Terry A. Davis
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GULF POWER
A SOUTHERN COMPANY

April 28, 2011

110000-OT

Mr. Phillip Ellis
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399

Dear Mr. Ellis:

Enclosed is a hard copy of Gulf Power Company's response to Staff's Supplemental Data Request dated February 18, 2011 for the 2011 Ten Year Site Plan. Also enclosed is a CD containing the electronic versions of the tables and appendices as requested.

Sincerely,

Terry A. Davis

nbm

Enclosures

cc: Beggs & Lane
Jeffrey A. Stone, Esq.
Florida Public Service Commission
Charles Murphy, Office of General Counsel
Ann Cole, Office of the Commission Clerk

[CLK note: No CD Filed w/ CLK.]
MM McLean

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.

ANSWER:

Please see attached Appendix A.

History and Forecast of Summer Peak Demand
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
					NOT AVAILABLE				
FORECAST:									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
				****NOT AVAILABLE****					
FORECAST:									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									

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	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2000/01									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09									
2009/10									
					NOT AVAILABLE				
FORECAST:									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									

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	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2000/01									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09									
2009/10					**NOT AVAILABLE**				
FORECAST:									
2010/11									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C / I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor (%)
HISTORY:								
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010				****NOT AVAILABLE****				
FORECAST:								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								

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	C / I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor (%)
HISTORY:								
2001								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010				****NOT AVAILABLE****				
FORECAST:								
2011								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								

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
Crist	1	—	—	—	—	—	—	—	—
Crist	2	—	—	—	—	—	—	—	—
Crist	3	—	—	—	—	—	—	—	—
Crist	4	9.24	4.30	0.43	3.26	89.46	92.44	11,075	11,219
Crist	5	9.48	5.51	0.36	4.10	88.22	90.40	11,075	11,145
Crist	6	9.56	10.60	2.78	4.20	85.48	85.20	11,165	11,238
Crist	7	10.46	6.14	1.78	3.79	82.69	90.07	10,754	10,394
Smith	1	2.45	4.27	1.05	3.74	89.46	91.98	10,539	10,584
Smith	2	4.01	3.89	0.15	4.72	88.22	91.39	10,466	10,492
Smith	3	11.41	3.81	0.38	3.45	85.48	92.74	6,939	7,252
Smith	A	4.86	0.00	0.17	0.00	82.69	100.00	17,231	—
Scholz	1	2.88	4.08	0.05	4.06	96.22	91.86	12,151	12,409
Scholz	2	0.00	4.11	0.26	3.62	98.97	92.27	12,655	12,926
Daniel	1	5.00	7.45	5.19	3.22	88.07	89.32	10,294	10,305
Daniel	2	6.86	8.96	1.47	3.60	86.55	87.24	10,236	10,350
Scherer	3	13.58	5.45	0.76	2.29	84.22	92.25	10,187	10,117

NOTES: Historical - average of past three years. Scholz 1 ANOHR based on average of years 2008 and 2010.
Projected - average of next ten years
Crist 1 retired 3/31/2003. Crist 2 and 3 retired 05/1/2006.

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:									
2008									
2009					**N/A**				
2010									
FORECAST:									
2011									
2012									
2013									
2014					**NOT FORECASTED**				
2015									
2016									
2017									
2018									
2019									
2020									

ASSUMPTIONS:

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	¢/MBTU	%	$/BBL	¢/MBTU	%	$/BBL	¢/MBTU	%
HISTORY:									
2008									
2009				**N/A**					
2010									
FORECAST:									
2011									
2012									
2013									
2014				**NOT FORECASTED**					
2015									
2016									
2017									
2018									
2019									
2020									

ASSUMPTIONS:

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:									
2008									
2009					**N/A**				
2010									
FORECAST:									
2011									
2012									
2013									
2014					**NOT FORECASTED**				
2015									
2016									
2017									
2018									
2019									
2020									

ASSUMPTIONS:

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil*			Natural Gas		
Year	$/BBL	c/MBTU	Escalation *** %	c/MBTU	$/MCF	Escalation *** %
HISTORY:						
2008	89.65	1549	24.9%	946	9.08	5.5%
2009	79.63	1373	-11.4%	485	4.98	-48.7%
2010	95.72	1650	20.2%	614	6.25	26.6%
FORECAST: **						
2011	96.36	1646	-0.2%	536	5.52	-12.7%
2012	100.43	1715	4.2%	574	5.91	7.1%
2013	108.38	1851	7.9%	657	6.76	14.5%
2014	125.52	2144	15.8%	796	8.20	21.2%
2015	142.66	2437	13.7%	935	9.63	17.5%
2016	150.69	2574	5.6%	983	10.12	5.1%
2017	158.72	2711	5.3%	1030	10.61	4.8%
2018	166.75	2848	5.1%	1078	11.11	4.7%
2019	174.78	2985	4.8%	1126	11.60	4.5%
2020	182.82	3123	4.6%	1174	12.09	4.3%

ASSUMPTIONS:
*Distillate Oil: 0.0015% Sulfur, 139,400 BTU
**Forecast prices shown are nominal, delivered prices to plant Crist.
***Escalation in c/MBTU

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	¢/MBTU	Escalation %	¢/MBTU	$/MCF	Escalation %
HISTORY:						
2008						
2009			**N/A**			
2010						
FORECAST:						
2011						
2012						
2013						
2014			**NOT FORECASTED**			
2015						
2016						
2017						
2018						
2019						
2020						

ASSUMPTIONS:

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
HISTORY:						
2008						
2009			**N/A**.			
2010						
FORECAST:						
2011						
2012						
2013						
2014			**NOT FORECASTED**			
2015						
2016						
2017						
2018						
2019						
2020						

ASSUMPTIONS:

Nominal, Delivered Coal Prices
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	105.08	443	65.9%	61.9%	95.54	392	95.0%	38.1%	n/a	n/a	n/a	n/a
2009	90.66	423	-4.5%	0.0%	98.31	410	4.6%	2.5%	n/a	n/a	n/a	n/a
2010	113.24	510	20.6%	0.0%	96.01	400	-2.4%	0.0%	63.71	274	n/a	0.0%
FORECAST:****												
2011	94.43	400	-21.6%	0.0%	86.38	360	-10.0%	0.0%	75.44	334	21.9%	
2012	96.70	410	2.5%	0.0%	86.54	361	0.3%	0.0%	75.30	333	-0.3%	
2013	117.19	497	21.2%	0.0%	106.08	442	22.4%	0.0%	75.92	336	0.9%	
2014	111.27	471	-5.2%	0.0%	96.26	401	-9.3%	0.0%	74.68	330	-1.8%	
2015	105.67	448	-4.9%	0.0%	86.61	361	-10.0%	0.0%	73.82	327	-0.9%	
2016	108.72	461	2.9%	0.0%	88.00	367	1.7%	0.0%	75.47	334	2.1%	
2017	111.82	474	2.8%	0.0%	89.45	373	1.6%	0.0%	77.16	341	2.1%	
2018	114.95	487	2.7%	0.0%	90.92	379	1.6%	0.0%	78.86	349	2.3%	
2019	118.14	501	2.9%	0.0%	92.41	385	1.6%	0.0%	80.60	357	2.3%	
2020	121.35	514	2.6%	0.0%	93.90	391	1.6%	0.0%	82.34	364	2.0%	

ASSUMPTIONS:

*For the forecast years, a western (0.5%S, 11800 BTU/LB) coal was chosen.

**For the forecast years, a Central Appalachia Barge (1.0%S, 12000 BTU/LB) coal was chosen. History includes actuals, of which most was the same Central Appalachia coal.

***For the forecast years, a Illinois Basin > (2.0% S, 11,300) BTU/LB) coal was chosen.

****Forecast prices shown are nominal, delivered prices to plant Crist.

*****Escalation in c/MBTU

Nominal, Delivered Coal Prices
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												
2009						**N/A**						
2010												
FORECAST:												
2011												
2012												
2013												
2014						**NOT FORECASTED**							
2015												
2016												
2017												
2018												
2019												
2020												

ASSUMPTIONS:

Staff's First Supplemental Data Request
2011 Ten Year Site Plan
Gulf Power Company
April 28, 2011 Item No. 1, Appendix A
Page 15 of 20

Nominal, Delivered Coal Prices
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												
2009						**N/A**						
2010												
FORECAST:												
2011												
2012												
2013												
2014						**NOT FORECASTED**							
2015												
2016												
2017												
2018												
2019												
2020												

ASSUMPTIONS:

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
Year	c/MBTU	Escalation %	$/MWh *	Escalation %
HISTORY:				
2008	n/a	n/a	None	n/a
2009	n/a	n/a	None	n/a
2010	n/a	n/a	58.3	n/a
FORECAST:				
2011	n/a	n/a	3,584.0	6047.5%
2012	n/a	n/a	3,259.0	-9.1%
2013	n/a	n/a	3,260.0	0.0%
2014	n/a	n/a	105.0	-96.8%
2015	n/a	n/a	117.0	11.4%
2016	n/a	n/a	123.0	5.1%
2017	n/a	n/a	128.0	4.1%
2018	n/a	n/a	128.0	0.0%
2019	n/a	n/a	125.0	-2.3%
2020	n/a	n/a	128.0	2.4%

* Includes capacity and energy dollars

Financial Assumptions
Base Case

AFUDC RATE	9.31	%
CAPITALIZATION RATIOS:		
DEBT	50.0	%
PREFERRED	5.0	%
EQUITY	45.0	%
RATE OF RETURN		
DEBT	7.1	%
PREFERRED	7.2	%
EQUITY	12.0	%
INCOME TAX RATE:		
STATE	5.5	%
FEDERAL	35.0	%
EFFECTIVE	38.575	%
OTHER TAX RATE:	0.65	%
DISCOUNT RATE:	7.94	%
TAX DEPRECIATION RATE:	See adjacent table	%

Tax Depreciation Rates

Year	CT
1	5.000%
2	9.500%
3	8.550%
4	7.695%
5	6.926%
6	6.233%
7	5.905%
8	5.905%
9	5.905%
10	5.905%
11	5.905%
12	5.905%
13	5.905%
14	5.904%
15	5.905%
16	2.952%

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2011	1.958	1.958	1.958	1.958
2012	1.958	1.958	1.958	1.958
2013	1.958	1.958	1.958	1.958
2014	1.958	1.958	1.958	1.958
2015	1.958	1.958	1.958	1.958
2016	1.958	1.958	1.958	1.958
2017	1.958	1.958	1.958	1.958
2018	1.958	1.958	1.958	1.958
2019	1.958	1.958	1.958	1.958
2020	1.958	1.958	1.958	1.958

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated (A)			Annual Assisted		
Year	Loss of Load Probability (B) (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (B) (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2011						0.00
2012						0.00
2013						0.00
2014						0.00
2015						0.00
2016						0.00
2017						0.00
2018						0.00
2019						0.08
2020						0.26

Note: (A) Not Available
(B) LOLP is not used by Gulf Power

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

ANSWER:

Please see attached Appendix B.

Schedule 1
Existing Generating Facilities
As of December 31, 2010

GULF POWER COMPANY

(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 Transp Pri	Fuel Transp Alt	Alt. Fuel Days Use	Com'l In-Service Mo/Yr	Expld Retrmnt Mo/Yr	Gen Max Nameplate KW	Net Capability Summer MW	Net Capability Winter MW
Crist		Escambia County 25/1N/30W									1,135,250	906.0	906.0
	4		FS	C	NG	WA	PL	1	07/59	12/24	93,750	75.0	75.0
	5		FS	C	NG	WA	PL	1	06/61	12/26	93,750	75.0	75.0
	6		FS	C	NG	WA	PL	1	05/70	12/35	369,750	291.0	291.0
	7		FS	C	NG	WA	PL	1	09/73	12/38	578,000	465.0	465.0
Lansing Smith		Bay County 38/2S/15W									1,001,500	945.0	981.0
	1		FS	C	--	WA	--	--	06/65	12/30	149,600	162.0	162.0
	2		FS	C	--	WA	--	--	06/67	12/32	190,400	195.0	195.0
	3		CC	NG	--	PL	--	--	04/02	12/42	619,650	556.0	584.0
	A		CT	LO	--	TK	--	--	05/71	12/27	41,850	32.0	40.0
(A) Scholz		Jackson County 12/3N/7W									98,000	92.0	92.0
	1		FS	C	--	RR	WA	--	03/53	*Note A*	49,000	46.0	46.0
	2		FS	C	--	RR	WA	--	10/53	*Note A*	49,000	46.0	46.0
(B) Daniel		Jackson County, MS 42/5S/6W									548,250	510.0	510.0
	1		FS	C	HO	RR	TK	--	09/77	12/42	274,125	255.0	255.0
	2		FS	C	HO	RR	TK	--	06/81	12/46	274,125	255.0	255.0
(B) Scherer	3	Monroe County, GA	FS	C	--	RR	--	--	01/87	12/52	222,750	218.0	218.0
Pea Ridge		Santa Rosa County 15/1N/29W									14,250	12.0	15.0
	1		CT	NG	--	PL	--	--	05/98	12/18	4,750	4.0	5.0
	2		CT	NG	--	PL	--	--	05/98	12/18	4,750	4.0	5.0
	3		CT	NG	--	PL	--	--	05/98	12/18	4,750	4.0	5.0
Perdido LFG		Escambia County 32/1N/31W									3.2	3.0	3.0
	1		IC	LFG	--	PL	--	--	10/10	12/29	1.6	1.5	1.5
	2		IC	LFG	--	PL	--	--	10/10	12/29	1.6	1.5	1.5
										Total System		2,686.0	2,725.0

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	Members per Household	GWH	Average No. of Customers	Average KWH Consumption Per Customer	GWH	Average No. of Customers	Average KWH Consumption Per Customer
2001	742,110	2.60	4,716	325,343	14,497	3,417	48,482	70,490
2002	755,930	2.61	5,144	331,637	15,510	3,553	49,139	72,304
2003	766,930	2.61	5,101	338,631	15,064	3,614	50,420	71,683
2004	780,100	2.61	5,215	345,467	15,096	3,695	51,981	71,093
2005	789,800	2.61	5,320	350,404	15,181	3,736	52,916	70,599
2006	795,820	2.60	5,425	360,930	15,032	3,843	53,479	71,862
2007	794,550	2.60	5,477	371,213	14,755	3,971	53,791	73,821
2008	796,460	2.61	5,349	374,709	14,274	3,961	53,810	73,610
2009	798,340	2.60	5,254	374,010	14,049	3,896	53,414	72,942
2010	802,190	2.60	5,651	375,847	15,036	3,997	53,349	74,912
2011	805,170	2.59	5,436	377,660	14,395	3,964	53,822	73,658
2012	813,540	2.59	5,633	381,182	14,778	4,083	54,502	74,916
2013	826,820	2.58	5,815	386,914	15,028	4,195	55,127	76,103
2014	842,400	2.57	6,005	393,848	15,246	4,309	55,865	77,129
2015	857,060	2.56	6,130	400,949	15,288	4,387	56,617	77,492
2016	872,480	2.55	6,212	408,012	15,224	4,446	57,367	77,510
2017	888,330	2.55	6,314	414,933	15,218	4,523	58,106	77,844
2018	904,330	2.55	6,421	421,603	15,229	4,598	58,822	78,160
2019	920,470	2.55	6,547	428,018	15,296	4,693	59,514	78,849
2020	936,590	2.55	6,692	434,112	15,416	4,776	60,176	79,362
CAAG								
01-10	0.9%	0.0%	2.0%	1.6%	0.4%	1.8%	1.1%	0.7%
10-15	1.3%	-0.3%	1.6%	1.3%	0.3%	1.9%	1.2%	0.7%
10-20	1.6%	-0.2%	1.7%	1.5%	0.3%	1.8%	1.2%	0.6%

* Historical and projected figures include Pensacola, Ft Walton, and Panama City MSAs

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		Industrial					
Year	GWH	Average No. of Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
2001	2,018	277	7,290,329	0	21	0	10,173
2002	2,054	272	7,552,563	0	21	0	10,772
2003	2,147	285	7,526,577	0	22	0	10,885
2004	2,113	279	7,569,053	0	23	0	11,046
2005	2,161	295	7,332,898	0	23	0	11,239
2006	2,136	294	7,260,626	0	24	0	11,429
2007	2,048	303	6,769,670	0	24	0	11,521
2008	2,211	291	7,592,204	0	23	0	11,543
2009	1,727	280	6,164,567	0	25	0	10,903
2010	1,686	275	6,133,961	0	26	0	11,359
2011	1,993	286	6,958,806	0	28	0	11,421
2012	2,024	295	6,869,032	0	29	0	11,768
2013	2,024	296	6,837,280	0	29	0	12,064
2014	2,026	298	6,786,410	0	30	0	12,369
2015	2,026	299	6,771,651	0	31	0	12,574
2016	2,028	301	6,743,493	0	32	0	12,718
2017	2,029	302	6,707,808	0	33	0	12,899
2018	2,029	304	6,671,280	0	34	0	13,081
2019	2,030	307	6,619,389	0	35	0	13,304
2020	2,032	308	6,605,480	0	36	0	13,536
CAAG							
01-10	-2.0%	-0.1%	-1.9%	0.0%	2.2%	0.0%	1.2%
10-15	3.7%	1.7%	2.0%	0.0%	4.0%	0.0%	2.1%
10-20	1.9%	1.1%	0.7%	0.0%	3.5%	0.0%	1.8%

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

(1)	(2)	(3)	(4)	(5)	(6)
Year	Sales for Resale GWH	Utility Use & Losses GWH	Net Energy for Load GWH	Other Customers (Average No.)	Total No. of Customers
2001	360	671	11,204	460	374,561
2002	384	754	11,910	474	381,521
2003	383	685	11,952	473	389,809
2004	389	727	12,162	474	396,200
2005	418	666	12,322	472	404,086
2006	415	743	12,586	482	415,185
2007	417	733	12,671	486	425,793
2008	398	676	12,617	493	429,302
2009	390	682	11,975	502	428,206
2010	409	750	12,518	559	430,030
2011	392	715	12,528	573	432,342
2012	405	738	12,911	587	436,565
2013	411	758	13,233	600	442,938
2014	418	778	13,566	614	450,625
2015	422	790	13,786	628	458,493
2016	427	801	13,946	642	466,321
2017	430	815	14,144	657	473,999
2018	435	828	14,343	672	481,401
2019	440	844	14,588	688	488,526
2020	447	857	14,840	703	495,299
CAAG					
01-10	1.4%	1.3%	1.2%	2.2%	1.5%
10-15	0.6%	1.0%	1.9%	2.4%	1.3%
10-20	0.9%	1.3%	1.7%	2.3%	1.4%

Note: Sales for Resale and Net Energy for Load include contracted energy allocated to certain customers by Southeastern Power Administration (SEPA).

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	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Net Firm Demand
2001	2,528	86	2,442	17	0	137	0	143	2,231
2002	2,755	94	2,661	0	0	145	0	148	2,462
2003	2,582	87	2,495	0	0	152	0	155	2,275
2004	2,752	92	2,659	0	0	161	0	159	2,431
2005	2,767	90	2,677	0	0	167	0	164	2,435
2006	2,828	97	2,731	0	0	171	0	173	2,483
2007	2,989	103	2,886	0	0	175	0	180	2,634
2008	2,898	96	2,802	0	0	176	0	182	2,541
2009	2,909	93	2,816	0	0	177	0	186	2,546
2010	2,896	92	2,804	0	0	178	0	192	2,525
2011	2,977	80	2,898	0	0	187	0	199	2,592
2012	3,040	81	2,959	0	0	197	0	201	2,642
2013	3,090	83	3,007	0	0	211	0	204	2,675
2014	3,141	84	3,058	0	0	228	0	207	2,706
2015	3,171	84	3,086	0	0	247	0	212	2,712
2016	3,204	85	3,119	0	0	266	0	216	2,722
2017	3,258	86	3,173	0	0	283	0	221	2,754
2018	3,313	87	3,227	0	0	301	0	226	2,787
2019	3,378	87	3,291	0	0	317	0	231	2,830
2020	3,449	88	3,360	0	0	333	0	235	2,880
CAAG									
01-10	1.5%	0.7%	1.5%	0.0%	0.0%	3.0%	0.0%	3.3%	1.4%
10-15	1.8%	-1.7%	1.9%	0.0%	0.0%	6.7%	0.0%	1.9%	1.4%
10-20	1.8%	-0.4%	1.8%	0.0%	0.0%	6.5%	0.0%	2.0%	1.3%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	Comm/Ind Load Management	Comm/Ind Conservation	Net Firm Demand
00-01	2,486	94	2,393	0	0	200	0	126	2,160
01-02	2,530	93	2,437	0	0	211	0	129	2,190
02-03	2,856	100	2,757	0	0	224	0	133	2,500
03-04	2,445	84	2,361	0	0	240	0	135	2,070
04-05	2,518	97	2,420	0	0	250	0	137	2,130
05-06	2,476	97	2,379	0	0	262	0	142	2,072
06-07	2,644	93	2,551	0	0	275	0	146	2,224
07-08	2,793	102	2,691	0	0	276	0	147	2,370
08-09	2,757	77	2,681	0	0	287	0	150	2,320
09-10	2,996	111	2,885	0	0	289	0	154	2,553
10-11	2,752	74	2,678	0	0	298	0	158	2,296
11-12	2,840	77	2,762	0	0	310	0	159	2,371
12-13	2,886	79	2,807	0	0	324	0	160	2,401
13-14	2,958	80	2,877	0	0	342	0	162	2,454
14-15	2,964	81	2,882	0	0	361	0	164	2,439
15-16	2,995	82	2,913	0	0	379	0	166	2,450
16-17	3,045	83	2,963	0	0	396	0	168	2,481
17-18	3,096	83	3,013	0	0	414	0	170	2,512
18-19	3,154	84	3,069	0	0	432	0	172	2,550
19-20	3,220	86	3,134	0	0	449	0	174	2,597
CAAG									
01-10	2.1%	1.9%	2.1%	0.0%	0.0%	4.2%	0.0%	2.2%	1.9%
10-15	-0.2%	-6.1%	0.0%	0.0%	0.0%	4.5%	0.0%	1.2%	-0.9%
10-20	0.7%	-2.5%	0.8%	0.0%	0.0%	4.5%	0.0%	1.2%	0.2%

NOTE 1: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

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	Comm/Ind Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor %
2001	11,801	314	284	10,173	360	671	11,204	57.3%
2002	12,520	323	288	10,772	384	754	11,910	55.2%
2003	12,584	335	297	10,885	383	685	11,952	60.0%
2004	12,813	348	303	11,046	389	727	12,162	57.0%
2005	12,998	357	319	11,239	418	666	12,322	57.8%
2006	13,273	365	322	11,429	415	743	12,586	57.9%
2007	13,373	375	327	11,521	417	733	12,671	54.9%
2008	13,326	378	331	11,543	398	676	12,617	56.5%
2009	12,705	384	345	10,903	390	682	11,975	53.7%
2010	13,256	388	350	11,359	409	750	12,518	56.6%
2011	13,305	424	353	11,421	392	715	12,528	55.2%
2012	13,734	464	359	11,768	405	738	12,911	55.6%
2013	14,118	518	367	12,064	411	758	13,233	56.5%
2014	14,517	575	376	12,369	418	778	13,566	57.2%
2015	14,814	641	387	12,574	422	790	13,786	58.0%
2016	15,049	704	399	12,718	427	801	13,946	58.3%
2017	15,318	762	412	12,899	430	815	14,144	58.6%
2018	15,592	824	425	13,081	435	828	14,343	58.8%
2019	15,909	883	438	13,304	440	844	14,588	58.8%
2020	16,230	940	450	13,536	447	857	14,840	58.7%
CAAG								
01-10	1.3%	2.4%	2.4%	1.2%	1.4%	1.3%	1.2%	-0.1%
10-15	2.2%	10.6%	2.0%	2.1%	0.6%	1.0%	1.9%	0.5%
10-20	2.0%	9.3%	2.5%	1.8%	0.9%	1.3%	1.7%	0.4%

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA).

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		2012 Forecast	
	Peak Demand	NEL	Peak Demand	NEL	Peak Demand	NEL
Month	MW	GWH	MW	GWH	MW	GWH
January	2,553	1,106	2,296	1,005	2,371	1,039
February	2,144	955	2,083	841	2,226	894
March	1,934	851	1,821	871	1,892	902
April	1,488	803	1,897	859	1,966	889
May	2,219	1,070	2,320	1,096	2,393	1,129
June	2,419	1,244	2,526	1,230	2,581	1,261
July	2,525	1,325	2,592	1,331	2,642	1,363
August	2,458	1,282	2,574	1,319	2,625	1,351
September	2,300	1,139	2,424	1,143	2,482	1,171
October	1,881	891	2,227	1,006	2,288	1,035
November	1,574	796	1,836	870	1,892	896
December	2,314	1,057	2,092	957	2,152	982

NOTE: Includes contracted capacity and energy allocated to certain Resale customers by Southeastern Power Administration (SEPA)

Schedule 5
Fuel Requirements

(1)	(2) Fuel Requirements	(3)	(4) Units	(5) Actual 2009	(6) Actual 2010	(7) 2011	(8) 2012	(9) 2013	(10) 2014	(11) 2015	(12) 2016	(13) 2017	(14) 2018	(15) 2019	(16) 2020
(1)	Nuclear		Trillion BTU	None	None	None	None	None	None	None	None	None	None	None	None
(2)	Coal		1000 TON	4,427	5,179	4,478	4,381	5,134	5,726	5,727	5,851	5,887	5,830	6,204	6,051
(3)	Residual	Total	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(4)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	None	None	None	None	None	None	None	None	None	None	None	None
(6)		CT	1000 BBL	None	None	None	None	None	None	None	None	None	None	None	None
(7)		Diesel	1000 BBL	None	None	None	None	None	None	None	None	None	None	None	None
(8)	Distillate	Total	1000 BBL	15	18	9	10	9	8	8	8	8	8	7	8
(9)		Steam	1000 BBL	14	17	9	10	9	8	8	8	8	8	7	8
(10)		CC	1000 BBL	None	None	None	None	None	None	None	None	None	None	None	None
(11)		CT	1000 BBL	1	1	0	0	0	0	0	0	0	0	0	0
(12)		Diesel	1000 BBL	None	None	None	None	None	None	None	None	None	None	None	None
(13)	Natural Gas	Total	1000 MCF	28,355	34,320	24,243	24,494	23,695	24,958	26,713	23,725	21,723	25,309	28,853	29,070
(14)		Steam	1000 MCF	632	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	26,702	31,715	23,845	24,068	23,247	24,950	26,713	23,725	21,723	25,309	28,853	29,070
(16)		CT	1000 MCF	1,021	2,605	398	426	448	8	0	0	0	0	0	0
(17)	Other (A)		Trillion BTU	None	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

(A) Perdido Units 1 and 2 landfill gas burn shown in Other

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)	Annual Firm Interchange		GWH	(996)	(2,936)	(1,224)	(683)	(2,020)	(3,199)	(2,988)	(2,682)	(2,274)	(2,518)	(3,580)	(3,021)
(2)	Nuclear		GWH	None	None	None	None	None	None	None	None	None	None	None	None
(3)	Coal		GWH	8,871	10,531	10,108	9,916	11,676	13,065	12,935	13,209	13,261	13,213	14,077	13,746
(4)	Residual	Total	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(5)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWH	None	None	None	None	None	None	None	None	None	None	None	None
(7)		CT	GWH	None	None	None	None	None	None	None	None	None	None	None	None
(8)		Diesel	GWH	None	None	None	None	None	None	None	None	None	None	None	None
(9)	Distillate	Total	GWH	0	0.2	0	0	0	0	0	0	0	0	0	0
(10)		Steam	GWH	None	None	None	None	None	None	None	None	None	None	None	None
(11)		CC	GWH	None	None	None	None	None	None	None	None	None	None	None	None
(12)		CT	GWH	0	0.2	0	0	0	0	0	0	0	0	0	0
(13)		Diesel	GWH	None	None	None	None	None	None	None	None	None	None	None	None
(14)	Natural Gas	Total	GWH	4,024	4,805	3,512	3,555	3,443	3,565	3,753	3,332	3,049	3,568	4,000	4,023
(15)		Steam	GWH	6	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWH	3,858	4,485	3,423	3,462	3,349	3,514	3,702	3,281	2,998	3,507	4,000	4,023
(17)		CT	GWH	160	320	89	93	94	51	51	51	51	51	0	0
(18)	NUGs		GWH	76	118	132	133	134	135	86	87	88	90	91	92
(19)	Net Energy for Load		GWH	11,975	12,518	12,528	12,911	13,233	13,568	13,786	13,946	14,144	14,343	14,588	14,840

NOTE: Line (18) includes energy purchased from Non-Renewable and Renewable resources. See Schedule 6.3 for details on Gulf's renewable resources .

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)	Annual Firm Interchange		%	(8.32)	(23.46)	(9.77)	(5.37)	(15.26)	(23.58)	(21.67)	(19.23)	(16.06)	(17.56)	(24.54)	(20.36)
(2)	Nuclear		%	None	None	None	None	None	None	None	None	None	None	None	None
(3)	Coal		%	74.06	64.13	80.68	76.80	88.23	96.31	93.83	94.72	93.90	92.12	96.50	92.63
(4)	Residual	Total	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(5)		Steam	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(6)		CC	%	None	None	None	None	None	None	None	None	None	None	None	None
(7)		CT	%	None	None	None	None	None	None	None	None	None	None	None	None
(8)		Diesel	%	None	None	None	None	None	None	None	None	None	None	None	None
(9)	Distillate	Total	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(10)		Steam	%	None	None	None	None	None	None	None	None	None	None	None	None
(11)		CC	%	None	None	None	None	None	None	None	None	None	None	None	None
(12)		CT	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(13)		Diesel	%	None	None	None	None	None	None	None	None	None	None	None	None
(14)	Natural Ga	Total	%	33.60	36.36	28.03	27.53	26.02	26.28	27.22	23.89	21.56	24.81	27.42	27.11
(15)		Steam	%	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(16)		CC	%	32.22	35.63	27.32	26.81	25.31	25.90	26.85	23.53	21.20	24.45	27.42	27.11
(17)		CT	%	1.34	2.56	0.71	0.72	0.71	0.38	0.37	0.37	0.36	0.36	0.00	0.00
(18)	NUGs		%	0.63	0.94	1.05	1.03	1.01	1.00	0.62	0.62	0.62	0.63	0.62	0.62
(19)	Net Energy for Load		%	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
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
HISTORY:											
2001	2251	470	(212)	19	2528	2231	297	13.3%	NONE	297	13.3%
2002	2815	27	(210)	19	2651	2462	189	7.7%	NONE	189	7.7%
2003	2800	26	(211)	19	2634	2275	359	15.8%	NONE	359	15.8%
2004	2800	26	(211)	19	2634	2431	203	8.4%	NONE	203	8.4%
2005	2796	0	(211)	0	2585	2435	150	6.2%	NONE	150	6.2%
2006	2733	0	(211)	0	2522	2483	39	1.6%	NONE	39	1.6%
2007	2714	0	(211)	0	2503	2634	(131)	-5.0%	NONE	(131)	-5.0%
2008	2711	0	(211)	0	2500	2541	(41)	-1.6%	NONE	(41)	-1.6%
2009	2703	488	(211)	0	2980	2546	434	17.0%	NONE	434	17.0%
2010	2686	496	(211)	0	2971	2525	446	17.7%	NONE	446	17.7%
FORECAST:											
2011	2686	496	(211)	0	2971	2592	379	14.6%	NONE	379	14.6%
2012	2686	496	(211)	0	2971	2642	329	12.5%	NONE	329	12.5%
2013	2686	496	(211)	0	2971	2675	296	11.1%	NONE	296	11.1%
2014	2686	886	(211)	0	3360	2706	654	24.2%	NONE	654	24.2%
2015	2682	885	(211)	0	3356	2712	644	23.7%	NONE	644	23.7%
2016	2682	885	(211)	0	3356	2722	634	23.3%	NONE	634	23.3%
2017	2682	885	(211)	0	3356	2754	602	21.9%	NONE	602	21.9%
2018	2674	885	(211)	0	3348	2787	561	20.1%	NONE	561	20.1%
2019	2662	885	(211)	0	3336	2830	506	17.9%	NONE	506	17.9%
2020	2662	885	(211)	0	3336	2880	456	15.8%	NONE	456	15.8%

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
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	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance MW	Reserve Margin after Maintenance MW	Reserve Margin after Maintenance % of Peak
HISTORY:											
2000/01	2259	320	(219)	19	2379	2160	219	10.1%	NONE	219	10.1%
2001/02	2262	321	(219)	19	2383	2190	193	8.8%	NONE	193	8.8%
2002/03	2844	27	(211)	19	2679	2500	179	7.2%	NONE	179	7.2%
2003/04	2828	27	(211)	19	2663	2070	593	28.6%	NONE	593	28.6%
2004/05	2828	0	(211)	19	2636	2130	506	23.8%	NONE	506	23.8%
2005/06	2824	0	(211)	0	2613	2072	541	26.1%	NONE	541	26.1%
2006/07	2771	0	(211)	0	2560	2224	336	15.1%	NONE	336	15.1%
2007/08	2752	0	(211)	0	2541	2370	171	7.2%	NONE	171	7.2%
2008/09	2750	0	(211)	0	2539	2292	247	10.8%	NONE	247	10.8%
2009/10	2742	488	(211)	0	3019	2553	466	18.3%	NONE	466	18.3%
FORECAST:											
2010/11	2725	496	(211)	0	3010	2296	714	31.1%	NONE	714	31.1%
2011/12	2725	496	(211)	0	3010	2371	639	27.0%	NONE	639	27.0%
2012/13	2725	496	(211)	0	3010	2401	609	25.4%	NONE	609	25.4%
2013/14	2725	496	(211)	0	3010	2454	556	22.7%	NONE	556	22.7%
2014/15	2725	885	(211)	0	3399	2439	960	39.4%	NONE	960	39.4%
2015/16	2721	885	(211)	0	3395	2450	945	38.6%	NONE	945	38.6%
2016/17	2721	885	(211)	0	3395	2481	914	36.8%	NONE	914	36.8%
2017/18	2721	885	(211)	0	3395	2512	883	35.2%	NONE	883	35.2%
2018/19	2698	885	(211)	0	3372	2550	822	32.2%	NONE	822	32.2%
2019/20	2698	885	(211)	0	3372	2597	775	29.8%	NONE	775	29.8%

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)
				Fuel		Fuel Transport						Net Capability		
Plant Name	Unit No.	Location	Unit Type	Pri	Alt	Pri	Alt	Const Start Mo/Yr	Com'l In-Service Mo/Yr	Expected Retirement Mo/Yr	Gen Max Nameplate KW	Summer MW	Winter MW	Status
Daniel	1	Jackson Cnty, MS 42/5S/6W	FS	C	HO	RR	TK	--	09/77	06/15	274,125	(2.0)	(2.0)	D
Daniel	2	Jackson Cnty, MS 42/5S/6W	FS	C	HO	RR	TK	--	06/81	06/15	274,125	(2.0)	(2.0)	D
Lansing Smith	1	Bay County 36/2S/15W	FS	C	--	WA	--	--	06/65	06/18	149,600	(4.0)	(4.0)	D
Lansing Smith	2	Bay County 36/2S/15W	FS	C	--	WA	--	--	06/67	06/18	190,400	(4.0)	(4.0)	D
Pea Ridge	1 - 3	Santa Rosa County 15/1N/29W	CT	NG	--	PL	--	--	05/98	12/18	14,250	(12.0)	(15.0)	R

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	Plant Name and Unit Number:	No Unit planned for 2011-2020
(2)	Net Capacity	
	a. Summer:	N/A
	b. Winter	N/A
	Gross Capacity	
	a. Summer:	N/A
	b. Winter	N/A
(3)	Technology Type:	
(4)	Anticipated Construction Timing	
	a. Field construction start - date:	N/A
	b. Commercial in-service date:	N/A
(5)	Fuel	
	a. Primary fuel:	N/A
	b. Alternate fuel:	N/A
(6)	Air Pollution Control Strategy:	N/A
(7)	Cooling Method:	N/A
(8)	Total Site Area:	N/A
(9)	Construction Status:	N/A
(10)	Certification Status:	N/A
(11)	Status with Federal Agencies:	N/A
(12)	Projected Unit Performance Data	N/A
	Planned Outage Factor (POF):	
	Unplanned Outage Factor (UOF):	
	Equivalent Availability Factor (EAF):	
	Capacity Factor (%):	
	Average Net Operating Heat Rate (ANOHR):	
(13)	Projected Unit Financial Data	N/A
	Book Life (Years):	
	Total Installed Cost (In-Service Year $/kW):	
	Direct Construction Cost ($/kW):	
	AFUDC Amount ($/kW):	
	Escalation ($/kW):	
	Fixed O&M ($/kW - Yr):	
	Variable O&M ($/MWH):	
	K Factor:	

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

(1) Point of Origin and Termination:	Unknown
(2) Number of Lines:	Unknown
(3) Right-of-Way:	Unknown
(4) Line Length:	Unknown
(5) Voltage:	Unknown
(6) Anticipated Construction Timing:	Unknown
(7) Anticipated Capital Investment:	Unknown
(8) Substations:	Unknown
(9) Participation with Other Utilities:	N/A

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.

ANSWER:

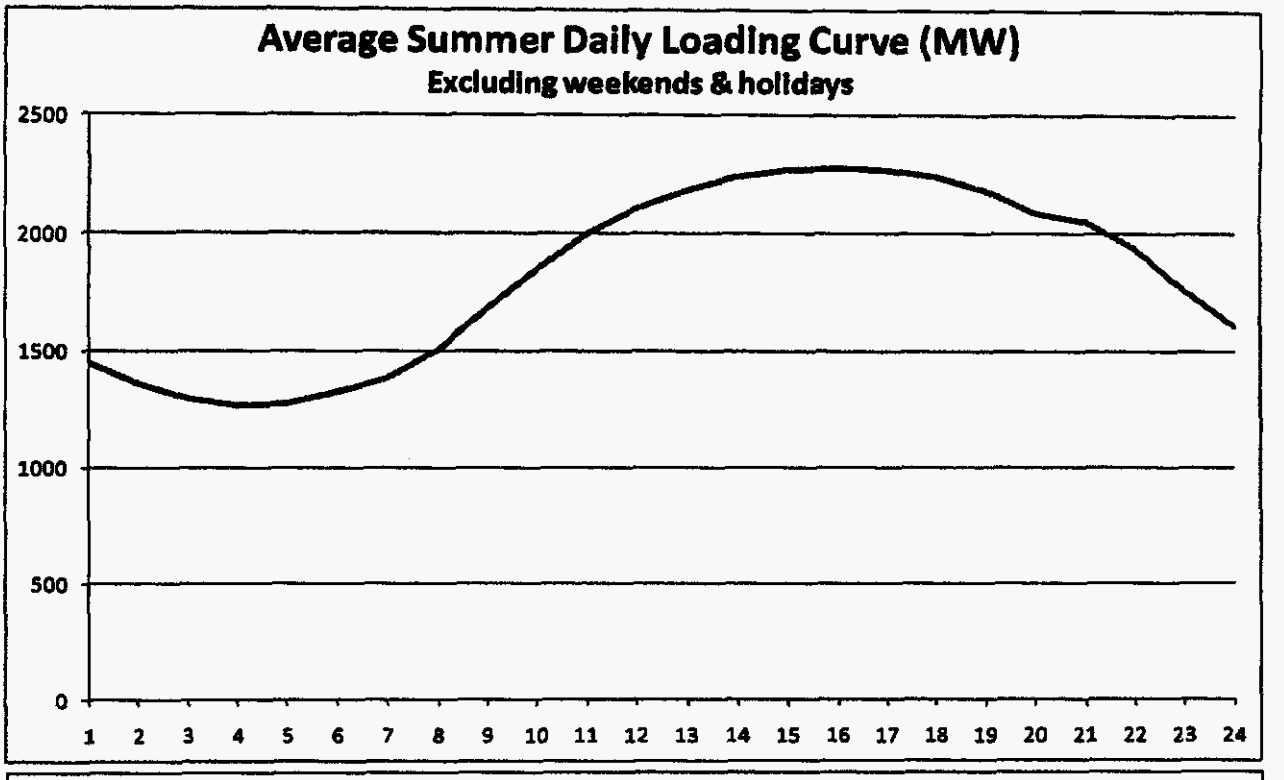
Please see pages 2 through 4.

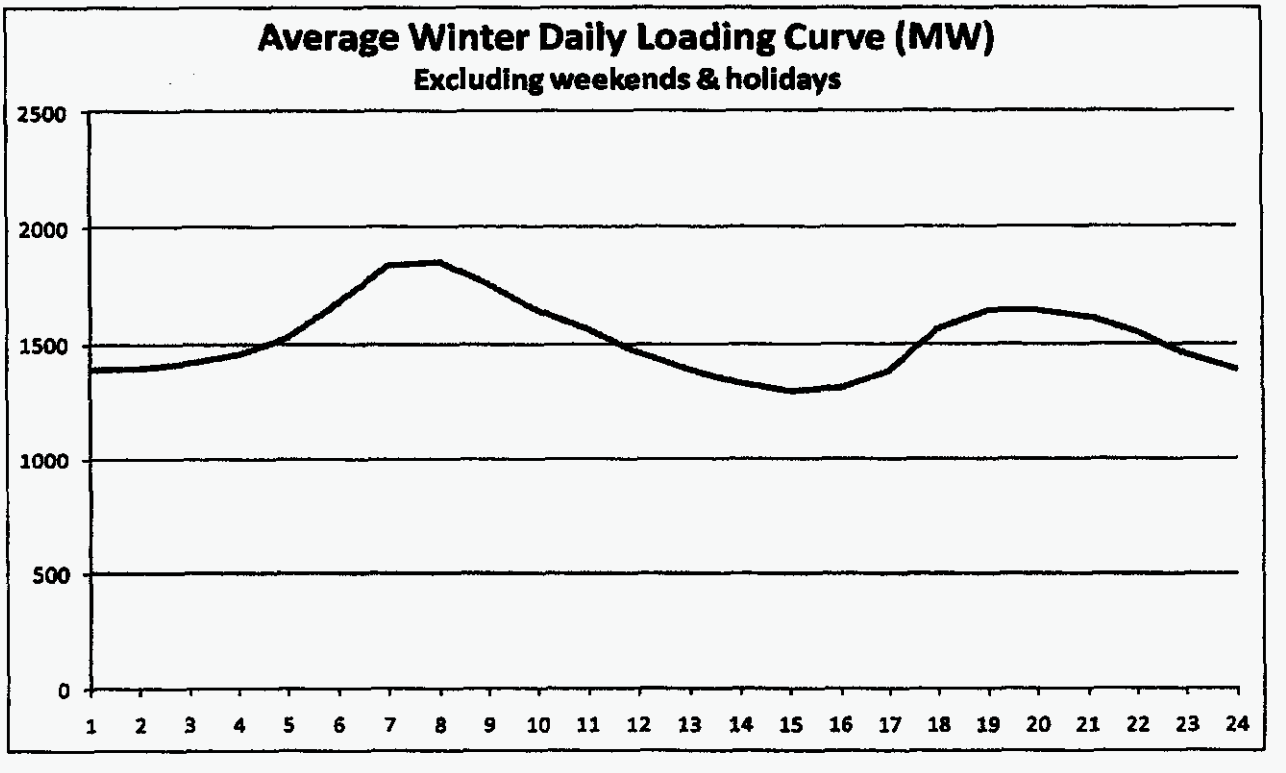
Typical Winter Month

Year	Month	Day	Day of Week	Observed Hourly Peak Capacity (MW)																								MAX	MIN
				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	(MW)	(MW)
2010	January	1	F	1018	1003	966	995	1013	1045	1091	1132	1219	1308	1356	1384	1331	1269	1229	1215	1302	1479	1532	1537	1516	1497	1438	1406	1537	966
2010	January	2	S	1382	1382	1408	1454	1514	1597	1687	1738	1757	1711	1649	1553	1453	1369	1316	1328	1435	1632	1703	1725	1728	1708	1670	1648	1757	1316
2010	January	3	S	1614	1613	1637	1663	1694	1794	1819	1923	1979	1953	1848	1747	1649	1564	1504	1454	1630	1807	1902	1926	1912	1864	1734	1710	1979	1454
2010	January	4	M	1686	1709	1732	1780	1860	2024	2199	2216	2112	1999	1917	1817	1727	1628	1569	1604	1765	2017	2111	2145	2142	2060	1946	1912	2216	1569
2010	January	5	T	1891	1917	1968	2027	2114	2293	2448	2475	2367	2227	2076	1952	1847	1742	1682	1692	1811	2069	2205	2236	2229	2159	2032	1986	2475	1682
2010	January	6	W	1967	1969	2009	2045	2122	2277	2455	2429	2288	2137	1995	1843	1713	1615	1553	1544	1631	1940	2035	2090	2091	2031	1940	1872	2455	1544
2010	January	7	Th	1872	1881	1903	1936	1995	2119	2276	2235	2065	1865	1685	1531	1401	1325	1295	1322	1424	1577	1618	1603	1567	1532	1478	1452	2276	1295
2010	January	8	F	1451	1491	1567	1637	1743	1936	2160	2246	2253	2201	2139	2001	1909	1841	1824	1919	2055	2249	2292	2296	2280	2230	2143	2087	2296	1451
2010	January	9	S	2050	2054	2100	2142	2195	2278	2330	2422	2485	2410	2294	2143	2002	1872	1789	1801	1899	2142	2223	2251	2253	2216	2141	2112	2485	1789
2010	January	10	S	2091	2091	2124	2152	2201	2312	2405	2477	2472	2380	2239	2106	1980	1867	1794	1748	1851	2096	2195	2248	2236	2197	2109	2055	2477	1748
2010	January	11	M	2043	2074	2120	2176	2263	2448	2553	2536	2362	2169	2033	1891	1756	1647	1555	1547	1669	1934	2082	2108	2096	2036	1902	1828	2553	1547
2010	January	12	T	1784	1790	1805	1837	1892	2055	2218	2203	2015	1846	1696	1563	1455	1376	1323	1319	1413	1656	1770	1798	1794	1746	1664	1622	2218	1319
2010	January	13	W	1632	1675	1733	1824	1913	2080	2274	2309	2120	1983	1782	1638	1524	1449	1438	1444	1547	1809	1908	1942	1943	1902	1818	1748	2309	1438
2010	January	14	Th	1706	1700	1730	1742	1821	1959	2090	2084	1919	1783	1647	1486	1379	1308	1260	1276	1340	1543	1621	1639	1656	1583	1490	1440	2090	1260
2010	January	15	F	1406	1427	1451	1497	1565	1728	1868	1863	1718	1569	1456	1325	1233	1173	1139	1158	1216	1356	1353	1318	1259	1214	1132	1050	1868	1050
2010	January	16	S	1002	987	965	953	967	1013	1057	1111	1193	1260	1285	1284	1275	1238	1206	1196	1220	1287	1273	1232	1170	1120	1050	967	1287	953
2010	January	17	S	894	863	854	853	858	908	977	1046	1147	1197	1239	1241	1243	1248	1223	1247	1288	1398	1403	1374	1312	1256	1176	1095	1403	853
2010	January	18	M	1041	1021	1008	1018	1070	1174	1270	1345	1354	1343	1290	1226	1175	1133	1098	1098	1132	1320	1402	1387	1357	1301	1200	1140	1402	1008
2010	January	19	T	1103	1096	1112	1155	1223	1382	1559	1577	1474	1363	1292	1216	1169	1120	1098	1092	1131	1298	1389	1372	1336	1248	1161	1074	1577	1074
2010	January	20	W	1013	1003	991	996	1048	1185	1353	1349	1288	1242	1214	1186	1133	1221	1191	1191	1262	1367	1380	1320	1258	1145	1032	918	1380	918
2010	January	21	Th	877	847	818	830	852	951	1098	1133	1214	1081	1157	1161	1150	1144	1131	1125	1147	1251	1295	1262	1205	1107	991	897	1295	818
2010	January	22	F	819	793	790	789	835	945	1092	1145	1142	1079	1213	1141	1122	1102	1101	1105	1106	1187	1239	1206	1154	1094	1026	964	1239	789
2010	January	23	S	914	895	889	892	930	978	1034	1107	1187	1235	1242	1212	1157	1131	1102	1116	1155	1273	1280	1237	1193	1111	1032	951	1280	889
2010	January	24	S	877	846	824	806	809	826	869	916	1002	1062	1093	1101	1115	1118	1109	1106	1139	1233	1242	1208	1136	1083	1003	916	1242	806
2010	January	25	M	862	838	836	865	924	1056	1242	1290	1278	1251	1230	1197	1140	1150	1094	1087	1130	1292	1379	1385	1338	1278	1165	1072	1385	836
2010	January	26	T	1018	1000	1010	1021	1086	1246	1424	1430	1359	1280	1237	1158	1154	1112	1086	1087	1128	1282	1382	1381	1375	1313	1210	1152	1430	1000
2010	January	27	W	1109	1121	1134	1192	1291	1448	1641	1648	1544	1443	1358	1252	1190	1150	1108	1135	1183	1342	1465	1473	1466	1423	1335	1277	1648	1108
2010	January	28	Th	1214	1220	1238	1279	1371	1523	1685	1671	1554	1428	1303	1225	1161	1114	1090	1078	1130	1285	1379	1375	1339	1271	1145	1051	1685	1051
2010	January	29	F	1003	985	976	980	1035	1172	1328	1328	1307	1267	1227	1171	1146	1123	1105	1115	1177	1277	1277	1229	1167	1101	1010	917	1328	917
2010	January	30	S	847	804	793	776	793	824	883	964	1070	1172	1217	1239	1231	1214	1231	1274	1360	1487	1541	1523	1518	1481	1430	1375	1541	776
2010	January	31	S	1345	1348	1364	1392	1440	1504	1604	1695	1798	1758	1656	1559	1485	1403	1351	1347	1407	1549	1662	1673	1668	1610	1519	1438	1798	1345
		AVG		1392	1397	1417	1453	1524	1675	1840	1851	1757	1643	1560	1461	1385	1334	1297	1307	1382	1565	1641	1641	1616	1551	1454	1385		
		MAX		2091	2091	2124	2176	2263	2448	2553	2536	2485	2410	2294	2143	2002	1872	1824	1919	2055	2249	2292	2296	2280	2230	2143	2112		
		MIN		819	793	790	776	793	824	869	916	1002	1062	1093	1101	1115	1102	1086	1078	1106	1187	1239	1206	1136	1083	991	897		

Typical Summer Month

Year	Month	Day	Day of Week	Observed Hourly Peak Capacity (MW)																								MAX	MIN
				1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	(MW)	(MW)
2010	July	1	Th	1245	1193	1142	1142	1145	1209	1270	1362	1460	1561	1615	1654	1673	1684	1671	1666	1660	1626	1642	1635	1646	1584	1466	1343	1684	1142
2010	July	2	F	1240	1165	1130	1105	1121	1166	1237	1358	1502	1662	1794	1895	1974	2037	2065	2104	2145	2145	2084	1969	1933	1794	1634	1499	2145	1105
2010	July	3	S	1364	1276	1188	1159	1135	1134	1122	1231	1391	1555	1690	1805	1897	1958	2019	2043	2087	2074	2020	1907	1869	1757	1608	1464	2087	1122
2010	July	4	S	1325	1220	1159	1113	1105	1105	1096	1223	1423	1595	1726	1806	1873	1908	1934	1946	1944	1930	1863	1768	1706	1631	1570	1479	1946	1096
2010	July	5	M	1349	1254	1195	1161	1176	1173	1183	1262	1393	1545	1640	1704	1700	1707	1703	1720	1780	1766	1767	1728	1728	1660	1506	1367	1780	1161
2010	July	6	T	1271	1191	1152	1133	1139	1190	1257	1367	1520	1666	1755	1754	1719	1725	1719	1737	1785	1802	1825	1790	1801	1697	1537	1385	1825	1133
2010	July	7	W	1268	1194	1135	1124	1128	1181	1244	1398	1568	1743	1901	2003	2095	2165	2209	2247	2273	2261	2209	2099	2041	1908	1700	1517	2273	1124
2010	July	8	Th	1369	1281	1206	1172	1174	1207	1285	1436	1614	1797	1977	2112	2202	2277	2310	2328	2334	2294	2236	2108	2064	1936	1750	1574	2334	1172
2010	July	9	F	1434	1322	1256	1231	1224	1274	1331	1479	1663	1857	2033	2155	2254	2270	2297	2249	2125	2058	2024	1961	1944	1850	1714	1576	2297	1224
2010	July	10	S	1446	1359	1287	1258	1241	1261	1269	1384	1580	1787	1944	2074	2168	2221	2250	2192	2096	2090	2042	1970	1955	1854	1714	1573	2250	1241
2010	July	11	S	1432	1352	1289	1248	1227	1225	1222	1373	1556	1737	1904	2025	2132	2186	2223	2243	2293	2196	2139	2046	2032	1940	1795	1631	2293	1222
2010	July	12	M	1499	1422	1369	1325	1350	1406	1461	1588	1741	1896	2030	2109	2191	2267	2308	2330	2343	2321	2251	2145	2119	2001	1797	1643	2343	1325
2010	July	13	T	1482	1409	1376	1352	1377	1431	1489	1621	1753	1895	2019	2124	2219	2280	2308	2328	2333	2340	2279	2164	2125	2017	1841	1684	2340	1352
2010	July	14	W	1562	1466	1397	1362	1364	1413	1468	1591	1747	1920	2089	2211	2305	2366	2387	2421	2432	2372	2285	2173	2114	1983	1784	1611	2432	1362
2010	July	15	Th	1487	1385	1346	1293	1312	1356	1440	1521	1671	1848	2031	2144	2234	2243	2216	2156	2077	2050	2003	1929	1893	1809	1681	1550	2243	1293
2010	July	16	F	1421	1353	1301	1278	1294	1349	1390	1521	1680	1811	1944	2055	2137	2203	2228	2237	2211	2172	2070	1982	1938	1818	1667	1518	2237	1278
2010	July	17	S	1392	1313	1257	1238	1228	1235	1250	1357	1545	1715	1874	1973	2019	2031	2037	2056	2063	2064	2007	1939	1916	1816	1669	1558	2064	1228
2010	July	18	S	1425	1349	1283	1249	1243	1250	1232	1361	1576	1749	1913	2037	2095	2118	2128	2125	2140	2120	2037	1934	1894	1771	1611	1452	2140	1232
2010	July	19	M	1334	1247	1194	1168	1179	1230	1302	1444	1638	1809	1992	2096	2188	2268	2284	2329	2316	2313	2259	2143	2100	1958	1756	1567	2329	1168
2010	July	20	T	1441	1367	1303	1278	1279	1330	1381	1529	1712	1912	2066	2192	2291	2371	2397	2395	2369	2273	2200	2122	2096	1976	1815	1631	2397	1278
2010	July	21	W	1480	1384	1314	1282	1295	1345	1381	1530	1710	1905	2073	2205	2285	2359	2396	2407	2420	2395	2333	2226	2179	2043	1840	1654	2420	1282
2010	July	22	Th	1516	1408	1328	1294	1289	1339	1382	1533	1708	1922	2088	2220	2306	2368	2417	2460	2438	2418	2376	2264	2218	2070	1886	1708	2460	1289
2010	July	23	F	1557	1460	1397	1356	1350	1400	1466	1584	1741	1894	2051	2202	2320	2386	2387	2314	2213	2112	2013	1938	1888	1811	1675	1544	2387	1350
2010	July	24	S	1426	1334	1274	1241	1238	1250	1255	1373	1593	1792	1927	2048	2076	2063	2076	2091	2109	2123	2086	2028	2016	1949	1807	1678	2123	1238
2010	July	25	S	1571	1495	1447	1414	1394	1388	1382	1491	1694	1810	1899	1965	2024	2007	1944	1961	2013	2068	2043	1983	1978	1872	1757	1611	2068	1382
2010	July	26	M	1484	1402	1336	1311	1311	1372	1429	1585	1758	1942	2113	2243	2326	2394	2424	2432	2427	2396	2323	2220	2181	2052	1857	1691	2432	1311
2010	July	27	T	1558	1465	1397	1364	1359	1407	1465	1590	1767	1940	2094	2216	2333	2370	2415	2436	2448	2415	2348	2253	2207	2073	1880	1709	2448	1359
2010	July	28	W	1565	1449	1366	1329	1326	1367	1403	1526	1711	1890	2065	2150	2248	2329	2402	2427	2477	2444	2374	2246	2205	2056	1881	1702	2477	1326
2010	July	29	Th	1574	1474	1401	1344	1335	1371	1427	1496	1794	1908	2075	2203	2277	2342	2379	2379	2345	2311	2271	2186	2157	2027	1843	1687	2379	1335
2010	July	30	F	1540	1468	1394	1370	1359	1409	1454	1549	1782	1929	2142	2258	2369	2447	2498	2523	2525	2510	2427	2339	2288	2177	2012	1860	2525	1359
2010	July	31	S	1725	1614	1528	1477	1458	1445	1425	1538	1749	1963	2168	2302	2377	2438	2479	2470	2452	2374	2285	2186	2160	2054	1905	1758	2479	1425
		AVG		1444	1357	1297	1267	1272	1322	1379	1505	1678	1843	1997	2105	2188	2245	2272	2281	2271	2239	2182	2090	2054	1935	1763	1603		
		MAX		1725	1614	1528	1477	1458	1445	1489	1621	1794	1963	2168	2302	2377	2447	2498	2523	2525	2510	2427	2339	2288	2177	2012	1860		
		MIN		1240	1165	1130	1105	1105	1105	1096	1223	1391	1545	1615	1654	1673	1684	1671	1666	1660	1626	1642	1635	1646	1584	1466	1343		


Average Summer Daily Loading Curve (MW)
Excluding weekends & holidays
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24


Average Winter Daily Loading Curve (MW)
Excluding weekends & holidays
2500
2000
1500
1000
500
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

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.

ANSWER:

	Year	HDD	CDD
Actual	2001	1387	2468
	2002	1669	2774
	2003	1607	2539
	2004	1518	2633
	2005	1361	2675
	2006	1213	2805
	2007	1368	2832
	2008	1540	2769
	2009	1505	2635
	2010	2110	2800
Projected	2011	1480	2696
	2012	1490	2696
	2013	1480	2696
	2014	1480	2696
	2015	1480	2696
	2016	1490	2696
	2017	1480	2696
	2018	1480	2696
	2019	1480	2696
	2020	1490	2696

* Gulf Power uses the Pensacola NOAA weather station

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.

ANSWER:

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1	2370	39450	Th	700	23
	2	2155	39492	Th	700	31
	3	1648	39532	T	800	45
	4	1700	39560	T	1700	81
	5	2231	39598	F	1700	86
	6	2398	39603	W	1600	90
	7	2541	39650	M	1600	93
	8	2529	39666	W	1600	92
	9	2335	39699	M	1500	89
	10	1926	39734	M	1700	82
	11	1896	39771	W	700	37
	12	1809	39804	M	900	32
2009	1	2292	39834	W	700	25
	2	2320	39849	Th	700	27
	3	1930	39875	T	700	33
	4	1674	39932	W	1700	75
	5	2055	39961	Th	1700	84
	6	2546	39986	M	1700	100
	7	2429	39996	Th	1400	94
	8	2317	40035	M	1600	86
	9	2180	40081	F	1600	87
	10	2202	40093	W	1600	88
	11	1387	40121	W	1800	66
	12	1932	40176	T	700	33
2010	1	2553	40189	M	700	21
	2	2144	40226	W	700	31
	3	1934	40241	Th	700	34
	4	1488	40293	Su	1700	81
	5	2219	40322	M	1600	94
	6	2419	40343	M	1400	91
	7	2525	40389	F	1700	97
	8	2458	40391	Su	1600	95
	9	2300	40433	Su	1700	95
	10	1881	40478	W	1500	83
	11	1574	40483	M	1900	73
	12	2314	40526	T	700	26

* Gulf Power uses the Pensacola NOAA weather station

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?

ANSWER:

Gulf Power has experienced customer growth of 0.1%, 0.1%, and 0.6% in 2008, 2009, and 2010, respectively. As a result of the recession, Gulf has seen declines in customer growth rates in all three customer classes: Residential, Commercial and Industrial.

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?)

ANSWER:

"Smart" meter installations have not affected the forecasting of sales or net energy for load.

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.

ANSWER:

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar	0	0
Wind	0	0
Biomass (1)	68	0
Municipal Solid Waste (2)	11	0
Waste Heat	0	0
Landfill Gas	3	0
Hydro	0	0

(1) 43 MW wood waste, 25 MW black liquor
(2) Non-Firm

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.

ANSWER:

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)	(%)
Perdido 1	IC	LFG	10/2010	1518	1518	12513	94.1
Perdido 2	IC	LFG	10/2010	1518	1518	12513	94.1

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)	(%)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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)	(%)		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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)	(%)		
Bay County Solid Waste	ST	MSW	07/2008	11000	11000	50107	51.9	7/23/2008	7/22/2014

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.

ANSWER:

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)	(%)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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)	(%)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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)	(%)		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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)	(%)		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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.

ANSWER:

Not applicable.

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.

ANSWER:

Not applicable.

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.

ANSWER:

Listed below are self-service generating facilities served by Gulf that use renewable fuels. These facilities can sell as-available energy to Gulf under the COG-1 tariff. There are no existing renewable facilities in areas served by Gulf that could execute a PPA for the sale of firm capacity and energy.

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (kW)		Annual Generation	Capacity Factor
			(MM/YYYY)	Sum	Win	(MWh)	(%)
Industrial Customer	ST	WDS	Unknown	43000	43000	Varies	N/A
Industrial Customer	ST	BL	Unknown	25000	25000	Varies	N/A

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.

ANSWER:

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic	57	222.7	114991
Residential	Solar Thermal Water Heating	94	23.5	179164
Residential	Geothermal Heat Pump	2640	3905	5178639
Residential	Wind Turbine	1	2.4	3
Residential	Other (Describe)	0	0	0
Commercial	Solar Photovoltaic	16	52.5	21181
Commercial	Solar Thermal Water Heating	0	0	0
Commercial	Geothermal Heat Pump	4867	4385	2433500
Commercial	Wind Turbine	15	36	3617
Commercial	Other (Describe)	0	0	0

- The Solar PV installed capacity (kW) is based on the gross power rating (AC nameplate capacity) for each interconnected system as defined in the Net Metering rule, Rule 25-6.065(2)(b), F.A.C.
- The Solar PV annual output (kWh) reflects the total kWh received by Gulf Power from the customer.
- Residential Geothermal installations are based upon 1995-2010 installations with average energy savings of 1,962 kWh per unit and average demand of 1.5 kW per unit versus an average alternative base unit. Actual per unit savings are derived from annual FEECA reports.
- Commercial Geothermal installations are reported in tons of cooling capacity. Actual per unit savings are derived from annual FEECA reports.
- Solar Thermal installed capacity (kW) is based on a diversified summer peak demand of 0.25 kW for a standard residential electric water heater.
- Solar Thermal annual output (kWh) is based on an average annual kWh savings of 1,906 kWh per unit per year.

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.

ANSWER:

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	6	26	26	26	26	26	26	26	26	26	26
	PPA	57	50	50	50	50	0	0	0	0	0	0
	Total	63	76	76	76	76	26	26	26	26	26	26
Retail Sales		11359	11359	11421	11768	12064	12369	12574	12718	12899	13081	13304
Net Energy for Load		12518	12518	12528	12911	13233	13566	13786	13946	14144	14343	14588

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.

ANSWER:

Year	As-Available Energy *		CPI **
	Real	Nominal	
2001	1.591	2.717	1.7077
2002	1.292	2.242	1.7349
2003	1.336	2.371	1.7745
2004	1.809	3.294	1.8207
2005	2.483	4.671	1.8809
2006	2.127	4.127	1.9402
2007	2.097	4.182	1.9945
2008	2.875	5.951	2.0696
2009	1.768	3.649	2.0643
2010	1.854	3.896	2.1017
2011	1.894	4.065	2.1458
2012	1.964	4.342	2.2103
2013	2.115	4.801	2.2698
2014	2.167	5.028	2.3205
2015	2.223	5.265	2.3689
2016	2.186	5.287	2.4191
2017	2.226	5.502	2.4713
2018	2.266	5.722	2.5250
2019	2.389	6.163	2.5796
2020	2.393	6.305	2.6351

* In ¢/kWh

**Source: Moody's Analytics

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?

ANSWER:

Southern Company continues to study the feasibility of using biomass with fossil fuel to generate energy at several system coal-fired units. Test results from these biomass co-milling projects at these plants will help determine what quantities of biomass can be efficiently co-fired at these and other plants around the Southern electric system.

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?

ANSWER:

Not applicable.

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.

ANSWER:

Gulf Power currently does not purchase or sell Renewable Energy Credits and does not currently offer the sale of Renewable Energy Credits to its customers through a green pricing or similar program.

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.

ANSWER:

Gulf Power's environmental compliance program reflects a comprehensive assessment of requirements Gulf and its customers face in meeting CAIR/Transport Rule, CAVR, the potential EGU MACT rule, potential 8-hour ozone nonattainment designations, SO2, and NOx NAAQS regulations. As discussed in its 2011 Environmental Compliance Plan Update, using 12 scenarios that considered fuel price variations and the potential costs associated with CO_2 legislation, Gulf assessed meeting plant-by-plant emission requirements through retrofit measures supplemented by allowance purchases and compared those options to retiring and replacing existing units. Adding new environmental controls and supplementing that action with allowance purchases was determined to be the more cost effective option for compliance at this time. The environmental capital expenditures and O&M costs for future in-service projects at Plants Crist, Smith, and Daniel to keep the units operational over the evaluation period are outlined in tables 3.1-1 and 3.1-2 of the Environmental Compliance Program Update. The Net Present Value (NPV 2011) of the revenue requirements needed to recover these incremental capital and O&M expenses over the remaining life of these assets is approximately $1.2 billion.

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.

ANSWER:

Gulf's generation expansion plans have not changed significantly due to annual changes in demand over the past several years. Therefore, no sensitivities on base case demand have been developed.
Each year, Gulf and the Southern electric system operating companies (SES) develop an Integrated Resource Plan (IRP) that incorporates the latest demand forecasts. Gulf uses the IRP to develop its generation expansion plan that specifies the timing, type and size of its capacity additions for the current planning period.

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

ANSWER:

Generating Unit Name	Summer Capacity (MW)	Certification Dates (If Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
N/A	N/A	N/A	N/A	N/A
Combustion Turbine Unit Additions				
N/A	N/A	N/A	N/A	N/A
Combined Cycle Unit Additions				
N/A	N/A	N/A	N/A	N/A
Steam Turbine Unit Additions				
N/A	N/A	N/A	N/A	N/A

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.

ANSWER:

Not applicable. Gulf's purchased power agreements for peaking and combined cycle capacity meet its needs during the 2011-2020 planning period.

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.

ANSWER:

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	
Crist	4	ST	BIT	93.8	75	75	239954	36.5	92.58	07/1959
Crist	5	ST	BIT	93.8	75	75	441871	67.3	95.24	06/1961
Crist	6	ST	BIT	369.8	291	291	1176180	46.1	95.33	05/1970
Crist	7	ST	BIT	578.0	465	465	2982539	73.2	98.08	08/1973
Smith	1	ST	BIT	149.6	162	162	936875	66.0	95.64	06/1965
Smith	2	ST	BIT	190.4	195	195	881208	51.6	85.67	06/1967
Smith	3	CC	NG	619.7	556	584	2847102	58.5	77.19	04/2002
Smith	A	CT	DFO	41.9	32	40	159	0.1	85.15	05/1971
Scholz	1	ST	BIT	49.0	46	46	49932	12.4	97.02	03/1953
Scholz	2	ST	BIT	49.0	46	46	40423	10.0	98.40	10/1953
Scherer	3	ST	BIT	222.8	218	218	1228813	64.3	76.45	01/1987
Daniel	1	ST	BIT	274.1	255	255	1257113	56.3	80.76	09/1977
Daniel	2	ST	BIT	274.1	255	255	1296163	58.0	94.39	06/1981
Pea Ridge	1,2,3	CT	NG	14.3	12	15	55797	57.1	N/A	05/1998
Perdido	1,2	IC	LFG	3.2	3	3	6167	99.5	96.10	10/2010

Note: Pea Ridge units operated by industrial customer for steam requirements, customer supplies natural gas.

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned (2)	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	MMBTU	($000)	($/MMBTU)	(¢/kWh)
Crist	4	BIT	11988	2876618	15381	5.35	6.4
Crist	5	BIT	11385	5030488	27099	5.39	6.1
Crist	6	BIT	11615	13660926	73362	5.37	6.2
Crist	7	BIT	10544	31449375	169645	5.39	5.7
Smith	1	BIT	10649	9976601	53464	5.36	5.7
Smith	2	BIT	10625	9362532	49772	5.32	5.7
Smith	3	NG	6203	17660986	108465	6.14	3.8
Smith	A	DFO	51348	8164	117	14.33	73.6
Scholz	1	BIT	12718	635040	3534	5.57	7.1
Scholz	2	BIT	13578	548858	3052	5.56	7.6
Scherer	3	BIT	10230	12570905	28232	2.25	2.3
Daniel	1	BIT	10214	12840274	50126	3.90	4.0
Daniel	2	BIT	10456	13553141	51437	3.80	4.0
Pea Ridge (1)	1,2,3	NG	N/A	N/A	N/A	N/A	4.7
Perdido	1,2	LFG	11015	67930	168	2.47	2.7

(1) Pea Ridge units operated by industrial customer for steam requirements, customer supplies natural gas.
(2) Total Fuel Burned includes startup Oil and Gas.

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.

ANSWER:

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Crist	4	ST	BIT	36.5	62.8	63.1	73.4	79.8	83.8	79.5	86.0	70.5	88.2	83.8
Crist	5	ST	BIT	67.3	42.3	48.2	62.9	70.0	77.3	72.8	76.6	63.5	80.0	73.3
Crist	6	ST	BIT	46.1	39.1	39.2	52.3	70.1	67.7	67.7	71.5	66.4	70.0	64.2
Crist	7	ST	BIT	73.2	71.0	61.3	84.9	85.2	85.1	91.1	84.7	85.0	92.3	86.6
Smith	1	ST	BIT	66.0	63.2	69.6	61.0	82.2	73.3	85.5	81.4	87.0	83.6	89.5
Smith	2	ST	BIT	51.6	62.8	59.6	66.3	69.9	84.3	79.7	85.5	77.7	86.4	81.8
Smith	3	CC	NG	58.5	69.1	69.7	67.6	43.7	39.7	33.6	28.4	36.1	40.3	40.0
Smith	A	CT	DFO	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Scholz	1	ST	BIT	12.4	17.4	16.3	17.4	35.1	50.0	46.8	48.0	41.0	48.2	41.3
Scholz	2	ST	BIT	10.0	11.3	11.9	14.2	30.0	41.5	43.5	39.5	43.2	39.5	40.6
Scherer	3	ST	BIT	64.3	93.1	82.7	95.0	87.1	97.3	87.3	96.9	87.2	87.2	75.7
Daniel	1	ST	BIT	56.3	58.2	52.8	60.0	58.3	63.3	55.3	62.6	69.6	78.4	70.0
Daniel	2	ST	BIT	58.0	41.2	55.5	52.6	73.4	46.9	58.9	54.2	69.2	66.4	72.5
Pea Ridge	1,2,3	CT	NG	57.1	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	0.0	0.0
Perdido	1,2	IC	LFG	99.5	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1

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

ANSWER:

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Crist 4	BIT, ST	75	07/1959	NG
Crist 5	BIT, ST	75	06/1961	NG
Smith 1	BIT, ST	162	06/1965	WDS
Smith 2	BIT, ST	195	06/1967	WDS
Scholz 1	BIT, ST	46	03/1953	WDS
Scholz 2	BIT, ST	46	10/1953	WDS

Note: MW ratings based on current fuel type

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.

ANSWER:

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (1)	Capacity Type	Summer Capacity
				(%)		(MW)
Crist	4	ST	BIT	77.1	FS	75
	5	ST	BIT	66.7	FS	75
	6	ST	BIT	60.8	FS	291
	7	ST	BIT	82.7	FS	465
Smith	1	ST	BIT	77.6	FS	162
	2	ST	BIT	75.4	FS	195
Scholz	1	ST	BIT	36.2	FS	46
	2	ST	BIT	31.5	FS	46
Daniel	1	ST	BIT	62.8	FS	255
	2	ST	BIT	59.1	FS	255
Scherer	3	ST	BIT	88.9	FS	218
Perdido	1	IC	LFG	94.1	IC	1.5
Perdido	2	IC	LFG	94.1	IC	1.5
				Sub-Total	Baseload	2086
Smith	3	CC	NG	46.8	CC	556
				Sub-Total	Intermediate	556
Pea Ridge	1	GT	NG	96.0	CT	4
	2	GT	NG	96.0	CT	4
	3	GT	NG	96.0	CT	4
Smith	A	GT	DFO	0.0	CT	32
				Sub-Total	Peaking	44
					Total	2686

(1) Average of projected capacity factors over 10 year period.

Planned Facilities during 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor	Capacity Type	Summer Capacity
				(%)		(MW)
N/A	N/A	N/A	N/A	N/A	N/A	N/A
				Sub-Total	Baseload	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A
				Sub-Total	Intermediate	N/A
N/A	N/A	N/A	N/A	N/A	N/A	N/A
				Sub-Total	Peaking	N/A
					Total	N/A

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.

ANSWER:

	Year	Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual	2001	2207	0	44	2251
	2002	2205	566	44	2815
	2003	2190	566	44	2800
	2004	2190	566	44	2800
	2005	2186	566	44	2796
	2006	2133	556	44	2733
	2007	2114	556	44	2714
	2008	2111	556	44	2711
	2009	2103	556	44	2703
	2010	2086	556	44	2686
Projected	2011	2086	556	44	2686
	2012	2086	556	44	2686
	2013	2086	556	44	2686
	2014	2086	556	44	2686
	2015	2082	556	44	2682
	2016	2082	556	44	2682
	2017	2082	556	44	2682
	2018	2074	556	44	2674
	2019	2074	556	32	2662
	2020	2074	556	32	2662

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.

ANSWER:

	Year	System Average Heat Rate (BTU/kWh)
Actual	2001	10348
	2002	10066
	2003	9992
	2004	10034
	2005	10108
	2006	10065
	2007	10092
	2008	10057
	2009	9784
	2010	10021
Projected	2011	9742
	2012	9696
	2013	9780
	2014	10054
	2015	10197
	2016	10270
	2017	10331
	2018	10209
	2019	10179
	2020	10165

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.

ANSWER:

Year		Residential Bill ($/1200-kWh)		CPI *
		Real	Nominal	
Actual	2001	44.61	76.18	1.7077
	2002	50.79	88.12	1.7349
	2003	51.21	90.87	1.7745
	2004	51.66	94.05	1.8207
	2005	54.99	103.44	1.8809
	2006	56.05	108.75	1.9402
	2007	60.27	120.20	1.9945
	2008	64.96	134.45	2.0696
	2009	69.62	143.72	2.0643
	2010	71.07	149.36	2.1017
Projected	2011	67.64	145.15	2.1458
	2012	65.55	144.89	2.2103
	2013	65.45	148.56	2.2698
	2014	65.79	152.67	2.3205
	2015	67.36	159.56	2.3689
	2016	66.72	161.41	2.4191
	2017	66.05	163.22	2.4713
	2018	65.15	164.50	2.5250
	2019	63.45	163.67	2.5796
	2020	62.65	165.08	2.6351

*Source: Moody's Analytics

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

ANSWER:

Existing Purchased Power Agreements as of January 1, 2011

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		
Coral Power LLC	6/1/2009	5/31/2014	197	197	26812	1.6	N/G	CT
Southern Power	6/1/2009	5/31/2014	299	299	6134	0.2	N/G	CT
Shell Energy NA (1)	11/2/2009	5/24/2023	885	885	1721546	23.2	N/G	CC

(1) Firm capacity begins June 1, 2014. Annual Gwh from firm capacity shown.

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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

ANSWER:

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor (1)	Primary Fuel (if any)	Description (2)
	Begins	Ends	Summer	Winter	(MWh)	(%)		
Florida Pwr & Light	6/1/2010	12/31/2015	111	111	632034	65	BIT	Scherer 3
Progress Energy	6/1/2010	12/31/2015	50	50	284700	65	BIT	Scherer 3
Flint Energy	6/1/2010	12/31/2019	50	50	284700	65	BIT	Scherer 3

(1) Typical capacity factors shown.
(2) See response to Item # 24 for unit details.

Planned Power Sales for 2011 through 2020

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel (if any)	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)		
Unknown	1/1/2016	Unknown	161	161	705180	50	BIT	Scherer 3
Unknown	1/1/2020	Unknown	50	50	219000	50	BIT	Scherer 3

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.

ANSWER:

Due to the addition of Gulf's 496 MWs of peaking power PPAs with Coral Baconton and Southern Power and its Shell PPA that will provide 885 MWs of firm power beginning in 2014 no additional capacity is needed during the 2011-2020 period. There are no specific contractual terms in any of the currently executed PPAs that would allow for automatic extension of the contracts' terms. It is unknown at this time whether Gulf would engage the sellers of this capacity in future negotiations regarding purchases from their resources, although this could be a possible option.

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.

ANSWER:

During 2010 there were no permanent, long-term impacts to unit operations due to environmental restrictions. However, several temporary unit derate and outage events as reported in Gulf's monthly GPIF filings were experienced due to action taken to avoid thermal discharge and opacity limits from being exceeded.

As mentioned in Gulf's 2011 TYSP and its Environmental Compliance Plan Update, additional environmental regulations that require lower power plant emissions may lead to significant cost increases associated with additions of environmental control equipment that affect units' dispatch order or ultimately result in accelerated retirements of Gulf's existing coal-fired units during the 2011-2020 period. Preliminary studies indicate that new environmental regulations as currently proposed put coal units at Plants Smith and Scholz at a higher risk of retirement rather than being retrofitted with controls. Gulf will continue to evaluate options for compliance with pending environmental regulations which include the purchase of emission allowances, the addition of new emission controls, fuel switching at coal-fired units, or the acquisition of new generating resources to replace retired generating capacity.

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.

ANSWER:

	Year	SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001	15.24	53663	4.75	16709	0.00004	0.14	0.23	804	2167	7630658
	2002	11.61	51574	3.8	16892	0.00003	0.13	0.21	916	1629	7236273
	2003	9.64	50577	3.94	20672	0.00003	0.14	0.18	947	1753	9196458
	2004	10.3	55461	3.44	18503	0.00003	0.14	0.2	1080	1661	8942744
	2005	10.18	49859	2.88	14122	0.00003	0.15	0.21	1034	1998	9785257
	2006	9.03	50782	2.36	13283	0.00004	0.25	0.22	1243	2054	11545455
	2007	10.08	57813	2.27	13019	0.00002	0.14	0.21	1215	1934	11087278
	2008	10.62	54404	2.27	11640	0.00003	0.16	0.24	1214	1909	9781945
	2009	9.18	39002	1.7	7242	0.00005	0.2	0.17	1435	1636	6950688
	2010	3.42	16403	1.96	9381	0.00004	0.18	0.22	1072	2002	9605157
Projected	2011	2.51	12675	1.51	7609	0.00002	0.12	0.19	960	1589	8016532
	2012	4.3	21199	1.39	6846	0.00003	0.13	0.19	938	1582	7795080
	2013	3.28	18441	1.32	7425	0.00003	0.16	0.19	1086	1638	9212513
	2014	3.92	21796	1.56	8687	0.00003	0.19	0.2	1120	1771	9856803
	2015	4.23	23641	1.66	9244	0.00004	0.2	0.2	1133	1797	10031653
	2016	4.36	24365	1.68	9402	0.00004	0.2	0.2	1144	1828	10213453
	2017	4.08	22082	1.73	9378	0.00004	0.2	0.21	1115	1854	10026033
	2018	1.71	9199	1.65	8906	0.00003	0.14	0.2	1097	1810	9739991
	2019	1.68	9824	1.64	9619	0.00003	0.15	0.2	1189	1801	10545399
	2020	1.65	9269	1.66	9335	0.00003	0.15	0.2	1139	1793	10080295

Notes: All emissions reported as short tons.
CO2(e) reported as carbon equivalent.
2001-2010 Hg reported as stack air emissions from the Environmental Protection Agency's Toxic Release Inventory.
2001-2010 emissions for Gulf's Crist, Lansing Smith and Scholz Plants as reported in the Florida Department of Environmental Protection's Annual Operating Report.

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

ANSWER:

Nominal Fuel Price ($/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	1.64	3.34	N/A	6.09
	2002	N/A	1.69	5.44	N/A	5.45
	2003	N/A	1.64	6.87	N/A	5.58
	2004	N/A	1.74	7.14	N/A	6.39
	2005	N/A	2.03	10.22	N/A	9.58
	2006	N/A	2.50	8.65	N/A	12.87
	2007	N/A	2.62	8.70	N/A	14.50
	2008	N/A	3.30	10.77	N/A	19.91
	2009	N/A	3.77	4.85	N/A	13.73
	2010	N/A	4.64	6.10	N/A	16.04
Projected	2011	N/A	4.52	5.35	N/A	16.46
	2012	N/A	4.07	5.76	N/A	17.15
	2013	N/A	3.91	6.58	N/A	18.51
	2014	N/A	3.76	8.08	N/A	21.44
	2015	N/A	3.54	9.56	N/A	24.37
	2016	N/A	3.62	10.02	N/A	25.74
	2017	N/A	3.70	10.53	N/A	27.11
	2018	N/A	3.74	11.02	N/A	28.48
	2019	N/A	3.86	11.51	N/A	29.85
	2020	N/A	3.96	11.98	N/A	31.23

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.

ANSWER:

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	11290	127	N/A	6
	2002	N/A	10752	2086	N/A	1
	2003	N/A	13025	1963	N/A	1
	2004	N/A	13366	2476	N/A	1
	2005	N/A	12907	2117	N/A	1
	2006	N/A	14216	2132	N/A	1
	2007	N/A	14281	2374	N/A	1
	2008	N/A	12334	2428	N/A	1
	2009	N/A	8871	4024	N/A	0
	2010	N/A	10531	4805	N/A	0
Projected	2011	N/A	10108	3512	N/A	0
	2012	N/A	9916	3555	N/A	0
	2013	N/A	11676	3443	N/A	0
	2014	N/A	13065	3565	N/A	0
	2015	N/A	12935	3753	N/A	0
	2016	N/A	13209	3332	N/A	0
	2017	N/A	13281	3049	N/A	0
	2018	N/A	13213	3558	N/A	0
	2019	N/A	14077	4000	N/A	0
	2020	N/A	13746	4023	N/A	0

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

ANSWER:

- Fuel Price Forecasts are received from recognized independent consulting firms for natural gas, oil, coal, and emissions allowance markets. These independent consulting firms currently include the following:
  - •Domestic Coal - Energy Ventures Analysis (EVA), Inc.,
  - •Import Coal – Energy Venture Analysis
  - •Emission Allowances & Limestone – ICF Consulting, Inc
  - •Natural Gas, Oil and LNG - Energy Ventures Analysis, Inc.,
- SES develops short-term (current year +2) and long-term (year 4 and beyond) fuel price forecasts for coal, oil, and natural gas which extend through the Gulf's 10-year planning horizon. The short-term forecasts are used in the system's fuel budgeting process and marginal pricing dispatch procedures. This forecast is developed by Southern Company Services (SCS) Fuel Services and is approved by Gulf Power's fuel manager.
- The long-term forecasts are developed in early spring of each year for use in system planning activities. The long-term forecasts are governed by the SCS Executive Planning Coordination Team (Executive PCT). Charles River & Associates International (CRA) is the modeling vendor used by the system to develop the long-term forecasts. This process is a collaborative effort between CRA and members of the cross-functional Planning Coordination Team (PCT) with final approval from the Executive PCT and/or Southern Company Management Council.
- Southern Company Services reviews the assumptions that CRA uses as inputs to their long term forecasting models and makes adjustments to these assumptions as appropriate. Adjustments are based on feedback provided by the PCT, Fuel Services, Strategic Generation Planning, and others to reflect what SES believes are reasonable. CRA generates fuel forecasts from its model incorporating Gulf's assumption modifications to produce a long term (50 year) fuel price forecast.
- Comparisons of the fuel price forecasts are made against each fuel price forecast of the consulting firms listed above, as well as other sources which SES uses in daily activities to gain information about fuel markets.

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.

ANSWER:

Coal:

Fuel price forecasts are used for a variety of purposes within Southern Company, including such diverse uses as long-term generation planning. The most pressing industry factors expected to affect Southern Company and the coal industry are environmental pressures including, but not limited to, potential climate and renewable legislation. Specifically, a Renewable Portfolio Standard (RPS) or climate legislation, whether cap and trade or carbon control, may not allow for coal generation to be competitive during the 2011 - 2020 time frame. Also, the impact of such factors on coal prices, electricity prices, and electric demand will be of much importance. Other trends that may affect the company are the global demand for coal, and coal production costs, both of which affect coal market prices. Southern Company closely monitors potential future impacts and will adjust to meet regulatory requirements.

Natural Gas:

The natural gas long-term outlook is highly dependent on two significant uncertainties; (1) The possibility for increased gas demand in the electric sector, because of the failure to meet projections for coal, nuclear and renewable capacity or higher electricity demand growth rates. This would be directly impacted by any climate or renewable legislation (2) The potential for the reduction in drilling of shale gas and the further delays of either or both of the Arctic gas pipeline projects, with litigation being a likely cause of such reduction or delays. Depending on the outcome of the above uncertainties, Southern Company may be affected.

Nuclear:

Nuclear is not applicable during the 2011-2020 time frame for Gulf Power Company.

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

ANSWER:

Southern Company purchases gas supply on a spot and contract basis from a variety of supply locations, including Gulf of Mexico production, on-shore mid-continent production and LNG, ensuring a diverse gas supply mix both currently and in the future. Additionally, Southern Company has contracted for firm transportation on several different gas pipelines under long term service agreements ensuring the ability to deliver gas supply to its electric generation facilities.

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

ANSWER:

As of March 24, 2011, the FERC granted Florida Gas Transmission (FGT) the authority to place into service the remaining portions of the Phase VIII Expansion Project, which will add over 475 miles of natural gas pipeline from Florida to Alabama. The project's expected completion date is April 2011. The purpose of the expansion, which will increase FGT's capacity by 36%, is to meet the growing needs of the Gulf Coast and Florida areas and ensure that these areas will receive a reliable, secure natural gas supply.

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.

ANSWER:

The Southeastern Supply Header (SESH), a new pipeline that became operational on October 1, 2008, brings supply from east Texas and northern Louisiana to southeast markets. Southern Company has contracted for 175,000 mmbtu/d of firm transportation on SESH. This arrangement will increase the diversity of supply to the coastal areas of Southern Company's territory (including Gulf Power), which is predominantly served by offshore gas supply. Supply diversity benefits Southern Company by providing an alternate supply source that is not vulnerable to weather-related disruptions in the Gulf of Mexico.

The Mid-continent Express Pipeline (MEP), owned and operated by Kinder Morgan, will carry mid-continent gas from Oklahoma to southwestern Alabama. This new pipeline began service in Alabama on August 1, 2009. MEP adds to the Southeast's fuel diversity mix by providing an alternative source of natural gas in event of weather-related disruptions to offshore gas production.

Transcontinental Gas Pipeline Corporation (Transco) is building a new pipeline expansion in Transco's Zone 4A that will add over 460,000 mmbtu/d per day of firm transportation service from the Gulf LNG Clean Energy import terminal in Pascagoula, MS to Transco's Station 85 Pool near Butler, Alabama. The proposed in-service date for this expansion project is October 1, 2011. Transco is also adding compression to its Transco 4A pipeline in order to deliver over 253,000 mmbtu/d from the Transco Station 85 Pool to markets in the Mobile, AL area. Southern Company has 100,000 mmbtu/d of firm transportation in this expansion and Transco will place an additional 380,000 mmbtu/d of capacity in the 4A lateral from Station 85 on May 1, 2011. SCS will pick up an additional 25,000 mmbtu/d of this capacity. Transco's 4A expansion will increase supply diversity in the Southeast by providing a means of transportation for LNG that is shipped to the Gulf Coast or mid-continent supply.

The ETC Tiger Pipeline is a 2.0 bcf/day, 175-mile, 42-in. diameter pipeline with four compressor stations that delivers to the Perryville Hub in Louisiana from the Haynesville Shale play and the East Texas Carthage Hub. This can be delivered into Florida via SESH, Gulf South, or FGT. Tiger Pipeline went into service effective December 1, 2010.

The Gulf LNG terminal in Pascagoula, Mississippi is a receiving terminal for liquefied natural gas (LNG) and as such has two onsite storage tanks with combined capacity of 6.6 bcf and send-out capacity of 1.3 bcf/day. It is fully contracted with two 20-year firm service agreements and the expected in-service date is October 2011. This supply could be transported into the Florida market by way of Transco, FGT, Gulfstream and Destin pipelines.

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.

ANSWER:

Unconventional gas production activity was reduced in 2009 due to a significant drop in natural gas prices in late 2008 and 2009. While the economic slowdown caused demand to fall off, the shutdown of active drilling rigs did not occur quickly enough to match the reduced demand. With the continuation of the depressed economy and production still at high levels, gas prices have remained low, while oil prices have been on the rise. In the long term, natural gas supply from unconventional resources is expected to increase as natural gas from conventional resources declines. Southern Company is expected to benefit from the production of gas from unconventional resources over the next ten years. The increase in drilling of unconventional gas wells will help to ensure an adequate supply source for companies that generate electricity with natural gas.

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.

ANSWER:

LNG supply will continue to grow with new liquefaction projects in Trinidad, Qatar, Norway, West Africa and elsewhere, but imported LNG will be immaterial due to lower natural gas prices domestically and abundant gas supply. With the recent earthquake and tsunami in Japan, several LNG facilities in North America are considering the export of LNG if they can acquire permits to do so. The U.S. will continue to be a secondary market for LNG while demand in Europe and Asia remains strong. If demand in Europe and Asia weakens, the U.S. will become a "dumping ground" for LNG imports. Additional supply into the U.S. will result in downward pricing pressure on natural gas. Lower natural gas prices could potentially increase the percentage of natural gas in Southern Company's generation mix.

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

ANSWER:

Southern Company has contracted for natural gas storage with four different facilities during the time period 2011 to 2020. The amount of contracted storage will increase from 12.6 bcf in 2011 to 18.6 bcf in 2013. Southern uses firm natural gas storage primarily to ensure that the natural gas plants in its fleet will receive gas in the event of a supply disruption.

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

ANSWER:

Competition within and among coal transportation modes is easily achieved where infrastructure exists to allow such competition. This competition can exist through multiple transportation mode access either directly to the generating plant site where the coal is ultimately burned or an intermediate point such as a transloading facility. To achieve this competition, Southern Company attempts to identify a variety of coal sources acceptable for use at the generating plant. Through a request for proposal process each coal supply is economically evaluated based on total delivered cost to the plant site. In Gulf's case most coals can ship via truck, rail, river barge, or ocean vessel to an intermediate point for transloading into barges, railcars, or truck for final delivery to the plant. This transloading point could be on the Ohio River, Mississippi River, or points along the Intracoastal Waterway such as Mobile, AL.

At many locations, transportation mode competition is either not cost effective or physically not possible due to a lack of infrastructure. This infrastructure (rail tracks, navigable waterways, railcar or barge unloaders, acceptable roads for heavy truck traffic, etc.) may be more expensive to build than projected savings from competition would justify. In many cases, infrastructure cannot be built due to objections from the local community, such as building a rail line through a national forest, dredging a river system considered environmentally sensitive, or trucking coal through a residential neighborhood and past schools. However, there have been cases where building infrastructure was cost effective and physically possible. While few in number, in those cases Southern Company has built the transportation infrastructure needed to develop competition.

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.

ANSWER:

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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.

ANSWER:

U.S. waterway improvements have always been funded partially by Congressional appropriation bills for Army Corps of Engineers' projects and a waterways user tax that has been levied on fuel used by inland waterway transportation companies. The Obama administration has recommended that the tax on fuel be eliminated in favor of a fee levied on every barge using a lock on the inland waterway system. To the extent that fuel taxes have been included in barge rates charged to Gulf Power in the past, a reduction of cost may be realized in the future for barge coal originating in Mobile that does not pass through a lock. Likewise, barge coal originating upriver may become less competitive due to the lockage fees. Though this concept is still a possibility, it has not gained adequate support in Congress.

Through a successful RFP process, Gulf Power has entered into a five (5) year barge transportation contract through 2014. The new contract and its amendments have minimized cost and have improved overall deliveries and operating efficiencies.

The Alabama State Docks' McDuffie Coal Terminal has the capacity to receive approximately 16 million tons of import coal per year. In addition, the Alabama State Docks recently completed the bulk unloader railcar project at its Bulk Materials Handling Plant (Bulk Plant). Upgrade of railcar handling facilities provides the Bulk Plant with the ability to receive an additional 3 million tons of coal per year by rail; however, the Alabama State Docks is soliciting bids for a third party to take over the operation and marketing of the Bulk Plant which might lead to more congestion at the terminal and more difficult operating conditions in the future for Southern Company operating companies utilizing the terminal.

Historically, a large portion of Gulf's coal supply has been imported through ASD and delivered by ocean vessel. The quantity of import coal utilized by Gulf is influenced by world market conditions that can periodically shift sourcing to domestic origins due to pricing increases. It has been determined that to minimize the risk of volatile ocean freight rates and the need to increase staff to manage ocean freight purchasing, import

coal will continue to be purchased on a delivered basis at Mobile. This policy will be reviewed periodically when market conditions warrant it.

Gulf is also investigating the use of other rail and barge served terminals on the Mississippi and Ohio Rivers that could provide additional blending services for western, Illinois Basin and Appalachian coals which could provide increased competition and flexibility for procuring and delivering coals and reduce potential congestion at the Alabama State Docks.

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.

ANSWER:

Gulf will purchase and install a new coal unloader (crane) designed for fossil fuel production. The new unloader will act as the primary unloading equipment to maintain and stock pile inventory for fuels operations at Plant Crist. The Crist E-Crane will remain as a back-up unloader, which will be capable of maintaining production, should the new primary unloader need maintenance or servicing. The E-Crane will also be used for operations, as well as, slop or wet coal barges unloading. Additionally, both unloaders will use the same barge haul system and feed hopper, which will be modified during the construction of the new unloader. The projected completion date for the new unloader, hopper modification, chute repairs, and possibly number 7 conveyor belt change out is currently June 1, 2011.

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.

ANSWER:

Not applicable to Gulf Power for the period 2011 through 2020.

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.

ANSWER:

Not applicable to Gulf Power for the period 2011 through 2020.

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.

ANSWER:

Gulf Power does not foresee any transportation concerns over the next several years as it relates to No.6 / heavy oil. Gulf does not use No.6 oil at any of its generating facilities. No. 2 oil is delivered exclusively by truck to Gulf's generating plants. Over the next ten years Gulf Power expects that adequate infrastructure and equipment will be in place to accommodate its No.2 oil transportation needs. Transportation prices for fuel have remained relatively stable (in real dollars) for the last decade. Transportation cost represents only 1-2% of the delivered cost, which is an insignificant piece of the total fuel oil expense.

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

ANSWER:

Typically renewable generation technologies have higher fixed costs and lower variable costs, such as fuel and O&M costs. Once installed, renewable generation costs should be fairly stable since they are not significantly influenced by changes in variable costs, the largest being fuel for fossil generation. Changes in fossil fuel prices will change the competitiveness of renewable generation relative to fossil generation. Installed renewable generation will be more price competitive in the energy market as fossil fuel prices increase and less competitive as fossil fuel prices decrease. Since the market price of fossil fuel has been volatile in recent years and is expected to remain volatile in the future, the economic decision to install new renewable generation technologies is highly dependent on uncertain fossil fuel price forecasts.

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

ANSWER:

The cost to produce and transport fossil fuels to a generating plant are unaffected by the development of renewable generation resources. Forecasts of fossil fuel prices are typically cost based. Production costs for fossil fuels have been increasing in recent years and are expected to continue to increase. If a significant portion of the nation's installed electric generation capacity is non-fossil fueled generation, it is possible that demand driven higher market price spikes for fossil fuels could be dampened. This would only occur if electric generators have the capability to shift significant amounts of electric generation output from fossil fueled resources to non-fossil fuel resources in response to fossil fuel price changes. The resulting reduction in demand for fossil fuels would have an impact on market prices. However, market prices for fossil fuels should not be expected to fall below the cost of production.

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.

ANSWER:

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
N/A	N/A	N/A	N/A	N/A	N/A