
Year
RM w/o DSM
RM w/ DSM
17% RM Criterion

City Of Tallahassee

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak [1]

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Year	Total Installed Capacity (MW)	Firm Capacity Import (MW)	Firm Capacity Export (MW)	QF (MW)	Total Capacity Available (MW)	System Firm Summer Peak Demand (MW)	Reserve Margin Before Maintenance (MW)	Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance (MW)	Reserve Margin After Maintenance (MW)	Reserve Margin After Maintenance % of Peak
2008	749	11	0	0	760	620	140	23	0	140	23
2009	812	11	0	0	823	627	196	31	0	196	31
2010	812	11	0	0	823	620	203	33	0	203	33
2011	744	11	0	0	755	612	143	23	0	143	23
2012	744	11	0	0	755	611	144	24	0	144	24
2013	744	11	0	0	755	612	143	23	0	143	23
2014	744	11	0	0	755	611	144	24	0	144	24
2015	732	11	0	0	743	611	132	22	0	132	22
2016	702	11	0	0	713	609	104	17	0	104	17
2017	724	0	0	0	724	609	115	19	0	115	19

Notes
[1] All installed and firm import capacity changes are identified in the proposed generation expansion plan (Table 3.4).

Table 3.1

City Of Tallahassee

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak [1]

(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
2008/09	890	11	0	0	901	565	336	59	0	336	59
2009/10	890	11	0	0	901	559	342	61	0	342	61
2010/11	890	11	0	0	901	551	350	64	0	350	64
2011/12	820	11	0	0	831	551	280	51	0	280	51
2012/13	820	11	0	0	831	553	278	50	0	278	50
2013/14	820	11	0	0	831	552	279	51	0	279	51
2014/15	820	11	0	0	831	550	281	51	0	281	51
2015/16	806	11	0	0	817	550	267	49	0	267	49
2016/17	776	0	0	0	776	550	226	41	0	226	41
2017/18	798	0	0	0	798	551	247	45	0	247	45

Notes

[1] All installed and firm import capacity changes are identified in the proposed generation expansion plan (Table 3.4).

City Of Tallahassee

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)
				Fuel		Fuel Transportation		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
Hopkins [1], [2]	2	Leon	ST	NG	DFO	PL	TK	1/07	6/08	Unknown	259,250	-151	-159	V
Hopkins [1]	2A	Leon	CT	NG	DFO	PL	TK	1/07	6/08	Unknown	187,510	156	183	V
Hopkins [1], [2]	2	Leon	ST	NG	DFO	PL	TK	1/07	11/08	Unknown	259,250	63	71	V
Purdom	CT-1	Wakulla	GT	NG	DFO	PL	TK	NA	12/63	3/11	15000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	PL	TK	NA	5/64	3/11	15000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	PL	WA	NA	6/66	3/11	50000	-48	-50	RT
Hopkins	CT-1	Leon	GT	NG	DFO	PL	TK	NA	2/70	3/15	16320	-12	-14	RT
Hopkins	1	Leon	ST	NG	RFO	PL	TK	NA	5/71	3/16	75000	-76	-78	RT
Unsited [3]	A	Unknown	CT	NG	DFO	PL	TK	12/14	5/16	Unknown	Unknown	46	48	P
Unsited [3]	B	Unknown	CT	NG	DFO	PL	TK	12/15	5/17	Unknown	Unknown	46	48	P

Notes

[1] The City has committed to a combined cycle repowering project converting the existing Hopkins 2 steam unit to a 1-on-1 combined cycle unit (296 MW summer, 333 MW winter) with the addition of a new Hopkins 2A combustion turbine to be in service by June of 2008. The "Net Capability" values in the table above reflect the changes in the existing Hopkins 2 net capacity and the additional net capacity of the Hopkins 2A combustion turbine associated with the repowering project.

[2] Reflects initial decrease in Hopkins 2 steam/turbine generator capability with conversion to CC in June 2008 and increase with operation of supplemental HRSG duct firing targeted to begin in November 2008.

[3] Prospective units needed to maintain 17% reserve margin. Site not yet determined. Can be accomodated at existing Hopkins Plant if more preferable site cannot be obtained

Acronyms

CC	Combined cycle	DFO	Diesel Fuel Oil	V	Under construction, more than 50% complete.
GT	Gas Turbine	BIT	Bituminous Coal	P	Planned for installation but not utility authorized. Not under construction
PC	Pulverized Coal	PC	Petroleum Coke	RT	Existing generator scheduled for retirement.
PRI	Primary Fuel	PL	Pipeline	kW	Kilowatts
ALT	Alternate Fuel	TK	Truck	MW	Megawatts
NG	Natural Gas	RR	Railroad		

City Of Tallahassee

Generation Expansion Plan

	Load Forecast & Adjustments									
Year	Summer Peak Demand (MW)	DSM [1] (MW)	Net Peak Demand (MW)	Existing Capacity Net (MW)	Firm Imports [2] (MW)	Firm Exports (MW)	Resource Additions (Cumulative) (MW)	Total Capacity (MW)	Res %	New Resources
2008	622	2	620	744	11		5	760	23	[3]
2009	638	11	627	744	11		68	823	31	[3]
2010	650	30	620	744	11		68	823	33	
2011	662	50	612	676	11		68	755	23	
2012	674	63	611	676 [4]	11		68	755	24	
2013	686	74	612	676	11		68	755	23	
2014	697	86	611	676	11		68	755	24	
2015	708	97	611	664 [5]	11		68	743	22	
2016	717	108	609	588 [6]	11		114	713	17	[8]
2017	726	117	609	564 [7]			160	724	19	[8]

Notes

[1] Demand Side Management includes energy efficiency and demand response/control measures. Identified as maximum achieveable reductions in the City's recently completed integrated resource planning study.

[2] Firm imports include 11 MW purchase from Progress Energy Florida (formerly Florida Power Corporation). Expires 12/3/2016.

[3] Hopkins 2 combined cycle repowering.

[4] Purdom 7 and Purdom CTs 1 & 2 official retirement currently scheduled for March 2011.

[5] Hopkins CT 1 official retirement currently scheduled for March 2015.

[6] Hopkins 1 official retirement currently scheduled for March 2016.

[7] Hopkins CT 2 official retirement currently scheduled for March 2017.

[8] New resources assumed to be two 46 MW (summer net) combustion turbines, one each to be added in the summers of 2016 and 2017. Amount and type of capacity ultimately to be added will be determined through a formal resource planning process.

Chapter IV

Proposed Plant Sites and Transmission Lines

4.1 PROPOSED PLANT SITE

As discussed in Chapter 3 the City's proposed plan to meet future system needs includes two peaking units added in the last two years of this reporting period (see Tables 4.2 and 4.3). No site selection work has been started for either of these units, but it is likely that these units can be located at one or both of the City's existing plant sites (see Figures D-1 and D-2) if a more preferable site cannot be secured. Site assessment should begin in the 2011 timeframe.

4.2 TRANSMISSION LINE ADDITIONS/UPGRADES

Internal studies of the transmission system have identified a number of system improvements and additions that will be required to reliably serve future load. The majority of these improvements are planned to the City's 115kV transmission network.

As discussed in Section 3.2, the City has been working with its neighboring utilities, Progress and Southern, to identify improvements to assure the continued reliability and commercial viability of the transmission systems in and around Tallahassee. At a minimum, the City attempts to plan for and maintain sufficient transmission import capability to allow for emergency power purchases in the event of the most severe single contingency, the loss of the system's largest generating unit. The City's internal transmission studies have reflected a gradual deterioration of the system's transmission import (and export) capability into the future. This reduction in capability is driven by lack of investment in facilities in the panhandle region as well as the impact of unscheduled power flow-through on the City's transmission system. The City is committed to continue to work with Progress and Southern as well as existing and prospective regulatory bodies in an effort to pursue improvements to the regional transmission systems that will allow the City to continue to provide reliable and affordable electric service to the citizens of Tallahassee in the future. The City will provide the FPSC with information regarding any such improvements as it becomes available.

Beyond assessing import and export capability, the City also conducted additional studies of its transmission system to identify further improvements and expansions to provide increased reliability and respond more effectively to certain critical contingencies both on the system and in the surrounding grid in the panhandle. While these evaluations are not yet complete, initial results indicate that additional infrastructure projects may be included in subsequent Ten Year Site Plan filings; these projects generally address either (i) improvements in capability to deliver power from the Hopkins Plant (on the west side of the City's service territory) to the load center, or (ii) the strengthening of the system on the east side of the City's service territory to improve the voltage profile in that area and enhance response to contingencies.

For this Ten Year Site Plan, the City's most recent system transmission expansion planning studies indicate that, if the aggressive DSM portfolio does not perform as expected throughout the planning window, a 230 kV loop around the City would be necessary by summer 2016 to ensure reliable service consistent with current and anticipated FERC and NERC requirements. For this proposed transmission project, the City intends to tap its existing Hopkins-PEF Crawfordville 230 kV transmission line and extend a 230 kV transmission line to the east terminating at the existing Substation BP-5 as the first phase of the project to be in service as early as summer 2012 (if DSM performance warrants), and then upgrade existing 115 kV lines to 230 kV from Substation BP-5 to Substation BP-4 to Substation BP-7 as the second phase of the project completing the loop by summer 2016. This new 230 kV line would address a number of potential line overloads for the single contingency loss of other key transmission lines in the City's system. Possible locations for 230/115 kV transformation along the new 230 kV line include Substations BP-5 or BP-4. This transformation may be accomplished through the addition of a new autotransformer or the relocation of the second autotransformer currently planned for connection at Substation BP-7. Table 4.4 summarizes the proposed new facilities or improvements from the transmission planning study that are within this Ten Year Site Plan reporting period.

With the exception of the second 230/115 kV autotransformer currently planned for addition at Substation BP-7, the 230 kV additions discussed in the preceding paragraph represent budgeted projects that have not yet been initiated. The City's budget planning cycle for FY 2009 is currently ongoing, and project budgets in the electric utility will not be finalized until the summer of 2008. Some of the preliminary engineering and design work is planned for later this year in anticipation of these projects being authorized during the budget planning cycle for FY 2009. If these improvements do not make the approved project list, or if other budget priorities result in the postponement of budgeted but not initiated projects, the City has prepared operating solutions to mitigate adverse system conditions that might occur as a result of the delay in the in-service date of these improvements.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Hopkins 2A Combustion Turbine	
(2)	Capacity		
	a.) Summer:	156	[1]
	b.) Winter:	183	[1]
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Jan-07	
	b.) Commercial in-service date:	Jun-08	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	DLN on natural gas, Water Injection for LFO, SCR	
(7)	Cooling Status:	Closed loop cooling (existing)	
(8)	Total Site Area:	5 acres	
(9)	Construction Status:	Under construction, more than 50% complete.	
(10)	Certification Status:	Regulatory approval received.	
(11)	Status with Federal Agencies:	Regulatory approval received.	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	6.82%	[2]
	Forced Outage Factor:	3.70%	[2]
	Equivalent Availability Factor (EAF):	86.50%	[2]
	Resulting Capacity Factor (%):	32.00%	[3]
	Average Net Operating Heat Rate (ANOHR):	7,198	[4]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW)	502	[5]
	Direct Construction Cost ($/kW):	478	[6]
	AFUDC Amount ($/kW):	NA	
	Escalation ($/kW):	24	
	Fixed O & M ($kW-Yr):	9.53	[5]
	Variable O & M ($/MWH):	4.58	[5]
	K Factor:	NA	

Notes

[1] With the addition of Hopkins CT 2A (a GE Frame 7A CT) the City's existing Hopkins 2 steam unit is being repowered to combined cycle operation to begin in June of 2008. The "Capacity" values provided in the table above reflect the total net capacity of the CT 2A unit addition. With the modifications to be made to the existing Hopkins 2 steam unit the total net CC unit seasonal capabilities will be 296 MW summer and 333 MW winter representing incremental net seasonal capacity additions of 68 MW summer and 95 MW winter.

[2] Per North American Electric Reliability Council's (NERC) Generating Availability Data System (GADS) report of 2002-2006 averages for "Combined Cycle, All MW Sizes".

[3] Projected capacity factor from in service date through 2017.

[4] Expected CC full load average net heat rate at 68°F without supplemental duct firing.

[5] 2008 dollars.

[6] 2006 dollars.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Unsited A	
(2)	Capacity		
	a.) Summer:	46	
	b.) Winter:	48	
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Dec-14	
	b.) Commercial in-service date	May-16	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	BACT compliant	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Not started	
(10)	Certification Status:	Not started	
(11)	Status with Federal Agencies:	Not started	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	4.32%	
	Forced Outage Factor:	2.40%	
	Equivalent Availability Factor (EAF):	89%	
	Resulting Capacity Factor (%):	1%	
	Average Net Operating Heat Rate (ANOHR)	9,815 Btu/kWh	[1]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW)	1,037	[1]
	Direct Construction Cost ($/kW):	851	[1]
	AFUDC Amount ($/kW):	NA	[1]
	Escalation ($/kW):	186	[1]
	Fixed O & M ($kW-Yr):	29.02	[1] [2]
	Variable O & M ($/MWH):	4.07	[1] [2]
	K Factor:	NA	

Notes
[1] Expected full load average net heat rate at 68°F.
[2] 2016 dollars.
[3] 2008 dollars.

City Of Tallahassee

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Unsited B	
(2)	Capacity		
	a.) Summer:	46	
	b.) Winter:	48	
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing		
	a.) Field Construction start - date:	Dec-15	
	b.) Commercial in-service date	May-17	
(5)	Fuel		
	a.) Primary fuel:	NG	
	b.) Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	BACT compliant	
(7)	Cooling Status:	Unknown	
(8)	Total Site Area:	Unknown	
(9)	Construction Status:	Not started	
(10)	Certification Status:	Not started	
(11)	Status with Federal Agencies:	Not started	
(12)	Projected Unit Performance Data		
	Planned Outage Factor (POF):	4.32%	
	Forced Outage Factor:	2.40%	
	Equivalent Availability Factor (EAF):	89%	
	Resulting Capacity Factor (%):	1%	
	Average Net Operating Heat Rate (ANOHR)	9,815 Btu/kWh	[1]
(13)	Projected Unit Financial Data		
	Book Life (Years)	30	
	Total Installed Cost (In-Service Year $/kW	1,063	[2]
	Direct Construction Cost ($/kW):	851	[3]
	AFUDC Amount ($/kW):	NA	
	Escalation ($/kW):	212	
	Fixed O & M ($kW-Yr):	29.75	[2]
	Variable O & M ($/MWH):	4.17	[2]
	K Factor:	NA	

Notes
[1] Expected full load average net heat rate at 6$8^{o}$F.
[2] 2017 dollars.
[3] 2008 dollars.

Figure D-1 – Hopkins Plant Site

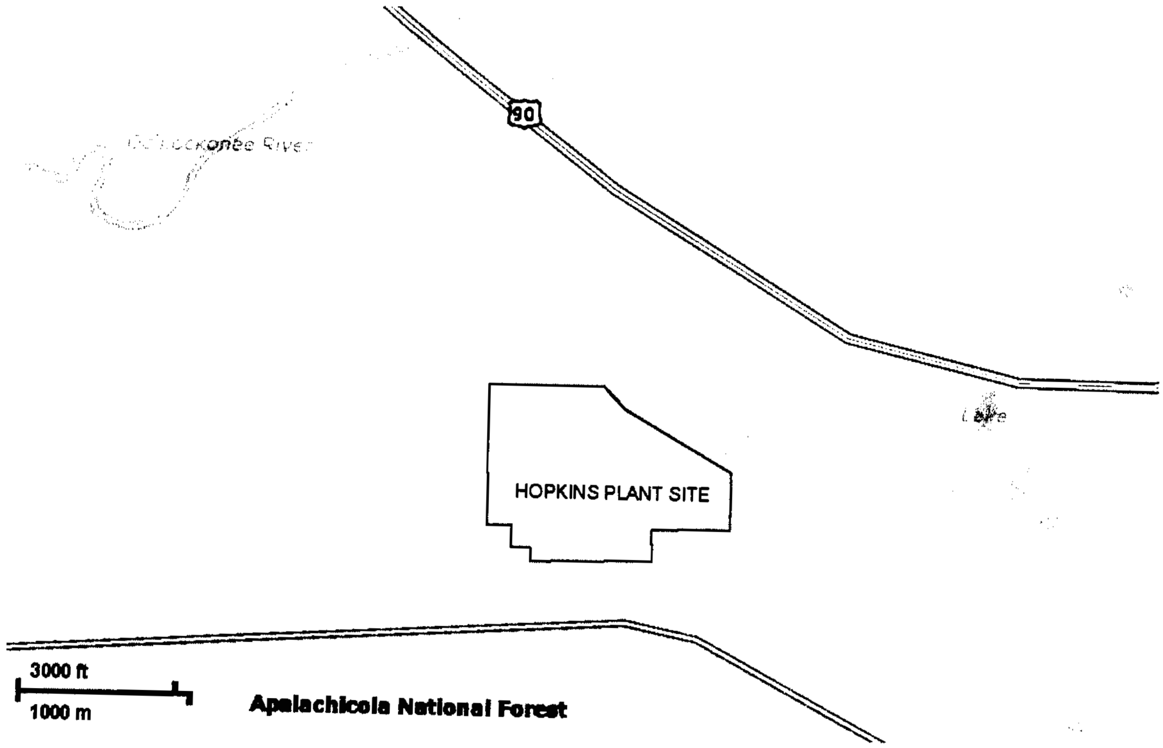


Figure D-2 – Purdom Plant Site

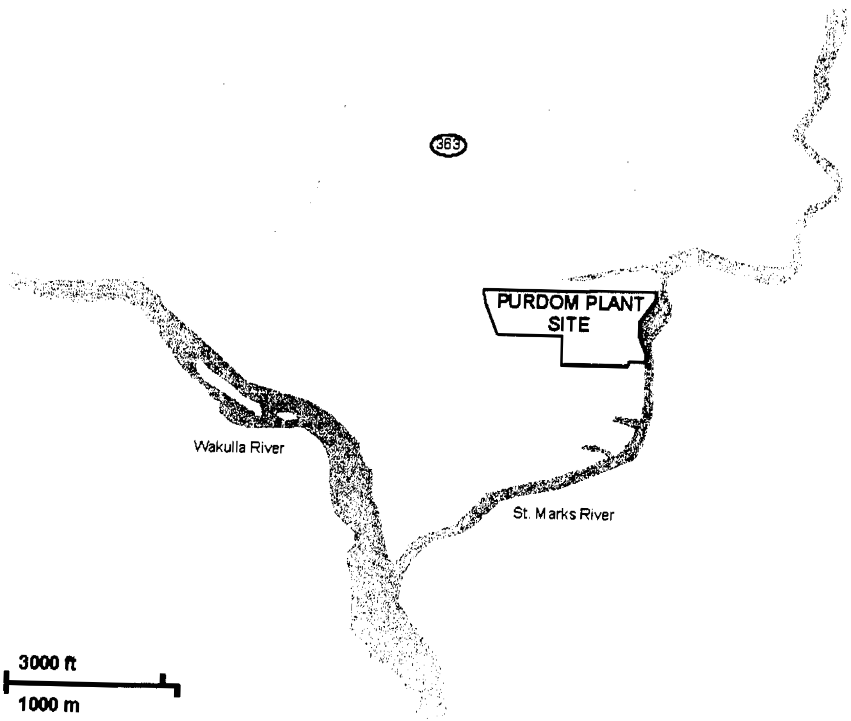


Table 4.4

Planned Transmission Projects, 2007-2016

Project Type	Project Name	From Bus Name	From Bus Number	To Bus Name	To Bus Number	Expected In-Service Date	Voltage (kV)	Line Length (miles)
New Line	Line 26 (formerly 9B)	Sub 17	7517	Sub 14	7514	12/1/09	115	4.0
	Line 25 (formerly 9A)	Sub 21	7521	Sub 17	7517	12/1/09	115	6.0
	Line 24 (formerly 9A)	Sub 9	7509	Sub 21	7521	6/1/09	115	3.0
	Line 27 (formerly 9C)	Sub 14	7514	Sub 7	7507	3/31/10	115	6.0
	Hopkins - PEF Tallahassee	Hopkins	7550	Tallahas	3136	6/1/10	115	4.0
	Line 18C	Sub 18	7518	Sub 9	7509	12/1/12	115	9.0
	Line 18B	Sub 15	7515	Sub 18	7518	12/1/12	115	6.0
	230 loop Phase I	Hop-Craw Tap	NA	Sub 5	7605	6/1/12	230	8.0
	231 loop Phase II	Sub 5	7605	Sub 7	7607	6/1/16	230	12.8
Rebuild/ Reconductor	Line 12B	Sub 2	7502	Sub 31	7531	3/31/09	115	4.3
	Line 10	Sub 6	7506	Sub 31	7531	3/31/09	115	2.0
	Line 3C	Sub 3	7503	Sub 31	7503	12/1/08	115	0.4
	Line 21	Sub 31	7531	Tallahas	3136	6/1/10	115	4.0
	Line 2C	Switch St	7553	Sub 5	7505	6/1/09	115	1.6
	Line 15C	Sub 9	7509	Sub 4	7504	6/1/10	115	4.0
	Line 15B	Sub 5	7505	Sub 9	7509	6/1/10	115	6.0
	Line 15A	Sub 5	7505	Sub 4	7504	6/1/10	115	9.0
	Line 7A	Hopkins	7550	Sub 10	7510	12/1/09	115	5.0

City Of Tallahassee

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	Hopkins/Crawfordville 230 kV Tap - Substation 5
(2)	Number of Lines:	1
(3)	Right-of -Way:	TAL Owned and New Acquisitions
(4)	Line Length:	~ 10 miles
(5)	Voltage:	230 kV
(6)	Anticipated Capital Timing [1]:	Start: Pre-2008 End: 2012
(7)	Anticipated Capital Investment:	$9.86 million
(8)	Substations:	Hopkins/Crawfordville 230 kV Tap [2]
(9)	Participation with Other Utilities:	None

Notes

[1] Capital timing contemplated in FY 2008 budget for former target in service summer 2011. Target in service slipped to summer 2012. Will update capital timing/investment as part of FY 2009 budget process.

[2] New substation to serve as origin for new 230 kV line to existing Substation 5.

City Of Tallahassee

Schedule 10
Status Report and Specifications of Proposed Directly Associated Transmission Lines

(1)	Point of Origin and Termination:	Substation 5 - Substation 7
(2)	Number of Lines:	1
(3)	Right-of -Way:	TAL Owned and New Acquisitions
(4)	Line Length:	~ 13 miles
(5)	Voltage:	230 kV
(6)	Anticipated Capital Timing:	Not yet determined; target in service summer 2016
(7)	Anticipated Capital Investment:	Not yet determined
(8)	Substations:	None [1]
(9)	Participation with Other Utilities:	None

Notes

[1] Origin and termination of new line will be at existing Substations 5 and 7.

APPENDIX A
Supplemental Data

The following Appendix represents supplemental data typically requested by the Florida Public Service Commission.

Existing Generating Unit Operating Performance

(1)	(2)		(3)		(4)		(5)		(6)	
			Planned Outage Factor (POF)		Forced Outage Factor (FOF)		Equivalent Availability Factor (EAF)		Average Net Operating Heat Rate (ANOHR)	
Plant Name	Unit No.		Historical	Projected	Historical	Projected	Historical	Projected	Historical	Projected
Existing Units										
Corn	1	[1]	NA	8.37%	NA	2.95%	NA	88.36%	NA	NA
Corn	2	[1]	NA	8.37%	NA	2.95%	NA	88.36%	NA	NA
Corn	3	[1]	NA	8.37%	NA	2.95%	NA	88.36%	NA	NA
Hopkins	1		5.34%	5.14%	0.03%	1.73%	94.63%	92.44%	12,653	12,159
Hopkins	2	[2]	15.66%	6.82%	0.08%	3.65%	84.19%	86.52%	11,092	10,362
Hopkins	GT-1		0.58%	4.30%	0.06%	3.89%	99.36%	88.62%	26,676	22,158
Hopkins	GT-2		8.49%	3.18%	2.98%	2.38%	88.53%	89.58%	26,433	18,929
Hopkins	GT-3	[3]	2.99%	4.32%	0.60%	2.43%	96.41%	89.40%	9,386	9,886
Hopkins	GT-4	[3]	1.16%	4.32%	0.15%	2.43%	98.69%	89.40%	10,437	9,907
Purdom	7		0.39%	5.14%	0.15%	1.73%	99.46%	92.44%	12,429	14,496
Purdom	8		6.33%	6.82%	2.88%	3.65%	90.79%	86.52%	7,469	7,438
Purdom	GT-1		0.07%	4.30%	0.09%	3.89%	99.84%	88.62%	25,636	28,936
Purdom	GT-2		0.26%	4.30%	0.36%	3.89%	99.38%	88.62%	24,381	28,936
Future Units										
Unsited	A		NA	8.61%	NA	2.39%	NA	89.00%	NA	9,815
Unsited	B		NA	4.38%	NA	5.20%	NA	90.00%	NA	9,815

NOTES: Historical - average of past three fiscal years
Projected - average of next ten fiscal years

[1] The City does not track the planned outage, forced outage or equivalent availability factors for the Corn Hydro units.
[2] Unit to be repowered to combined cycle operation in 2008. Historical values reflect those for existing unit, projected values reflect those expected of repowered CC.
[3] Units placed in service in the fall of 2005. Available historical data provided.

Nominal, Delivered Residual Oil Prices
Base Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2005	NA	NA	NA	40.86	649	-	NA	NA	NA
	2006	NA	NA	NA	54.80	870	34.1%	NA	NA	NA
	2007	NA	NA	NA	57.91	919	5.6%	NA	NA	NA
Forecast	2008	NA	NA	NA	81.84	1299	41.3%	NA	NA	NA
	2009	NA	NA	NA	84.92	1348	3.8%	NA	NA	NA
	2010	NA	NA	NA	87.05	1382	2.5%	NA	NA	NA
	2011	NA	NA	NA	89.21	1416	2.5%	NA	NA	NA
	2012	NA	NA	NA	91.48	1452	2.5%	NA	NA	NA
	2013	NA	NA	NA	93.74	1488	2.5%	NA	NA	NA
	2014	NA	NA	NA	96.08	1525	2.5%	NA	NA	NA
	2015	NA	NA	NA	98.47	1563	2.5%	NA	NA	NA
	2016	NA	NA	NA	100.93	1602	2.5%	NA	NA	NA
	2017	NA	NA	NA	103.45	1642	2.5%	NA	NA	NA

ASSUMPTIONS: heat content - 6.3 MMBtu/BBL, ash content - Not Available

[1] Actual average cost of oil burned.

Nominal, Delivered Residual Oil Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2005	NA	NA	NA	40.86	649	-	NA	NA	NA
	2006	NA	NA	NA	54.80	870	34.1%	NA	NA	NA
	2007	NA	NA	NA	57.91	919	5.6%	NA	NA	NA
Forecast [2]	2008	NA	NA	NA	81.84	1299	41.3%	NA	NA	NA
	2009	NA	NA	NA	87.00	1381	6.3%	NA	NA	NA
	2010	NA	NA	NA	91.35	1450	5.0%	NA	NA	NA
	2011	NA	NA	NA	95.95	1523	5.0%	NA	NA	NA
	2012	NA	NA	NA	100.74	1599	5.0%	NA	NA	NA
	2013	NA	NA	NA	105.78	1679	5.0%	NA	NA	NA
	2014	NA	NA	NA	111.07	1763	5.0%	NA	NA	NA
	2015	NA	NA	NA	116.61	1851	5.0%	NA	NA	NA
	2016	NA	NA	NA	122.47	1944	5.0%	NA	NA	NA
	2017	NA	NA	NA	128.58	2041	5.0%	NA	NA	NA

ASSUMPTIONS: heat content - 6.3 MMBtu/BBL, ash content - Not Available

[1] Actual fiscal year average cost of oil burned.
[2] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.

Nominal, Delivered Residual Oil Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
		Residual Oil (By Sulfur Content)								
		Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
	Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
History [1]	2005	NA	NA	NA	40.86	649	-	NA	NA	NA
	2006	NA	NA	NA	54.80	870	34.1%	NA	NA	NA
	2007	NA	NA	NA	57.91	919	5.6%	NA	NA	NA
Forecast [2]	2008	NA	NA	NA	81.84	1299	41.3%	NA	NA	NA
	2009	NA	NA	NA	82.91	1316	1.3%	NA	NA	NA
	2010	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2011	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2012	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2013	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2014	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2015	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2016	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA
	2017	NA	NA	NA	82.91	1316	0.0%	NA	NA	NA

ASSUMPTIONS: heat content - 6.3 MMBtu/BBL, ash content - Not Available

[1] Actual fiscal year average cost of oil burned.
[2] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas [2]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	69.26	1194	-	765	7.95	-
	2006	77.72	1340	12.2%	916	9.47	19.1%
	2007	75.34	1299	-3.1%	834	8.62	-9.0%
Forecast	2008	119.31	2057	58.4%	1,085	11.28	30.9%
	2009	123.37	2127	3.4%	1,065	11.08	-1.8%
	2010	123.54	2130	0.1%	1,007	10.47	-5.5%
	2011	126.56	2182	2.4%	993	10.33	-1.3%
	2012	129.28	2229	2.2%	997	10.37	0.4%
	2013	132.24	2280	2.3%	1,004	10.44	0.7%
	2014	137.05	2363	3.6%	1,015	10.56	1.1%
	2015	140.19	2417	2.3%	1,038	10.80	2.3%
	2016	143.78	2479	2.6%	1,062	11.04	2.2%
	2017	147.49	2543	2.6%	1,089	11.33	2.6%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.8 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] Delivered gas price reflects cost at Henry Hub increased by 3% for compression losses plus firm transportation cost.

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	69.26	1194	-	765	7.96	-
	2006	77.72	1340	12.2%	916	9.53	19.7%
	2007	75.34	1299	-3.1%	834	8.67	-9.0%
Forecast [2]	2008	119.31	2057	58.4%	1,085	11.28	30.1%
	2009	126.32	2178	5.9%	1,093	11.37	0.8%
	2010	129.63	2235	2.6%	1,060	11.02	-3.1%
	2011	136.01	2345	4.9%	1,073	11.16	1.3%
	2012	142.39	2455	4.7%	1,104	11.48	2.9%
	2013	149.23	2573	4.8%	1,139	11.85	3.2%
	2014	158.34	2730	6.1%	1,180	12.27	3.5%
	2015	165.94	2861	4.8%	1,237	12.86	4.8%
	2016	174.41	3007	5.1%	1,295	13.47	4.7%
	2017	183.28	3160	5.1%	1,361	14.15	5.0%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.8 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.
[3] Delivered gas price reflects cost at Henry Hub increased by 3% for compression losses plus firm transportation cost.

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
		Distillate Oil			Natural Gas [3]		
	Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
History [1]	2005	69.26	1194	-	765	7.96	-
	2006	77.72	1340	12.2%	916	9.53	19.7%
	2007	75.34	1299	-3.1%	834	8.67	-9.0%
Forecast [2]	2008	119.31	2057	58.4%	1,085	11.28	30.1%
	2009	120.41	2076	0.9%	1,038	10.80	-4.3%
	2010	117.51	2026	-2.4%	955	9.93	-8.1%
	2011	117.39	2024	-0.1%	919	9.56	-3.7%
	2012	117.04	2018	-0.3%	900	9.36	-2.1%
	2013	116.81	2014	-0.2%	884	9.19	-1.8%
	2014	118.09	2036	1.1%	872	9.07	-1.3%
	2015	117.86	2032	-0.2%	870	9.05	-0.2%
	2016	117.97	2034	0.1%	867	9.02	-0.3%
	2017	118.09	2036	0.1%	868	9.03	0.1%

ASSUMPTIONS FOR DISTILLATE OIL: heat content - 5.8 MMBtu/BBL;
ash content, sulfur content - Not Available

[1] Actual average cost of distillate oil and gas burned.
[2] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.
[3] Delivered gas price reflects cost at Henry Hub increased by 3% for compression losses plus firm transportation cost.

Nominal, Delivered Coal Prices [1]
Base Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2]	2008	61.14	255	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	62.89	262	2.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	60.64	253	-3.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	60.47	252	-0.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	58.62	244	-3.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	56.96	237	-2.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	60.30	251	5.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	61.58	257	2.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	61.23	255	-0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	60.15	251	-1.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is required for the City's resource planning efforts as it will allow for the evaluation of coal-based resource options.

[2] Base Case is Hill & Associates forecast for a 72% Latin American coal/28% petroleum coke blend as prepared for the partners to the former Taylor Energy Center project.

Nominal, Delivered Coal Prices [1]
High Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2], [3]	2008	45.74	255	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.09	269	5.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	46.48	266	-1.1%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	46.68	272	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	47.66	270	-0.7%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	48.68	269	-0.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	49.72	292	8.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	50.80	305	4.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	51.92	311	2.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	52.92	313	0.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is required for the City's resource planning efforts as it will allow for the evaluation of coal-based resource options.

[2] Base Case is Hill & Associates forecast for a 72% Latin American coal/28% petroleum coke blend as prepared for the partners to the former Taylor Energy Center project.

[3] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base case CAERs.

Nominal, Delivered Coal Prices [1]
Low Case

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
		Low Sulfur Coal (< 1.0%)				Medium Sulfur Coal (1.0 - 2.0%)				High Sulfur Coal (> 2.0%)			
	Year	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase	$/Ton	c/MBTU	Escalation %	% Spot Purchase
History	2005	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2006	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2007	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Forecast [2], [3]	2008	45.74	255	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2009	46.09	256	0.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2010	46.48	240	-6.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2011	46.68	233	-2.9%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2012	47.66	220	-5.6%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2013	48.68	208	-5.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2014	49.72	215	3.4%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2015	50.80	214	-0.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2016	51.92	207	-3.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
	2017	52.92	198	-4.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA

[1] Coal is not currently a part of the City's generation fuel mix. However, it's forecast price is required for the City's resource planning efforts as it will allow for the evaluation of coal-based resource options.

[2] Base Case is Hill & Associates forecast for a 72% Latin American coal/28% petroleum coke blend as prepared for the partners to the former Taylor Energy Center project.

[3] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base case CAERs.

Nominal, Delivered Nuclear Fuel and Firm Purchases

	(1)	(2)	(3)	(4)	(5)
		Nuclear		Firm Purchases	
	Year	c/MBTU	Escalation %	$/MWh	Escalation %
History	2005	NA	NA	45.56	-
	2006	NA	NA	42.00	-7.8%
	2007	NA	NA	51.05	21.5%
Forecast	2008	NA	NA	58.95	15.5%
	2009	NA	NA	44.81	-24.0%
	2010	NA	NA	45.93	2.5%
	2011	NA	NA	47.08	2.5%
	2012	NA	NA	48.26	2.5%
	2013	NA	NA	49.47	2.5%
	2014	NA	NA	50.71	2.5%
	2015	NA	NA	51.98	2.5%
	2016	NA	NA	53.28	2.5%
	2017	NA	NA	54.61	2.5%

Financial Assumptions
Base Case

AFUDC RATE	5.25%	
CAPITALIZATION RATIOS:		
DEBT	104.07%	[1]
PREFERRED	N/A	[2]
ASSETS	55.77%	[3]
EQUITY	152.80%	[3]
RATE OF RETURN (6)		
DEBT	1.80%	[4]
PREFERRED	N/A	[2]
ASSETS	0.96%	[5]
EQUITY	2.64%	[5]
INCOME TAX RATE:		
STATE	N/A	[6]
FEDERAL	N/A	[6]
EFFECTIVE	N/A	[6]
OTHER TAX RATE:		
Sales Tax (< $5,000)	7.00%	[7]
Sales Tax (> $5,000)	6.00%	[7]
DISCOUNT RATE:	2.75% - 5.25%	
TAX DEPRECIATION RATE:	N/A	[6]

[1] Plant-in-service compared to total debt

[2] No preferred "stock" in municipal utilities

[3] Net plant-in-service compared to total assets / net plant-in-service compared to total fund equity

[4] Net income compared to total debt

[5] Net income compared to total assets / net income compared to total fund equity

[6] Municipal utilities are exempt from income tax

[7] Municipal utilities are exempt from other taxes except Florida sales tax on expansion of electric transmission and distribution (T&D) tangible personal property used in the T&D system (7.0% on first $5,000 and 6% thereafter). Sales tax is no longer charged for T&D system maintenance.

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2008	2.5	2.5	2.5	2.5
2009	2.5	2.5	2.5	2.5
2010	2.5	2.5	2.5	2.5
2011	2.5	2.5	2.5	2.5
2012	2.5	2.5	2.5	2.5
2013	2.5	2.5	2.5	2.5
2014	2.5	2.5	2.5	2.5
2015	2.5	2.5	2.5	2.5
2016	2.5	2.5	2.5	2.5
2017	2.5	2.5	2.5	2.5

Monthly Peak Demands and Date of Occurrence for 2005 - 2007

Calendar Year 2005

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	24-Jan	8:00 A.M.	19	54	532
February	11-Feb	8:00 A.M.	32	59	428
March	2-Mar	10:00 A.M.	27	59	462
April	22-Apr	3:00 P.M.	52	83	391
May	24-May	5:00 P.M.	75	96	550
June	15-Jun	4:00 P.M.	73	97	579
July	27-Jul	4:00 P.M.	76	96	583
August	22-Aug	5:00 P.M.	75	96	598
September	19-Sep	5:00 P.M.	74	99	578
October	3-Oct	3:00 P.M.	76	90	494
November	30-Nov	8:00 P.M.	37	63	425
December	23-Dec	9:00 A.M.	23	62	476

Calendar Year 2006

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	19-Jan	8:00 A.M.	28	78	465
February	14-Feb	8:00 A.M.	22	82	537
March	21-Mar	4:00 P.M.	29	91	406
April	20-Apr	4:00 P.M.	38	93	502
May	30-May	5:00 P.M.	48	96	524
June	22-Jun	4:00 P.M.	54	98	572
July	19-Jul	6:00 P.M.	61	99	577
August	8-Aug	4:00 P.M.	68	97	576
September	1-Sep	5:00 P.M.	47	95	539
October	2-Oct	5:00 P.M.	35	92	473
November	20-Nov	7:00 A.M.	33	82	406
December	8-Dec	9:00 P.M.	21	79	528

Calendar Year 2007

Month	Date	Hour Ending	Daily Temp. (°F) Min.	Daily Temp. (°F) Max.	Peak Demand (MW)
January	29-Jan	8:00 A.M.	27	50	493
February	17-Feb	9:00 A.M.	18	61	504
March	28-Mar	5:00 P.M.	53	87	441
April	27-Apr	5:00 P.M.	63	85	464
May	22-May	6:00 P.M.	61	90	497
June	11-Jun	6:00 P.M.	65	101	576
July	18-Jul	5:00 P.M.	70	99	601
August	22-Aug	5:00 P.M.	75	99	621
September	6-Sep	5:00 P.M.	74	93	559
October	10-Oct	5:00 P.M.	70	91	512
November	1-Nov	6:00 P.M.	62	83	398
December	18-Dec	8:00 A.M.	31	57	437

Historical and Projected Heating and Cooling Degree Days

	Year	Heating Degree Days (HDD)	Cooling Degree Days (CDD)
History	1998	1,272	3,148
	1999	1,461	2,768
	2000	1,640	2,757
	2001	1,429	2,451
	2002	1,504	2,910
	2003	1,645	2,578
	2004	1,646	2,705
	2005	1,509	2,743
	2006	1,464	2,595
	2007	1,562	2,873
Forecast	2008	1,554	2,680
	2009	1,554	2,680
	2010	1,554	2,680
	2011	1,554	2,680
	2012	1,554	2,680
	2013	1,554	2,680
	2014	1,554	2,680
	2015	1,554	2,680
	2016	1,554	2,680
	2017	1,554	2,680

Average Real Retail Price of Electricity

Residential Real Price of Electricity ($/MWh)	Commercial Real Price of Electricity ($/MWh)	System-Wide Real Price of Electricity ($/MWh)	Deflator [1]
52.98	45.96	45.06	1.630
51.32	42.87	43.67	1.666
52.47	45.63	43.62	1.722
52.48	44.04	43.17	1.771
45.22	37.08	42.50	1.799
53.00	44.28	43.29	1.840
55.29	46.84	48.01	1.889
55.08	46.81	47.92	1.953
65.57	57.21	58.43	2.016
67.44	58.57	59.63	2.073
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	
67.44	58.57	62.23	

Deflator is CPI Index per U. S. Dept. of Labor Bureau of Labor Stats. ('82 Dollars).

For the City's 2008 Load Forecast, it was assumed that the future real price of electricity for commercial customers would remain constant at the 2007 level. While fuel prices are projected to increase in real terms, as in past load forecasts, it was assumed that these price increases would be offset by more efficient generation, reduced operations and maintenance costs, and the effects of competition.

Loss of Load Probability, Reserve Margin,
and Expected Unserved Energy
Base Case Load Forecast

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin % (Including Firm Purch.)	Expected Unserved Energy (MWh)
2003						
2004						
2005						
2006			See note [1] below			
2007						
2008						
2009						
2010						
2011						
2012						

[1] The City provides its projection of reserve margin with and without supply resource additions in Tables 3.1 and 3.2 (Schedules 7.1 and 7.2, respectively) on pages 40 and 41 and in Table 3.4 (Generation Expansion Plan) on page 43 of the City's 2008 Ten Year Site Plan. The City does not currently evaluate isolated and assisted LOLP and EUE reliability indices.