State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

110000-OT

DATE: May 4, 2011

TO: Ann Cole, Commission Clerk, Office of Commission Clerk

FROM: Phillip O. Ellis, Engineering Specialist II, Division of Regulatory Analysis POE
Traci L. Matthews, Government Analyst I, Division of Regulatory Analysis

RE: TAL's Response to 2011 Ten-Year Site Plan Supplemental Data Request #1

Attached is City of Tallahassee's Response to 2011 Ten-Year Site Plan Supplemental Data Request #1, submitted by April 29, 2011. Please place this item in Docket No. 110000 – Undocketed Filings for 2011, as it relates to the annual undocketed staff Ten-Year Site Plan Review project.

If you have any additional questions, please contact me.

POE

Attachment

2011 TEN YEAR SITE PLANS : SUPPLEMENTAL DATA REQUEST

Company Name: City of Tallahassee, Electric Utility (TAL)

Renewable Generation Resources

As used in the proceeding questions, the term "renewable energy" has the same meaning as used in Section 377.803, Florida Statutes. Please refer to the tables below when identifying fuel and generator types.

Fuel Types	Shorthand	Examples
Biomass	AB	Agriculture By-Products, Bagasse, Straw, Energy Crops.
	MSW	Municipal Solid Waste
	SLW	Sludge Waste.
	WDS	Wood / Wood Waste Solids
	OBS	Biomass Solids
Landfill Gas	LFG	Landfill gas.
Water	WAT	Hydro
Geothermal	GEO	Geothermal
Biofuels	WDL	Wood / Wood Waste Liquids
	BL	Black Liquor
	OBL	Biomass Liquids
	OBG	Biomass Gases
Solar	SUN	Solar Photovoltaic and Thermal devices
Waste Heat	WH	Waste heat from sulfuric acid manufacture
Wind	WND	Wind Energy.
Other	OTH	Any renewable not covered above. Please describe.

Generation Types	Shorthand
Combined Cycle - Steam Part	CA
Combined Cycle - Combustion Turbine Part	CT
Combined Cycle - Total Unit	CC
Compressed Air Energy Storage	CE
Combined Cycle Single Shaft	CS
Fuel Cell	FC
Combustion Turbine	GT
Hydraulic Turbine	HY
Hydraulic Turbine - Pumped Storage	PS
Internal Combustion Engine	IC
Not Available	NA
Other	OT
Photovoltaic Cells	PV
Steam Turbine	ST
Wind Turbine	WT

GENERAL QUESTIONS

1. Please provide all data requested in the attached forms labeled 'Appendix A,' in electronic (Excel) and hard copy. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

   Electronic copies of the requested data/forms are provided on the accompanying compact disc (CD). Hard copies of the requested data/forms are included in TAL's "Ten Year Site Plan: 2011-2020" delivered to the Florida Public Service Commission (FPSC) on April 1, 2011.

2. Please provide all data requested in the attached forms labeled 'Appendix B,' which consist of Schedules 1 through 10 from the Company's Ten-Year Site Plan, in an electronic copy in Excel (.xls file format).

   Electronic copies of the requested data/forms are provided on the accompanying CD.

LOAD & DEMAND FORECASTING

3. Please provide, on a system-wide basis, an average month of observed peak capacity values for Summer and Winter. From this data, excluding weekends and holidays, generate an average seasonal Daily Loading Curve. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

   Electronic copies of the requested data/forms are provided on the accompanying CD. Hard copies are presented on the following pages. February and July 2010 were selected as representative of typical winter and summer months, respectively.

Typical Summer Month

Year	Month	Day	Day of Week	Observed Hourly Peak (MW) 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24		MIN
2010		1	Thu	311	291	267	260	258	272	301	321	339	348	365	380	388	387	391	397	401	396	383	390	380	375	346	343	401	258
2010		2	Fri	295	285	263	256	255	267	291	314	328	342	352	361	366	388	400	440	435	430	405	399	380	377	350	327	440	255
2010		3	Sat	295	268	254	247	238	238	237	240	259	285	310	334		367	375		399	404	393	379	369	364	340	316	404	237
2010		4	Sun	287	267	252	245	241	240	240	242	264	297	323	345	358	367	375	380	390	395	385	369	356	346	333	313	395	240
2010		5	Mon	292	273	261	255	255	261	267	269	282	302	327	353	366	378	385	395	409	408	396	381	373	366	340	317	409	255
2010	July	6	Tue	284	266	253	245	243	254	277	306	327	348	374	397	424	453	456	440	450	464	465	449	437	425	393	309	465	243
2010		7	Wed	305	282	265	256	255	267	291	321	343	368	397	422	442	473	494	515	519	513	500	482	462	437	392	349	519	255
2010		8	Thu	328	283	266	256	254	266	295	319	349	374	407	437	467	481	511	538	546	545	540	518	491	473	438	361	546	254
2010		9	Fri	342	312	293	279	272	280	307	327	345	374	415		479	514	541	562	561	570	537	515	475	471	430	387	570	272
2010		10	Sat	351	327	304	290	282	281	232	288	314	350	384	416	448	473		454	414	402	403	399	384	380	356	392	489	281
2010	Jul	11	Sun	304	288	277	271	270	273	274	277	303	342	378	413	448	468	485		507	509	504	485	467	454	422	330	509	270
2010	Jul	12	Mon	357	335	317	310	308	321	348	368	384	405	436	468	482	463	461	457	473	495	493	490	461	449	416	389	495	308
2010		13	Tue	337	311	297	287	286	298	321	343	386	420	438	461	483	505	529	531	492	476	460	443	427	425	393	372	531	286
2010		14	Wed	317	295	283	276	275	291	320	342	378	407	426	465	490	509	507		483	476	451	437	428	415	386	355	509	275
2010		15	Thu	316	293	276	268		279	304	328	353	382	418	452	481	509	532		549	506	440	419	412	390	356	347	557	266
2010		16	Fri	295	278	265	257	256	270	295	316	344	373	409	444	470	486		499	482	483	459	435	416		376	324	509	256
2010	Jul	17	Sat	316	293	276	266	261	263	269		296	318	339	373	407	425	429		454	456	437	395	380	371	347	362	456	261
2010		18	Sun	296	279	265	257	251	250	251	254	280	321	355	389	421	450	470	481	475	436	407	392		381	358	320	481	250
2010	July	19		296	275	261	255	256	268	293	315	340	371	407	432	443	426	413	406	413	412	415	410	408	403	378	324	443	255
2010				307	286		266	267	280	308	329	361	386	419	455	489	511	526	535	535	537	526	501	492	460	422	345	537	
2010		21		348	322	300	290	288	300	325	345	367	393	423	449	475	501	530	551	559	559	543	514	493	473	427	383	559	288
2010		22	Thu	357	329	306	295	291	302	326		367	395	435	466	497	526	549	575	592	590	557	531	383	467	423	396	592	291
2010		23	Fri	342	315	297	288	283	294	317		357	396	442	479	516	544	574	574	577	570	549	522	495	483	446	377	577	283
2010		24	Sat	374	357	325	308	298	297	299	302	329	364	399	430	459	484		500	513	518	506	484	473	457	423	415	518	297
2010		25	Sun	356	337	320	307	298	296	295	295	322	364	400	428	456	457	455	466	481	488	474	458	444	433	402	388	488	295
2010		26	Mon	337	320	306	300	299	309	331		374	404	438	471	506	534	553	565	548	524	501	468	455	442	407	370	565	299
2010		27	Tue	337	316	299	290		299	325	345	368	399	439	470	500	533	552	574	576	576	553	529	506	490	448	369	576	286
2010		28	Wed	368	341	319	308	304	316	342		385	410	447	477	509	545	568	570	584	584	563	542	517	503	460	408	584	304
2010		29	Thu	377	347	323	309	303	312	336		383	412	460	495	514	538	563	574	586	575	562	519	507	485	453	422	586	303
2010	Jul	30	Fri	376		329	318	315	327			399	425	460	500	532	559	576		601	586	570	549	529	514	474	415	601	
2010	July	31		403	378	356		332	328	328	328	350	386	428	474	507	538	549	549	500	458	435	418	411	365	343	438	549	328
		AVG[1]		328	306	289	279	276	284	302	317	341	370	402	432	457	477	492	499	500	495	478	459	439	428	396	363	512	275
		MAX[1]		377	378	356	342	332	328	351	368	399	425	460	500	532	559	576	593	601	590	570	549	529	514	474	438	601	328
		MIN[1]		284	266	252	245	238		237	240	259	285	310	334	355	367	375	380	390	395		369	356			309	395	237

[1] Values calculated excluding weekends and holidays

Typical Winter Month

Year	Month	Day	Day of Week	Observed Hourly Peak Capacity (MW) 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	MAX (MW)	MIN (MW)
2010	February	1	Mon	341	334	326	320	326	352	399	425	410	391	390	369	356	344	333	324	325	348	385	387	372	344	316	356	425	316
2010	February	2	Tue	256	246	231	229	235	255	300	331	322	314	313	316	313	314	306	313	313	343	371	372	365	351	323	288	372	229
2010	February	3	Wed	291	288	277	278	290	319	371	408	401	360	342	328	311	300	290	287	298	314	345	355	354	338	311	302	408	277
2010	February	4	Thu	263	250	243	242	249	270	314	342	333	320	315	310	294	290	296	283	284	294	323	330	328	308	283	288	342	242
2010	February	5	Fri	240	227	216	210	213	233	267	301	302	299	302	303	304	299	298	290	298	306	317	321	311	292	275	262	321	210
2010	February	6	Sat	240	236	219	213	214	222	236	253	271	287	292	293	292	289	282	283	291	309	333	339	337	331	321	255	339	213
2010	February	7	Sun	294	287	284	284	288	297	310	326	342	354	351	346	344	333	317	306	306	320	345	353	356	350	350	307	356	284
2010	February	8	Mon	323	317	319	327	341	376	436	468	439	404	369	343	324	307	295	289	289	312	342	364	361	356	336	336	468	289
2010	February	9	Tue	291	284	277	274	280	303	352	386	369	359	359	353	337	314	303	313	306	316	343	356	349	335	318	312	386	274
2010	February	10	Wed	290	294	300	314	336	374	441	495	475	450	428	404	384	365	348	344	360	382	429	446	449	431	403	297	495	290
2010	February	11	Thu	359	355	352	359	374	407	466	486	462	441	415	406	395	383	375	375	382	410	448	455	445	423	394	377	486	352
2010	February	12	Fri	336	326	322	324	333	359	414	451	437	431	435	436	432	431	418	419	417	441	464	461	457	449	425	361	464	322
2010	February	13	Sat	391	378	373	374	378	391	415	437	454	448	424	395	367	345	328	319	318	334	370	394	402	404	398	406	454	318
2010	February	14	Sun	386	388	394	400	409	425	446	461	465	430	383	345	322	304	289	280	280	294	325	344	345	338	329	392	465	280
2010	February	15	Mon	301	295	295	299	312	337	375	400	388	377	377	376	370	351	345	334	332	342	382	416	422	417	400	313	422	295
2010	February	16	Tue	370	367	371	375	395	432	493	523	498	462	433	404	379	358	341	331	333	358	401	429	431	419	409	378	523	331
2010	February	17	Wed	366	364	372	386	408	450	514	542	507	458	419	388	365	345	332	322	326	344	384	409	415	403	387	392	542	322
2010	February	18	Thu	343	339	345	357	381	422	488	518	486	439	402	373	349	332	316	302	269	321	358	383	389	384	371	369	518	269
2010	February	19	Fri	334	325	313	317	330	362	419	447	424	385	356	329	309	300	291	285	287	302	314	329	325	311	302	355	447	285
2010	February	20	Sat	269	266	269	275	283	297	319	338	351	335	314	295	282	270	261	256	257	264	285	302	299	292	282	284	351	256
2010	February	21	Sun	259	255	258	262	271	286	317	320	331	317	296	277	268	264	260	258	260	270	291	304	298	281	262	272	331	255
2010	February	22	Mon	221	209	203	201	205	225	266	302	304	303	306	306	301	297	291	288	288	305	326	342	330	308	291	241	342	201
2010	February	23	Tue	232	220	213	211	216	238	283	318	315	318	314	292	302	303	302	299	295	295	314	337	332	319	296	264	337	211
2010	February	24	Wed	263	253	237	236	245	275	332	363	353	345	338	340	339	348	349	361	362	388	417	439	428	421	396	284	439	236
2010	February	25	Thu	360	353	347	352	367	402	468	498	476	445	424	397	373	355	333	329	331	345	389	428	433	432	410	374	498	329
2010	February	26	Fri	380	377	382	387	405	441	502	526	484	429	394	369	347	330	314	305	305	313	338	371	361	362	348	393	526	305
2010	February	27	Sat	330	311	305	299	298	305	319	330	342	343	342	334	327	315	302	290	291	299	322	348	352	349	340	342	352	290
2010	February	28	Sun	319	315	316	320	329	344	364	382	382	360	336	312	297	284	275	268	267	274	297	323	327	320	306	329	382	267
		29																											
		30																											
		31																											
		AVG[1]		308	301	297	300	312	342	395	427	409	387	372	357	344	333	324	320	320	339	370	386	383	370	350	327	438	279
		MAX[1]		380	377	382	387	408	450	514	542	507	462	435	436	432	431	418	419	417	441	464	461	457	449	425	393	542	352
		MIN[1]		221	209	203	201	205	225	266	301	302	299	302	292	294	290	290	283	269	294	314	321	311	292	275	241	321	201

[1] Values calculated excluding weekends and holidays.

4. Please provide, on a system-wide basis, historical annual heating degree day (HDD) and cooling degree day (CDD) data for the period 2001 through 2010 and forecasted annual HDD and CDD data for the period 2011 through 2020. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		HDD	CDD
Actual	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	1,410	2,493
	2007	1,364	2,905
	2008	1,587	2,610
	2009	1,573	2,797
	2010	1,924	3,047
Projected	2011	1,578	2,787
	2012	1,578	2,787
	2013	1,578	2,787
	2014	1,578	2,787
	2015	1,578	2,787
	2016	1,578	2,787
	2017	1,578	2,787
	2018	1,578	2,787
	2019	1,578	2,787
	2020	1,578	2,787

An electronic copy of the requested data/form is provided on the accompanying CD. This information is also presented in a table that appears on page A-15 of TAL's "Ten Year Site Plan: 2011-2020" report delivered to the Florida Public Service Commission (FPSC) on April 1, 2011.

5. Please provide the following data to support Schedule 4 of the Company's Ten-Year Site Plan: the 12 monthly peak demands for the years 2008, 2009, and 2010; the date when these monthly peaks occurred; and, the temperature at the time of these monthly peaks. Describe how the Company derives system-wide temperature if more than one weather station is used. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

An electronic copy of the requested data/form is provided on the accompanying CD. A hardcopy is provided on the following page. This information is also presented in a table that appears on page A-14 of TAL's "Ten Year Site Plan: 2011-2020" report delivered to the Florida Public Service Commission (FPSC) on April 1, 2011.

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour[1]	Temperature[2] Min (°F)	Max (°F)
2008	1	526	3	Thu	8:00 A.M.	25	46
	2	510	14	Thu	8:00 A.M.	25	64
	3	394	25	Tue	8:00 A.M.	26	66
	4	430	25	Fri	8:00 P.M.	62	84
	5	516	29	Thu	6:00 P.M.	66	94
	6	548	25	Wed	6:00 P.M.	70	96
	7	587	21	Mon	5:00 P.M.	75	97
	8	556	6	Wed	5:00 P.M.	73	98
	9	542	15	Mon	5:00 P.M.	69	93
	10	520	4	Sat	8:00 P.M.	53	87
	11	465	19	Wed	8:00 A.M.	25	56
	12	468	3	Wed	8:00 A.M.	27	59
2009	1	579	22	Thu	8:00 A.M.	18	59
	2	578	5	Thu	8:00 A.M.	14	51
	3	481	4	Wed	8:00 A.M.	26	65
	4	415	22	Wed	5:00 P.M.	52	91
	5	491	11	Mon	6:00 P.M.	69	94
	6	605	22	Mon	5:00 P.M.	76	103
	7	578	2	Thu	4:00 P.M.	72	98
	8	569	12	Wed	5:00 P.M.	74	95
	9	530	24	Thu	6:00 P.M.	74	92
	10	539	7	Wed	4:00 P.M.	74	94
	11	345	2	Mon	8:00 P.M.	45	61
	12	465	21	Mon	8:00 A.M.	28	56
2010	1	633	11	Mon	8:00 A.M.	14	50
	2	542	17	Wed	8:00 A.M	23	56
	3	476	4	Thu	8:00 A.M.	28	56
	4	399	6	Tue	5:00 P.M.	52	85
	5	526	24	Mon	6:00 P.M	66	96
	6	581	16	Wed	5:00 P.M.	75	98
	7	601	30	Fri	5:00 P.M.	78	103
	8	580	4	Wed	4:00 P.M.	74	96
	9	557	10	Fri	5:00 P.M.	68	97
	10	483	27	Wed	4:00 P.M.	72	88
	11	376	8	Mon	8:00 A.M.	31	72
	12	539	14	Tue	8:00 A.M.	24	46

[1] Hour ending.

[2] Temperature at time of peak not recorded. Daily minimum and maximum temperatures provided.

6. Please discuss any recent trends in customer growth, by customer type (residential, industrial & commercial, etc), and as a whole. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, is a decline in customers a loss of temporary construction meters or a decline in population?)

Growth has slowed in recent years for residential and commercial customers (TAL has no industrial customers). The slower customer growth generally corresponds with the slower pace of population growth. For the period from 2001-2005, the average annual growth rates (AAGR) for Leon County population, residential and commercial customers were 2.36%, 2.72% and 1.89%, respectively. In contrast, the AAGRs for 2006-2010 were 0.27%, 0.87% and -0.15%. Economic conditions during and following the 2008 recession likely impacted population and customer growth rates. For example, real per capita taxable sales declined significantly for the period 2006-2010, and this impacted customer growth, with the commercial customers more affected than residential.

7. Please discuss any impacts of "smart" or digital meter installations on forecasting sales and net energy for load. Please explain the nature or reason for these trends, and identify what types of customers are most affected by these trends. (For example, are increased sales due to more accurate measurement of low-load conditions?)

There is no discernible difference in energy measurement due to the replacement of existing meters with smart meters, and thus no adjustment has been made to the sales and net energy for load forecast. Reductions in demand and energy sales are anticipated when TAL adopts programs and rates associated with its Smart Grid implementation that will primarily impact residential and small commercial customers. These impacts are reflected in TAL's DSM plan.

RENEWABLE GENERATION

8. Please provide the estimated total capacity of all renewable resources the utility owns or purchases as of January 1, 2011. Include in this value the sum of all utility-owned, and purchased power contracts (firm and non-firm), and purchases from as-available energy producers (net-metering, self-generators, etc.). Please also include the estimated total capacity of all renewable resources (firm and non-firm) the utility is anticipated to own or purchase as of the end of the planning period in 2020.

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar	0.940	0.025
Wind	0.000	0.000
Biomass	0.000	0.000
Municipal Solid Waste	0.000	35.000
Waste Heat	0.000	0.000
Landfill Gas	0.000	0.000
Hydro	12.500	0.000
Total	13.440	35.025

9. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement as of January 1, 2011. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

Existing Renewables as of January 1, 2011

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
NONE							

Existing Renewables as of January 1, 2011 (Continued)

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)[3]		Annual Generation[4]	Capacity Factor[5]
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
Corn Hydro[1]	HY	WAT	06/1986	0.0	0.0	18,000.0	19
Trousdell Pool[2]	PV	SUN	1998	10.0	8.0	13.5	15
CCOC[2]	PV	SUN	1998	18.0	14.4	24.3	15
McLean Pool[2]	PV	SUN	03/2009	7.0	5.6	9.5	15
Wade-Wehunt Pool[2]	PV	SUN	08/2009	5.0	5.0	7.9	15
Montford School[2]	PV	SUN	11/2008	2.0	2.0	2.6	15
Oakridge School[2]	PV	SUN	12/2008	2.0	2.0	2.6	15
Hilaman Golf[2]	PV	SUN	03/2010	5.0	4.6	6.6	15
Smith-Williams Center[2]	PV	SUN	05/2010	5.0	4.6	6.6	15
Smith-Williams Annex[2]	PV	SUN	05/2010	5.0	4.6	6.6	15
Fire Station #12	PV	SUN	03/2011	5.0	5.0	6.6	15
Animal Service Center[2]	PV	SUN	09/2010	4.2	4.2	5.5	15
FSU/FAMU COE[2]	PV	SUN	02/2005	6.2	6.2	8.1	15
FSU CAPS[2]	PV	SUN	02/2005	6.0	6.0	7.9	15

[1] Because the C. H. Corn hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservior and downstream conditions), the City considers these units as "energy only" and not as dependable capacity for planning purposes.
[2] The PV installations at these facilities are installed on the customer's side of the meter and are, for planning purposes, treated not as firm supply resources but as DSM reductions to the customer's actual billing demand and energy consumption.
[3] The Net Capacity of solar resources is rated in volts DC
[4] The Annual Generation of solar resources is calculated as the DC rating x 1314 /hours per year
[5] The Capacity Factor of solar resources is calculated as (1314/8760)*100 = 0.15 CF

Firm Renewable Purchased Power Agreements

Facility Name			Unit Commercial In-Service Date	Net Capacity		Annual Generation	Capacity Factor		
-	-	-	(MM/YYYY)	Sum			(%)		
NONE									

Non-Firm Renewable Purchased Power Agreements

Facility Name			Unit Commercial In-Service Date	Net Capacity		Annual Generation	Factor		
-	-	-	(MM/YYYY)	Sum	Win		(%)		
NONE									

10. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement planned during the 2011 through 2020 period. For both utility-owned and purchased resources, please divide them into Firm and Non-Firm categories as shown below. Please also include those renewable resources which provide fuel to conventional facilities, if applicable, with estimates of their capacity and energy contributions. As part of this response, please include the description of the unit's generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. For purchased power agreements, also provide the contract start and end dates. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

Planned Renewables for 2011 through 2020

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
Jake Gaither Golf	PV	SUN	04/2011	15.0	15.0	19.7	15
StarMetro	PV	SUN	06/2011	10.2	10.2	13.4	15

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
NONE							

Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)		
Renewable Fuels Tallahassee	ST	Biomass - MSW	12/31/2013	35,000	35,000	260,610	85	12/31/2013	12/31/2033

Non-Firm Renewable Purchased Power Agreements

Facility Name	Unit Type	Fuel Type	Unit Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)		
NONE									

11. Please refer to the list of planned utility-owned renewable resource additions with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.

The City will continue to promote renewable activities include the participation in FSEC's SunSmart program. Information on the goals and objects of the SunSmart program can be found on FSEC's website. The "Schools on Solar" program with the Leon County School Board primary objective is bring both solar PV and Thermal into the classroom as teaching and learning tool for local students and teachers, by having actual working systems located at certain schools. For the planning period 2010 – 2019, the City expects to continue with the installation of small scale Solar PV (25 KW or less) on city owned facilities as part of the City's program to make all City owned facilities as energy efficient as possible. The City does not expect to add large scale utility grade Solar PV resources as these projects have negative impacts to rate payers due to high cost of the projects.

12. Please refer to the list of existing or planned renewable PPAs with an in-service date for the renewable generator during the 2011 through 2020 period outlined above. Please discuss the current status of each project.

The Renewable Fuel Tallahassee contract remains in effect. The current condition of the financial market has slowed the project as RFT continues to seek the remaining financing requirements. The RFT developer has assigned the contract to ECOSPHERE LLC for financing and development. The COD has been amended to December 31, 2013. The City remains optimistic that the new project owners will meet the new COD.

13. Please provide a description of each renewable facility in the company's service territory that it does not currently have a PPA with, including self-service facilities. As part of this response, please include the description of the unit's location, generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), annual energy generation. Please exclude from this response small customer-owned renewable resources, such as rooftop PV, which are more appropriately included in the following question. Please complete the tables below and provide an electronic copy in Excel format and hardcopy.

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
NONE							

14. Please provide the number of customer-owned renewable resources within the Company's service territory. Please organize by resource type, and include total estimated installed capacity and annual output. Please exclude from this response any customer-owned renewable resources already accounted for under PPAs or other sources. If renewable energy types beyond those listed were utilized, please include an additional row and a description of the renewable fuel and generator. For non-electricity generating renewable energy systems, such as geothermal cooling and solar hot water heaters, please use kilowatt-equivalent and kilowatt-hour-equivalent units. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic	38	220	286,452
Residential	Solar Thermal Water Heating	44	443	101,200
Residential	Geothermal Heat Pump	10	30	84,090
Residential	Wind Turbine	0	0	0
Residential	Other (Describe)	0	0	0
Commercial	Solar Photovoltaic	45	640	840,960
Commercial	Solar Thermal Water Heating	2	141	32,200
Commercial	Geothermal Heat Pump	0	0	0
Commercial	Wind Turbine	0	0	0
Commercial	Other (Describe)	0	0	0

The PV installations at these facilities are installed on the customer's side of the meter and are, for planning purposes, treated not as firm supply resources but as DSM reductions to the customer's actual billing demand and energy consumption.

Solar Photovoltaic installations are assumed to provide 1,314 kWh/year for each kW of installed capacity and Solar Thermal Water Heating installations are assumed to provide 2,300 kWh per installation based on National Renewable Energy Laboratory (NREL) and Florida Solar Energy Center estimates for Tallahassee.

Solar Thermal Installed Capacity is calculated using panel daily BTU production/ 3412 BTU/ kW.

15. Please provide the annual output for the company's renewable resources (owned and purchased through PPA), retail sales, and the net energy for load for the period 2010 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	19.9	17.5	17.6	17.6	17.6	17.6	16.3	17.6	17.6	17.6	17.6
	PPA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total	19.9	17.5	17.6	17.6	17.6	17.6	16.3	17.6	17.6	17.6	17.6
Retail Sales		2,754.3	2,643.1	2,652.3	2,639.8	2,626.4	2,614.3	2,601.9	2,589.0	2,577.4	2,568.7	2,558.7
Net Energy for Load		2,931.3	2,800.2	2,809.9	2,796.7	2,782.5	2,769.7	2,756.6	2,742.9	2,730.6	2,721.4	2,710.7

16. Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2001 through 2010. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2011 through 2020. Please use the Consumer Price Index to calculate real as-available energy rates. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year	As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2010	Not Applicable		
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			

The City does not calculate or publish an as-available energy rate.

17. Please discuss any studies conducted or planned regarding the use combinations of renewable and fossil fuels in existing or future fossil units. What potential does the Company identify in this area?

The City was approached in 2005 by a company promoting plasma torch technology to convert municipal solid waste to a synthesis gas to supplement the fuel needs of the now decommissioned Hopkins Unit 2 boiler. The idea was abandoned because it had several technical problems, such as distance from the plasma torch site to the generating station, high temperature, low heat content and small potential amount of synthesis gas. Potential application to Hopkins Unit 1 was also considered but discounted for the same reasons and because Hopkins Unit 1's expected capacity factor would not allow for a reason period for return on the investment.

The original equipment manufacturers (OEM) of combustion turbine generators (CTG) are in the process of testing various biofuels. This appears to be a lower priority effort because of the current abundance and lower prices of natural gas. At the moment, the City is not aware of any OEM approved biofuel for use in LM 6000 or 7 FA CTGs like those in the City's generation fleet.

The City has not conducted any studies regarding the combined use of renewable and fossil fuels in existing or future fossil units other than those mentioned above.

18. Please discuss any planned renewable generation or renewable purchased power agreements within the past 5 years that did not materialize. What was the primary reason these generation plans or purchased power contracts were not realized? What, if any, were the secondary reasons?

The City had a 30 year PPA with Biomass Gas & Electric for a 42 MW advanced gasification projected to be located in southwest Tallahassee. After filing permits, insurmountable public sentiment against the project was encountered. BG&E decided to cancel the contract rather than fight with the public over the plant.

19. Please discuss whether the company purchases or sells Renewable Energy Credits. As part of this response, please discuss whether the company offers the sale of Renewable Energy Credits to its customers through a green pricing or similar program.

At the present time, there is not a market for Renewable Energy Credits (REC) in Florida or the Southeast. The City has explored selling RECs generated from PV systems into PJM and Europe, but these have little economic value if not generated in the control area.

TRADITIONAL GENERATION

20. Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2011 Ten-Year Site Plan. If available, please provide the cumulative present worth revenue requirement for any sensitivities conducted of the Company's generation expansion plan.

The resource plan reflected in the City's 2011 Ten Year Site Plan is fundamentally that identified in our last integrated resource planning study completed in 2007. Since that time one renewable PPA was terminated, the progress of another renewable PPA has been has been delayed and implementation of the City's Demand Side Management (DSM) program has been delayed by contract negotiations with an energy services provider and slower than expected maturity of associated technologies. The City has not re-evaluated the cumulative present worth of revenue requirements associated with the revised resource plan.

21. Please illustrate what the Company's generation expansion plan would be as a result of sensitivities to the base case demand. Include impacts on unit in-service dates for any possible delays, cancellations, accelerated completion, or new additions as a result.

Under its high band peak demand forecast sensitivity the City's generation expansion plan would likely be changed. The timing of need does not change under that sensitivity but a total of 65 MW of additional summer net capacity would be needed by summer 2020 to satisfy load and planning reserve requirements through the planning period versus 5 MW assuming base case demand with DSM.

Additional generating capacity could also be needed depending upon the actual vs. predicted performance of the City's demand-side management (DSM) portfolio. Assuming only half of the currently projected DSM summer peak demand reductions are realized, an additional 4 MW summer net capacity would be needed by summer 2017 and a cumulative total 65 MW would be needed to satisfy load and planning reserve requirements through the planning period ending 2020.

These prospective needs could be satisfied with the 2020 addition of a second 50 MW class combustion turbine generator (CTG) similar to the Hopkins GT 3 and 4 added in 2005 (in addition to the single CT shown in the City's Ten Year Site Plan as added in 2020). The timing, site, type and size of any new power supply resources may vary as the nature of the need becomes better defined. Alternatively, proposed additions could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

22. Please complete the following table detailing planned unit additions, including information on capacity and in-service dates. Please include only planned conventional units with an in-service date past January 1, 2011, and including nuclear units, nuclear unit uprates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

Planned Unit Additions for 2011 through 2020

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
NONE				
Combustion Turbine Unit Additions				
Hopkins CT 5[1]	46	NA	NA	May-20
Combined Cycle Unit Additions				
NONE				
Steam Turbine Unit Additions				
NONE				

[1] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. No petition to certify the need for this capacity has yet been filed. Siting under the Power Plant Siting Act (PPSA) would not be required for a 50 MW class simple cycle combustion turbine generator. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

23. For each of the generating units contained in the Company's Ten-Year Site Plan, please discuss the "drop dead" date for a decision on whether or not to construct each unit. Provide a time line for the construction of each unit, including regulatory approval, and final decision point.

For a simple cycle combustion turbine generator (CTG), delivery times are estimated as approximately twelve (12) months for a General Electric (GE) LM6000 and 16-18 months for a GE LMS 100. A CTG project developed sequentially (i.e., engineering and permitting performed together, then equipment purchased equipment, then unit constructed) at an existing plant ("brownfield") site would require a construction decision to be made approximately 36 months prior to the desired in-service date. This assumes:

- *4 months – permit application process*
- *6 months permitting*
- *4 months – procurement cycle*
- *12 months delivery*
- *10 months construction*

It is possible to compress the schedule above by buying equipment prior to permitting being approved, engineering just in time for construction and starting construction before all equipment is delivered.

Additional time would be required for land acquisition if the CTG were to be planned for a new ("greenfield") site.

24. Please complete the following table detailing unit specific information on capacity and fuel consumption for 2010. For each unit on the Company's system, provide the following data based upon historic data from 2010: the unit's capacity; annual generation; resulting capacity factor; estimated annual availability factor; unit average heat rate; quantity of fuel burned; average cost of fuel; and resulting average energy cost for the unit's production. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	
Purdom	7	ST	NG	50.0	48	48	50,576	12.0	97.0	Jun-66
Purdom	8	CC	NG/DFO	247.7	222	258	1,138,784	58.6	82.2	Jul-00
Purdom	CT 1	CT	NG/DFO	15.0	10	10	526	0.6	100.0	Dec-63
Purdom	CT 2	CT	NG/DFO	15.0	10	10	348	0.4	98.5	May-64
Hopkins	1	ST	NG/RFO	75.0	76	78	149,491	22.5	99.8	May-71
Hopkins	2	CC	NG/DFO	358.2	300	330	1,243,954	47.3	85.5	Jun-08
Hopkins	CT 1	CT	NG/DFO	16.3	12	14	238	0.2	100.0	Feb-70
Hopkins	CT 2	CT	NG/DFO	27.0	24	26	1,121	0.5	100.0	Sep-72
Hopkins	CT 3	CT	NG/DFO	60.5	46	48	19,159	4.8	98.1	Sep-11
Hopkins	CT 4	CT	NG/DFO	60.5	46	48	28,982	7.2	99.6	Nov-11
Corn[1]	1	HYD	WAT	4.4	0	0	2,846	8.1	NA[2]	Sep-85
Corn[1]	2	HYD	WAT	4.4	0	0	6,265	17.9	NA[2]	Aug-85
Corn[1]	3	HYD	WAT	3.4	0	0	10,659	40.6	NA[2]	Jan-86

1 Because the C. H. Corn hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservoir and downstream conditions), the City considers these units as "energy only" and not as dependable capacity for planning purposes.

2 The City does not track the planned outage, forced outage or equivalent availability factors for the Corn Hydro units.

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	(MMBTU)	($000)	($/MMBTU)	(¢/kWh)
Purdom	7	NG	13,447	680,097	5,302	7.80	10.48
Purdom	8	NG/DFO	7,842	8,929,814	68,065	7.62	5.98
Purdom	CT 1	NG/DFO	33,024	17,354	119	6.85	22.63
Purdom	CT 2	NG/DFO	34,291	11,916	82	6.85	23.50
Hopkins	1	NG/RFO	13,003	1,943,827	14,493	7.46	9.70
Hopkins	2	NG/DFO	7,824	9,732,221	74,807	7.69	6.01
Hopkins	CT 1	NG/DFO	38,147	9,079	65	7.16	27.30
Hopkins	CT 2	NG/DFO	26,772	30,011	215	7.16	19.16
Hopkins	CT 3	NG/DFO	10,525	201,652	1,443	7.16	7.53
Hopkins	CT 4	NG/DFO	10,289	298,183	2,134	7.16	7.36
Corn	1	WAT	NA	NA	NA	NA	NA
Corn	2	WAT	NA	NA	NA	NA	NA
Corn	3	WAT	NA	NA	NA	NA	NA

25. For each unit on the Company's system, provide the following data based upon historic data from 2010 and forecasted capacity factor values for the period 2011 through 2020. Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Purdom	7	ST	NG	12.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Purdom	8	CC	NG/DFO	58.6	74.5	72.3	54.3	61.0	59.7	57.0	61.4	62.6	55.2	61.4
Purdom	CT 1	CT	NG/DFO	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Purdom	CT 2	CT	NG/DFO	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hopkins	1	ST	NG/RFO	22.5	9.1	8.9	14.9	16.3	10.2	12.1	13.8	10.3	13.6	4.2
Hopkins	2	CC	NG/DFO	47.3	42.6	44.3	55.8	48.9	53.1	53.8	51.7	51.9	56.1	49.2
Hopkins	CT 1	CT	NG/DFO	0.2	0.0	1.0	1.8	1.8	0.0	0.0	0.0	0.0	0.0	0.0
Hopkins	CT 2	CT	NG/DFO	0.5	0.2	2.1	2.4	2.4	0.1	0.1	0.0	0.0	0.0	0.0
Hopkins	CT 3	CT	NG/DFO	4.8	12.8	13.2	11.8	15.9	10.0	12.2	13.4	11.9	11.5	20.9
Hopkins	CT 4	CT	NG/DFO	7.2	3.3	7.2	4.8	7.1	2.2	3.1	6.0	5.8	4.4	13.9
Hopkins	CT 5 (Future)	CT	NG/DFO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.1
Corn	1	HYD	WAT	8.1	18.2	18.2	18.2	18.2	18.2	16.8	18.2	18.2	18.2	18.2
Corn	2	HYD	WAT	17.9	18.2	18.2	18.2	18.2	18.2	16.8	18.2	18.2	18.2	18.2
Corn	3	HYD	WAT	40.6	18.2	18.2	18.2	18.2	18.2	16.8	18.2	18.2	18.2	18.2

26. Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are candidates for repowering. As part of this response, please provide the unit's fuel and unit type, summer capacity rating, in-service date, and what potential conversion/repowering would be most applicable. Also include a description of any major obstacles that could affect repowering efforts at any of these sites, such as unit age, land availability, or other requirements.

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Hopkins	1 ST	76	May-71	See Discussion Below
Hopkins	3 CT	46	Sep-05	
Hopkins	4 CT	46	Nov-05	
Purdom	7 ST	48	Jun-66	

Hopkins Steam Unit 1, CT 3 and CT 4 and Purdom Steam Unit 7, HC3 and HC4 are all units that could potentially be converted to combined cycle. Major obstacles are combined cycle conversion are as follows:

- *Hopkins 1 - Age of the steam turbine generator (STG) and the fact that its current design does not incorporate a steam reheat cycle.*
- *Hopkins CTs 3 and 4 – An extended outage would be required to remove/relocate the existing selective catalytic reduction (SCR)/carbon monoxide (CO) catalyst ductwork and install the new heat recovery steam generator (HRSG). It is uncertain whether a construction plan could be implemented whereby the existing units could remain in operation while a new HRSG is installed. It is also not certain whether conversion of these units to combined cycle operation would allow for their continued utilization as the City's only "quick start" units needed for contingency reserves.*
- *Purdom 7 - Age of the STG, site space restrictions and environmental permitting limitations.*

27. Please complete the table below, in electronic (Excel) and hard copy, regarding the Company's generation fleet and the typical use of each unit. Please identify capacity type as either Baseload, Intermediate, or Peaking, and group units by their capacity type. Please use the abbreviations for fuel and generation facilities from the FRCC Load and Resource Plan for the table below. (For example, a combustion turbine that is not part of a combined cycle unit is identified with generator code "GT.") Please complete the tables below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Facilities[1] as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
Purdom	8	CC	NG/DFO	60-65	Baseload	222
				Sub-Total	**Baseload**	222
Hopkins	2	CC	NG/DFO	50-55	Intermediate	300
Hopkins	1	ST	NG/RFO	10-15	Intermediate	76
Purdom	7	ST	NG	1-5	Intermediate	48
				Sub-Total	**Intermediate**	424
Hopkins	CT 1	CT	NG/DFO	1-5	Peaking	12
Hopkins	CT 2	CT	NG/DFO	1-5	Peaking	24
Hopkins	CT 3	CT	NG/DFO	5-15	Peaking	46
Hopkins	CT 4	CT	NG/DFO	5-15	Peaking	46
Purdom	CT 1	CT	NG/DFO	1-5	Peaking	10
Purdom	CT 2	CT	NG/DFO	1-5	Peaking	10
				Sub-Total	**Peaking**	148
					Total	794

[1] Because the C. H. Corn hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservoir and downstream conditions), the City considers these units as "energy only" and not as dependable capacity for planning purposes.

Planned Facilities during 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
NONE						
				Sub-Total	**Baseload**	0
NONE						
				Sub-Total	**Intermediate**	0
Hopkins	5	CT	NG/DFO	1-5	Peaking	46
				Sub-Total	**Peaking**	46
					Total	46

28. Please complete the table below regarding the system's installed capacity, categorized by capacity type, for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

System Installed Capacity Type[1,2]

	Year	Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual[3]	2001	232	362	56	650
	2002	233	352	56	641
	2003	233	352	56	641
	2004	233	352	56	641
	2005	233	352	56	641
	2006	233	352	148	733
	2007	233	352	148	733
	2008	233	352	148	733
	2009	233	424	148	805
	2010	222	424	148	794
Projected[4]	2011	222	424	148	794
	2012	222	376	128	726
	2013	222	376	128	726
	2014	222	376	128	726
	2015	222	376	116	714
	2016	222	376	116	714
	2017	222	376	92	690
	2018	222	376	92	690
	2019	222	376	92	690
	2020	222	300	138	660

1 Net summer generating capability.
2 Corn hydro units considered "energy only", not dependable capacity. Capability of these units not reflected on this table.
3 Per TYSP Schedule 1 for the reporting year.
4 Reflects retirements of Purdom 7 and Purdom CTs 1 and 2 (2012), Hopkins CT 1 (2015) and Hopkins CT 2 (2017) and addition of prospective Hopkins CT 5 (2020).

29. Please provide the system average heat rate for the generation fleet for each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		System Average Heat Rate (BTU/kWh)
Actual	**2001**	8,499
	2002	8,462
	2003	7,297
	2004	7,141
	2005	7,336
	2006	8,068
	2007	8,611
	2008	8,358
	2009	8,141
	2010	8,313
Projected	**2011**	7,800
	2012	7,867
	2013	8,012
	2014	8,042
	2015	7,946
	2016	7,968
	2017	7,956
	2018	7,948
	2019	7,945
	2020	7,945

30. Please provide the average cost of a residential customer bill, based upon a monthly usage of 1200 kilowatt-hours, in nominal and real dollars for the period 2001 through 2020. Please use the Consumer Price Index to calculate real residential bill values. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Year		Residential Bill ($/1200-kWh)		CPI
		Real	Nominal	
Actual	2001	55.00	97.40	1.771
	2002	56.12	100.96	1.799
	2003	67.41	124.03	1.840
	2004	62.99	118.98	1.889
	2005	72.47	141.54	1.953
	2006	81.24	163.78	2.016
	2007	80.98	167.88	2.073
	2008	87.37	188.10	2.153
	2009	71.85	154.14	2.145
	2010	69.84	152.28	2.181
Projected	2011	69.84	156.09	2.235
	2012	69.84	159.99	2.291
	2013	69.84	163.99	2.348
	2014	69.84	168.09	2.407
	2015	69.84	172.29	2.467
	2016	69.84	176.60	2.529
	2017	69.84	181.01	2.592
	2018	69.84	185.54	2.657
	2019	69.84	190.18	2.723
	2020	69.84	194.93	2.791

1 For planning purposes, it is assumed that the future real price of electricity would remain constant at the 2010 level. While fuel prices are projected to increase in real terms it was assumed that these price increases would be offset by more efficient generation, reduced operations and maintenance costs, and the effects of competition.

2 For 2000-2009 the deflator is the CPI Index per U. S. Dept. of Labor Bureau of Labor Stats. ('82 Dollars). The 2010 deflator is escalated at 2.5% per year for 2011-2020 to derive future nominal values.

POWER PURCHASES / SALES

31. Please identify each of the Company's existing and planned power purchase contracts, including firm capacity imports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the seller, capacity, associated energy, and term of each purchase, and provide unit information if a unit power purchase. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Progress Energy Florida	12/9/1988	12/3/2016	11.4	11.4	99,864	100	NA	System Capacity/Energy Purchase

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
NONE								

32. Please identify each of the Company's existing and planned power sales, including firm capacity exports reflected in Schedule 7 of the Company's Ten-Year Site Plan. Provide the purchaser, capacity, associated energy, and term of each purchase, and provide unit information if a unit power sale. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
NONE								

Planned Power Sales for 2011 through 2020

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
NONE								

33. Please discuss and identify the impacts on the Company's capacity needs of all known firm power purchases and sales over the planning horizon. As part of this discussion, please include whether options to extend purchases or sales exist, and the potential effects of expiration of these purchase or sales.

The expiration of the City's 11.4 MW capacity purchase from Progress Energy Florida is not currently expected to cause the need for any new capacity. There are no provisions in the PPA that explicitly address extension but the City believes it possible given mutual agreement with Progress. The associated transmission service is eligible to be extended or "rolled over".

The City currently has no existing nor plans for future contracts for the purchase or sale of firm capacity.

ENVIRONMENTAL ISSUES

34. Please discuss the impact of environmental restrictions, relating to air or water quality or emissions, on the Company's system during the 2010 period, such as unit curtailments. As part of your discussion, please include the potential for environmental restrictions to impact unit dispatch or retirement during the 2011 through 2020 period.

The City's Electric Utility operates under numerous state and federal environmental laws, rules and regulations. The United States Environmental Protection Agency (EPA) and the Florida Department of Environmental Protection (FDEP) are the main environmental regulatory agencies that the City interacts with on these laws, rules and regulations. Over the past ten years, a number of federal regulations have been promulgated that have impacted the City's ability to meet electric demand with its fleet of electric generators. The City owns and operates two electric power generating stations: Arvah B. Hopkins and Sam O. Purdom Stations.

The City's Purdom Generating Station operates under Title V air operation permit number 1290001-011-AV. This permit has a facility wide emissions cap for nitrogen oxides (NOx) and sulfur dioxide (SO2) of 467 tons and 80 tons per year respectively. As such, operations of all units at the facility are carefully monitored to ensure that emissions of these two pollutants do not exceed the cap. As such, in part due to this facility wide cap, the City has elected to limit the operation of an older boiler (Emission unit Purdom 7, which began commercial operation in 1966) by firing only natural gas as its fuel.

In 1999, the EPA issued regulations to improve visibility, or visual air quality, in 156 national parks and wilderness areas across the country. The regulations call for States to establish goals for improving visibility in national parks and wilderness areas and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment. Visibility impairment is one of the most basic indicators of pollution in the air and often it is in the form of regional haze. Haze obscures the clarity, color, texture, and form of what individuals see. By eliminating the haze-causing pollutants that are directly emitted to the atmosphere by a number of activities (such as electric power *generation), it is expected that visibility will improve. One of the principal elements of visibility protections is the installation of best available retrofit technology (BART) for existing sources of pollution that were placed into operation between 1962 and 1977.*

Purdom Unit 7, in order to avoid the costly requirements of BART, is to be permanently shut down on, or before, December 31, 2013. As such power generation responsibilities will be gradually shifted to more efficient, cleaner units in the City's fleet.

Currently, the City is required to participate in two federal cap and trade programs, Acid Rain and the Clean Air Interstate Rule (CAIR). Under these programs, a federally imposed cap limits the total number of tons that may be emitted over a certain area. The City is allocated a number of emission allowances (tons of pollutant) annually, or in the case of CAIR, both annually and ozone season (May 1st to September 30th) that is slowly reduced over time. The expectation of the program is that companies will limit their emissions through technological improvements and controls, fuel-switching, and the retirement of older, more inefficient electric generation units. The City must hold a sufficient number of allowances to cover the amount of tons per year of each regulated pollutant that the City has emitted for the season (ozone or annual) covered. If a facility does not have enough allowances to meet its demand, then it must acquire additional allowances. The Acid Rain program addresses SO2 emissions, and the CAIR program addresses NOx and SO2 emissions. In the year 2010, the City held a sufficient number of allowances to meet both program requirements.

On August 2, 2010, the Clean Air Transport Rule (CATR or Transport Rule), a rule that replaces the CAIR program, was proposed. The new Transport Rule was in response to the decision of the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit") to vacate and then remand CAIR. At this date it is too early to detail the exact impact this will have on operations at the power utility, but the program is expected to produce greater reductions in NOx and SO2 emissions nationwide, most of those coming from the power generation sector. The proposed rule would allocate allowances to existing units based on either 2009 emissions or 2012 emissions projections. The rule is expected to be in place and emissions reductions to begin in 2012. The EPA has *proposed several methodologies concerning the number of allowances that will be allocated to participating companies, but it is expected that the amount of allowances will be less than what was allocated under the CAIR program. This will necessitate careful monitoring on the City's part to ensure that the City will operate their electric fleet in a manner which will minimize the need to acquire additional allowances.*

In recent years, the City has operated in a manner that emphasized the use of natural gas as its primary fuel (99.5% natural gas versus 0.5% oil use). It is therefore, expected that the City will utilize its more modern and more efficient units primarily to meet the demands of its customers.

Over the past two years, there have been many attempts at legislation concerning the regulation and reduction of greenhouse gas emissions (GHGs). In particular, efforts have been focused on developing a regulatory, market-based cap-and-trade GHG emissions limiting program that would seek an approximate 20% reduction of 2005 GHG emissions by the year 2020. Currently, national and state efforts to pass carbon legislation have stalled, although it hasn't stopped the Environmental Protection Agency from interpreting the Clean Air Act in a manner which would allow the agency to regulate GHGs through regulatory obligations that could have far-reaching and unintended consequences. The EPA is prepared to regulate GHGs through permitting mechanisms that would require companies to determine potential GHG emissions prior to obtaining construction permits and initiating construction. In addition, any new construction projects that trigger the EPA threshold for GHGs would be required to consider installing control technology to limit CO2 emissions or would require the consideration of cleaner combustion technology (natural gas fired vs. coal fired for instance). As things currently stand, there is no proven control technology to limit or sequester the production of CO2 that is in widespread use. Given the uncertainty of the appropriateness of using the Clean Air Act as the vehicle for GHG reductions, it generally believed that Congress will be swayed into passing legislation to strip the EPA of its authority to regulate GHGs or it will reduce the budget of EPA so that the agency has no means to implement the programs as currently conceived. As such, the City *cannot fully address at this time what the impacts of these proposed regulations may have on City operations.*

The City is operating in compliance with all of the National Pollutant Discharge Elimination System (NPDES) permit conditions for both the Hopkins and Purdom facilities. However, the Hopkins Permit was issued with an Administrative Order (AO) attached to it due to the removal of the Copper Mixing Zone (MZ) from the previous permit. The MZ had provided relief from the Water Quality Standard (WQS) limit for copper. Currently, the City has an interim limit of 50 parts per billion (ppb), however, the City will have to be in compliance with the WQS limit for copper before the expiration of the NPDES permit. This limit varies depending on the hardness of the receiving water (Beaver Creek) but it could range anywhere from 2.85 ppb to as high as 30.5 ppb.

To achieve compliance with the WQS limit for copper, the City is currently conducting a metal translator study. Depending on the final results, the study could provide the necessary relief from the WQS limit for copper through a dissolved copper limit instead of a total recoverable limit. If this study fails, the City will be required to develop engineering solutions that may require investing in capital expenditure. If the capital expenditure is too great, this may potentially cause the early retirement of Unit 1 at the Hopkins facility. Hopkins Unit 1 is a fossil fuel-fired steam generator that began commercial operation in May 1971.

The City also continues to monitor the proposed Numeric Nutrient Criteria Rule (NNCR) which may have significant impacts on the operations of the two generating stations. The proposed NNCR is currently under litigation, but if adopted by FDEP in its current form, it will negatively impact the ability of municipalities to utilize re-use water (Purdom currently is allowed to use re-use via its NPDES permit).

35. Please provide the rate of emissions, on an annual and per megawatt-hour basis, of regulated materials and carbon dioxide for the generation fleet each year for the period 2001 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

	Year	SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001	0.344	439	0.747	954	NA	NA	0.098	125	1,083	1,384,225
	2002	0.222	306	0.651	896	NA	NA	0.046	63	1,119	1,540,194
	2003	1.021	1,407	1.061	1,461	NA	NA	0.139	192	1,094	1,506,678
	2004	1.128	1,603	0.915	1,300	NA	NA	0.142	201	1,185	1,683,563
	2005	1.162	1,679	0.727	1,050	NA	NA	0.154	222	1,218	1,759,856
	2006	0.400	575	0.490	704	NA	NA	0.084	121	1,205	1,730,733
	2007	0.344	502	0.687	1,002	NA	NA	0.046	68	1,248	1,819,661
	2008	0.039	55	0.366	519	NA	NA	0.053	75	990	1,402,638
	2009	0.006	8	0.309	434	NA	NA	0.051	72	851	1,193,491
	2010	0.035	52	0.350	512	NA	NA	0.050	74	830	1,217,028
Projected	2011	0.004	6	0.206	288	NA	NA	0.050	69	843	1,180,318
	2012	0.004	6	0.210	295	NA	NA	0.050	70	853	1,199,024
	2013	0.004	6	0.228	319	NA	NA	0.049	69	870	1,217,139
	2014	0.004	6	0.245	341	NA	NA	0.049	69	871	1,211,682
	2015	0.004	6	0.194	269	NA	NA	0.050	69	864	1,196,312
	2016	0.004	6	0.203	280	NA	NA	0.050	69	868	1,196,828
	2017	0.004	6	0.220	301	NA	NA	0.052	71	889	1,219,631
	2018	0.004	6	0.201	275	NA	NA	0.052	71	891	1,216,890
	2019	0.004	6	0.212	288	NA	NA	0.052	70	890	1,210,408
	2020	0.004	6	0.170	231	NA	NA	0.052	70	884	1,198,666

FUEL

36. Please provide, on a system-wide basis, the historic average fuel price (in nominal $/MMBTU) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Nominal Fuel Price ($/MMBTU)		Uranium	Coal[1]	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	NA	NA	4.34	5.45	7.01
	2002	NA	NA	3.93	5.52	6.05
	2003	NA	NA	5.54	5.14	6.26
	2004	NA	NA	6.43	5.04	6.73
	2005	NA	NA	7.65	6.49	11.91
	2006	NA	NA	9.16	8.70	13.36
	2007	NA	NA	8.34	9.19	12.95
	2008	NA	NA	10.64	9.19	12.09
	2009	NA	NA	8.57	9.32	18.66
	2010	NA	NA	7.69	9.08	22.15
Projected	2011	NA	2.24	4.98	12.27	21.59
	2012	NA	2.26	5.58	12.49	22.39
	2013	NA	2.29	5.98	12.74	22.88
	2014	NA	2.31	6.31	13.00	23.34
	2015	NA	2.33	6.62	13.26	23.81
	2016	NA	2.38	6.89	13.52	24.28
	2017	NA	2.44	7.05	13.80	24.77
	2018	NA	2.49	7.24	14.07	25.26
	2019	NA	2.55	7.40	14.35	25.77
	2020	NA	2.61	7.56	14.64	26.29

[1] Nominal "Electric Power, Steam Coal" price per U.S. Energy Information Administration's 2011 Annual Energy Outlook. 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.

37. Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) for each fuel type for the period 2001 through 2010. Also, provide the forecasted annual fuel usage (in GWh) for each fuel type for the period 2011 through 2020. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	NA	NA	2,265	75	10
	2002	NA	NA	2,308	52	4
	2003	NA	NA	2,019	323	4
	2004	NA	NA	1,671	355	3
	2005	NA	NA	2,041	327	4
	2006	NA	NA	2,409	110	4
	2007	NA	NA	2,165	97	1
	2008	NA	NA	2,424	7	1
	2009	NA	NA	2,612	0	4
	2010	NA	NA	2,614	6	3
Projected	2011	NA	NA	2,697	0	0
	2012	NA	NA	2,716	0	0
	2013	NA	NA	2,694	0	0
	2014	NA	NA	2,678	0	0
	2015	NA	NA	2,674	0	0
	2016	NA	NA	2,666	0	0
	2017	NA	NA	2,724	0	0
	2018	NA	NA	2,721	0	0
	2019	NA	NA	2,702	0	0
	2020	NA	NA	2,687	0	0

38. Please discuss how the Company compares its fuel price forecasts to recognized, authoritative independent forecasts.

The City based its fuel price forecast for natural gas and distillate fuel oil on the New York Mercantile Exchange (NYMEX) and Gas Daily for residual oil. Because the City does not have a recent fuel forecast performed by outside consultants we used the NYMEX and Gas Daily as a basis for our fuel forecasts submitted to the PSC in the Ten-Year Site Plan (TYSP). At the time the City prepared the TYSP forecast, the latest public fuel forecast available was from the Energy Information Administration's (EIA) annual forecast published in December 2009. The City reviewed the EIA data before we prepared the TYSP forecast and found their natural gas prices to be about 15% lower than the NYMEX and distillate prices were 46% higher than the NYMEX. Because market prices solicited from our suppliers closely tracked the NYMEX, we used the

NYMEX as the basis for our TYSP fuel forecasts for natural gas and distillate. The NYMEX does not list pricing for residual fuel oil, so the City used Gas Daily published indexes. Because most suppliers use the NYMEX as a basis for fixed price term deals, the City believes the NYMEX and Gas Daily provide better basis for fuel forecasting than the EIA.

39. For each fuel type (coal, natural gas, nuclear fuel, etc.), please discuss in detail the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

Natural Gas: The City is well aware of the expansion of shale gas production in the United States. Reserves have increased from 50 to 200 years, improvements in technology have decreased production costs and the on-shore nature of shale production reduces interruptions and price volatility due hurricanes. If shale gas production trends continue, the City should have reasonably priced and stable natural gas supplies for the ten-year planning horizon.

Oil: Due to the re-powering of Hopkins #2 the City is not planning to use significant volumes of distillate or residual fuel oil except for reliability purposes and testing.

Distillate and residual fuel oils are likely to remain volatile and subject to the forces of supply, demand and geo-political influences.

Coal and Nuclear: The City does not have coal or nuclear generating resources at this time and has limited insight into expected industry trends for these two fuels.

40. What steps has the Company taken to ensure gas supply availability and transport over the 2011 through 2020 planning period?

The City currently has sufficient natural gas pipeline capacity to supply the Electric and Gas Utilities during peak periods. However, due to expected system growth the City has contracted for 4,000 MMBtu/day of additional pipeline capacity from Florida Gas Transmission (FGT) starting in 2011 and increasing to 6,000 MMBtu/day in 2013. The City will evaluate additional capacity needs for the 2014-2018 time period based on the impact our new Demand-Side Management program has on the City's gas needs. The City assumes gas supplies will continue to be available from on-shore and off-shore gas suppliers connected to FGT and Southern Natural Gas Company systems. LNG re-gasification facilities located on the Gulf Coast should provide additional supplies.

41. Regarding existing and planned natural gas pipeline expansion projects, including new pipelines, affecting the Company for the period 2011 through 2020, please identify each project and discuss it in detail.

Florida Gas Transmission is proposing to expand its natural gas pipeline system to meet the growing energy needs of the Gulf Coast and Florida to ensure an adequate, reliable and secure energy supply. Natural gas is the primary fuel for new electric generation plants and most of the natural gas consumed along the Gulf Coast and Florida is used for electric generation. The Phase VIII Expansion Project will consist of approximately 483.2 miles of multi diameter pipeline in Alabama, Mississippi and Florida with approximately 365.8 miles built parallel to existing pipelines. The project will add 213,600 horsepower of additional mainline compression with one new compressor station to be built in Highlands County, Fla. The project will provide an annual average of 820,000 MMbtu/day of additional firm transportation capacity. FGT estimates the total cost of the project will be $2,455 million. The project is expected to be completed and in service in the spring of 2011.

The City contracted for 4,000 MMBtu/day (year-round) of additional pipeline capacity from Florida Gas Transmission (FGT) Phase VIII, starting in 2011 and increasing to 6,000 MMBtu/day in 2013.

42. Please discuss in detail any existing or planned natural gas pipeline expansion project, including new pipelines and off-shore projects, outside the State of Florida that will affect the Company over the period 2011 through 2020.

The City continues to monitor possible pipeline expansions that may serve the City including off-shore LNG projects and pipelines. If these projects can provide economic benefits to the City and our customers we will evaluate them.

43. Regarding unconventional natural gas production (shale gas, tight sands, etc.), please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

There has been a tremendous increase in natural gas production from shale fields during the past two years and more production is likely in the future if prices for natural gas exceed the marginal cost of production from these resources. Shale production is increasingly replacing decreasing production from mature off-shore fields. This is a positive trend for the City since natural gas is a significant cost component.. On-shore production of shale gas should decrease our reliance on foreign sources of natural gas and increase reliability because shale wells are on-shore and not limited to the hurricane prone Gulf of Mexico.

44. Regarding liquefied natural gas (LNG) imports to the United States, please discuss in detail the expected industry factors and trends for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

The U.S. has adequate LNG re-gasification capacity and underground storage capability to take excess LNG production from around the world in the near-term. If additional storage capacity is added as planned, the U.S. should be the destination of last resort for any excess volumes of LNG. This should lead to lower natural gas prices for the City and our customers.

45. Please discuss in detail the Company's plans for the use of firm natural gas storage for the period 2011 through 2020.

The City has contracted storage capacity of 70,781 MMBtu on Southern Natural gas pipeline. The City continues to evaluate opportunities for storage capacity as needs arise.

46. Please discuss the actions taken by the Company to promote competition within and among coal transportation modes.

The City is currently not taking any direct action to promote competition within and among coal transportation modes.

47. Regarding coal transportation by rail, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.

The City does not have coal generating resources at this time and has limited insight into expected industry trends or changes to terminals and port facilities that could affect coal transportation.

48. Regarding coal transportation by water, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company. Also include a discussion of any expected changes to terminals and port facilities that could affect coal transportation for the Company.

The City does not have coal generating resources at this time and has limited insight into expected industry trends or changes regarding coal transportation by water.

49. Regarding planned changes and construction projects at coal generating units, please discuss the expected changes for coal handling, blending, unloading, and storage for the period 2011 through 2020.

The City does not have coal generating resources at this time and no plans for coal handling, blending, unloading, and storage for the reporting period.

50. For the period 2011 through 2020, please discuss in detail the Company's plans for the storage and disposal of spent nuclear fuel. As part of this discussion, please include the Company's expectation regarding Yucca Mountain, dry cask storage, and litigation involving spent nuclear fuel, and the future of the Nuclear Waste Disposal Act.

The City does not have nuclear generating resources.

51. Regarding uranium production, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

The City does not have nuclear generating resources.

52. Regarding the transportation of heavy fuel oil and distillate fuel oil, please discuss the expected industry trends and factors for the period 2011 through 2020. As part of this discussion, please include how these factors and trends will affect the Company.

Heavy and light fuel oils are used as back-up emergency fuel within the Tallahassee generation's system. The City has three delivery systems available for use. The first and most common is the use of over-the-road (OTR) trucking; the second is water borne delivery by barge into the Purdom Pant in St. Marks; the third is the use of rail in to the Hopkins Plant. While there are currently no issues associated with any of the three modes, the water borne delivery could face the greatest challenges if environmental regulations become such that delivery by barge becomes too onerous or expensive. As with OTR delivery, the transportation cost will remain expensive as the trucks require diesel fuel to operate and the cost per mile for delivery increase with fuel prices at the pump.

53. Please discuss the effect of changes in fossil fuel prices on the competitiveness of renewable technologies.

The continued downward to sideways movement of natural gas forward fuel pricing continues to challenge the cost-effectiveness of renewables such as solar PV, biomass, LFG, and wind versus conventional technologies.

54. Please discuss the effect of renewable resource development (for electric generation and non-generation technologies) on fossil fuel prices.

For the planning period of 2010 – 2019, the City does not anticipate renewable resource development (for electric generation and non-generation technologies) to progress such that it will have a significant impact on fossil fuel prices. To the contrary, the City expects that as more onshore shale or tight bed methane gas becomes available the cost of renewable resources will continue to exceed that of conventional technologies.

TRANSMISSION

55. Please provide a list of all proposed transmission lines in the planning period that require certification under the Transmission Line Siting Act. Please also include those that have been approved, but are not yet in-service.

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
NONE					

History and Forecast of Summer Peak Demand
High Case

(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]
HISTORY:									
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	587		587						587
2009	605		605						605
2010	602		602		0	1	0	0	601
FORECAST:									
2011	621		621		5	6	7	2	600
2012	633		633		19	8	18	4	584
2013	642		642		21	11	18	10	583
2014	652		652		23	13	18	16	582
2015	661		661		26	15	18	23	579
2016	672		672		26	17	19	29	581
2017	683		683		26	20	19	38	579
2018	694		694		26	23	19	46	579
2019	705		705		26	26	19	53	579
2020	716		716		27	30	20	60	580

[1] Values include DSM Impacts.

[2] Reduction estimated at busbar. 2010 DSM is actual at peak.

[3] 2010 values reflect incremental increase from 2009.

History and Forecast of Summer Peak Demand
Low Case

(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]
HISTORY:									
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	587		587						587
2009	605		605						605
2010	602		602		0	1	0	0	601
FORECAST:									
2011	595		595		5	6	7	1	574
2012	598		598		19	8	18	4	549
2013	600		600		21	11	18	10	541
2014	601		601		23	13	18	16	531
2015	603		603		26	15	18	22	521
2016	605		605		26	17	19	29	514
2017	607		607		26	20	19	39	503
2018	610		610		26	23	19	46	495
2019	612		612		26	26	19	54	486
2020	614		614		27	30	20	60	478

[1] Values include DSM Impacts.

[2] Reduction estimated at busbar. 2010 DSM is actual at peak.

[3] 2010 values reflect incremental increase from 2009

History and Forecast of Winter Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management [2], [3]	Residential Conservation [2], [4]	Comm./Ind Load Management [2], [3]	Comm./Ind Conservation [2], [4]	Net Firm Demand [1]
HISTORY:									
2001/02	510		510						510
2002/03	590		590						590
2003/04	509		509						509
2004/05	532		532						532
2005/06	537		537						537
2006/07	528		528						528
2007/08	526		526						526
2008/09	579		579						579
2009/10	633		633						633
2010/11	586		586		0	2	0	0	584
FORECAST:									
2011/12	570		570		0	8	0	5	557
2012/13	579		579		0	11	0	10	559
2013/14	587		587		0	13	0	17	558
2014/15	596		596		0	15	0	22	559
2015/16	606		606		0	16	0	29	561
2016/17	616		616		0	18	0	37	560
2017/18	625		625		0	20	0	43	562
2018/19	635		635		0	23	0	48	564
2019/20	645		645		0	26	0	52	567
2020/21	655		655		0	30	0	52	573

[1] Values include DSM Impacts.

[2] Reduction estimated at customer meter. 2010 DSM is actual.

[3] Reflects no expected utilization of demand response (DR) resources in winter. Winter DR capability presented in TYSP report on Table 2.17.

[4] 2010 values reflect incremental increase from 2009.

History and Forecast of Winter Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management [2], [3]	Residential Conservation [2], [4]	Comm./Ind Load Management [2], [3]	Comm./Ind Conservation [2], [4]	Net Firm Demand [1]
HISTORY:									
2001/02	510		510						510
2002/03	590		590						590
2003/04	509		509						509
2004/05	532		532						532
2005/06	537		537						537
2006/07	528		528						528
2007/08	526		526						526
2008/09	579		579						579
2009/10	633		633						633
2010/11	586		586		0	2	0	0	584
FORECAST:									
2011/12	539		539		0	8	0	5	525
2012/13	541		541		0	11	0	9	522
2013/14	542		542		0	13	0	17	512
2014/15	543		543		0	15	0	22	506
2015/16	545		545		0	16	0	30	500
2016/17	547		547		0	18	0	38	491
2017/18	549		549		0	20	0	43	486
2018/19	551		551		0	23	0	49	479
2019/20	553		553		0	26	0	52	475
2020/21	555		555		0	30	0	52	473

[1] Values include DSM Impacts.

[2] Reduction estimated at customer meter. 2010 DSM is actual.

[3] Reflects no expected utilization of demand response (DR) resources in winter. Winter DR capability presented in TYSP report on Table 2.17.

[4] 2010 values reflect incremental increase from 2009.

History and Forecast of Annual Net Energy for Load - GWH
High Case

(1) Year	(2) Total	(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]
HISTORY:								
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	2,726			2,726		164	2,890	62
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,679			2,679		154	2,834	55
2009	2,661			2,661		144	2,805	53
2010	2,767	12	1	2,754		177	2,931	56
FORECAST:								
2011	2,754	44	7	2,703		161	2,864	54
2012	2,805	56	19	2,730		163	2,892	57
2013	2,846	69	43	2,734		162	2,897	57
2014	2,887	80	69	2,738		163	2,901	57
2015	2,931	93	93	2,745		163	2,908	57
2016	2,978	109	118	2,751		164	2,915	57
2017	3,026	125	144	2,758		164	2,922	58
2018	3,073	141	168	2,765		164	2,929	58
2019	3,123	154	193	2,776		165	2,941	58
2020	3,172	167	219	2,786		166	2,952	58

[1] Values include DSM Impacts.

[2] Reduction estimated at customer meter. 2010 DSM is actual.

[3] 2010 values reflect incremental increase from 2009.

History and Forecast of Annual Net Energy for Load - GWH
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
HISTORY:								
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	2,726			2,726		164	2,890	62
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,679			2,679		154	2,834	55
2009	2,661			2,661		144	2,805	53
2010	2,767	12	1	2,754		177	2,931	56
FORECAST:								
2011	2,634	44	7	2,584		154	2,737	54
2012	2,650	56	19	2,575		153	2,728	57
2013	2,658	69	43	2,546		151	2,698	57
2014	2,664	80	69	2,515		149	2,665	57
2015	2,671	93	93	2,485		148	2,632	58
2016	2,681	109	118	2,454		146	2,600	58
2017	2,690	125	144	2,422		144	2,566	58
2018	2,701	141	168	2,392		142	2,534	58
2019	2,711	154	193	2,364		141	2,505	59
2020	2,719	167	219	2,333		139	2,472	59

[1] Values include DSM Impacts.

[2] Reduction estimated at customer meter. 2010 DSM is actual.

[3] 2010 values reflect incremental increase from 2009.

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	9.65%	NA	5.48%	NA	84.54%	NA	NA
Corn	2	[1]	NA	9.65%	NA	5.48%	NA	84.54%	NA	NA
Corn	3	[1]	NA	9.65%	NA	5.48%	NA	84.54%	NA	NA
Hopkins	1		1.94%	4.78%	0.07%	3.92%	97.99%	90.61%	12,175	11,846
Hopkins	CC 2	[2]	17.07%	7.27%	5.76%	3.19%	77.16%	86.90%	8,066	7,678
Hopkins	GT-1	[3]	0.06%	4.96%	0.00%	5.23%	99.94%	87.58%	29,582	22,190
Hopkins	GT-2	[3]	0.29%	3.41%	0.05%	4.27%	99.66%	89.22%	32,047	18,953
Hopkins	GT-3		0.45%	5.08%	0.46%	3.47%	99.09%	90.08%	10,710	9,969
Hopkins	GT-4		0.24%	5.08%	0.10%	3.47%	99.66%	90.08%	10,552	9,953
Purdom	7	[3]	0.71%	4.78%	7.52%	3.92%	91.78%	90.61%	12,791	14,911
Purdom	8		3.02%	7.27%	9.47%	3.19%	87.51%	86.90%	7,691	7,835
Purdom	GT-1	[3]	4.03%	4.96%	0.06%	5.23%	95.91%	87.58%	27,991	NA
Purdom	GT-2	[3]	4.06%	4.96%	1.46%	5.23%	94.49%	87.58%	24,221	NA
Future Units										
Hopkins	GT-5	[4]	NA	5.08%	NA	3.47%	NA	90.08%	NA	9877

NOTES: Historical - average of past three calendar years
Projected - average of next ten calendar years (Peer unit data in 2005-9 NERC Generating Availability Report (GAR) used for POF, FOF and EAF)

[1] The City does not track the planned outage, forced outage or equivalent availability factors for the Corn Hydro units.
[2] Reflects available data for Hopkins 2 combined cycle (CC) since it began operation in June 2008.
[3] Historical data reflects average gross operating heat rate (Btu/kWh).
[4] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location

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]:									
2008	NA	NA	NA	57.91	919	-	NA	NA	NA
2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
2010	NA	NA	NA	57.23	908	-2.5%	NA	NA	NA
FORECAST:									
2011	NA	NA	NA	77.33	1227	35.1%	NA	NA	NA
2012	NA	NA	NA	78.72	1249	1.8%	NA	NA	NA
2013	NA	NA	NA	80.29	1274	2.0%	NA	NA	NA
2014	NA	NA	NA	81.90	1300	2.0%	NA	NA	NA
2015	NA	NA	NA	83.54	1326	2.0%	NA	NA	NA
2016	NA	NA	NA	85.21	1352	2.0%	NA	NA	NA
2017	NA	NA	NA	86.91	1380	2.0%	NA	NA	NA
2018	NA	NA	NA	88.65	1407	2.0%	NA	NA	NA
2019	NA	NA	NA	90.42	1435	2.0%	NA	NA	NA
2020	NA	NA	NA	92.23	1464	2.0%	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]:									
2008	NA	NA	NA	57.91	919	-	NA	NA	NA
2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
2010	NA	NA	NA	57.23	908	-2.5%	NA	NA	NA
FORECAST [2]:									
2011	NA	NA	NA	77.33	1227	35.1%	NA	NA	NA
2012	NA	NA	NA	80.65	1280	4.3%	NA	NA	NA
2013	NA	NA	NA	84.28	1338	4.5%	NA	NA	NA
2014	NA	NA	NA	88.07	1398	4.5%	NA	NA	NA
2015	NA	NA	NA	92.04	1461	4.5%	NA	NA	NA
2016	NA	NA	NA	96.18	1527	4.5%	NA	NA	NA
2017	NA	NA	NA	100.51	1595	4.5%	NA	NA	NA
2018	NA	NA	NA	105.03	1667	4.5%	NA	NA	NA
2019	NA	NA	NA	109.76	1742	4.5%	NA	NA	NA
2020	NA	NA	NA	114.69	1821	4.5%	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]:									
2008	NA	NA	NA	57.91	919	-	NA	NA	NA
2009	NA	NA	NA	58.69	932	1.3%	NA	NA	NA
2010	NA	NA	NA	57.23	908	-2.5%	NA	NA	NA
FORECAST [2]:									
2011	NA	NA	NA	77.33	1227	35.1%	NA	NA	NA
2012	NA	NA	NA	76.78	1219	-0.7%	NA	NA	NA
2013	NA	NA	NA	76.40	1213	-0.5%	NA	NA	NA
2014	NA	NA	NA	76.02	1207	-0.5%	NA	NA	NA
2015	NA	NA	NA	75.64	1201	-0.5%	NA	NA	NA
2016	NA	NA	NA	75.26	1195	-0.5%	NA	NA	NA
2017	NA	NA	NA	74.88	1189	-0.5%	NA	NA	NA
2018	NA	NA	NA	74.51	1183	-0.5%	NA	NA	NA
2019	NA	NA	NA	74.14	1177	-0.5%	NA	NA	NA
2020	NA	NA	NA	73.77	1171	-0.5%	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 [2]			Natural Gas [3]		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY [1]:						
2008	70.44	1209	-	1064	10.98	-
2009	108.67	1866	54.3%	857	8.74	-20.4%
2010	128.49	2215	18.7%	769	7.83	-10.4%
FORECAST:						
2011	125.22	2159	-2.5%	498	5.08	-35.2%
2012	129.87	2239	3.7%	558	5.68	12.0%
2013	132.72	2288	2.2%	598	6.10	7.2%
2014	135.38	2334	2.0%	631	6.43	5.5%
2015	138.08	2381	2.0%	662	6.75	5.0%
2016	140.85	2428	2.0%	689	7.03	4.1%
2017	143.66	2477	2.0%	705	7.18	2.2%
2018	146.54	2526	2.0%	724	7.37	2.6%
2019	149.47	2577	2.0%	740	7.54	2.2%
2020	152.46	2629	2.0%	756	7.71	2.2%

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

[1] Actual average cost of distillate oil and gas burned.
[2] Forecast values reflected expected prices for Gulf Coast Ultra Low Sulfur Diesel
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil [2]			Natural Gas [3]		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY [1]:						
2008	70.44	1214	-	1064	11.07	-
2009	108.67	1874	54.3%	857	8.91	-19.5%
2010	128.49	2215	18.2%	769	8.00	-10.3%
FORECAST [4]:						
2011	125.22	2159	-2.5%	498	5.18	-35.2%
2012	133.00	2293	6.2%	570	5.93	14.5%
2013	139.25	2401	4.7%	626	6.51	9.7%
2014	145.51	2509	4.5%	676	7.03	8.0%
2015	152.06	2622	4.5%	726	7.55	7.5%
2016	158.90	2740	4.5%	774	8.05	6.6%
2017	166.05	2863	4.5%	811	8.43	4.7%
2018	173.53	2992	4.5%	853	8.87	5.1%
2019	181.33	3126	4.5%	893	9.29	4.7%
2020	189.49	3267	4.5%	935	9.73	4.7%

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

[1] Actual average cost of distillate oil and gas burned.
[2] Forecast values reflected expected prices for Gulf Coast Ultra Low Sulfur Diesel
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation
[4] For the high case, compound annual escalation rates (CAER) are assumed to be 2.5% higher than the base ca

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil [2]			Natural Gas [3]		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
HISTORY [1]:						
2008	70.44	1214	-	1064	11.07	-
2009	108.67	1874	54.3%	857	8.91	-19.5%
2010	128.49	2215	18.2%	769	8.00	-10.3%
FORECAST [4]:						
2011	125.22	2159	-2.5%	498	5.18	-35.2%
2012	126.74	2185	1.2%	545	5.67	9.5%
2013	126.35	2179	-0.3%	571	5.94	4.7%
2014	125.72	2168	-0.5%	588	6.12	3.0%
2015	125.09	2157	-0.5%	603	6.27	2.5%
2016	124.47	2146	-0.5%	612	6.37	1.6%
2017	123.85	2135	-0.5%	611	6.35	-0.3%
2018	123.23	2125	-0.5%	612	6.36	0.1%
2019	122.61	2114	-0.5%	610	6.34	-0.3%
2020	122.00	2103	-0.5%	609	6.33	-0.3%

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

[1] Actual average cost of distillate oil and gas burned.
[2] Forecast values reflected expected prices for Gulf Coast Ultra Low Sulfur Diesel
[3] Delivered gas price reflects cost at Henry Hub increased by compression losses, basis and firm transportation
[4] For the low case, compound annual escalation rates (CAER) are assumed to be 2.5% lower than the base cas

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:												
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST [2]:												
2011	53.82	224	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	54.34	226	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	54.86	229	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014	55.39	231	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	55.92	233	1.0%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	57.21	238	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	58.52	244	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	59.87	249	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2019	61.24	255	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	62.64	261	2.3%	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS type of coal, heat content, ash content - Not Available

[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] Nominal "Electric Power, Steam Coal" price per U.S. Energy Information Administration's 2011 Annual Energy Outlook (Table A3).

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:												
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST [2]:												
2011	53.82	224	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	55.69	232	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	57.61	240	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014	59.61	248	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	61.67	257	3.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	64.63	269	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	67.73	282	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	70.98	296	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2019	74.39	310	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	77.94	325	4.8%	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: type of coal, heat content, ash content - Not Available

[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] 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:												
2008	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2009	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2010	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
FORECAST [2]:												
2011	53.82	224	-	NA	NA	NA	NA	NA	NA	NA	NA	NA
2012	52.99	221	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2013	52.18	217	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2014	51.37	214	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2015	50.58	211	-1.5%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2016	50.48	210	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2017	50.38	210	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2018	50.28	210	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2019	50.18	209	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA
2020	50.07	209	-0.2%	NA	NA	NA	NA	NA	NA	NA	NA	NA

ASSUMPTIONS: type of coal, heat content, ash content - Not Available

[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] 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	
		Escalation		Escalation
Year	c/MBTU	%	$/MWh	%
HISTORY:				
2008	NA	NA	64.96	-
2009	NA	NA	57.40	-11.6%
2010	NA	NA	58.35	1.7%
FORECAST [1]:				
2011	NA	NA	60.12	3.0%
2012	NA	NA	61.83	2.8%
2013	NA	NA	63.60	2.9%
2014	NA	NA	65.42	2.9%
2015	NA	NA	67.29	2.9%
2016	NA	NA	70.33	4.5%
2017	NA	NA	144.43	105.4%
2018	NA	NA	148.04	2.5%
2019	NA	NA	151.74	2.5%
2020	NA	NA	155.53	2.5%

Financial Assumptions
Base Case

AFUDC RATE		5.25%	
CAPITALIZATION RATIOS:			
	DEBT	127.87%	[1]
	PREFERRED	N/A	[2]
	ASSETS	69.07%	[3]
	EQUITY	166.86%	[3]
RATE OF RETURN			
	DEBT	4.70%	[4]
	PREFERRED	N/A	[2]
	ASSETS	2.54%	[5]
	EQUITY	6.14%	[5]
INCOME TAX RATE:			
	STATE	N/A	[6]
	FEDERAL	N/A	[6]
	EFFECTIVE	N/A	[6]
OTHER TAX RATE:			
	Sales Tax (< $5,000)	7.50%	[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 (7.5% 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 %
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
2018	2.5	2.5	2.5	2.5
2019	2.5	2.5	2.5	2.5
2020	2.5	2.5	2.5	2.5

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 Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2011						
2012						
2013						
2014				See note [1] below		
2015						
2016						
2017						
2018						
2019						
2020						

[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 43 and 44 and in Table 3.4 (Generation Expansion Plan) on page 45 of the City's 2008 Ten Year Site Plan. The City does not currently evaluate isolated and assisted LOLP and EUE reliability indices.

Schedule 1
Existing Generating Facilities
As of December 31, 2010

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt	Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate KW	Net Capability Summer MW	Net Capability Winter MW	
Sam O. Purdom	7	Wakulla	ST	NG	NG	PL	PL	[1, 2]	06/66	3/12	50000	48	48	
	8		CC	NG	FO2	PL	TK	[2, 3]	07/00	12/40	247743	222	258	[7]
	GT-1		GT	NG	FO2	PL	TK	[2, 3]	12/63	3/12	15000	10	10	
	GT-2		GT	NG	FO2	PL	TK	[2, 3]	05/64	3/12	15000	10	10	
											Plant Total	290	326	
A. B. Hopkins	1	Leon	ST	NG	FO6	PL	TK	[1]	05/71	3/20	75000	76	78	
	2		CC	NG	FO2	PL	TK	[3]	6/08 [4]	Unknown	358,200 [5]	300	330	[7]
	GT-1		GT	NG	FO2	PL	TK	[3]	02/70	3/15	16320	12	14	
	GT-2		GT	NG	FO2	PL	TK	[3]	09/72	3/17	27000	24	26	
	GT-3		GT	NG	FO2	PL	TK	[3]	9/05	Unknown	60500	46	48	
	GT-4		GT	NG	FO2	PL	TK	[3]	11/05	Unknown	60500	46	48	
											Plant Total	504	544	
C. H. Corn	1	Leon/	HY	WAT	WAT	WAT	WAT	NA	09/85	Unknown	4440	0	0	
Hydro Station	2	Gadsden	HY	WAT	WAT	WAT	WAT	NA	08/85	Unknown	4440	0	0	
[6]	3		HY	WAT	WAT	WAT	WAT	NA	01/86	Unknown	3430	0	0	
											Plant Total	0	0	
									Total System Capacity as of December 31, 2010			794	870	

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 and Purdom sites are completed in summer/fall of 2009.

[4] Reflects the commercial operations date of Hopkins 2 repowered to a combined cycle generating unit with a new General Electric Frame 7A combustion turbine. The original commercial operations date of the existing steam turbine generator was October 1977.

[5] Hopkins 2 nameplate rating is based on combustion turbine generator (CTG) nameplate and modeled steam turbine generator (STG) output in a 1x1 combined cycle (CC) configuration with supplemental duct firing.

[6] Because the C. H. Corn hydroelectric generating units are effectively run-of-river (dependent upon rainfall, reservoir and downstream conditions), the City considers these units as "energy only" and not as dependable capacity for planning purposes.

[7] Summer and winter ratings are based on 95 oF and 29 oF ambient temperature, respectively.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Rural and Residential					Commercial	
Year	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
HISTORY:								
2001	245,640	-	959	80,348	11,936	1,459	16,988	85,884
2002	250,820	-	1,048	81,208	12,905	1,527	16,779	91,007
2003	258,627	-	1,035	82,219	12,588	1,555	17,289	89,942
2004	265,393	-	1,064	85,035	12,512	1,604	17,729	90,473
2005	269,619	-	1,088	89,468	12,164	1,623	18,312	88,630
2006	272,648	-	1,097	92,017	11,927	1,604	18,533	86,548
2007	273,684	-	1,099	93,569	11,744	1,657	18,583	89,169
2008	274,926	-	1,054	94,640	11,132	1,626	18,597	87,433
2009	274,822	-	1,050	94,827	11,071	1,611	18,478	87,180
2010	275,593	-	1,136	95,268	11,928	1,618	18,426	87,812
FORECAST:								
2011	277,575	-	1,017	95,527	10,641	1,627	18,720	86,890
2012	279,569	-	1,016	96,356	10,544	1,636	18,815	86,966
2013	281,576	-	1,015	97,190	10,444	1,625	18,911	85,918
2014	283,600	-	1,015	98,031	10,356	1,611	19,008	84,762
2015	285,806	-	1,015	98,947	10,261	1,599	19,114	83,657
2016	288,313	-	1,013	99,987	10,136	1,588	19,234	82,586
2017	290,845	-	1,012	101,037	10,015	1,577	19,355	81,482
2018	293,402	-	1,011	102,097	9,898	1,567	19,477	80,447
2019	295,979	-	1,012	103,166	9,810	1,557	19,600	79,424
2020	298,501	-	1,013	104,212	9,724	1,545	19,721	78,361

[1] Population data represents Leon County population.
[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 "Commercial" includes General Service Non-Demand, General Service Demand, General Service Large Demand, Interruptible (FSU and Goose Pond), Curtailable (TMH), Traffic Control, Security Lights and Street & Highway Lights.

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

(1) Year	(2) (GWh)	(3) Industrial Average No. of Customers [1]	(4) Average kWh Consumption Per Customer	(5) Railroads and Railways (GWh)	(6) Street & Highway Lighting (GWh) [2]	(7) Other Sales to Public Authorities (GWh)	(8) Total Sales to Ultimate Consumers (GWh)
HISTORY:							
2001	-	-	-		13		2,431
2002	-	-	-		13		2,588
2003	-	-	-		12		2,602
2004	-	-	-		14		2,682
2005	-	-	-		14		2,726
2006	-	-	-		15		2,716
2007	-	-	-		0		2,756
2008	-	-	-		0		2,679
2009	-	-	-		0		2,661
2010	-	-	-		0		2,754
FORECAST:							
2011	-	-	-		0		2,643
2012	-	-	-		0		2,652
2013	-	-	-		0		2,640
2014	-	-	-		0		2,626
2015	-	-	-		0		2,614
2016	-	-	-		0		2,602
2017	-	-	-		0		2,589
2018	-	-	-		0		2,577
2019	-	-	-		0		2,569
2020	-	-	-		0		2,559

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

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

(1) Year	(2) Sales for Resale (GWh)	(3) Utility Use & Losses (GWh)	(4) Net Energy for Load (GWh)	(5) Other Customers (Average No.)	(6) Total No. of Customers [1]
HISTORY:					
2001	0	125	2,556	0	97,336
2002	0	165	2,753	0	97,986
2003	0	153	2,755	0	99,508
2004	0	159	2,841	0	102,764
2005	0	164	2,890	0	107,780
2006	0	154	2,870	0	110,550
2007	0	158	2,914	0	112,151
2008	0	154	2,834	0	113,237
2009	0	144	2,805	0	113,305
2010	0	177	2,931	0	113,693
FORECAST:					
2011	0	157	2,800	0	114,247
2012	0	158	2,810	0	115,171
2013	0	157	2,797	0	116,101
2014	0	156	2,782	0	117,039
2015	0	155	2,770	0	118,061
2016	0	155	2,757	0	119,221
2017	0	154	2,743	0	120,391
2018	0	153	2,731	0	121,574
2019	0	153	2,721	0	122,766
2020	0	152	2,711	0	123,933

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

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(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]
HISTORY:									
2001	520		520						520
2002	580		580						580
2003	549		549						549
2004	565		565						565
2005	598		598						598
2006	577		577						577
2007	621		621						621
2008	587		587						587
2009	605		605						605
2010	602		602		0	1	0	0	601
FORECAST:									
2011	608		608		5	6	7	2	587
2012	615		615		19	8	18	4	566
2013	621		621		21	11	18	10	562
2014	626		626		23	13	18	16	556
2015	632		632		26	15	18	22	550
2016	638		638		26	17	19	30	547
2017	645		645		26	20	19	38	541
2018	651		651		26	23	19	47	536
2019	658		658		26	26	19	54	532
2020	665		665		27	30	20	60	529

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2010 DSM is actual at peak.
[3] 2010 values reflect incremental increase from 2009.

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management [2], [3]	(7) Residential Conservation [2], [4]	(8) Comm./Ind Load Management [2], [3]	(9) Comm./Ind Conservation [2], [4]	(10) Net Firm Demand [1]
HISTORY:									
2000/01	510		510						510
2001/02	590		590						590
2002/03	509		509						509
2003/04	532		532						532
2004/05	537		537						537
2005/06	528		528						528
2006/07	526		526						526
2007/08	579		579						579
2008/09	633		633						633
2009/10	586		586		0	2	0	0	584
FORECAST:									
2010/11	555		555		0	8	0	4	542
2011/12	560		560		0	11	0	10	540
2012/13	565		565		0	13	0	16	536
2013/14	570		570		0	15	0	22	533
2014/15	575		575		0	16	0	30	530
2015/16	581		581		0	18	0	38	525
2016/17	587		587		0	20	0	43	524
2017/18	593		593		0	23	0	48	522
2018/19	599		599		0	26	0	52	521
2019/20	605		605		0	30	0	52	523

[1] Values include DSM Impacts.
[2] Reduction estimated at busbar. 2010 DSM is actual at peak.
[3] Reflects no expected utilization of demand response (DR) resources in winter. Winter DR capability presented in TYSP report on Table 2.17.
[4] 2010 values reflect incremental increase from 2009.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation [2], [3]	Comm./Ind Conservation [2], [3]	Retail Sales [1]	Wholesale	Utility Use & Losses	Net Energy for Load [1]	Load Factor % [1]
HISTORY:								
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	2,726			2,726		164	2,890	62
2006	2,716			2,716		154	2,870	57
2007	2,756			2,756		158	2,914	54
2008	2,679			2,679		154	2,834	55
2009	2,661			2,661		144	2,805	53
2010	2,767	12	1	2,754		177	2,931	56
FORECAST:								
2011	2,694	44	7	2,643		157	2,800	54
2012	2,727	56	19	2,652		158	2,810	57
2013	2,752	69	43	2,640		157	2,797	57
2014	2,775	80	69	2,626		156	2,782	57
2015	2,800	93	93	2,614		155	2,770	57
2016	2,829	109	118	2,602		155	2,757	58
2017	2,857	125	144	2,589		154	2,743	58
2018	2,886	141	168	2,577		153	2,731	58
2019	2,916	154	193	2,569		153	2,721	58
2020	2,945	167	219	2,559		152	2,711	59

[1] Values include DSM Impacts.
[2] Reduction estimated at customer meter. 2010 DSM is actual.
[3] 2010 values reflect incremental increase from 2009.

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2010 Actual		2011 Forecast [1], [2]		2012 Forecast [1]	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWH	MW	GWH	MW	GWH
January	633	258	539	236	542	237
February	542	226	508	208	511	209
March	476	207	420	202	422	202
April	399	200	423	200	425	201
May	526	246	520	235	523	235
June	581	277	587	271	566	272
July	601	290	587	277	566	278
August	580	296	579	275	566	276
September	557	271	553	259	556	260
October	483	214	524	220	526	220
November	376	194	373	194	375	195
December	539	253	458	223	460	224

[1] Peak Demand and NEL include DSM Impacts.
[2] Represents forecast values for 2011.

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Nuclear		Trillion 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	0	12	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	12	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)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	9	8	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	9	2	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	0	6	0	0	0	0	0	0	0	0	0	0
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	20,677	21,282	20,231	20,231	20,754	20,711	20,428	20,424	20,835	20,796	20,639	20,526
(14)		Steam	1000 MCF	1,583	2,497	765	765	1,126	1,223	775	918	1,041	766	1,029	314
(15)		CC	1000 MCF	17,668	18,265	18,832	18,832	18,850	18,468	19,173	18,910	19,044	19,340	18,991	18,563
(16)		CT	1000 MCF	1,426	519	634	634	778	1,020	480	596	750	690	619	1,649
(17)		Other	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

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 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Firm Inter-Region Interchange		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(4)	Residual	Total	GWH	0	6	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH	0	6	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)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWH	4	3	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	4	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	0	3	0	0	0	0	0	0	0	0	0	0
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWH	2,612	2,614	2,698	2,716	2,694	2,678	2,673	2,667	2,723	2,721	2,701	2,687
(15)		Steam	GWH	122	191	64	59	99	109	68	81	92	68	90	28
(16)		CC	GWH	2,454	2,378	2,568	2,569	2,521	2,469	2,555	2,524	2,553	2,581	2,547	2,486
(17)		CT	GWH	37	45	66	88	74	100	50	62	78	72	64	173
(18)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(19)	NUG		GWH	0	0	0	0	0	0	0	0	0	0	0	0
(20)	Renewables	Total	GWH	21	20	18	18	18	18	18	16	18	18	18	18
(21)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Biomass	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Hydro	GWH	21	20	18	18	18	18	18	16	18	18	18	18
(24)		Landfill Gas	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(26)		Solar [1]	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(29)	Other Interchange [2]		GWH	163	288	84	76	85	86	79	74	2	-8	2	6
(30)	Net Energy for Load		GWH	2,801	2,931	2,800	2,810	2,797	2,782	2,770	2,757	2,743	2,731	2,721	2,711

[1] The PV installtions at these facilities are installed on the customer's side of the meter and are, for planning purposes, treated not as firm supply resources but as DSM reductions to the customer's actual billing demand and energy consumption.

[2] Includes firm and non-firm intra-region and non-firm inter-region interchange. Negative values reflect expected need to sell off-peak power to satisfy generator minimum load requirements, primarily in

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 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	Firm Inter-Region Interchange		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2)	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
(3)	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
(4)	Residual	Total	%	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5)		Steam	%	0.0	0.2	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)		Other	%	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	0.1	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	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(12)		CT	%	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(13)		Other	%	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	%	93.3	89.2	96.4	96.7	96.3	96.3	96.5	96.7	99.3	99.6	99.3	99.1
(15)		Steam	%	4.4	6.5	2.3	2.1	3.5	3.9	2.5	2.9	3.4	2.5	3.3	1.0
(16)		CC	%	87.6	81.1	91.7	91.4	90.1	88.7	92.2	91.5	93.1	94.5	93.6	91.7
(17)		CT	%	1.3	1.5	2.4	3.1	2.6	3.6	1.8	2.2	2.8	2.6	2.4	6.4
(18)		Other	%	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)	NUG		%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(20)	Renewables	Total	%	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
(21)		Biofuels	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(22)		Biomass	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(23)		Hydro	%	0.8	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
(24)		Landfill Gas	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(25)		MSW	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(26)		Solar	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(27)		Wind	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(28)		Other	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(29)	Other Interchange [1]		%	5.8	9.8	3.0	2.7	3.0	3.1	2.9	2.7	0.1	-0.3	0.1	0.2
(30)	Net Energy for Load		%	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

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	% of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	% of Peak
2011	794	11	0	0	805	587	218	37	0	218	37
2012	726	11	0	0	737	566	171	30	0	171	30
2013	726	11	0	0	737	562	175	31	0	175	31
2014	726	11	0	0	737	556	181	32	0	181	32
2015	714	11	0	0	725	550	175	32	0	175	32
2016	714	11	0	0	725	547	178	33	0	178	33
2017	690	0	0	0	690	541	149	27	0	149	27
2018	690	0	0	0	690	536	154	29	0	154	29
2019	690	0	0	0	690	532	158	30	0	158	30
2020	660	0	0	0	660	529	131	25	0	131	25

[1] All installed capacity changes are identified in the proposed generation expansion plan (Schedule 8).

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)
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Winter Peak Demand MW	Reserve Margin before Maintenance MW	% of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	% of Peak
2011/12	870	11	0	0	881	542	339	63	0	339	63
2012/13	802	11	0	0	813	540	273	51	0	273	51
2013/14	802	11	0	0	813	536	277	52	0	277	52
2014/15	802	11	0	0	813	533	280	53	0	280	53
2015/16	788	11	0	0	799	530	269	51	0	269	51
2016/17	788	0	0	0	788	525	263	50	0	263	50
2017/18	762	0	0	0	762	524	238	46	0	238	46
2018/19	762	0	0	0	762	522	240	46	0	240	46
2019/20	762	0	0	0	762	521	241	46	0	241	46
2020/21	732	0	0	0	732	523	209	40	0	209	40

[1] All installed capacity changes are identified in the proposed generation expansion plan (Schedule 8).

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	KW	MW	MW	Status
Purdom	CT-1	Wakulla	GT	NG	DFO	PL	TK	NA	12/63	3/12	15,000	-10	-10	RT
Purdom	CT-2	Wakulla	GT	NG	DFO	PL	TK	NA	5/64	3/12	15,000	-10	-10	RT
Purdom	7	Wakulla	ST	NG	RFO	PL	WA	NA	6/66	3/12	50,000	-48	-48	RT
Hopkins	CT-1	Leon	GT	NG	DFO	PL	TK	NA	2/70	3/15	16,320	-12	-14	RT
Hopkins	CT-2	Leon	GT	NG	DFO	PL	TK	NA	9/72	3/17	27,000	-24	-26	RT
Hopkins	1	Leon	ST	NG	RFO	PL	TK	NA	5/71	3/20	75,000	-76	-78	RT
Hopkins	CT-5 [1]	Leon	GT	NG	DFO	PL	TK	NA	5/20	Unknown	60,500	46	48	P

[1] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different location or a peak season purchase.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	Hopkins CT 5	[1]
(2)	Capacity		
	a. Summer:	46	
	b. Winter:	48	
(3)	Technology Type:	CT	
(4)	Anticipated Construction Timing		
	a. Field construction start-date:	12/18	
	b. Commercial in-service date:	05/20	
(5)	Fuel		
	a. Primary fuel:	NG	
	b. Alternate fuel:	DFO	
(6)	Air Pollution Control Strategy:	BACT compliant	
(7)	Cooling Method:	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 Perfomance Data		
	Planned Outage Factor (POF):	5.08	
	Forced Outage Factor (FOF):	3.47	
	Equivalent Availability Factor (EAF):	90.08	
	Resulting Capacity Factor (%):	4.30	[2]
	Average Net Operating Heat Rate (ANOHR):	9,815 Btu/kWh	[3]
(13)	Projected Unit Financial Data		
	Book Life (Years):	30	
	Total Installed Cost (In-Service Year $/kW):	1,216	[4]
	Direct Construction Cost ($/kW):	974	[5]
	AFUDC Amount ($/kW):	NA	
	Escalation ($/kW):	242	
	Fixed O&M ($/kW-Yr):	6.98	[5]
	Variable O&M ($/MWH):	14.70	[5]
	K Factor:	NA	

[1] For the purposes of this report, the City has identified the addition of a GE LM 6000 combustion turbine generator (similar to the City's existing Hopkins CT3 and CT4) at its existing Hopkins Plant site. The timing, site, type and size of this new power supply resource may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different

[2] Expected first year capacity factor.

[3] Expected full load average heat rate at 68oF.

[4] Estimated 2020 dollars.

[5] Estimated 2011 dollars.

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

(1)	Point of Origin and Termination:	Hopkins South - 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 Construction Timing:	Start - 2009 End - 2012
(7)	Anticipated Capital Investment [1]:	$11.0 million
(8)	Substations:	Hopkins South (tap Hopkins-Crawfordville 230 kV) [2]
(9)	Participation with Other Utilities:	None

[1] Cumulative capital requirement identified in FY 2011 budget.
[2] New substation to serve as west terminus for new 230 kV line. Existing Substation 5 will be east terminus.

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

(1)	Point of Origin and Termination:	Substation 5 - Substation 4 - 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 Construction Timing:	Not yet determined; target in service summer 2016
(7)	Anticipated Capital Investment:	See note [1]
(8)	Substations:	See note [2]
(9)	Participation with Other Utilities:	None

[1] Anticipated capital investment associated with rebuilding/reconductoring associated transmission and substation facilities has not been segregated from that related to other improvements being made to these facilities for purposes other than that of establishing this 230 kV

[2] North terminus will be existing Substation 7; south terminus will be existing Substation 5; intermediate terminus will be existing Substation 4.