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April 25, 2011

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Tallahassee, Florida 32399-0850

RE: Review of 2011 Ten-Year Site Plans – Supplemental Data Requests

Pursuant to the Commission's authority under section 366.05(7), Florida Statues, attached is the reply to requests 1 and 2 for supplemental information to JEA's 2011 Ten-Year Site Plan filing.

Enclosed is a hard copy of the answered questions and excel files. Also, enclosed is an electronic versions of all files. If you have any questions regarding this submittal, please contact me at (904) 665-6216 or GuytML@JEA.com.

Thank You,

Mary Guyton Baker

Mary Guyton Baker, PE
Electric System Planning, JEA

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2011 TEN YEAR SITE PLANS : SUPPLEMENTAL DATA REQUEST

Company Name: **JEA**

Renewable Generation Resources

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

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

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

GENERAL QUESTIONS

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

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

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	2389	0	0	0	0	0	0	0	2389
2002	2562	0	0	0	0	0	0	0	2562
2003	2535	0	0	0	0	0	0	0	2535
2004	2539	0	0	0	0	0	0	0	2539
2005	2815	0	0	0	0	0	0	0	2815
2006	2835	0	0	0	0	0	0	0	2835
2007	2897	0	0	0	0	0	0	0	2897
2008	2866	0	0	0	0	0	0	0	2866
2009	2754	0	0	0	0	0	0	0	2754
2010	2817	0	0	0	0	0	0	0	2817
FORECAST:									
2011	3132	0	0	105	0	2.68	0	6.67	3123
2012	3188	0	0	105	0	2.79	0	6.94	3178
2013	3245	0	0	105	0	2.79	0	6.94	3235
2014	3301	0	0	105	0	2.79	0	6.94	3291
2015	3358	0	0	105	0	2.79	0	6.94	3348
2016	3414	0	0	105	0	2.32	0	5.78	3406
2017	3471	0	0	105	0	2.30	0	5.72	3463
2018	3527	0	0	105	0	2.32	0	5.77	3519
2019	3584	0	0	105	0	2.35	0	5.83	3576
2020	3640	0	0	105	0	2.37	0	5.89	3632

History and Forecast of Summer Peak Demand
Low Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2001	2389	0	0	0	0	0	0	0	2389
2002	2562	0	0	0	0	0	0	0	2562
2003	2535	0	0	0	0	0	0	0	2535
2004	2539	0	0	0	0	0	0	0	2539
2005	2815	0	0	0	0	0	0	0	2815
2006	2835	0	0	0	0	0	0	0	2835
2007	2897	0	0	0	0	0	0	0	2897
2008	2866	0	0	0	0	0	0	0	2866
2009	2754	0	0	0	0	0	0	0	2754
2010	2817	0	0	0	0	0	0	0	2817
FORECAST:									
2011	2849	0	0	105	0	2.68	0	6.67	2840
2012	2900	0	0	105	0	2.79	0	6.94	2890
2013	2950	0	0	105	0	2.79	0	6.94	2940
2014	3001	0	0	105	0	2.79	0	6.94	2991
2015	3051	0	0	105	0	2.79	0	6.94	3041
2016	3101	0	0	105	0	2.32	0	5.78	3093
2017	3152	0	0	105	0	2.30	0	5.72	3144
2018	3202	0	0	105	0	2.32	0	5.77	3194
2019	3253	0	0	105	0	2.35	0	5.83	3245
2020	3303	0	0	105	0	2.37	0	5.89	3295

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	2666	0	0	0	0	0	0	0	2666
2001/02	2590	0	0	0	0	0	0	0	2590
2002/03	3083	0	0	0	0	0	0	0	3083
2003/04	2668	0	0	0	0	0	0	0	2668
2004/05	2860	0	0	0	0	0	0	0	2860
2005/06	2919	0	0	0	0	0	0	0	2919
2006/07	2722	0	0	0	0	0	0	0	2722
2007/08	2914	0	0	0	0	0	0	0	2914
2008/09	3054	0	0	0	0	0	0	0	3054
2009/10	3224	0	0	0	0	0	0	0	3224
2010/11	3062	0	0	0	0	0	0	0	3062 (a)
FORECAST:									
2011/12	3400	0	0	65	0	8.11	0	10.89	3381
2012/13	3471	0	0	65	0	4.14	0	5.55	3461
2013/14	3542	0	0	65	0	4.14	0	5.55	3532
2014/15	3613	0	0	65	0	4.14	0	5.55	3603
2015/16	3684	0	0	65	0	3.45	0	4.63	3676
2016/17	3756	0	0	65	0	3.41	0	4.58	3748
2017/18	3827	0	0	65	0	3.44	0	4.62	3819
2018/19	3898	0	0	65	0	3.48	0	4.67	3890
2019/20	3969	0	0	65	0	3.51	0	4.72	3961

Note:
(a) Forecast 2010/11 winter peak demand is actual peak demand.

History and Forecast of Winter Peak Demand
Low Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) C / I Load Management	(9) C / I Conservation	(10) Net Firm Demand
HISTORY:									
2000/01	2666	0	0	0	0	0	0	0	2666
2001/02	2590	0	0	0	0	0	0	0	2590
2002/03	3083	0	0	0	0	0	0	0	3083
2003/04	2668	0	0	0	0	0	0	0	2668
2004/05	2860	0	0	0	0	0	0	0	2860
2005/06	2919	0	0	0	0	0	0	0	2919
2006/07	2722	0	0	0	0	0	0	0	2722
2007/08	2914	0	0	0	0	0	0	0	2914
2008/09	3054	0	0	0	0	0	0	0	3054
2009/10	3224	0	0	0	0	0	0	0	3224
2010/11	3062	0	0	0	0	0	0	0	3062 (a)
FORECAST:									
2011/12	3055	0	0	65	0	8.11	0	10.89	3036
2012/13	3115	0	0	65	0	4.14	0	5.55	3105
2013/14	3176	0	0	65	0	4.14	0	5.55	3166
2014/15	3237	0	0	65	0	4.14	0	5.55	3227
2015/16	3298	0	0	65	0	3.45	0	4.63	3290
2016/17	3359	0	0	65	0	3.41	0	4.58	3351
2017/18	3420	0	0	65	0	3.44	0	4.62	3412
2018/19	3481	0	0	65	0	3.48	0	4.67	3473
2019/20	3542	0	0	65	0	3.51	0	4.72	3534

Note:
(a) Forecast 2010/11 winter peak demand is actual peak demand.

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

(1) Year	(2) Total	(3) Residential Conservation	(4) C / I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor (%)
HISTORY:								
2001	12322	0	0	0	0	0	12322	53%
2002	12983	0	0	0	0	0	12983	57%
2003	13204	0	0	0	0	0	13204	49%
2004	13243	0	0	0	0	0	13243	57%
2005	13696	0	0	0	0	0	13696	55%
2006	13811	0	0	0	0	0	13811	54%
2007	13854	0	0	0	0	0	13854	55%
2008	13530	0	0	0	0	0	13530	53%
2009	13155	0	0	0	0	0	13155	49%
2010	13842	0	0	0	0	0	13842	49%
FORECAST:								
2011	15834	17.75	38.93	0	0	0	15777	58%
2012	16117	18.46	40.49	0	0	0	16058	54%
2013	16330	18.46	40.49	0	0	0	16271	54%
2014	16577	18.46	40.49	0	0	0	16518	53%
2015	16825	18.46	40.49	0	0	0	16766	53%
2016	17109	15.37	33.73	0	0	0	17060	53%
2017	17320	15.21	33.38	0	0	0	17271	52%
2018	17568	15.37	33.71	0	0	0	17519	52%
2019	17815	15.52	34.05	0	0	0	17765	52%
2020	18102	15.67	34.39	0	0	0	18052	52%

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

(1) Year	(2) Total	(3) Residential Conservation	(4) C / I Conservation	(5) Retail	(6) Wholesale	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor (%)
HISTORY:								
2001	12322	0	0	0	0	0	12322	53%
2002	12983	0	0	0	0	0	12983	57%
2003	13204	0	0	0	0	0	13204	49%
2004	13243	0	0	0	0	0	13243	57%
2005	13696	0	0	0	0	0	13696	55%
2006	13811	0	0	0	0	0	13811	54%
2007	13854	0	0	0	0	0	13854	55%
2008	13530	0	0	0	0	0	13530	53%
2009	13155	0	0	0	0	0	13155	49%
2010	13842	0	0	0	0	0	13842	49%
FORECAST:								
2011	13703	17.75	38.93	0	0	0	13646	50%
2012	13950	18.46	40.49	0	0	0	13891	47%
2013	14127	18.46	40.49	0	0	0	14068	46%
2014	14339	18.46	40.49	0	0	0	14280	46%
2015	14551	18.46	40.49	0	0	0	14492	46%
2016	14800	15.37	33.73	0	0	0	14751	46%
2017	14976	15.21	33.38	0	0	0	14927	45%
2018	15187	15.37	33.71	0	0	0	15138	45%
2019	15399	15.52	34.05	0	0	0	15349	45%
2020	15650	15.67	34.39	0	0	0	15600	45%

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
Kennedy GT	37	0.00%	1.1%	1.2%	5.0%	96.3%	93.9%	12,879	10,907
Kennedy GT	38	0.00%	1.1%	0.7%	5.0%	96.3%	93.9%	11,428	10,772
Northside	1	7.80%	7.4%	5.3%	6.0%	84.0%	86.6%	9,695	9,647
Northside	2	9.12%	7.1%	8.0%	6.0%	80.1%	86.9%	9,711	9,649
Northside	3	7.11%	3.5%	1.0%	5.0%	89.7%	91.5%	11,922	11,221
Northside GT	33	28.25%	3.1%	8.8%	5.0%	63.0%	91.9%	19,567	14,058
Northside GT	34	28.73%	3.1%	2.6%	5.0%	67.7%	91.9%	19,437	13,717
Northside GT	35	8.25%	5.5%	0.4%	5.0%	86.8%	89.5%	20,540	13,259
Northside GT	36	0.05%	5.5%	0.2%	5.0%	99.5%	89.5%	19,091	13,086
Brandy Branch GT	1	0.36%	0.6%	0.8%	5.0%	98.4%	94.4%	12,465	11,356
Brandy Branch CC	2,3 & 4	2.54%	3.3%	4.0%	3.1%	88.9%	93.6%	7,496	7,010
Brandy Branch CT 2		11.64%	Modeled as one unit	1.4%	Modeled as one unit	85.4%	Modeled as one unit	11,733	Modeled as one unit
Brandy Branch CT 3		12.78%		0.9%		84.3%		11,690	
Brandy Branch STM 4		12.17%		1.5%		84.6%		N/A	

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	N/A	N/A	N/A	47.71	757	-12.6%	N/A	N/A	N/A
2009	N/A	N/A	N/A	50.73	805	6.3%	N/A	N/A	N/A
2010	N/A	N/A	N/A	71.00	1127	40.0%	N/A	N/A	N/A
FORECAST:									
2011	N/A	N/A	N/A	74.59	1184	4.8%	N/A	N/A	N/A
2012	N/A	N/A	N/A	82.91	1316	10.0%	N/A	N/A	N/A
2013	N/A	N/A	N/A	87.13	1383	4.8%	N/A	N/A	N/A
2014	N/A	N/A	N/A	92.93	1475	6.2%	N/A	N/A	N/A
2015	N/A	N/A	N/A	98.28	1560	5.4%	N/A	N/A	N/A
2016	N/A	N/A	N/A	103.95	1650	5.5%	N/A	N/A	N/A
2017	N/A	N/A	N/A	109.37	1736	5.0%	N/A	N/A	N/A
2018	N/A	N/A	N/A	115.61	1835	5.4%	N/A	N/A	N/A
2019	N/A	N/A	N/A	120.83	1918	4.3%	N/A	N/A	N/A
2020	N/A	N/A	N/A	126.32	2005	4.3%	N/A	N/A	N/A

ASSUMPTIONS: heat content, ash content

Nominal, Delivered Residual Oil Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Residual Oil (By Sulfur Content)								
	Less Than 0.7%		Escalation	0.7 - 2.0%		Escalation	Greater Than 2.0%		Escalation
Year	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%	$/BBL	c/MBTU	%
HISTORY:									
2008	N/A	N/A	N/A	47.71	757	-12.6%	N/A	N/A	N/A
2009	N/A	N/A	N/A	50.73	805	6.3%	N/A	N/A	N/A
2010	N/A	N/A	N/A	71.00	1127	40.0%	N/A	N/A	N/A
FORECAST:									
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS: heat content, ash content

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	N/A	N/A	N/A	47.71	757	-12.6%	N/A	N/A	N/A
2009	N/A	N/A	N/A	50.73	805	6.3%	N/A	N/A	N/A
2010	N/A	N/A	N/A	71.00	1127	40.0%	N/A	N/A	N/A
FORECAST:									
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS: heat content, ash content

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	87.17	1495	-4.3%	918	9.71	6.9%
2009	73.43	1259	-15.8%	495	5.23	-46.1%
2010	98.41	1688	34.1%	574	6.11	16.8%
FORECAST:						
2011	100.16	1718	1.7%	601	6.39	4.5%
2012	95.67	1641	-4.7%	604	6.43	0.5%
2013	100.98	1732	5.3%	614	6.53	1.6%
2014	105.93	1817	4.7%	624	6.64	1.6%
2015	110.36	1893	4.0%	646	6.87	3.4%
2016	118.47	2032	6.8%	670	7.13	3.6%
2017	126.80	2175	6.6%	694	7.38	3.5%
2018	134.44	2306	5.7%	717	7.63	3.2%
2019	141.84	2433	5.2%	741	7.88	3.2%
2020	148.37	2545	4.4%	774	8.24	4.3%

ASSUMPTIONS FOR DISTILLATE OIL: heat content, ash content, sulfur content

Nominal, Delivered Distillate Oil and Natural Gas Prices
High Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY:						
2008	87.17	1495	-4.3%	918	9.71	6.9%
2009	73.43	1259	-15.8%	495	5.23	-46.1%
2010	98.41	1688	34.1%	574	6.11	16.8%
FORECAST:						
2011	N/A	N/A	N/A	N/A	N/A	N/A
2012	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS FOR DISTILLATE OIL: heat content, ash content, sulfur content

Nominal, Delivered Distillate Oil and Natural Gas Prices
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY:						
2008	87.17	1495	-4.3%	918	9.71	6.9%
2009	73.43	1259	-15.8%	495	5.23	-46.1%
2010	98.41	1688	34.1%	574	6.11	16.8%
FORECAST:						
2011	N/A	N/A	N/A	N/A	N/A	N/A
2012	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS FOR DISTILLATE OIL: heat content, ash content, sulfur content

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	51.85	232.7	5.0	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2009	74.47	330.3	43.6	19.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2010	63.21	282.0	-14.6	10.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FORECAST:												
2011	72.42	426	33.8%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012	72.42	426	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	73.95	435	2.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	74.80	440	1.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	78.37	461	4.6%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	79.05	465	0.9%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	81.60	480	3.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	83.30	490	2.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	85.51	503	2.6%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	87.89	517	2.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS: type of coal, heat content, ash content

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	51.85	232.7	5.0	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2009	74.47	330.3	43.6	19.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2010	63.21	282.0	-14.6	10.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FORECAST:												
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS: type of coal, heat content, ash content

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	51.85	232.7	5.0	0.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2009	74.47	330.3	43.6	19.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2010	63.21	282.0	-14.6	10.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
FORECAST:												
2011	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2012	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2013	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2014	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2015	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2016	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2020	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

ASSUMPTIONS: type of coal, heat content, ash content

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
		Escalation		Escalation
Year	c/MBTU	%	$/MWh	%
HISTORY:				
2008	N/A	N/A	42.20	14.3%
2009	N/A	N/A	45.87	8.0%
2010	N/A	N/A	53.68	14.5%
FORECAST:				
2011	N/A	N/A	87.66	38.8%
2012	N/A	N/A	78.26	-12.0%
2013	N/A	N/A	70.02	-11.8%
2014	N/A	N/A	80.81	13.4%
2015	N/A	N/A	72.16	-12.0%
2016	N/A	N/A	80.10	9.9%
2017	N/A	N/A	82.28	2.6%
2018	N/A	N/A	84.79	3.0%
2019	N/A	N/A	85.30	0.6%
2020	N/A	N/A	85.79	0.6%

Financial Assumptions
Base Case

AFUDC RATE			%
CAPITALIZATION RATIOS:			
	DEBT		%
	PREFERRED		%
	EQUITY		%
RATE OF RETURN			
	DEBT		%
	PREFERRED		%
	EQUITY		%
INCOME TAX RATE:			
	STATE		%
	FEDERAL		%
	EFFECTIVE		%
OTHER TAX RATE:			%
DISCOUNT RATE:		6.00	%
TAX DEPRECIATION RATE:			%

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2011	2.50%	2.50%	2.50%	2.50%
2012	2.50%	2.50%	2.50%	2.50%
2013	2.50%	2.50%	2.50%	2.50%
2014	2.50%	2.50%	2.50%	2.50%
2015	2.50%	2.50%	2.50%	2.50%
2016	2.50%	2.50%	2.50%	2.50%
2017	2.50%	2.50%	2.50%	2.50%
2018	2.50%	2.50%	2.50%	2.50%
2019	2.50%	2.50%	2.50%	2.50%
2020	2.50%	2.50%	2.50%	2.50%

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Annual Isolated			Annual Assisted		
Year	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)	Loss of Load Probability (Days/Yr)	Reserve Margin (%) (Including Firm Purchases)	Expected Unserved Energy (MWh)
2011	1.38	17%	12700	N/A	N/A	N/A
2012	1.02	16%	6900	N/A	N/A	N/A
2013	1.06	15%	2800	N/A	N/A	N/A
2014	5.25	15%	28500	N/A	N/A	N/A
2015	0.87	15%	2600	N/A	N/A	N/A
2016	1.43	15%	10700	N/A	N/A	N/A
2017	0.19	26%	2100	N/A	N/A	N/A
2018	0.23	24%	2000	N/A	N/A	N/A
2019	0.28	22%	0	N/A	N/A	N/A
2020	1.00	20%	4100	N/A	N/A	N/A

Note: Reserve margin based on Summer Firm Peak Demand

Schedule 1
Existing Generating Facilities
As of December 31, 2010

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)		(14)
								Alt. Fuel Days Use	Commercial In-Service Month/Year	Expected Retirement Month/Year	Gen. Max. Nameplate KW	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Fuel Pri	Fuel Alt	Fuel Transport Pri	Fuel Transport Alt					Summer MW		Winter MW
Kennedy	7	12-031	GT	NG	FO2	PL	WA		6/2000	(a)	203,800	150		191
Kennedy	8	12-031	GT	NG	FO2	PL	WA		6/2009	(a)	203,800	150		191
Northside	1	12-031	ST	PC	BIT	WA	RR		2003	(a)	350,000	293		293
Northside	2	12-031	ST	PC	BIT	WA	RR		2002	(a)	350,000	293		293
Northside	3	12-031	ST	NG	FO6	PL	WA		7/1977	(a)	563,700	524		524
Northside	3	12-031	GT	FO2		WA	TK		1/1975	(a)	248,400	212		246
Northside	4	12-031	GT	FO2		WA	TK		1/1975	(a)	248400	212		246
Northside	5	12-031	GT	FO2		WA	TK		1/1975	(a)	248400	212		246
Northside	6	12-031	GT	FO2		WA	TK		1/1975	(a)	248400	212		246
Brandy Branch	1	12-031	GT	NG	FO2	PL	TK		5/2001	(a)	203,800	150		191
Brandy Branch	2	12-031	CT	NG	FO2	PL	TK		5/2001	(a)	203,800	150		191
Brandy Branch	3	12-031	CT	NG	FO2	PL	TK		5/2001	(a)	203,800	150		191
Brandy Branch	4	12-031	CA	WH					1/2005	(a)	268,400	201		223
Girvin Landfill	1-2	12-031	IC	NG		PL			6/1997	(a)	1,200	1		1
St. Johns River Power Park	1	12-031	ST	BIT	PC	RR	WA		3/1987	(a)	679,600	501	(b)	510
St. Johns River Power Park	2	12-031	ST	BIT	PC	RR	WA		5/1988	(a)	679,600	501	(b)	510
Scherer	4	13-207	ST	SUB	BIT	RR	RR		2/1989	(a)	846,000	194	(c)	194

Notes

(a) Units expected to be maintained throughout the study period.
(b) Net capability reflects JEA's 80% ownership of SJRPP.
(c) Nameplate and net capability reflects JEA's 23.64% ownership ini Scherer Unit 4.

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
HISTORY:								
2001			4,884	319,532	15,285	1,104	32,990	33,465
2002			5,108	326,362	15,651	1,157	33,841	34,189
2003			5,226	332,492	15,718	1,184	33,762	35,069
2004			5,400	348,320	15,503	1,185	32,123	36,889
2005			5,550	358,770	15,469	1,249	33,087	37,738
2006			5,637	357,232	15,780	1,289	37,136	34,704
2007			5,478	364,284	15,039	1,328	39,919	33,279
2008			5,364	365,632	14,670	1,357	40,608	33,417
2009			5,300	367,864	14,408	1,303	41,150	31,660
2010			5,748	369,050	15,575	1,329	41,693	31,869
FORECAST:								
2011			5,990	383,765	15,608	1,385	43,356	31,935
2012			6,073	388,306	15,641	1,404	43,869	32,002
2013			6,128	390,989	15,673	1,417	44,172	32,069
2014			6,197	394,568	15,706	1,433	44,576	32,136
2015			6,266	398,130	15,739	1,448	44,979	32,204
2016			6,355	402,910	15,772	1,469	45,519	32,271
2017			6,413	405,752	15,805	1,482	45,840	32,339
2018			6,486	409,522	15,838	1,499	46,266	32,406
2019			6,559	413,261	15,871	1,516	46,688	32,474
2020			6,648	429,935	15,905	1,537	47,223	32,542

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Year	GWH	Industrial 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
HISTORY:							
2001	5,411	3,450	1,568,406	0	109	0	11,508
2002	5,479	3,475	1,576,691	0	112	0	11,856
2003	5,605	3,630	1,544,077	0	115	0	12,130
2004	5,396	3,638	1,483,233	0	76	0	12,057
2005	5,686	3,747	1,517,473	0	111	0	12,596
2006	5,658	4,206	1,345,307	0	110	0	12,694
2007	5,832	4,521	1,290,035	0	113	0	12,751
2008	5,777	4,599	1,256,240	0	117	0	12,615
2009	5,546	4,660	1,190,207	0	120	0	12,270
2010	5,657	4,722	1,198,052	0	122	0	12,855
FORECAST:							
2011	5,895	4,910	1,200,560	0	127	0	13,396
2012	5,977	4,968	1,203,073	0	129	0	13,583
2013	6,031	5,002	1,205,591	0	130	0	13,705
2014	6,099	5,048	1,208,115	0	131	0	13,860
2015	6,167	5,094	1,210,644	0	133	0	14,014
2016	6,254	5,155	1,213,179	0	135	0	14,212
2017	6,311	5,191	1,215,718	0	136	0	14,342
2018	6,383	5,239	1,218,263	0	137	0	14,506
2019	6,455	5,287	1,220,814	0	139	0	14,669
2020	6,542	5,348	1,223,369	0	141	0	14,868

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
HISTORY:					
2001	453	361	12322	2	355,994
2002	446	681	12983	2	363,698
2003	453	595	13178	2	369,904
2004	468	718	13243	2	384,108
2005	486	615	13696	2	395,606
2006	522	595	13811	7	398,581
2007	624	479	13854	5	408,729
2008	451	464	13530	3	414,418
2009	479	406	13155	3	413,677
2010	343	644	13842	2	415,467
FORECAST:					
2011	357	671	14424	2	432,033
2012	362	680	14625	2	437,145
2013	365	687	14757	2	440,165
2014	369	694	14923	2	444,194
2015	374	702	15090	2	448,204
2016	379	712	15303	2	453,586
2017	382	718	15443	2	456,785
2018	387	727	15619	2	461,029
2019	391	735	15795	2	465,239
2020	396	745	16009	2	482,508

Schedule 3.1
History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand
HISTORY:									
2001	2,389	0	0	0	0	0	0	0	2,389
2002	2,562	0	0	0	0	0	0	0	2,562
2003	2,535	0	0	0	0	0	0	0	2,535
2004	2,539	0	0	0	0	0	0	0	2,539
2005	2,815	0	0	0	0	0	0	0	2,815
2006	2,835	0	0	0	0	0	0	0	2,835
2007	2,897	0	0	0	0	0	0	0	2,897
2008	2,866	0	0	0	0	0	0	0	2,866
2009	2,754	0	0	0	0	0	0	0	2,754
2010	2,817	0	0	0	0	0	0	0	2,817
FORECAST:									
2011	3,006	0	0	105	0	2.7	0	6.7	2,892
2012	3,059	0	0	105	0	5.5	0	13.6	2,935
2013	3,112	0	0	105	0	8.3	0	20.5	2,978
2014	3,165	0	0	105	0	11.1	0	27.5	3,021
2015	3,218	0	0	105	0	13.9	0	34.4	3,065
2016	3,271	0	0	105	0	16.2	0	40.2	3,110
2017	3,324	0	0	105	0	18.5	0	45.9	3,155
2018	3,377	0	0	105	0	20.8	0	51.7	3,200
2019	3,431	0	0	105	0	23.1	0	57.5	3,245
2020	3,484	0	0	105	0	25.5	0	63.4	3,290

Schedule 3.2
History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total	(3) Wholesale	(4) Retail	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
HISTORY:										
2000/01	2,666	0	0	0	0	0	0	0	2,666	
2001/02	2,590	0	0	0	0	0	0	0	2,590	
2002/03	3,083	0	0	0	0	0	0	0	3,083	
2003/04	2,668	0	0	0	0	0	0	0	2,668	
2004/05	2,860	0	0	0	0	0	0	0	2,860	
2005/06	2,919	0	0	0	0	0	0	0	2,919	
2006/07	2,722	0	0	0	0	0	0	0	2,722	
2007/08	2,914	0	0	0	0	0	0	0	2,914	
2008/09	3,064	0	0	0	0	0	0	0	3,064	
2009/10	3,224	0	0	0	0	0	0	0	3,224	
FORECAST:										
2010/11	3,062	0	0	0	0	0	0	0	3,062	(a)
2011/12	3,254	0	0	65	0	8.1	0	10.9	3,170	
2012/13	3,320	0	0	65	0	12.3	0	16.4	3,227	
2013/14	3,387	0	0	65	0	16.4	0	22.0	3,284	
2014/15	3,454	0	0	65	0	20.5	0	27.6	3,341	
2015/16	3,521	0	0	65	0	24.0	0	32.2	3,400	
2016/17	3,588	0	0	65	0	27.4	0	36.8	3,459	
2017/18	3,655	0	0	65	0	30.8	0	41.4	3,518	
2018/19	3,722	0	0	65	0	34.3	0	46.0	3,576	
2019/20	3,788	0	0	65	0	37.8	0	50.8	3,635	

Notes

(a) Forecast 2010/11 winter peak demand is actual peak demand.

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 %
HISTORY:								
2001	12,340	0	0	0	0	0	12,340	53%
2002	12,910	0	0	0	0	0	12,910	57%
2003	13,120	0	0	0	0	0	13,120	49%
2004	13,349	0	0	0	0	0	13,349	57%
2005	13,696	0	0	0	0	0	13,696	55%
2006	13,811	0	0	0	0	0	13,811	54%
2007	13,854	0	0	0	0	0	13,854	55%
2008	13,531	0	0	0	0	0	13,531	53%
2009	13,155	0	0	0	0	0	13,155	49%
2010	13,842	0	0	0	0	0	13,842	49%
FORECAST:								
2011	14,481	18	39	0	0	0	14,424	54%
2012	14,741	36	79	0	0	0	14,625	53%
2013	14,932	55	120	0	0	0	14,757	52%
2014	15,157	73	160	0	0	0	14,923	52%
2015	15,382	92	201	0	0	0	15,090	52%
2016	15,644	107	235	0	0	0	15,303	51%
2017	15,833	122	268	0	0	0	15,443	51%
2018	16,058	138	302	0	0	0	15,619	51%
2019	16,283	153	336	0	0	0	15,795	50%
2020	16,548	169	370	0	0	0	16,009	50%

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 (a)	NEL	Peak Demand	NEL
Month	MW	GWH	MW	GWH	MW	GWH
January	3,224	1,254	3,062	1,149	3,170	1,168
February	2,667	1,071	2,346	904	2,629	1,051
March	2,335	988	2,198	1,074	2,239	1,086
April	2,016	926	2,159	1,041	2,191	1,053
May	2,368	1,189	2,590	1,199	2,629	1,213
June	2,817	1,306	2,728	1,343	2,769	1,360
July	2,749	1,375	2,848	1,518	2,891	1,537
August	2,731	1,379	2,892	1,487	2,935	1,506
September	2,595	1,219	2,669	1,282	2,709	1,297
October	2,199	986	2,498	1,127	2,544	1,140
November	1,785	891	2,428	1,049	2,472	1,061
December	3,053	1,259	2,875	1,142	2,927	1,155

Notes

(a) Highligts are actual data.

Schedule 5
Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	**Nuclear**		**Trillion BTU**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(2)	**Coal**		**1000 Ton**	**2,918**	**2,847**	**2,301**	**2,271**	**2,380**	**2,292**	**2,505**	**2,269**	**2,691**	**2,965**	**3,124**	**2,992**
(3)	**Residual**	**Total**	**1000 BBL**	**66**	**151**	**229**	**182**	**199**	**230**	**201**	**189**	**151**	**115**	**127**	**136**
(4)		Steam	1000 BBL	66	151	229	182	199	230	201	189	151	115	127	136
(5)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Other	1000 BBL	**0**	**0**	0	0	0	0	0	0	0	0	0	0
(8)	**Distillate**	**Total**	**1000 BBL**	**48**	**40**	**64**	**45**	**31**	**95**	**31**	**63**	**20**	**14**	**3**	**33**
(9)		Steam	1000 BBL	9	3	1	1	0	1	0	1	1	1	1	1
(10)		CC	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CT	1000 BBL	39	37	63	44	31	94	31	62	19	13	2	32
(12)		Other	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
	Natural Gas	**Total**	**1000 MCF**	**20,754**	**24,084**	**46,673**	**45,520**	**45,730**	**48,066**	**47,181**	**46,723**	**33,362**	**28,407**	**26,534**	**28,890**
(13)		Steam	1000 MCF	7,920	6,631	16,246	12,939	14,100	16,253	14,249	13,373	10,740	8,170	9,044	9,667
(14)		CC	1000 MCF	11,372	15,698	24,302	26,597	26,058	23,172	27,162	25,739	18,593	17,818	15,518	14,752
(15)		CT	1000 MCF	1,462	1,755	6,125	5,984	5,572	8,641	5,770	7,611	4,030	2,420	1,973	4,470
(16)	**Other (Specify)** - Petroleum Coke		**1000 Ton**	**1033**	**1123**	**1225**	**1321**	**1339**	**1383**	**1280**	**1262**	**1310**	**1323**	**1369**	**1417**

Schedule 6.1
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	**Firm Inter-Region Interchange**		**GWH**	**1,606**	**1,418**	**7**	**4**	**0**	**24**	**0**	**860**	**1,658**	**1,596**	**1,657**	**1,637**
(2)	**Nuclear**		**GWH**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(3)	**Coal**		**GWH**	**6,019**	**5,598**	**5,266**	**5,269**	**5,362**	**5,230**	**5,675**	**5,150**	**6,141**	**6,936**	**7,276**	**7,132**
(4)	**Residual**	**Total**	**GWH**	**38**	**90**	**135**	**105**	**115**	**136**	**115**	**111**	**84**	**59**	**66**	**75**
(5)		Steam	GWH	38	90	135	105	115	136	115	111	84	59	66	75
(6)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(9)	**Distillate**	**Total**	**GWH**	**15**	**15**	**27**	**19**	**13**	**40**	**13**	**26**	**8**	**5**	**1**	**14**
(10)		Steam	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWH	15	15	27	19	13	40	13	26	8	5	1	14
(13)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(14)	**Natural Gas**	**Total**	**GWH**	**2,403**	**2,986**	**5,684**	**5,656**	**5,651**	**5,762**	**5,823**	**5,736**	**4,006**	**3,470**	**3,177**	**3,412**
(15)		Steam	GWH	699	592	1,555	1,202	1,319	1,568	1,322	1,272	962	682	760	857
(16)		CC	GWH	1,577	2,244	3,578	3,920	3,833	3,410	3,987	3,780	2,682	2,575	2,249	2,155
(17)		CT	GWH	127	150	550	535	499	784	515	685	362	213	169	400
(18)	**NUG**		**GWH**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
(19)	**Renewables**	**Total**	**GWH**	**75**	**87**	**158**	**178**	**177**	**177**	**177**	**177**	**177**	**150**	**98**	**98**
(20)		Biofuels	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(21)		Biomass	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(22)		Hydro	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(23)		Landfill Gas	GWH	75	75	137	156	156	156	156	156	156	130	77	78
(24)		MSW	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(25)		Solar	GWH	0	12	22	22	21	21	21	21	21	21	21	21
(26)		Wind	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(27)		Other	GWH	0	0	0	0	0	0	0	0	0	0	0	0
(28)	**Other (Specify)** - Petroleum Coke		**GWH**	**2,999**	**3,649**	**3,147**	**3,395**	**3,439**	**3,554**	**3,287**	**3,243**	**3,370**	**3,403**	**3,520**	**3,641**
(29)	**Net Energy for Load**		**GWH**	**13,155**	**13,842**	**14,424**	**14,625**	**14,757**	**14,923**	**15,090**	**15,303**	**15,443**	**15,619**	**15,795**	**16,009**

Schedule 6.2
Energy Sources

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2009	Actual 2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
(1)	**Firm Inter-Region Interchange**		%	**12%**	**10%**	**0%**	**0%**	**0%**	**0%**	**0%**	**6%**	**11%**	**10%**	**10%**	**10%**
(2)	**Nuclear**		%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
(3)	**Coal**		%	**46%**	**40%**	**37%**	**36%**	**36%**	**35%**	**38%**	**34%**	**40%**	**44%**	**46%**	**45%**
(4)	**Residual**	**Total**	%	**0%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**0%**	**0%**	**0%**
(5)		Steam	%	0%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
(6)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(7)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(8)		Other	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(9)	**Distillate**	**Total**	%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
(10)		Steam	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(11)		CC	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(12)		CT	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(13)		Other	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(14)	**Natural Gas**	**Total**	%	**18%**	**22%**	**39%**	**39%**	**38%**	**39%**	**39%**	**37%**	**26%**	**22%**	**20%**	**21%**
(15)		Steam	%	5%	4%	11%	8%	9%	11%	9%	8%	6%	4%	5%	5%
(16)		CC	%	12%	16%	25%	27%	26%	23%	26%	25%	17%	16%	14%	13%
(17)		CT	%	1%	1%	4%	4%	3%	5%	3%	4%	2%	1%	1%	2%
(18)	**NUG**		%	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
(19)	**Renewables**	**Total**	%	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**	**1%**
(20)		Biofuels	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(21)		Biomass	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(22)		Hydro	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(23)		Landfill Gas	%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%
(24)		MSW	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(25)		Solar	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(26)		Wind	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(27)		Other	%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
(28)	**Other (Specify)** - Petroleum Coke		%	**23%**	**26%**	**22%**	**23%**	**23%**	**24%**	**22%**	**21%**	**22%**	**22%**	**22%**	**23%**
(29)	**Net Energy for Load**		%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**
				100%											

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	Reserve Margin before Maintenance % of Peak	Scheduled Maintenance (a MW	Reserve Margin after Maintenance MW	% of Peak
HISTORY:											
2001	3023	298	430	0	2891	2,389	502	21%	0	502	21%
2002	2976	282	430	0	2828	2,562	266	10%	275	-9	0%
2003	3257	207	428	0	3036	2,535	501	20%	0	501	20%
2004	3257	207	428	0	3036	2,539	497	20%	0	497	20%
2005	3485	207	376	0	3316	2,815	501	18%	100	401	14%
2006	3417	207	376	0	3248	2,835	413	15%	0	413	15%
2007	3371	207	376	0	3202	2,897	305	11%	0	305	11%
2008	3371	207	376	0	3202	2,866	336	12%	106	230	8%
2009	3371	257	376	0	3252	2,754	498	18%	0	498	18%
2010	3470	10	376	0	3104	2,817	287	10%	0	287	10%
FORECAST:											
2011	3,754	9	376	0	3,387	2,892	495	17%	0	496	17%
2012	3,754	18	376	0	3,396	2,935	461	16%	0	461	16%
2013	3,754	48	376	0	3,426	2,978	418	14%	0	448	15%
2014	3,754	98	376	0	3,476	3,021	375	12%	0	455	15%
2015	3,754	148	376	0	3,526	3,065	331	11%	0	461	15%
2016	3,754	198	376	0	3,576	3,110	386	12%	0	466	15%
2017	3,754	218	0	0	3,972	3,155	817	26%	0	817	26%
2018	3,753	218	0	0	3,971	3,200	771	24%	0	771	24%
2019	3,753	209	0	0	3,962	3,245	717	22%	0	717	22%
2020	3,753	209	0	0	3,962	3,290	672	20%	0	672	20%

Notes

(a) Maintenance outage and deration

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 (a) MW	Reserve Margin after Maintenance MW	Reserve Margin after Maintenance % of Peak	
HISTORY:												
2000/01	2828	560	445	0	2943	2,666	277	10%	0	277	10%	
2001/02	2928	427	445	0	2910	2,590	320	12%	275	45	2%	
2002/03	3476	207	445	0	3238	3,083	155	5%	62	93	3%	
2003/04	3476	207	445	0	3238	2,668	570	21%	0	570	21%	
2004/05	3476	207	383	0	3300	2,860	440	15%	15	425	15%	
2005/06	3553	207	383	0	3377	2,919	458	16%	0	458	16%	
2006/07	3621	207	383	0	3445	2,722	723	27%	124	599	22%	
2007/08	3621	282	383	0	3520	2,914	606	21%	586	20	1%	
2008/09	3621	367	383	0	3605	3,064	541	18%	124	417	14%	
2009/10	3750	367	383	0	3734	3,224	510	16%	0	510	16%	
2010/11	3750	10	383	0	3377	3,062	315	10%	0	315	10%	(b)
FORECAST:												
2011/12	4,126	18	383	0	3,761	3,170	592	19%	0	592	19%	
2012/13	4,126	18	383	0	3,761	3,227	534	17%	0	534	17%	
2013/14	4,126	48	383	0	3,791	3,284	477	15%	0	507	15%	
2014/15	4,126	98	383	0	3,841	3,341	420	13%	0	500	15%	
2015/16	4,126	168	383	0	3,941	3,400	461	14%	0	541	16%	
2016/17	4,126	248	383	0	3,991	3,459	502	15%	0	532	15%	
2017/18	4,124	218	0	0	4,343	3,518	825	23%	0	825	23%	
2018/19	4,124	209	0	0	4,333	3,576	757	21%	0	757	21%	
2019/20	4,124	209	0	0	4,333	3,635	698	19%	0	698	19%	

Notes

(a) Actual data include maintenance outages and derations.

(b) 2010/11 is actual winter peak data.

Schedule 8
Planned and Prospective Generating Facility Additions and Changes

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
								Const.	Commercial	Expected	Gen. Max.	Net Capability		
	Unit		Unit	Fuel		Fuel Transport		Start	In-Service	Retirement	Nameplate	Summer	Winter	
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Mo/Yr	Mo/Yr	Mo/Yr	KW	MW	MW	Status
Greenland Energy Center	1	12-031	GT	NG	FO2	PL	TK		6/2011	(a)	203,800	142	185	> 90% Complete
Greenland Energy Center	2	12-031	CT	NG	FO2	PL	TK		6/2011	(a)	203,800	142	185	> 90% Complete
SJRPP	1	SJRPP	ST	Bit/PC		RR	WA		3/1/2017		679,600	186	189	
SJRPP	2	SJRPP	ST	Bit/PC		RR	WA		3/1/2017		679,600	186	189	

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) Plant Name and Unit Number:

(2) Capacity
a. Summer:
b. Winter:

(3) Technology Type:

(4) Anticipated Construction Timing
a. Field construction start-date:
b. Commercial in-service date:

(5) Fuel
a. Primary fuel:
b. Alternate fuel:

(6) Air Pollution Control Strategy:

(7) Cooling Method:

(8) Total Site Area:

(9) Construction Status:

None To Report

(10) Certification Status:

(11) Status with Federal Agencies:

(12) Projected Unit Perfomance Data
Planned Outage Factor (POF):
Forced Outage Factor (FOF):
Equivalent Availability Factor (EAF):
Resulting Capacity Factor (%):
Average Net Operating Heat Rate (ANOHR):

(13) Projected Unit Financial Data
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:

(2) Number of Lines:

(3) Right-of-Way:

(4) Line Length:

(5) Voltage:

None To Report

(6) Anticipated Construction Timing:

(7) Anticipated Capital Investment:

(8) Substations:

(9) Participation with Other Utilities:

LOAD & DEMAND FORECASTING

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

   See excel spreadsheet.

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.**

   Only one weather station is used to derive system-wide temperature. HDD data and CDD data are shown in the table below.

Year		HDD	CDD
Actual	2001	1213	2537
	2002	1333	2872
	2003	1432	2616
	2004	1427	2834
	2005	1342	2682
	2006	1170	2742
	2007	1128	2662
	2008	1369	2499
	2009	1347	2797
	2010	1988	2835
Projected	2011	1375	2707
	2012	1375	2707
	2013	1375	2707
	2014	1375	2707
	2015	1375	2707
	2016	1375	2707
	2017	1375	2707
	2018	1375	2707
	2019	1375	2707
	2020	1375	2707

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.

Only one weather station is used. Monthly peak demands, date of occurrence, and temperature associated with the peak are shown in the table below.

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1	2914	3	Thursday	8	25
	2	2484	14	Thursday	8	29
	3	2059	25	Tuesday	8	34
	4	2017	12	Saturday	17	89
	5	2363	21	Wednesday	18	89
	6	2694	9	Monday	17	93
	7	2732	21	Monday	16	95
	8	2866	7	Thursday	16	96
	9	2647	15	Monday	17	92
	10	2263	1	Wednesday	17	87
	11	2310	19	Wednesday	8	28
	12	2473	3	Wednesday	8	29
2009	1	3060	22	Thursday	8	21
	2	3064	6	Friday	8	23
	3	2476	4	Wednesday	8	29
	4	2048	24	Friday	17	89
	5	2451	11	Monday	17	94
	6	2754	22	Monday	16	98
	7	2628	2	Thursday	17	95
	8	2735	12	Wednesday	17	95
	9	2417	25	Friday	17	89
	10	2423	9	Friday	16	93
	11	1710	10	Tuesday	13	82
	12	2151	29	Tuesday	8	31
2010	1	3224	11	Monday	8	20
	2	2667	26	Friday	8	27
	3	2335	4	Thursday	8	32
	4	2016	23	Friday	18	87
	5	2368	3	Monday	17	93
	6	2817	15	Tuesday	17	102
	7	2749	27	Tuesday	16	99
	8	2731	18	Wednesday	17	96
	9	2595	10	Friday	17	95
	10	2199	28	Thursday	17	89
	11	1785	8	Monday	8	33
	12	3053	14	Tuesday	8	20

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?)**

During 2003 and 2004, JEA's service territory experienced a level of new development that was significantly higher than average annual development. This fostered a greater amount of construction labor in the area and subsequently greater need for residential and commercial development to support the construction industry employees. Due to the downturn of construction, many construction laborers have migrated out of the area. This has resulted in a decrease in population and thus demand. In addition, home foreclosures have caused a migration of customers from larger demand houses to smaller demand apartments. Within past year, however, there is a significant improvement in the residential sector. Due to the large number of foreclosures, prices for the local homes have been driven down to a more affordable range; hence, emptied larger demand homes are slowly being occupied, both by customers migrating from the smaller demand apartments and new customers from outside JEA's service territory.

As a whole, JEA experienced an average annual growth rate of 2% in sales and 2.29% in customer accounts from 2001-2006. However, the use per customer during the same period decreased 0.28%. From 2007-2009, the overall sales decreased 1.95%, customer accounts increased 0.60%, and use per customer decreased 2.54%. Within the past year, the overall sales increased by 4.81%, customer account increased by 0.43%, and average use per customer increased by 4.36%.

The residential sector experienced an average annual growth rate of approximately 2.91% in sales, 2.26% in customer accounts, and 0.64% in use per customer from 2001-2006. From 2007-2009, residential sales decreased 1.64% and use per customer decreased 2.12%. However, the numbers of customer accounts increased 0.49%. Within the past year, the sales increased by 8.45%, customer account increased by 0.32%, and average use per customer increased by 8.10%.

The commercial and industrial sectors experienced an average annual growth rate of approximately 1.29% in sales, 2.56% in customer accounts, and -1.23% in use per customer from 2001-2006. From 2007-2009, commercial and industrial sales decreased 2.20%, customer accounts increased 1.53%, and use per customer decreased 3.67%. Within the past year, the sales increased by 1.99%, customer account increased by 1.32%, and average use per customer increased by 0.66%.

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?)

JEA has formed a Smart Grid Steering committee that will provide direction and oversight for the implementation of Smart Grid initiatives and will insure the success of the DOE Smart Grid program scope. For the next three years, the focus of JEA's Smart Grid program is to deploy a customer facing energy management program. The program will enable JEA residential customers to become partners with JEA in the daily management of their energy consumption. JEA will enhance existing systems and processes, integrate them into a cohesive effort, and provide a measured outcome that will help drive future Smart Grid efforts.

The expectations of the Smart Grid program are to implement or upgrade the Consumer Engagement Software (Energy Portal) system, Meter Data Management System (MDMS), Network Metering Infrastructure (2-way network, NMR), Field Management System (FMS) and Outage Management System (OMS), and Remote Connect and Disconnect and pre-pay function.

The energy portal is the central focus of the Smart Grid effort. This is the customer interface that will allow JEA to interact with their residential customers in a way that will enable them to become partners in managing their energy. The full deployment of the pilot Energy Portal is expected to allow the collection of hourly electric consumption data up dated every two hours and monthly water consumption data up dated monthly.

RENEWABLE GENERATION

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

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar	15.6	0.0
Wind	10.0	0.0
Biomass	0.0	0.5
Municipal Solid Waste	0.0	0.0
Waste Heat	0.0	0.0
Landfill Gas	15.1	9.6
Hydro	0.0	0.0
Total	40.7	10.1

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.***

Solar: JEA has installed 35 solar PV systems, totaling approximately 220 kW, on public high schools, a local college and university in Duval County, as well as many of JEA's facilities, the Jacksonville Zoo and the Jacksonville International Airport (one of the largest solar PV systems in the Southeast).

JEA signed a purchase power agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 15.0 MW DC rated solar farm which was declared full commercial operation on September 30, 2010. The facility is located in western Duval County and consists of approximately 200,000 photovoltaic panels on a 100 acre site and generates about 22,340 megawatt-hours (MWh) of electricity per year.

Landfill Gas and Biogas: JEA owns three internal combustion engine generators located at the City of Jacksonville's Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Since that time, gas generation has declined and one generator was removed and placed into service at the Buckman Wastewater Treatment facility. The JEA Buckman Wastewater Treatment Plant previously dewatered and incinerated the sludge from the treatment process and disposed of the ash in a landfill. The current facility manages the sludge using two anaerobic digesters and a sludge dryer to produce a fertilizer pellet product. The methane gas from the digesters is used, as a fuel, for the sludge dryer and for the relocated on-site 800 kW generator. JEA also receives approximately landfill gas from the City of Jacksonville's closed North Landfill, which is piped to the Northside Generating Station and is used to generate power at Northside Unit 3.

JEA has under contract, through a PPA, energy produced from Landfill Energy System's 9.6 MW Trail Ridge landfill gas-to-energy facility, which is located in west Duval County.

Wind: JEA entered into a 20 year agreement with Nebraska Public Power District (NPPD) in 2004 to participate in a wind generation project located in Ainsworth, Nebraska. JEA's participation in NPPD's wind generation project allows JEA to receive environmental credits associated with this green power project. Under the wind generation agreement, JEA purchases 10 MW of capacity from NPPD's wind generation facility. In turn, NPPD buys back the energy at specified on/off peak charges. JEA retains the rights to the environmental attributes.

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)	(%)
North *	IC	LFG	1997			1,513	
Girvin	IC	LFG	1999	1200	1200	2,932	28%

* Landfill gas fuel contribution only. LFG burned in an existing conventional unit.

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)	(%)
Buckman	IC	OBG	2003	800	800	137	1.95%
Solar	SUN	PV	1999/2000/2001/2002/2003			181	

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)	(%)		(%)
Trail Ridge I	IC	LFG	12/2009	9100	9100	74,915	94%	12/2008	12/2018
Jacksonville Solar	SUN	PV	09/2010			11,812		09/2010	09/2040

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)	(%)	(%)	(%)

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.

At this time, there is no planned utility-owned renewable resource additions with an in-service date during the 2011 through 2020 period. JEA has under contract, through a PPA, energy produced from Landfill Energy System's 9.6 MW Trail Ridge landfill gas-to-energy facility which is located in west Duval County. An amendment to this PPA was signed in March 2011 to provide for the development and operation of up to 9.6 MWs of additional electric generating capacity at the Trail Ridge Landfill which is anticipated to commence commercial operation in 2011/2012.

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)	(%)

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)	(%)

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)			(%)
Trail Ridge II	IC	LFG	2011/2012	9100	9100	75,490	95%	12/2011	12/2026

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)	(%)	(%)	(%)

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.**

    At this time, there is no planned utility-owned renewable resource additions planned with an in-service date during the 2011 through 2020 period.

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.**

    At this time, there is no planned utility-owned renewable resource additions planned with an in-service date during the 2011 through 2020 period. JEA has under contract, through a PPA, energy produced from Landfill Energy System's 9.6 MW Trail Ridge landfill gas-to-energy facility which is located in west Duval County. An amendment to this PPA was signed in March 2011 to provide for the development and operation of up to 9.6 MWs of additional electric generating capacity at the Trail Ridge Landfill which is anticipated to commence commercial operation in 2011/2012.

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.

There are no renewable facilities in the JEA service territory that does not have a PPA with JEA.

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

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

Customer Class	Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (kWh)
Residential	Solar Photovoltaic	55.00	257.89	*
Residential	Solar Thermal Water Heating	815.00	2,463.00	*
Residential	Geothermal Heat Pump	0.00	0.00	0.00
Residential	Wind Turbine	0.00	0.00	0.00
Residential	Other (Describe)	0.00	0.00	0.00
Commercial	Solar Photovoltaic	11.00	142.11	*
Commercial	Solar Thermal Water Heating	0.00	0.00	0.00
Commercial	Geothermal Heat Pump	0.00	0.00	0.00
Commercial	Wind Turbine	1.00	3.60	*
Commercial	Other (Describe)	0.00	0.00	0.00

* Net Metered Customers - Customer's system not metered by JEA; data available for kWh sent to JEA from customer

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

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	4.8										
	PPA	86.7	158.4	177.8	177.2	177.1	176.9	177.4	176.7	150.4	98.1	98.4
	Total	91.5	158.4	177.8	177.2	177.1	176.9	177.4	176.7	150.4	98.1	98.4
Retail Sales		13,198	13,753	13,945	14,070	14,229	14,388	14,591	14,725	14,892	15,060	15,264
Net Energy for Load		13,842	14,424	14,625	14,757	14,923	15,090	15,303	15,443	15,619	15,795	16,009

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

Year	As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2010	18.90	41.15	218
2011	19.22	42.90	223
2012	21.68	49.60	229
2013	21.02	49.30	235
2014	21.84	52.50	240
2015	25.16	62.00	246
2016			253
2017			259
2018			265
2019			272
2020			279

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?

JEA conducted a detailed feasibility study of both self-build stand-alone biomass units and the co-firing of biomass in JEA's Northside 1 and 2 circulating fluidized bed units in

2008. Northside 1 and 2 have historically been two of JEA's least cost units, therefore any decreases in reliability due to the co-firing of alternative for Northside 1 and 2 would result in increases in costs to JEA's customers due to the higher costs of replacement power. The study data have been and will continue to be utilized to evaluate any future biomass PPA proposals.

In 2009 and 2010, JEA conducted analytical and technical evaluations for specific biomass fuel types and the utility's wastewater treatment facility's bio-solids to determine the possibility of conducting a co-firing test in Northside 1 or 2. Based on the evaluation, it was determined not to pursue a test at this time utilizing the utility's wastewater treatment facility's bio-solids.

As part of the assessment, JEA evaluated co-firing of biomass consisting of woodchips from tree trimming activities within the JEA territory in the Northside 1 or 2. JEA is in the process of requesting the authorization to co-fire up to 12 tons of the biomass consisting of woodchips from tree trimming activities.

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?

In April 2007, JEA received responses to JEA's Letters of Interest from companies interested in providing renewable energy projects to JEA. Of the 19 responses received, 13 were for biomass projects, the remaining were hydro, landfill gas, and digester gas projects. As a result, JEA issued Request for Proposals for the biomass respondents on August 13, 2007. Proposals were due on September 21, 2007 (extended to September 28, 2007). JEA received four acceptable proposals and rejected five proposals because they did not meet the screening criteria. Proposals were evaluated against JEA's base case of generation. Incremental costs ranged from $10/MWh to $59/MWh above base case and $51 to $306 million in net additional cost to JEA over 20 years. JEA chose not to negotiate with any of the proposers because of the high costs and the inability of proposers to demonstrate fuel or site availability or project financing.

In 2009, JEA received an unsolicited proposal for a 50 MW developer PPA for renewable energy generated by biomass. JEA and the biomass generation provider signed a "Letter of Intent" to pursue a PPA which expired on December 31, 2009 due to regulatory uncertainties and associated energy costs.

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

At this time, JEA does not have any contracts to sell Renewable Energy Credits (RECs). JEA had a contract through 2008 for the sale of RECs received from a PPA associated with "out –of-state" wind energy. In addition, JEA does not offer a green pricing program or similar program for the sale of RECs to customers.

TRADITIONAL GENERATION

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

Year	Base Case Resource Plan(1) (2)	Present Worth Rev. Req. 2011 Million $	
		Annual	Cumulative
2011	Build 2 - 7FA CTs at GEC (177 MW each)	734,722	734,722
2012	Trailridge II Purchase (9 MW)	723,944	1,458,666
2013		720,636	2,179,302
2014		749,982	2,929,285
2015		741,706	3,670,991
2016	MEAG Plant Vogtle Purchase (100 MW) (3)	772,384	4,443,375
2017	MEAG Plant Vogtle Purchase (100 MW) (3) SJRPP Sale to FPL Suspended (383 MW) (4)	798,329	5,241,704
2018	Trailridge I Contract Expires (9 MW)	802,268	6,043,973
2019		806,773	6,850,746
2020		829,205	7,679,952

Notes:

(1) Seasonal purchases may be required in operating horizon in years 2013-2016.

(2) Cumulative DSM addition of 89 MW Winter and Summer by 2020.

(3) After accounting for transmission losses, JEA is anticipating to receive a total of 200 MW of net firm capacity from the proposed units.

(4) SJRPP Sales return projected in March 2017.

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.

N/A

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 up rates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination

of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date.

Planned Unit Additions for 2011 through 2020

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Combustion Turbine Unit Additions				
Greenland Energy Center CT1	142	N/A	N/A	June 2011
Greenland Energy Center CT2	142	N/A	N/A	June 2011
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

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.**

By the due date of this report both units will have passed their substantial completion date. Both units are scheduled to be released for commercial operation on or before June 1, 2011.

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

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	
Kennedy	CT 7	GT	NG/FO2	203.8	150.0	191.0	36,771	2.3%	99.0%	6/2000
Kennedy	CT 8	GT	NG/FO2	203.8	150.0	191.0	96,089	5.8%	97.9%	6/2009
Northside	1	ST	PC/BIT	350.0	293.0	293.0	1,800,519	73.0%	97.1%	2003
Northside	2	ST	PC/BIT	350.0	293.0	293.0	1,891,526	75.9%	95.3%	2002
Northside	3	ST	NG/FO6	563.7	524.0	524.0	640,163	14.4%	77.4%	7/1977
Northside	CT 3	GT	FO2	248.4	53.0	61.5	1,214	0.3%	85.4%	1/1975
Northside	CT 4	GT	FO2	248.4	53.0	61.5	1,174	0.3%	99.2%	1/1975
Northside	CT 5	GT	FO2	248.4	53.0	61.5	524	0.1%	99.7%	1/1975
Northside	CT 6	GT	FO2	248.4	53.0	61.5	1,108	0.3%	99.7%	1/1975
Brandy Branch	CT 1	GT	NG/FO2	203.8	150.0	191.0	31,335	2.0%	98.9%	5/2001
Brandy Branch	CT 2	CT	NG/FO2	203.8	501.0	605.0	2,248,921	42.1%	90.9%	5/2001
Brandy Branch	CT 3	CT	NG/FO2	203.8				43.9%	91.4%	5/2001
Brandy Branch	4	CA	WH	268.4				54.4%	91.3%	1/2005
Girvin Landfill	1-2	IC	NG	1.2	1.2	1.2	2,892	12.3%		6/1997
St. Johns River Power Park	1	ST	BIT/PC	679.6	313.0	319.0	2,272,185	82.2%	96.0%	3/1987
St. Johns River Power Park	2	ST	BIT/PC	679.6	313.0	319.0	2,092,239	75.7%	88.6%	5/1988
Scherer	4	ST	SUB/BIT	846.0	200.0	200.0	1,288,131	73.5%	78.0%	2/1989

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	(MMBTU)	($000)	($/MMBTU)	(¢/kWh)
Kennedy	CT 7	GT	12,568	462,123	4,093,862	8.86	11.13
Kennedy	CT 8	GT	11,672	1,121,514	9,682,122	8.63	10.08
Northside	1	ST	9,647	17,370,009	61,609,159	3.55	3.42
Northside	2	ST	9,611	18,179,851	64,723,182	3.56	3.42
Northside	3	ST	11,926	7,634,756	60,833,288	7.97	9.50
Northside	CT 3	GT	19,605	23,805	277,673	11.66	22.87
Northside	CT 4	GT	20,863	24,491	268,449	10.96	22.87
Northside	CT 5	GT	17,632	9,231	119,722	12.97	22.87
Northside	CT 6	GT	20,431	22,642	253,439	11.19	22.87
Brandy Branch	CT 1	GT	12,376	387,817	3,162,022	8.15	10.09
Brandy Branch	CT 2	CT	7,302	16,421,758	147,108,370	8.96	6.54
Brandy Branch	CT 3	CT					
Brandy Branch	4	CA					
Girvin Landfill	1-2	IC	16,129	46,645			
St. Johns River Power Park	1	ST	9,927	22,556,117	75,389,626	3.34	3.32
St. Johns River Power Park	2	ST	9,887	20,685,325	69,419,104	3.36	3.32
Scherer	4	ST	10,151	13,076,248	30,967,837	2.37	2.40

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

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Kennedy	CT 7	GT	NG/FO2	2.3%	6.5%	4.4%	4.3%	7.6%	4.0%	6.4%	3.4%	1.6%	0.8%	3.6%
Kennedy	CT 8	GT	NG/FO2	5.8%	4.7%	2.9%	2.5%	5.0%	2.3%	4.1%	2.2%	1.0%	0.3%	2.6%
Northside	1	ST	PC/BIT	73.0%	66.4%	75.3%	78.2%	79.7%	68.7%	69.7%	75.3%	76.3%	78.0%	81.4%
Northside	2	ST	PC/BIT	75.9%	73.8%	75.6%	75.1%	78.7%	77.9%	74.5%	74.9%	75.4%	78.9%	80.4%
Northside	3	ST	NG/FO6	14.4%	36.5%	28.1%	30.9%	36.8%	31.0%	29.7%	22.6%	16.0%	17.8%	20.0%
Northside	CT 3	GT	FO2	0.3%	1.8%	1.2%	0.9%	2.2%	0.9%	1.7%	0.6%	0.4%	0.1%	0.9%
Northside	CT 4	GT	FO2	0.3%	1.4%	1.0%	0.7%	2.2%	0.7%	1.4%	0.4%	0.3%	0.1%	0.8%
Northside	CT 5	GT	FO2	0.1%	1.2%	0.9%	0.6%	2.0%	0.6%	1.2%	0.4%	0.2%	0.0%	0.6%
Northside	CT 6	GT	FO2	0.3%	1.0%	0.7%	0.3%	1.7%	0.4%	1.0%	0.2%	0.2%	0.0%	0.4%
Brandy Branch	CT 1	GT	NG/FO2	2.0%	14.1%	11.5%	10.5%	13.6%	12.2%	14.6%	6.8%	4.6%	4.0%	8.1%
Brandy Branch	CT 2	CT	NG/FO2	42.1%	80.1%	87.4%	85.8%	76.3%	89.2%	84.3%	60.0%	57.6%	50.3%	48.1%
Brandy Branch	CT 3	CT	NG/FO2	43.9%										
Brandy Branch	4	CA	WH	54.4%										
SJRPP	1	ST	BIT/PC	82.2%	64.4%	71.7%	61.3%	67.7%	60.6%	63.3%	57.7%	64.0%	60.3%	74.0%
SJRPP	2	ST	BIT/PC	75.7%	62.8%	60.9%	61.5%	55.8%	74.7%	58.4%	44.8%	53.6%	60.9%	51.0%
Scherer	4	ST	SUB/BIT	73.5%	86.3%	75.1%	97.6%	87.6%	96.9%	87.1%	92.8%	83.7%	94.0%	73.1%
GEC	CT 1	GT	NG/FO2	N/A	14.4%	11.4%	10.8%	17.2%	10.6%	14.1%	7.8%	5.1%	4.6%	8.3%
GEC	CT 2	GT	NG/FO2	N/A	8.5%	7.0%	6.6%	11.2%	6.7%	8.3%	5.0%	2.6%	2.0%	5.2%

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

The 7 FA CTs (Brandy Branch CT 1, Kennedy CT 7, Kennedy CT 8, GEC CT1, and GEC CT 2) and steam units (Northside 3, SJRPP 1, and SJRPP 2) are capable of repowering into combined cycle configurations. Brandy Branch Generating Station currently holds a 2x1 Combined Cycle configuration with CTs 2 and 3. Brandy Branch

CT 1 is capable of a 1x1 conversion. Likewise, Kennedy CTs 7 & 8 and GEC CTs 1 & 2 could each convert to a 1x1 configuration or both CTs at each station convert to a single 2x1 configuration similar to the Brandy Branch Combined Cycle unit.

Some of the obstacles common to CT and steam unit conversions are site space, transmission, switchyard, cooling water, gas supply, and gas infrastructure. An added challenge for steam unit conversions is unit size. The conversion of 524 MWs of Northside 3, for example, would result in a unit greater than 1000 MW of capacity, approximately one-third of the size of JEA. Conversion of an SJRPP unit to combined-cycle would result in a unit size greater than 1400 MW. Either of these would result in significant transmission, reserve margin, and operational issues for JEA.

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Northside 3	NG/FO6 - ST	524	7/1977	Combined Cycle
SJRPP 1	BIT/PC - ST	313	3/1987	Combined Cycle
SJRPP 2	BIT/PC - ST	313	5/1988	Combined Cycle
Kennedy CT 7	NG/FO2 - GT	150	6/2000	Combined Cycle
Brandy Branch CT 1	NG/FO2 - GT	150	5/2001	Combined Cycle
Kennedy CT 8	NG/FO2 - GT	150	6/2009	Combined Cycle
GEC CT 1	NG/FO2 - GT	142	6/2011	Combined Cycle
GEC CT 2	NG/FO2 - GT	142	6/2011	Combined Cycle

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

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (1)	Capacity Type	Summer Capacity
Northside	1	ST	BIT/PC	72.8%	Baseload	293
Northside	2	ST	BIT/PC	70.3%	Baseload	293
SJRPP	1	ST	BIT	78.0%	Baseload	319
SJRPP	2	ST	BIT	78.4%	Baseload	319
Scherer	4	ST	SUB	81.1%	Baseload	194
				Sub-Total	**Baseload**	**1418**
Brandy Branch	4	CC	NG	41.1%	Intermediate	501
Northside	3	ST	NG/F06	15.5%	Intermediate	524
				Sub-Total	**Intermediate**	**1025**
Brandy Branch	CT 1	GT	NG/FO2	1.3%	Peaking	150
Brandy Branch	CT 2	CT	NG/FO2	31.1%	Peaking	150
Brandy Branch	CT 3	CT	NG/FO2	16.7%	Peaking	150
Kennedy	CT 7	GT	NG/FO2	2.2%	Peaking	150
Kennedy	CT 8	GT	NG/FO2	1.9%	Peaking	150
Northside	CT 3	GT	FO2	0.4%	Peaking	53
Northside	CT 4	GT	FO2	0.4%	Peaking	53
Northside	CT 5	GT	FO2	0.3%	Peaking	53
Northside	CT 6	GT	FO2	0.6%	Peaking	53
				Sub-Total	**Peaking**	**962**
					Total	**3405**

Planned Facilities During 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (2)	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	**Baseload**	
				Sub-Total	**Intermediate**	
Greenland Energy Center	CT 1	GT	NG/FO2	10.4%	Peaking	142
Greenland Energy Center	CT 2	GT	NG/FO2	6.3%	Peaking	142
				Sub-Total	**Peaking**	**284**
					Total	**284**

Notes:

(1) Historical three year average capacity factor.
(2) Average capacity factor over the years 2011-2020.

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.

Data in the table below represents summer capacity (MW), 50% interest in SJRPP after sale to FPL, and the sale to FPL projected to return to JEA in 2017. The data also does not include any firm power purchases.

Year		Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual	2001	823	767	524	2,114
	2002	823	505	1,001	2,329
	2003	1,371	505	1,001	2,877
	2004	1,371	505	1,001	2,877
	2005	1,371	1,038	683	3,092
	2006	1,389	1,038	581	3,008
	2007	1,407	1,025	563	2,995
	2008	1,407	1,025	563	2,995
	2009	1,407	1,025	662	3,094
	2010	1,407	1,025	662	3,094
Projected	2011	1,407	1,025	662	3,094
	2012	1,407	1,025	847	3,280
	2013	1,407	1,025	847	3,280
	2014	1,407	1,025	847	3,280
	2015	1,407	1,025	847	3,280
	2016	1,407	1,025	847	3,280
	2017	1,783	1,025	847	3,656
	2018	1,782	1,025	847	3,654
	2019	1,782	1,025	847	3,654
	2020	1,782	1,025	847	3,654

Notes:

(a) Summer Capacity (MW).

(b) Included in baseload capacity is 50% interest in SJRPP after sale to FPL. Sale from FPL is projected to return to JEA in 2017.

(c) Does not include firm power purchases.

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

Year		System Average Heat Rate (BTU/kWh)
Actual	2001	9,924
	2002	10,360
	2003	10,103
	2004	10,132
	2005	9,886
	2006	9,727
	2007	9,789
	2008	9,975
	2009	9,735
	2010	9,562
Projected	2011	9,184
	2012	9,125
	2013	9,160
	2014	9,246
	2015	9,169
	2016	9,163
	2017	9,398
	2018	9,395
	2019	9,457
	2020	9,442

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

Year		Residential Bill ($/1200-kWh)		CPI
		Real	Nominal	
Actual	2001	45.56	80.68	177
	2002	44.85	80.68	180
	2003	43.86	80.68	184
	2004	42.71	80.68	189
	2005	43.77	85.48	195
	2006	52.52	105.88	202
	2007	50.59	104.90	207
	2008	52.96	114.02	215
	2009	64.59	138.23	214
	2010	60.38	131.45	218
Projected	2011	64.08	143.02	223
	2012	62.51	143.02	229
	2013	60.99	143.02	235
	2014	59.49	143.02	240
	2015	58.04	143.02	246
	2016	56.64	143.02	253
	2017	55.27	143.02	259
	2018	53.93	143.02	265
	2019	52.61	143.02	272
	2020	51.33	143.02	279

POWER PURCHASES / SALES

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

Existing Purchased Power Agreements as of January 1, 2011

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

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
MEAG	1/1/2016	1/1/2036	100	100	821	94%	NUC	PPA
MEAG	1/1/2017	1/1/2037	100	100	821	94%	NUC	PPA

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

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
FPL	1986	2022 *	188	192	1,543	92%	BIT	PPA
FPL	1987	2022 *	188	192	1,459	87%	BIT	PPA

* Not to exceed date. Projected early suspension of 2017.

ENVIRONMENTAL ISSUES

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

There were no unit curtailments or other significant events that could be attributed to environmental restrictions on the company's system during 2010. No unit retirements or impacts to unit dispatch are anticipated for 2011 through 2020 as a result of environmental restrictions. JEA continues to monitor the development of legislation and regulations at the federal, state, and local levels in order to evaluate the potential impact to JEA and its customers.

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

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001	7.25	42,935	4.94	29,231	N/A	N/A	N/A	N/A	2,132	12,627,485
	2002	4.96	30,803	3.91	24,308	N/A	N/A	N/A	N/A	2,047	12,711,113
	2003	4.33	27,799	3.72	23,908	N/A	N/A	N/A	N/A	2,109	13,542,657
	2004	4.54	28,189	3.52	21,850	N/A	N/A	N/A	N/A	2,075	12,886,710
	2005	4.03	26,343	2.85	18,595	N/A	N/A	N/A	N/A	2,072	13,537,327
	2006	3.22	21,608	3.04	20,405	N/A	N/A	N/A	N/A	2,056	13,798,041
	2007	2.18	15,174	2.88	20,044	N/A	N/A	N/A	N/A	2,000	13,934,209
	2008	1.58	10,126	2.82	17,999	N/A	N/A	N/A	N/A	2,027	12,952,896
	2009	1.66	10,438	1.32	8,328	N/A	N/A	N/A	N/A	2,019	12,723,344
	2010	1.50	10,560	0.91	6,436	N/A	N/A	N/A	N/A	1,964	13,840,570
Projected	2011	1.68	12,087	1.10	7,914	0.0000258	0.19	0.18	1,319	1,603	11,541,264
	2012	1.60	11,711	1.02	7,469	0.0000277	0.20	0.16	1,151	1,604	11,708,379
	2013	1.74	12,794	1.04	7,670	0.0000275	0.20	0.17	1,235	1,611	11,870,979
	2014	1.67	12,431	1.10	8,212	0.0000281	0.21	0.18	1,345	1,620	12,048,927
	2015	1.75	13,209	1.06	7,965	0.0000257	0.19	0.16	1,237	1,616	12,180,591
	2016	1.67	12,009	1.04	7,468	0.0000265	0.19	0.16	1,176	1,597	11,515,928
	2017	1.89	12,979	1.07	7,367	0.0000282	0.19	0.15	1,008	1,685	11,597,834
	2018	2.02	14,131	1.12	7,844	0.0000287	0.20	0.12	827	1,772	12,404,138
	2019	2.08	14,671	1.14	8,022	0.0000289	0.20	0.13	890	1,784	12,589,891
	2020	1.86	13,328	1.12	8,012	0.0000286	0.21	0.13	936	1,745	12,518,998

FUEL

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

Nominal Fuel Price (\$/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	1.60	4.89	3.41	7.10
	2002	N/A	1.48	4.02	3.72	4.65
	2003	N/A	1.60	5.80	4.00	6.98
	2004	N/A	1.50	6.64	4.11	6.76
	2005	N/A	1.79	8.36	6.04	8.95
	2006	N/A	2.10	8.53	7.66	14.44
	2007	N/A	2.20	8.59	8.67	15.63
	2008	N/A	2.33	9.18	7.57	14.95
	2009	N/A	3.30	4.95	8.05	12.59
	2010	N/A	2.82	5.74	11.27	16.88
Projected	2011	N/A	4.26	6.01	11.84	17.18
	2012	N/A	4.26	6.04	13.16	16.41
	2013	N/A	4.35	6.14	13.83	17.32
	2014	N/A	4.40	6.24	14.75	18.17
	2015	N/A	4.61	6.46	15.60	18.93
	2016	N/A	4.65	6.70	16.50	20.32
	2017	N/A	4.80	6.94	17.36	21.75
	2018	N/A	4.90	7.17	18.35	23.06
	2019	N/A	5.03	7.41	19.18	24.33
	2020	N/A	5.17	7.74	20.05	25.45

* Lower priced contract expired.

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

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil	Petroleum Coke
Actual	2001	N/A	6,363	1,014	2,626	81	0
	2002	N/A	6,807	1,728	1,020	118	1,016
	2003	N/A	7,028	814	908	82	3,195
	2004	N/A	6,736	607	1,077	35	2,971
	2005	N/A	6,574	1,212	879	34	3,926
	2006	N/A	6,583	1,720	485	15	4,196
	2007	N/A	6,769	2,093	169	11	3,499
	2008	N/A	6,141	1,990	72	12	3,362
	2009	N/A	6,065	2,417	36	17	2,999
	2010	N/A	5,967	2,960	78	13	3,649
Projected	2011	N/A	5,266	5,684	135	27	3,147
	2012	N/A	5,269	5,656	105	19	3,395
	2013	N/A	5,362	5,651	115	13	3,439
	2014	N/A	5,230	5,762	136	40	3,554
	2015	N/A	5,675	5,823	115	13	3,287
	2016	N/A	5,150	5,736	111	26	3,243
	2017	N/A	6,141	4,006	84	8	3,370
	2018	N/A	6,936	3,470	59	5	3,403
	2019	N/A	7,276	3,177	66	1	3,520
	2020	N/A	7,132	3,412	75	14	3,641

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

JEA compares its forecasts to other independently produced forecasts at the commodity level excluding transportation. Some commodity prices are compared with monthly granularity, while others are compared on an annual basis. Transportation forecasts tend to be too generic for JEA's specific circumstances, but JEA does consider rail, tanker, and dry bulk cargo freight rates and forecasts from various sources to judge general trends within the respective industries.

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.

Using the 2011 Annual Energy Outlook (AEO) from the Energy Information Administration (EIA) as a basis, the price of natural gas is projected in nominal dollars to increase through 2020. Over the forecast horizon, the U.S. is expected to rely on more onshore unconventional natural gas sources which are expected to provide the largest

Planned Power Sales for 2011 through 2020

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

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.

JEA has evaluated future supply capacity needs for the electric system based on the peak demand/energy forecasts and existing/committed supply resources and contracts. Under a base case scenario, seasonal capacity needs occur in the planning horizon.

JEA's Planning Reserve Policy limits the level of market dependency to meet the 15% reserve margin to no more than 3% of Forecasted Firm Demand in any season. This assumes that JEA can obtain, within the operating horizon, resources capable of supplying up to 3% (90 MW for a 3000 MW firm demand level) of JEA's Firm Demand. JEA will utilize the extensive resources of The Energy Authority (TEA), JEA's affiliated energy market services company, to acquire any realized purchased power needs.

The St. Johns River Power Park (SJRPP) is jointly owned by JEA and FP&L. JEA sells to FPL, on a "take-or-pay" basis, 37.5 percent of JEA's 80 percent share of the generating capacity and related energy of SJRPP. This sale will continue until the earlier of the Joint Ownership Agreement expiration in 2022 or the realization of the sale limit. The 37.5% sale to FP&L is projected by JEA to suspend March, 2017.

If this capacity is not returned in 2017, JEA could test the market for short-term power purchases and, given enough lead-time, JEA could exercise the option of adding capacity to Greenland Energy Center (GEC). The GEC site has the capability for future installation of combined cycle and simple cycle units. The site layout and infrastructure supports the future installation of the conversion of GEC CTs 1 and 2 to combined cycle, an identical 2x1 combined cycle power plant, and one additional peaking unit. The ultimate certification capacity for GEC is approximately 1300 MW. All common equipment and facilities at the site were developed for ultimate build out of the future units; retention pond, the reclaimed water pipeline, natural gas supply pipelines, wastewater return lines, and potable waterlines.

growth in domestic supply. Natural gas is used as a primary fuel at four of JEA's existing electric generation facilities. Over the forecast period, JEA will benefit from the increasing contribution from unconventional gas supplies that will help insure sufficient availability of natural gas in the future as JEA relies more heavily on natural gas for electric generation.

In the 2011 AEO reference case, the price of residual fuel oil is projected in nominal dollars to significantly increase through 2020. Given considerable uncertainty surrounding the future price of residual fuel oil relative to natural gas, JEA's past fuel diversification efforts included allowing Northside Unit 3 to burn natural gas in addition to residual fuel oil. Natural gas is used as primary fuel for this unit when it is priced at or below the price of residual fuel oil.

The 2011 AEO reference case indicates that coal production and coal prices in nominal dollars will increase slightly per year from 2011 to 2020. The majority of the production increase will occur in the west utilizing the vast remaining surface-minable reserves located in the Powder River Basin (PRB). In the east, higher sulfur Illinois Basin and Northern Appalachia production is expected to offset significant production declines in the Central Appalachia region. The overall price of mine mouth coal in real dollars is expected to remain relatively constant through 2020.

JEA has ownership in Scherer Unit 4 which burns PRB coal. The trend of increasing production in the west supports continued operation of Scherer Unit 4 on PRB coal. Additionally JEA has ownership in St. Johns River Power Park which burns bituminous coal from international and domestic sources. Given the eastern production trends described above, SJRPP is likely to burn significant volumes of international coal and domestic coal from the Illinois Basin and Northern Appalachia regions as Central Appalachia production continues to decline during the forecast period.

JEA uses circulating fluidized bed technology in Northside Generating Station Units 1 and 2. This technology allows JEA to use a blend of petroleum coke and bituminous coal in these units. During the 2011 through 2020 period, JEA expects the petroleum coke market to typically trade at a discount to coal.

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

JEA has a firm long term agreement for gas volumes delivered to Jacksonville that utilizes both Florida Gas Transmission and Southern Natural Gas pipelines. To support future gas requirements, JEA has additional contracts that provide access to firm transportation on Florida Gas Transmission and Southern Natural Gas pipeline. JEA has long-term contracts with Florida Gas Transmission for firm gas transportation. JEA also has a long-term contract with SeaCoast Gas Transmission, LLC to deliver natural gas to JEA's Greenland Energy Center.

As necessary, JEA continues to add additional firm gas transportation to satisfy incremental needs. The various transportation contracts allow JEA the ability to access natural gas from diverse supply regions.

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.

To provide natural gas delivery to JEA's Greenland Energy Center (GEC), JEA contracted with Peoples Gas System (PGS) for the construction of the Greenland Energy Center Lateral (GEC Lateral) pipeline. Completed in November 2010, the GEC Lateral extends approximately 27 miles east from an interconnection with the SeaCoast Pipeline to the GEC site. The SeaCoast Pipeline is an intrastate pipeline that extends from, an interconnection with Southern Natural Gas Pipeline (SNG) near the interconnection with Florida Gas Transmission Pipeline (FGT) to the interconnection with the GEC Lateral.

JEA does not have any other natural gas pipeline expansion projects planned at this time.

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.

At this time, JEA doesn't foresee any new pipeline expansion projects on the horizon.

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.

Given the decline in conventional natural gas sources, the incremental production of lower 48 onshore natural gas is projected to come primarily from unconventional resources. As technology advances and new methods of extracting unconventional natural gas are refined, the resource potential is projected to play an increasing role in supplementing the natural gas supply.

Using existing firm natural gas transportation contracts, JEA is positioned to purchase natural gas volumes from unconventional as well as conventional production sources in various supply basins.

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.

U.S. imports of liquefied natural gas are expected to decline as a result of demand growth from exporting counties increasing faster than production. The inverse is true domestically with unconventional sources quickly outpacing demand. For these reasons LNG is expected to make a much smaller contribution to total natural gas supply than its 13 percent contribution in 2008.

JEA has a long-term natural gas supply contract that allows the natural gas to be sourced from the LNG facilities of SNG at Elba Island in Savannah, GA.

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

At this time, JEA does not plan to utilize firm natural gas storage.

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

JEA's fuel procurement process insures that potential fuel suppliers compete with one another for the opportunity to deliver coal to JEA facilities. The competitive process results in low delivered costs for JEA.

JEA's Northside Generating Station (NSGS) and St. Johns River Power Park (SJRPP) solid fuel-fired facility owned jointly with Florida Power and Light have water access to accommodate coal deliveries. In addition, SJRPP can also receive fuel from unit trains on the CSX system. JEA's Scherer Unit 4 receives coal deliveries by rail.

Utilizing water deliveries as a direct alternative to rail at SJRPP has encouraged the rail provider to offer SJRPP more competitive transportation rates. Water borne freight (international ocean freight and domestic freight from the US Gulf) has often cost less than rail transportation, and in 2008 SJRPP delivered 100 percent of its solid fuel by water due to a lower transportation cost by water versus rail.

Domestic coal suppliers using rail to barge logistics and international coal suppliers using ocean vessels compete to provide JEA with coal deliveries to NSGS. JEA currently has limited rail access at NSGS.

As a co-owner of Scherer Unit 4, JEA's fuel is delivered from the Powder River Basin in Wyoming to Plant Scherer located near Macon, Georgia by two rail carriers – one in the west and one in the east. Georgia Power Company entered into contracts with the rail carriers on behalf of the Scherer co-owners. Competition between the major rail carriers was insured by including all in the negotiation process.

JEA has and will continue to solicit coal bids in a competitive process and will make fuel selections based on prudent utility evaluations.

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.**

A recent trend has been for the major rail carriers to begin to transfer the burden of owning and maintaining rail equipment for the movement of coal to the larger utilities. Although the railroads still own rail cars, the trend is to reduce the railroad owned rolling stock.

The recent surge of export coal through East Coast ports that is expected to continue for the foreseeable future has decreased available supply. If the projected growth continues, any excess rail car supply will disappear both in railroad-owned equipment and leased rail equipment. This shortage of rail equipment doesn't impact JEA which owns enough rail cars to fully operate three 110 car unit trains and has spare equipment available.

Since both NSGS and SJRPP have water terminals for fuel receipts, any changes to terminals and port facilities in Jacksonville will not affect JEA.

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.**

Driven by global demand, U.S. coal exports by water are expected to expand to meet the demand from countries such as China and India. To accomplish higher exporting capacity additional loading terminals will have to be constructed, but public perception, environmental concerns and permitting could cause delays and ultimately some facility expansion projects canceled.

Publically owned coal companies, pushed by shareholders to sell globally for the highest profit margin, are directly impacting the market of coal that is available by water domestically. As more coal is sold into the international market the price the coal that is sold domestically will increase. JEA has and will continue to solicit coal bids in a competitive process and will make fuel selections based on prudent utility evaluations. Since both of the Jacksonville generating stations have their own terminals for receiving coal, any changes to other terminals and port facilities will not affect JEA.

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.

JEA currently has no coal handling, blending, or storage projects underway or approved.

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.

JEA does not have any self-build nuclear units in the ten-year site plan.

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.

Not Applicable

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.

The ongoing decline in utility consumption of residual fuel and distillate fuel oil is expected to continue. JEA has followed this industry trend and is consuming much less fuel oil than in past years. Northside Unit 3 is JEA's last generating unit capable of burning residual fuel oil. JEA burns residual fuel oil in Northside Unit 3 when oil is cheaper than gas including environmental considerations. Any industry trends in the transportation of heavy fuel oil and distillate fuel oil will have little impact on JEA as these fuels make up only a small portion of JEA's fuel use.

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

It is difficult to speculate on the effect that changes in fossil fuel prices may have on the competitiveness of renewable technologies. In general, if fossil fuel prices increase for a sustained period of time, the competitiveness of renewable technologies, from purely a cost-effectiveness perspective, would likely improve. Conversely, if fossil fuel prices decrease for a sustained period of time, the competitiveness of renewable technologies, from purely a cost-effectiveness perspective, would likely decline. However, there are other market factors that need to be considered, therefore it may not be feasible to conclude there will be a direct correlation between changes in fossil fuel prices and competitiveness of renewable technologies.

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

It is difficult to speculate on the effect that renewable resource (technology) development may have on fossil fuel prices. In general, if the use of renewable resources develop sufficiently to displace significant amounts of fossil fuel consumption, the price of fossil fuel would likely decline. However, there are other market factors that need to be considered, therefore it may not be feasible to conclude that there will be a direct correlation between changes renewable resource (technology) development and fossil fuel prices.

TRANSMISSION

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

There are no transmission lines to report for this period.

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

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)
2001	1	1	Monday	890	824	786	798	840	975	1192	1284	1242	1223	1219	1216	1212	1213	1222	1228	1238	1287	1398	1374	1313	1213	1094	960	1398	786
2001	1	2	Tuesday	862	811	787	785	817	939	1151	1225	1186	1186	1227	1273	1278	1290	1286	1301	1306	1345	1449	1435	1362	1228	1097	969	1449	785
2001	1	3	Wednesday	872	814	783	789	833	987	1259	1399	1387	1370	1342	1311	1273	1241	1222	1222	1277	1434	1631	1657	1639	1582	1475	1356	1657	783
2001	1	4	Thursday	1246	1184	1153	1146	1156	1273	1499	1509	1415	1359	1313	1252	1205	1180	1158	1152	1169	1252	1383	1387	1348	1267	1154	1044	1509	1044
2001	1	5	Friday	952	915	906	917	957	1090	1325	1402	1348	1367	1384	1381	1323	1325	1257	1249	1267	1338	1462	1454	1394	1336	1242	1172	1462	906
2001	1	6	Saturday	1110	1068	1047	1042	1051	1108	1195	1284	1346	1341	1308	1253	1210	1174	1132	1115	1127	1167	1271	1252	1202	1155	1094	1017	1346	1017
2001	1	7	Sunday	903	912	879	867	875	893	1000	1018	1102	1146	1150	1141	1129	1129	1129	1116	1149	1189	1301	1306	1259	1156	1068	959	1306	867
2001	1	8	Monday	871	834	811	811	837	963	1179	1262	1230	1226	1254	1291	1276	1258	1239	1227	1247	1299	1425	1420	1342	1257	1171	1019	1425	811
2001	1	9	Tuesday	921	885	861	865	908	1050	1301	1389	1326	1275	1260	1229	1229	1216	1222	1216	1223	1276	1409	1394	1351	1283	1171	1057	1409	861
2001	1	10	Wednesday	979	944	942	962	1010	1186	1472	1565	1477	1386	1315	1294	1257	1253	1243	1226	1244	1292	1365	1411	1375	1308	1231	1072	1565	942
2001	1	11	Thursday	997	977	974	988	1048	1211	1494	1573	1493	1392	1333	1283	1255	1228	1236	1215	1233	1279	1402	1391	1332	1239	1119	1008	1573	974
2001	1	12	Friday	916	886	878	877	966	1130	1423	1563	1576	1548	1544	1514	1462	1427	1384	1346	1385	1515	1690	1719	1721	1687	1640	1583	1721	877
2001	1	13	Saturday	1520	1484	1479	1501	1541	1606	1714	1848	1867	1760	1633	1580	1371	1259	1205	1139	1161	1264	1434	1467	1462	1474	1431	1374	1867	1139
2001	1	14	Sunday	1320	1313	1323	1349	1387	1446	1532	1654	1686	1576	1435	1303	1227	1166	1117	1093	1105	1163	1299	1303	1308	1268	1228	1132	1686	1093
2001	1	15	Monday	1077	1049	1037	1016	1050	1137	1284	1371	1401	1395	1409	1401	1362	1306	1285	1292	1339	1414	1533	1514	1467	1367	1237	1126	1533	1016
2001	1	16	Tuesday	1017	979	958	956	993	1131	1363	1434	1354	1329	1289	1292	1249	1210	1208	1187	1208	1269	1404	1410	1316	1252	1134	1010	1434	956
2001	1	17	Wednesday	919	867	842	835	868	1005	1253	1342	1294	1267	1269	1246	1244	1233	1259	1261	1321	1434	1543	1530	1458	1401	1290	1158	1543	835
2001	1	18	Thursday	1062	1008	962	963	981	1095	1296	1341	1292	1236	1219	1205	1190	1176	1167	1154	1186	1259	1428	1461	1468	1433	1371	1272	1468	962
2001	1	19	Friday	1212	1193	1253	1306	1405	1624	1935	2063	1995	1919	1828	1709	1608	1502	1438	1379	1422	1522	1722	1772	1795	1788	1756	1710	2063	1193
2001	1	20	Saturday	1671	1670	1687	1704	1740	1812	1920	2035	2061	1935	1775	1602	1444	1317	1265	1206	1211	1276	1441	1467	1453	1415	1371	1301	2061	1206
2001	1	21	Sunday	1219	1162	1146	1136	1129	1157	1240	1333	1407	1379	1294	1217	1153	1083	1057	1039	1100	1193	1264	1256	1215	1137	1052	956	1407	956
2001	1	22	Monday	889	855	839	843	875	1023	1244	1341	1318	1302	1349	1391	1401	1428	1493	1594	1716	1870	2040	2097	2098	2037	1898	1747	2098	839
2001	1	23	Tuesday	1650	1594	1572	1596	1695	1906	2209	2305	2195	2077	1947	1815	1701	1632	1581	1532	1549	1712	1965	2036	2032	1978	1886	1802	2305	1532
2001	1	24	Wednesday	1748	1754	1782	1824	1885	2085	2385	2463	2347	2239	2145	2024	1921	1824	1747	1707	1755	1957	2211	2288	2288	2274	2180	2081	2463	1707
2001	1	25	Thursday	2026	2013	2038	2068	2141	2328	2604	2666	2516	2370	2219	2083	1977	1854	1755	1687	1729	1893	2122	2196	2203	2164	2055	1934	2666	1687
2001	1	26	Friday	1847	1816	1795	1756	1784	1920	2127	2174	2068	1985	1886	1795	1752	1714	1709	1705	1743	1826	1875	1836	1746	1640	1545	1447	2174	1447
2001	1	27	Saturday	1333	1265	1217	1190	1183	1222	1298	1385	1471	1545	1543	1505	1425	1353	1285	1231	1225	1249	1386	1389	1367	1323	1249	1169	1545	1169
2001	1	28	Sunday	1091	1049	1015	1015	1018	1033	1089	1167	1257	1293	1243	1212	1189	1154	1124	1096	1137	1229	1314	1283	1294	1256	1257	1185	1314	1015
2001	1	29	Monday	1145	1145	1163	1211	1316	1529	1851	1953	1905	1910	1889	1868	1827	1727	1600	1543	1588	1717	1826	1948	1942	1884	1751	1661	1953	1145
2001	1	30	Tuesday	1586	1577	1606	1659	1745	1958	2250	2294	2150	1965	1826	1680	1573	1487	1415	1369	1400	1513	1696	1776	1746	1677	1556	1437	2294	1369
2001	1	31	Wednesday	1354	1315	1322	1335	1392	1568	1840	1919	1803	1728	1624	1530	1450	1386	1340	1327	1376	1515	1658	1739	1772	1731	1611	1446	1919	1315
Excludes Shaded Weekends and Holidays	AVG			1189	1155	1148	1159	1212	1370	1625	1707	1640	1583	1540	1494	1446	1404	1375	1359	1395	1497	1647	1676	1645	1582	1480	1369	1804	1090
	MAX			2026	2013	2038	2068	2141	2328	2604	2666	2516	2370	2219	2083	1977	1854	1755	1707	1755	1957	2211	2288	2288	2274	2180	2081	2666	1707
	MIN			862	811	783	785	817	939	1151	1225	1186	1186	1219	1205	1190	1176	1158	1152	1169	1252	1365	1387	1316	1228	1097	969	1409	783

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)
2001	8	1	Wednesday	1506	1419	1366	1340	1340	1398	1522	1576	1646	1745	1867	1996	2142	2274	2363	2423	2470	2470	2420	2323	2272	2192	2007	1830	2470	1340
2001	8	2	Thursday	1681	1574	1506	1452	1440	1491	1581	1626	1706	1800	1928	2053	2178	2296	2382	2434	2473	2462	2408	2316	2276	2191	2033	1870	2473	1440
2001	8	3	Friday	1727	1626	1559	1516	1517	1566	1663	1718	1762	1836	1932	2029	2144	2240	2294	2342	2391	2392	2321	2121	2035	1943	1785	1674	2392	1516
2001	8	4	Saturday	1556	1469	1415	1370	1348	1363	1396	1433	1512	1585	1638	1650	1643	1649	1689	1735	1790	1811	1791	1753	1744	1692	1608	1506	1811	1348
2001	8	5	Sunday	1414	1345	1300	1258	1241	1249	1284	1323	1423	1527	1593	1640	1689	1712	1709	1706	1723	1731	1700	1683	1696	1684	1607	1498	1731	1241
2001	8	6	Monday	1398	1333	1296	1280	1289	1355	1461	1516	1598	1693	1792	1875	1940	1963	1963	1996	2015	2024	1991	1930	1898	1843	1709	1565	2024	1280
2001	8	7	Tuesday	1444	1359	1306	1261	1256	1323	1427	1491	1574	1684	1781	1872	1946	2024	2077	2118	2136	2136	2078	1978	1925	1858	1709	1554	2136	1256
2001	8	8	Wednesday	1414	1329	1278	1237	1237	1294	1397	1446	1524	1639	1737	1831	1927	2010	2068	2098	2131	2111	2041	1957	1921	1859	1725	1565	2131	1237
2001	8	9	Thursday	1440	1348	1289	1251	1254	1313	1414	1469	1548	1656	1780	1884	1981	2050	2084	2077	2055	2007	1957	1910	1902	1861	1731	1580	2084	1251
2001	8	10	Friday	1461	1374	1336	1300	1297	1353	1464	1534	1628	1737	1847	1943	2029	2079	2123	2083	2041	2058	2034	1959	1933	1861	1753	1644	2123	1297
2001	8	11	Saturday	1527	1450	1391	1358	1348	1356	1382	1428	1579	1729	1844	1930	1884	1800	1753	1731	1689	1665	1647	1628	1639	1601	1532	1444	1930	1348
2001	8	12	Sunday	1354	1278	1236	1210	1195	1202	1220	1258	1374	1538	1674	1758	1827	1830	1813	1814	1792	1758	1731	1707	1737	1695	1608	1491	1830	1195
2001	8	13	Monday	1404	1340	1303	1280	1295	1371	1481	1556	1599	1692	1833	1949	2015	2015	2015	2035	2083	2128	2109	2025	1984	1910	1773	1627	2128	1280
2001	8	14	Tuesday	1496	1414	1355	1330	1339	1398	1514	1577	1652	1767	1907	2033	2165	2269	2333	2372	2395	2402	2361	2280	2262	2145	1970	1798	2402	1330
2001	8	15	Wednesday	1659	1540	1508	1470	1467	1511	1619	1663	1737	1848	1975	2103	2221	2327	2407	2439	2471	2462	2403	2308	2218	2064	1850	1698	2471	1467
2001	8	16	Thursday	1555	1465	1410	1373	1366	1420	1518	1566	1630	1708	1822	1948	2020	2011	1935	1875	1880	1909	1906	1885	1877	1828	1705	1587	2020	1366
2001	8	17	Friday	1468	1389	1347	1313	1317	1362	1492	1550	1644	1753	1861	1941	2041	2155	2233	2265	2250	2153	1932	1851	1814	1727	1644	1546	2265	1313
2001	8	18	Saturday	1461	1388	1335	1294	1282	1297	1333	1363	1484	1635	1789	1910	1992	2058	2093	2066	1969	1844	1803	1746	1749	1751	1656	1549	2093	1282
2001	8	19	Sunday	1438	1373	1322	1289	1273	1274	1289	1320	1447	1597	1737	1858	1975	2063	2136	2188	2234	2221	2139	2054	1976	1849	1718	1602	2234	1273
2001	8	20	Monday	1490	1423	1377	1356	1362	1422	1531	1588	1660	1792	1932	2066	2167	2244	2173	2078	2077	2112	2084	2060	2058	1958	1825	1690	2244	1356
2001	8	21	Tuesday	1566	1486	1431	1397	1399	1459	1581	1640	1715	1822	1926	2010	1968	1858	1810	1755	1748	1748	1726	1716	1731	1675	1587	1466	2010	1397
2001	8	22	Wednesday	1373	1306	1271	1251	1254	1342	1466	1550	1593	1665	1770	1876	1954	2018	2098	2174	2224	2234	2148	2058	2039	1946	1803	1655	2234	1251
2001	8	23	Thursday	1530	1454	1398	1370	1367	1431	1551	1617	1691	1778	1816	1901	1967	2051	2120	2163	2183	2085	2079	2041	2018	1935	1859	1658	2183	1367
2001	8	24	Friday	1531	1449	1398	1379	1383	1451	1568	1625	1666	1698	1807	1910	2022	2112	2135	2111	2088	2068	2018	1967	1937	1844	1739	1623	2135	1379
2001	8	25	Saturday	1500	1426	1373	1337	1325	1333	1370	1410	1515	1640	1744	1838	1924	1968	1962	1965	1948	1905	1852	1810	1813	1750	1647	1549	1968	1325
2001	8	26	Sunday	1407	1362	1312	1270	1237	1236	1249	1280	1397	1542	1663	1766	1853	1909	1960	1994	2018	2004	1982	1911	1903	1819	1683	1540	2018	1236
2001	8	27	Monday	1415	1335	1287	1264	1275	1330	1461	1527	1605	1735	1840	1943	2052	2142	2191	2237	2269	2269	2215	2140	2109	1995	1803	1633	2269	1264
2001	8	28	Tuesday	1495	1404	1356	1329	1339	1411	1558	1615	1640	1744	1870	1971	2062	2140	2221	2258	2284	2276	2224	2152	2148	2015	1830	1665	2284	1329
2001	8	29	Wednesday	1543	1475	1407	1379	1385	1452	1592	1647	1651	1706	1805	1919	2051	2176	2272	2336	2392	2404	2372	2317	2313	2171	1991	1807	2404	1379
2001	8	30	Thursday	1680	1593	1535	1496	1496	1568	1696	1738	1782	1882	2003	2117	2242	2357	2360	2396	2439	2476	2451	2395	2362	2220	2037	1868	2476	1496
2001	8	31	Friday	1717	1614	1539	1484	1478	1539	1660	1699	1750	1855	1985	2114	2234	2350	2421	2450	2476	2467	2398	2309	2268	2128	1992	1805	2476	1478
Excludes Shaded Weekends and Holidays		AVG		1521	1437	1385	1353	1354	1416	1531	1588	1652	1749	1862	1969	2064	2137	2177	2196	2216	2211	2160	2087	2057	1964	1820	1670	2254	1351
		MAX		1727	1626	1559	1516	1517	1568	1696	1738	1782	1882	2003	2117	2242	2357	2421	2450	2476	2476	2451	2395	2362	2220	2037	1870	2476	1516
		MIN		1373	1306	1271	1237	1237	1294	1397	1446	1524	1639	1737	1831	1927	1858	1810	1755	1748	1748	1726	1716	1731	1675	1587	1466	2010	1237

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

* None To Report

2011 TEN YEAR SITE PLANS : SUPPLEMENTAL DATA REQUEST #2

Company Name: <u>**JEA**</u>

RENEWABLE GENERATION

1. **Please provide a description of the costs associated with each existing and planned utility-owned renewable generation resource. Please also include each renewable resource which provides fuel to conventional facilities (co-firing), if applicable, with estimates of its capacity and energy contributions. As part of this response, please include a description of the unit's generator type, fuel type, installed cost (nominal $), fixed operations & maintenance (O&M) cost, variable O&M cost, fuel cost (if applicable), and the annual levelized cost of electricity. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Facility Name	Unit Type	Fuel Type	Installed Costs	Fixed O&M Cost	Variable O&M Cost	Fuel Cost	Levelized Cost of Electricity
			$/kW	$/kW-yr	$/MWh	$/MWh	$/MWh
Girvin	IC	LFG		$41.45/MWh		42.23	83.68
North	IC	LFG		$0.83/MWh		32.44	33.28
Buckman	IC	OBG		$21.19/MWh			21.19
Solar PV	SUN	PV	12,756.82				15,586.68

(a) 2010 Actual.

2. **Please provide a description of the costs associated with each existing and planned renewable purchased power agreement. Please also include each renewable resource which provides fuel to conventional facilities (co-firing), if applicable, with estimates of energy payments. As part of this response, please include a description of the unit's generator type, fuel type, annual capacity payments, annual energy payments, total annual payments to the facility, and the resulting levelized cost of electricity from the facility. Please complete the table below and provide an electronic copy in Excel (.xls file format) and hard copy.**

Facility Name	Unit Type	Fuel Type	Capacity Payment	Energy Payment	Total Payment (a)	Levelized Cost of Electricity (a)	Levelized Cost of Electricity (b)	
			$	$	$	$/MWh	$/MWh	$
Trail Ridge I					3,446,083.26	46.00	42.40	3,324,168.23
Trail Ridge II					n/a	n/a	59.65	4,610,693.59
Jacksonville Solar (c)					1,873,053.71	158.57	165.09	3,498,200.13

(a) 2010 Actual.

(b) 10 year levelized cost (2011-2020) in 2011$.

(c) Jacksonville Solar COD September 2010. Began receiving pre-commercial energy in April 2010.

3. **Please provide, on a system-wide basis, the hourly system load for the period January 1, 2010, through December 31, 2010. Please complete the table below (expanding as necessary) and provide an electronic copy in Excel (.xls file format).**

Data provided in excel spreadsheet.

4. **Please identify which climate station from the list below would most accurately represent the company's service territory, as a whole, for the purposes of determining a typical meteorological year. Alternatively, provide a data set for a typical meteorological year in an appropriate electronic format (TMY2, TMY3, or EPW). The stations below are drawn from the National Solar Radiation Data Base. Other publically available databases can be utilized, so long as an electronic copy is provided.**

Please refer to Excel for TMY3 for the site.

USAF	Station Name
722060	Jacksonville Intl Arpt

5. **Please provide, if available, the hourly output, for the period January 1, 2010, through December 31, 2010, for an existing solar photovoltaic system in the company's service territory. As part of the data response, please provide the**

array's DC rating, AC rating, Array Orientation (degrees from south), and whether it is a fixed or tracking array. If a fixed array, please provide the degree of tilt, specifying if the tilt is seasonally changed (if so, when, and by how much). If a tracking array, *specify whether it is a one or two axis tracking system.* Please also provide general information about the installation, including panel height, whether shading issues exist, or other notable factors which may influence the array's output. Please complete the table below (expanding as necessary) and provide an electronic copy in Excel (.xls file format).

Data provided in excel spreadsheet.

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)	(%)
North *	IC	LFG	1997			1,513	
Girvin	IC	LFG	1999	1200	1200	2,932	28%

* Landfill gas fuel contribution only. LFG burned in an existing conventional unit.

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)	(%)
Buckman	IC	OBG	2003	800	800	137	1.95%
Solar	SUN	PV	1999/2000/2001/2002/2003			181	

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)	(%)		
Trail Ridge I	IC	LFG	12/2009	9100	9100	74,915	94%	12/2008	12/2018
Jacksonville Solar	SUN	PV	09/2010			11,812		09/2010	09/2040

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)	(%)		

Fuel Type	Renewable Resource Capacity (MW)	
	Existing	Planned
Solar	15.6	0
Wind	10	0
Biomass	0	0.5
Municipal Solid Waste	0	0
Waste Heat	0	0
Landfill Gas	15.1	9.6
Hydro	0	0
Total	**40.7**	**10.1**

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)	(%)

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)	(%)

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)	(%)		
Trail Ridge II	IC	LFG	2011/2012	9100	9100	75,490	95%	12/2011	12/2026

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)	(%)		

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

Customer Class	Renewable Type	# of Connections	Installed Capacity	Annual Output
			(kW)	(kWh)
Residential	Solar Photovoltaic	55.00	257.89	*
Residential	Solar Thermal Water Heating	815.00	2,463.00	*
Residential	Geothermal Heat Pump	0.00	0.00	0.00
Residential	Wind Turbine	0.00	0.00	0.00
Residential	Other (Describe)	0.00	0.00	0.00
Commercial	Solar Photovoltaic	11.00	142.11	*
Commercial	Solar Thermal Water Heating	0.00	0.00	0.00
Commercial	Geothermal Heat Pump	0.00	0.00	0.00
Commercial	Wind Turbine	1.00	3.60	*
Commercial	Other (Describe)	0.00	0.00	0.00

* Net Metered Customers - Customer's system not metered by JEA;
data available for kWh sent to JEA from customer

Annual Output (GWh)		Actual	Projected									
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Renewable Generation	Utility	4.8										
	PPA	86.7	158.4	177.8	177.2	177.1	176.9	177.4	176.7	150.4	98.1	98.4
	Total	91.5	158.4	177.8	177.2	177.1	176.9	177.4	176.7	150.4	98.1	98.4
Retail Sales		13,198	13,753	13,945	14,070	14,229	14,388	14,591	14,725	14,892	15,060	15,264
Net Energy for Load		13,842	14,424	14,625	14,757	14,923	15,090	15,303	15,443	15,619	15,795	16,009

Year	As-Available Energy ($/MWh)		CPI
	Real	Nominal	
2010	18.90	41.15	218
2011	19.22	42.90	223
2012	21.68	49.60	229
2013	21.02	49.30	235
2014	21.84	52.50	240
2015	25.16	62.00	246
2016			253
2017			259
2018			265
2019			272
2020			279

Generating Unit Name	Summer Capacity (MW)	Certification Dates (if Applicable)		In-Service Date
		Need Approved (Commission)	PPSA Certified	
Nuclear Unit Additions / Uprates				
Combustion Turbine Unit Additions				
Greenland Energy Center CT 1	142	N/A	N/A	June-11
Greenland Energy Center CT 2	142	N/A	N/A	June-11
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

Plant	Unit #	Unit Type	Fuel Type	Nameplate Capacity	Net Capacity (MW)		Annual Generation	Capacity Factor	Availability Factor	In-Service Date
				(MW)	Sum	Win	(MWh)	(%)	(%)	
Kennedy	CT 7	GT	NG/FO2	203.8	150.0	191.0	36,771	2.3%	99.0%	6/2000
Kennedy	CT 8	GT	NG/FO2	203.8	150.0	191.0	96,089	5.8%	97.9%	6/2009
Northside	1	ST	PC/BIT	350.0	293.0	293.0	1,800,519	73.0%	97.1%	2003
Northside	2	ST	PC/BIT	350.0	293.0	293.0	1,891,526	75.9%	95.3%	2002
Northside	3	ST	NG/FO6	563.7	524.0	524.0	640,163	14.4%	77.4%	7/1977
Northside	CT 3	GT	FO2	248.4	53.0	61.5	1,214	0.3%	85.4%	1/1975
Northside	CT 4	GT	FO2	248.4	53.0	61.5	1,174	0.3%	99.2%	1/1975
Northside	CT 5	GT	FO2	248.4	53.0	61.5	524	0.1%	99.7%	1/1975
Northside	CT 6	GT	FO2	248.4	53.0	61.5	1,108	0.3%	99.7%	1/1975
Brandy Branch	CT 1	GT	NG/FO2	203.8	150.0	191.0	31,335	2.0%	98.9%	5/2001
Brandy Branch	CT 2	CT	NG/FO2	203.8	501.0	605.0	2,248,921	42.1%	90.9%	5/2001
Brandy Branch	CT 3	CT	NG/FO2	203.8				43.9%	91.4%	5/2001
Brandy Branch	4	CA	WH	268.4				54.4%	91.3%	1/2005
Girvin Landfill	1-2	IC	NG	1.2	1.2	1.2	2,892	12.3%		6/1997
St. Johns River Power Park	1	ST	BIT/PC	679.6	313.0	319.0	2,272,185	82.2%	96.0%	3/1987
St. Johns River Power Park	2	ST	BIT/PC	679.6	313.0	319.0	2,092,239	75.7%	88.6%	5/1988
Scherer	4	ST	SUB/BIT	846.0	200.0	200.0	1,288,131	73.5%	78.0%	2/1989

Plant	Unit #	Fuel Type	Heat Rate	Total Fuel Burned	Total Fuel Cost	Unit Fuel Cost	
			(BTU/kWh)	(MMBTU)	($000)	($/MMBTU)	(¢/kWh)
Kennedy	CT 7	GT	12,568	462,123	4,093,862	8.86	11.13
Kennedy	CT 8	GT	11,672	1,121,514	9,682,122	8.63	10.08
Northside	1	ST	9,647	17,370,009	61,609,159	3.55	3.42
Northside	2	ST	9,611	18,179,851	64,723,182	3.56	3.42
Northside	3	ST	11,926	7,634,756	60,833,288	7.97	9.50
Northside	CT 3	GT	19,605	23,805	277,673	11.66	22.87
Northside	CT 4	GT	20,863	24,491	268,449	10.96	22.87
Northside	CT 5	GT	17,632	9,231	119,722	12.97	22.87
Northside	CT 6	GT	20,431	22,642	253,439	11.19	22.87
Brandy Branch	CT 1	GT	12,376	387,817	3,162,022	8.15	10.09
Brandy Branch	CT 2	CT	7,302	16,421,758	147,108,370	8.96	6.54
Brandy Branch	CT 3	CT					
Brandy Branch	4	CA					
Girvin Landfill	1-2	IC	16,129	46,645			
St. Johns River Power Park	1	ST	9,927	22,556,117	75,389,626	3.34	3.32
St. Johns River Power Park	2	ST	9,887	20,685,325	69,419,104	3.36	3.32
Scherer	4	ST	10,151	13,076,248	30,967,837	2.37	2.40

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Kennedy	CT 7	GT	NG/FO2	2.3%	6.5%	4.4%	4.3%	7.6%	4.0%	6.4%	3.4%	1.6%	0.8%	3.6%
Kennedy	CT 8	GT	NG/FO2	5.8%	4.7%	2.9%	2.5%	5.0%	2.3%	4.1%	2.2%	1.0%	0.3%	2.6%
Northside	1	ST	PC/BIT	73.0%	66.4%	75.3%	78.2%	79.7%	68.7%	69.7%	75.3%	76.3%	78.0%	81.4%
Northside	2	ST	PC/BIT	75.9%	73.8%	75.6%	75.1%	78.7%	77.9%	74.5%	74.9%	75.4%	78.9%	80.4%
Northside	3	ST	NG/FO6	14.4%	36.5%	28.1%	30.9%	36.8%	31.0%	29.7%	22.6%	16.0%	17.8%	20.0%
Northside	CT 3	GT	FO2	0.3%	1.8%	1.2%	0.9%	2.2%	0.9%	1.7%	0.6%	0.4%	0.1%	0.9%
Northside	CT 4	GT	FO2	0.3%	1.4%	1.0%	0.7%	2.2%	0.7%	1.4%	0.4%	0.3%	0.1%	0.8%
Northside	CT 5	GT	FO2	0.1%	1.2%	0.9%	0.6%	2.0%	0.6%	1.2%	0.4%	0.2%	0.0%	0.6%
Northside	CT 6	GT	FO2	0.3%	1.0%	0.7%	0.3%	1.7%	0.4%	1.0%	0.2%	0.2%	0.0%	0.4%
Brandy Branch	CT 1	GT	NG/FO2	2.0%	14.1%	11.5%	10.5%	13.6%	12.2%	14.6%	6.8%	4.6%	4.0%	8.1%
Brandy Branch	CT 2	CT	NG/FO2	42.1%	80.1%	87.4%	85.8%	76.3%	89.2%	84.3%	60.0%	57.6%	50.3%	48.1%
Brandy Branch	CT 3	CT	NG/FO2	43.9%										
Brandy Branch	4	CA	WH	54.4%										
St. Johns River Power Park	1	ST	BIT/PC	82.2%	64.4%	71.7%	61.3%	67.7%	60.6%	63.3%	57.7%	64.0%	60.3%	74.0%
St. Johns River Power Park	2	ST	BIT/PC	75.7%	62.8%	60.9%	61.5%	55.8%	74.7%	58.4%	44.8%	53.6%	60.9%	51.0%
Scherer	4	ST	SUB/BIT	73.5%	86.3%	75.1%	97.6%	87.6%	96.9%	87.1%	92.8%	83.7%	94.0%	73.1%
GEC	CT 1	GT	NG/FO2	N/A	14.4%	11.4%	10.8%	17.2%	10.6%	14.1%	7.8%	5.1%	4.6%	8.3%
GEC	CT 2	GT	NG/FO2	N/A	8.5%	7.0%	6.0%	11.2%	6.7%	8.3%	5.0%	2.6%	2.0%	5.2%

Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Northside 3	NG/FO6 - ST	524	7/1977	Combined Cycle
St. Johns River Power Park 1	BIT/PC - ST	313	3/1987	Combined Cycle
St. Johns River Power Park 2	BIT/PC - ST	313	5/1988	Combined Cycle
Kennedy CT 7	NG/FO2 - GT	150	6/2000	Combined Cycle
Brandy Branch CT 1	NG/FO2 - GT	150	5/2001	Combined Cycle
Kennedy CT 8	NG/FO2 - GT	150	6/2009	Combined Cycle
GEC CT 1	NG/FO2 - GT	142	6/2011	Combined Cycle
GEC CT 2	NG/FO2 - GT	142	6/2011	Combined Cycle

Existing Facilities as of January 1, 2011

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (1)	Capacity Type	Summer Capacity
Northside	1	ST	BIT/PC	72.8%	Baseload	293
Northside	2	ST	BIT/PC	70.3%	Baseload	293
SJRPP	1	ST	BIT	78.0%	Baseload	319
SJRPP	2	ST	BIT	78.4%	Baseload	319
Scherer	4	ST	SUB	81.1%	Baseload	194
				Sub-Total	**Baseload**	**1418**
Brandy Branch	4	CC	NG	41.1%	Intermediate	501
Northside	3	ST	NG/F06	15.5%	Intermediate	524
				Sub-Total	**Intermediate**	**1025**
Brandy Branch	CT 1	GT	NG/FO2	1.3%	Peaking	150
Brandy Branch	CT 2	CT	NG/FO2	31.1%	Peaking	150
Brandy Branch	CT 3	CT	NG/FO2	16.7%	Peaking	150
Kennedy	CT 7	GT	NG/FO2	2.2%	Peaking	150
Kennedy	CT 8	GT	NG/FO2	1.9%	Peaking	150
Northside	CT 3	GT	FO2	0.4%	Peaking	53
Northside	CT 4	GT	FO2	0.4%	Peaking	53
Northside	CT 5	GT	FO2	0.3%	Peaking	53
Northside	CT 6	GT	FO2	0.6%	Peaking	53
				Sub-Total	**Peaking**	**962**
					Total	**3405**

Planned Facilities during 2011 to 2020

Plant	Unit #	Unit Type	Fuel Type	Typical Capacity Factor (2)	Capacity Type	Summer Capacity
				(%)		(MW)
				Sub-Total	**Baseload**	
				Sub-Total	**Intermediate**	
Greenland Energy Center	CT 1	GT	NG/FO2	10.4%	Peaking	142
Greenland Energy Center	CT 2	GT	NG/FO2	6.3%	Peaking	142
				Sub-Total	**Peaking**	**284**
					Total	**284**

Notes:

(1) Historical three year average capacity factor.

(2) Average capacity factor over the years 2011-2020.

Year		Baseload Capacity	Intermediate Capacity	Peaking Capacity	Total Installed Capacity
Actual	2001	823	767	524	2,114
	2002	823	505	1,001	2,329
	2003	1,371	505	1,001	2,877
	2004	1,371	505	1,001	2,877
	2005	1,371	1,038	683	3,092
	2006	1,389	1,038	581	3,008
	2007	1,407	1,025	563	2,995
	2008	1,407	1,025	563	2,995
	2009	1,407	1,025	662	3,094
	2010	1,407	1,025	662	3,094
Projected	2011	1,407	1,025	662	3,094
	2012	1,407	1,025	847	3,280
	2013	1,407	1,025	847	3,280
	2014	1,407	1,025	847	3,280
	2015	1,407	1,025	847	3,280
	2016	1,407	1,025	847	3,280
	2017	1,783	1,025	847	3,656
	2018	1,782	1,025	847	3,654
	2019	1,782	1,025	847	3,654
	2020	1,782	1,025	847	3,654

Notes:

(a) Summer Capacity (MW).

(b) Included in baseload capacity is 50% interest in SJRPP after sale to FPL. Sale from FPL is projected to return to JEA in 2017.

(c) Does not include firm power purchases.

Year		System Average Heat Rate (BTU/kWh)
Actual	2001	9,924
	2002	10,360
	2003	10,103
	2004	10,132
	2005	9,886
	2006	9,727
	2007	9,789
	2008	9,975
	2009	9,735
	2010	9,562
Projected	2011	9,184
	2012	9,125
	2013	9,160
	2014	9,246
	2015	9,169
	2016	9,163
	2017	9,398
	2018	9,395
	2019	9,457
	2020	9,442

Year		Residential Bill ($/1200-kWh)		CPI
		Real	Nominal	
Actual	2001	45.56	80.68	177
	2002	44.85	80.68	180
	2003	43.86	80.68	184
	2004	42.71	80.68	189
	2005	43.77	85.48	195
	2006	52.52	105.88	202
	2007	50.59	104.90	207
	2008	52.96	114.02	215
	2009	64.59	138.23	214
	2010	60.38	131.45	218
Proj ct d	2011	64.08	143.02	223
	2012	62.51	143.02	229
	2013	60.99	143.02	235
	2014	59.49	143.02	240
	2015	58.04	143.02	246
	2016	56.64	143.02	253
	2017	55.27	143.02	259
	2018	53.93	143.02	265
	2019	52.61	143.02	272
	2020	51.33	143.02	279

Existing Purchased Power Agreements as of January 1, 2011

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

Planned Purchased Power Agreements for 2011 through 2020

Seller	Contract Term		Contract Capacity (MW)		Annual Generation	[illegible]	[illegible]	[illegible]
	Begins	Ends	Summer	Winter	(MWh)	(%)	[illegible]	
MEAG	1/1/2016	1/1/2036	100	100	821	94%	NUC	PPA
MEAG	1/1/2017	1/1/2037	100	100	821	94%	NUC	PPA
			200	200	1,641			

Existing Power Sales as of January 1, 2011

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Capacity Factor	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
FPL	1986	2022 *	188	192	1,543	92%	BIT	PPA
FPL	1987	2022 *	188	192	1,459	87%	BIT	PPA
			376	383	3,003			

* Not to exceed date. Projected early suspension of 2017.

Planned Power Sales for 2011 through 2020

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

Year		SOX		NOX		Mercury		Particulates		CO2	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2001	7.25	42,935	4.94	29,231	N/A	N/A	N/A	N/A	2,132	12,627,485
	2002	4.96	30,803	3.91	24,308	N/A	N/A	N/A	N/A	2,047	12,711,113
	2003	4.33	27,799	3.72	23,908	N/A	N/A	N/A	N/A	2,109	13,542,657
	2004	4.54	28,189	3.52	21,850	N/A	N/A	N/A	N/A	2,075	12,886,710
	2005	4.03	26,343	2.85	18,595	N/A	N/A	N/A	N/A	2,072	13,537,327
	2006	3.22	21,608	3.04	20,405	N/A	N/A	N/A	N/A	2,056	13,798,041
	2007	2.18	15,174	2.88	20,044	N/A	N/A	N/A	N/A	2,000	13,934,209
	2008	1.58	10,126	2.82	17,999	N/A	N/A	N/A	N/A	2,027	12,952,896
	2009	1.66	10,438	1.32	8,328	N/A	N/A	N/A	N/A	2,019	12,723,344
	2010	1.50	10,560	0.91	6,436	N/A	N/A	N/A	N/A	1,964	13,840,570
Projected	2011	1.68	12,087	1.10	7,914	0.0000258	0.19	0.18	1,319	1,603	11,541,264
	2012	1.60	11,711	1.02	7,469	0.0000277	0.20	0.16	1,151	1,604	11,708,379
	2013	1.74	12,794	1.04	7,670	0.0000275	0.20	0.17	1,235	1,611	11,870,979
	2014	1.67	12,431	1.10	8,212	0.0000281	0.21	0.18	1,345	1,620	12,048,927
	2015	1.75	13,209	1.06	7,965	0.0000257	0.19	0.16	1,237	1,616	12,180,591
	2016	1.67	12,009	1.04	7,468	0.0000265	0.19	0.16	1,176	1,597	11,515,928
	2017	1.89	12,979	1.07	7,367	0.0000282	0.19	0.15	1,008	1,685	11,597,834
	2018	2.02	14,131	1.12	7,844	0.0000287	0.20	0.12	827	1,772	12,404,138
	2019	2.08	14,671	1.14	8,022	0.0000289	0.20	0.13	890	1,784	12,589,891
	2020	1.86	13,328	1.12	8,012	0.0000286	0.21	0.13	936	1,745	12,518,998

Nominal Fuel Price ($/MMBTU)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil
Actual	2001	N/A	1.60	4.89	3.41	7.10
	2002	N/A	1.48	4.02	3.72	4.65
	2003	N/A	1.60	5.80	4.00	6.98
	2004	N/A	1.50	6.64	4.11	6.76
	2005	N/A	1.79	8.36	6.04	8.95
	2006	N/A	2.10	8.53	7.66	14.44
	2007	N/A	2.20	8.59	8.67	15.63
	2008	N/A	2.33	9.18	7.57	14.95
	2009	N/A	3.30	4.95	8.05	12.59
	2010	N/A	2.82	5.74	11.27	16.88
Projected	2011	N/A	4.26	6.01	11.84	17.18
	2012	N/A	4.26	6.04	13.16	16.41
	2013	N/A	4.35	6.14	13.83	17.32
	2014	N/A	4.40	6.24	14.75	18.17
	2015	N/A	4.61	6.46	15.60	18.93
	2016	N/A	4.65	6.70	16.50	20.32
	2017	N/A	4.80	6.94	17.36	21.75
	2018	N/A	4.90	7.17	18.35	23.06
	2019	N/A	5.03	7.41	19.18	24.33
	2020	N/A	5.17	7.74	20.05	25.45

* Lower priced contract expired.

Fuel Usage (GWh)		Uranium	Coal	Natural Gas	Residual Oil	Distillate Oil	Petroleum Coke
Actual	2001	N/A	6,363	1,014	2,626	81	-
	2002	N/A	6,807	1,728	1,020	118	1,016
	2003	N/A	7,028	814	908	82	3,195
	2004	N/A	6,736	607	1,077	35	2,971
	2005	N/A	6,574	1,212	879	34	3,926
	2006	N/A	6,583	1,720	485	15	4,196
	2007	N/A	6,769	2,093	169	11	3,499
	2008	N/A	6,141	1,990	72	12	3,362
	2009	N/A	6,065	2,417	36	17	2,999
	2010	N/A	5,967	2,960	78	13	3,649
Projected	2011	N/A	5,266	5,684	135	27	3,147
	2012	N/A	5,269	5,656	105	19	3,395
	2013	N/A	5,362	5,651	115	13	3,439
	2014	N/A	5,230	5,762	136	40	3,554
	2015	N/A	5,675	5,823	115	13	3,287
	2016	N/A	5,150	5,736	111	26	3,243
	2017	N/A	6,141	4,006	84	8	3,370
	2018	N/A	6,936	3,470	59	5	3,403
	2019	N/A	7,276	3,177	66	1	3,520
	2020	N/A	7,132	3,412	75	14	3,641

Year	Month	Peak Demand (MW)	Date	Day of Week	Hour	Temperature (F)
2008	1	2914	3	Thursday	8:00	25
	2	2484	14	Thursday	8:00	29
	3	2059	25	Tuesday	8:00	34
	4	2017	12	Saturday	17:00	89
	5	2363	21	Wednesday	18:00	89
	6	2694	9	Monday	17:00	93
	7	2732	21	Monday	16:00	95
	8	2866	7	Thursday	16:00	96
	9	2647	15	Monday	17:00	92
	10	2263	1	Wednesday	17:00	87
	11	2310	19	Wednesday	8:00	28
	12	2473	3	Wednesday	8:00	29
2009	1	3060	22	Thursday	8:00	21
	2	3064	6	Friday	8:00	23
	3	2476	4	Wednesday	8:00	29
	4	2048	24	Friday	17:00	89
	5	2451	11	Monday	17:00	94
	6	2754	22	Monday	16:00	98
	7	2628	2	Thursday	17:00	95
	8	2735	12	Wednesday	17:00	95
	9	2417	25	Friday	17:00	89
	10	2423	9	Friday	16:00	93
	11	1710	10	Tuesday	13:00	82
	12	2151	29	Tuesday	8:00	31
2010	1	3224	11	Monday	8:00	20
	2	2667	26	Friday	8:00	27
	3	2335	4	Thursday	8:00	32
	4	2016	23	Friday	18:00	87
	5	2368	3	Monday	17:00	93
	6	2817	15	Tuesday	17:00	102
	7	2749	27	Tuesday	16:00	99
	8	2731	18	Wednesday	17:00	96
	9	2595	10	Friday	17:00	95
	10	2199	28	Thursday	17:00	89
	11	1785	8	Monday	8:00	33
	12	3053	14	Tuesday	8:00	20

Year		HDD	CDD
Actual	2001	1213	2537
	2002	1333	2872
	2003	1432	2616
	2004	1427	2834
	2005	1342	2682
	2006	1170	2742
	2007	1128	2662
	2008	1369	2499
	2009	1347	2797
	2010	1988	2835
Projected	2011	1375	2707
	2012	1375	2707
	2013	1375	2707
	2014	1375	2707
	2015	1375	2707
	2016	1375	2707
	2017	1375	2707
	2018	1375	2707
	2019	1375	2707
	2020	1375	2707