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Director, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850
Attn: Ann Cole

Jun 14, 2012

120000-OT

Dear Ms. Cole,

Per the request of your department by Mr. Phillip Ellis, I am submitting the 2012 TYSP Supplemental Data Requests (#1 & #2) in hardcopy.

Additionally, I have included a CD containing the same electronically.

If you have any questions please do not hesitate to contact us.

Sincerely,

John P. Guiseppi
System Planning Section

Enclosure

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FPSC-COMMISSION CLERK

REVIEW OF THE 2012 TEN-YEAR SITE PLANS: DATA REQUEST #1

Please provide an electronic copy of all responses in Adobe PDF format, with tables to be provided for in an Excel (.xls file format) document, unless otherwise specified in the question.

Please respond to the following question by **April 1, 2012.**

1. Please provide an electronic copy of the Company's 2012 Ten-Year Site Plan (in PDF format) and Schedules 1 through 10 (in Excel format).

Please respond to all remaining questions by **May 1, 2012.**

GENERAL QUESTIONS

2. Please provide all data requested in the attached forms labeled 'Appendix A,' as an electronic copy (in Excel). Please do **not** provide a hardcopy of this response. If any of the requested data is already included in the Company's Ten-Year Site Plan, state so on the appropriate form.

LOAD & DEMAND FORECASTING

3. [Investor-owned Utilities Only] Please provide, on a system-wide basis, the hourly system load for the period January 1, 2011, through December 31, 2011. Please provide this only as an electronic copy (in Excel). Please do **not** provide a hardcopy of this response.

4. 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.

   Residential – Since Fiscal Year 2007, Lakeland's residential customers have only increased by 376 accounts. Comparing the first six months of this Fiscal Year to the same time last Fiscal Year we are seeing some signs of customer growth. Lakeland has had an increase of 316 accts (+0.31% growth) so far for Fiscal Year 2012.

   Commercial/Industrial – Since Fiscal Year 2007, Lakeland has lost a total of 99 commercial/industrial (GS, GSD & Industrial) accounts. Comparing the first six months of this Fiscal Year to the same time last Fiscal Year we are seeing an increase of 32 accts (+0.27% growth), the first increase we have seen since 2008. We are seeing the most growth in the small commercial (GS) class category.

Lakeland attributes the decline in overall customer growth from 2007 to 2011 to the effects of the housing market crash.

5. Please describe the Company's current and planned number of digital and/or "smart" meter installations. As part of this response, please detail the number of installations and penetration level of installations by customer class. If possible, also identify how many digital and/or "smart" meters were installed as part of a DSM or Pilot program.

We are in an existing program to change-out all electric meters to "smart" meters by end of calendar year 2012. We now have approximately 84,000 installed of the 124,000 total to be installed. 1st meter installed 2/11.

6. Please describe the meters that are currently considered standard service. Please include at a minimum, the manufacturer, model, the capabilities, if the meter communicates one-way or two-way, and the frequency of meter reads.

Various manufacturers for both single phase and poly-phase no communications.

Note: 13,000 existing meters are Itron meters with one way drive by capability read monthly.

7. Please explain any meter replacement program, including the schedule and estimated cost. Please include at a minimum, the manufacturer, model, the capabilities, if the meter communicates one-way or two-way, and the frequency of meter reads.

Sensus icon-A (Gen3) meters, 2-way communication capability for single phase. Elster Alpha meters, 2-way communication capability for poly-phase.

Meters are read every 2-4 hours.

8. What new tariffs or programs is the utility planning to offer to customers as smart meters are installed throughout the utility service territory?

Lakeland had suspended its offering of a 2-period TOU rate during the installation of Smart meters. This rate will be reintroduced in the summer of 2012.

Lakeland, in cooperation with the Dept. of Energy is conduction a Consumer Behavior Study with a 3-period TOU rate. This involves 4000 customers over a 2 year period.

9. Are smart meters currently being used for purposes other than billing, outage reporting, and remote connect/disconnect?

Power theft detection, power restoration, Pre-pay (soon)

10. Please describe what impacts, if any, the Company identifies from installation of digital and/or "smart" metering installations on peak demand, net energy for load, enhanced identification of outages/faults, and voltage concerns. Please describe the impact these metering installations may have on DSM Programs, such as increasing participation in Time-of-Day rate programs.

It is expected through the use of TOU rat6es that a shift from the peak will be induced. Determination to as to the extent is the reason for the Consumer behavior Study. This could also lead to an overall residential consumption reduction.

Pre=pay is expected to produce a 3-5% consumption reduction among those enrolled.

System wide DSM is a future item and would be a large impact on peak loading, especially if it would include an utility controlled override.

11. 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 2009, 2010, and 2011; 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).

Year	Month	Peak Demand (MW)	Date	Hour	Temperature (F)
2009	1	710	22-Jan	700	27
	2	703	5-Feb	800	27
	3	546	3-Mar	800	43
	4	471	24-Apr	1700	88
	5	568	11-May	1800	90
	6	625	22-Jun	1700	96
	7	601	16-Jul	1700	92
	8	608	11-Aug	1800	93
	9	579	21-Sep	1700	90
	10	587	8-Oct	1700	95
	11	444	1-Nov	1600	84
	12	505	29-Dec	900	45
2010	1	804	11-Jan	800	28
	2	624	26-Feb	700	33
	3	645	5-Mar	700	35
	4	451	24-Apr	1800	87
	5	578	3-May	1700	93
	6	619	16-Jun	1500	98
	7	638	28-Jul	1600	92
	8	621	3-Aug	1700	95
	9	597	13-Sep	1700	90
	10	528	28-Oct	1600	93
	11	435	3-Nov	1700	86
	12	709	14-Dec	800	31
2011	1	665	13-Jan	800	32
	2	501	14-Feb	800	47
	3	434	30-Mar	1600	70
	4	552	28-Apr	1700	89
	5	568	12-May	1700	93
	6	609	23-Jun	1700	96
	7	591	25-Jul	1600	89
	8	611	12-Aug	611	97
	9	563	20-Sep	1700	88
	10	482	11-Oct	1600	87
	11	429	16-Nov	1600	84
	12	383	8-Dec	800	45

12. Please provide the company's historic projections of total retail energy sales for the years 2007 through 2011. Complete the table below by drawing this information from the company's forecasts in Schedule 2.2 in the 2002 through 2011 Ten-Year Site Plans. Please complete the table below and provide an electronic copy (in Excel).

Total Retail Energy Sales Forecasts (GWh)					
Year	2007	2008	2009	2010	2011
2011 TYSP					2918
2010 TYSP				2849	2875
2009 TYSP			2947	2993	3034
2008 TYSP		2980	3023	3065	3106
2007 TYSP	2885	2951	2990	3035	3080
2006 TYSP	2950	3014	3067	3123	3177
2005 TYSP	3014	3086	3153	3221	
2004 TYSP	3019	3087	3156		
2003 TYSP	NA	NA			
2002 TYSP	NA				

RENEWABLE GENERATION

13. Please provide the estimated total capacity of all renewable resources the utility owns or purchases as of January 1, 2012. 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 2021. Please complete the table below and provide an electronic copy (in Excel).

Fuel Type	Renewable Resource Capacity (MW)	
	Existing (2012)	Planned (2021)
Solar	2.837	44
Wind		
Biomass		
Municipal Solid Waste		
Waste Heat		
Landfill Gas		
Hydro		
Total		

14. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement (PPA) which delivered capacity or energy as of January 1, 2012. 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 type, fuel type, in-service date, net capacity (even if not considered firm capacity), and annual energy generation. For PPAs, also provide the contract start and end dates. For small (less than 100 kW) distributed generating units, please make a single summary entry which includes the total number of distributed generating units of that type. Please complete the tables below and provide an electronic copy (in Excel).

Existing Renewables as of January 1, 2012

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
N/A							

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
Thermal Solar	Solar Water heaters (57)	Sunshine	1998-2002	86	86	142	0.17

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
N/A										

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Regenesis Power	Thermal Solar	Solar Water Heaters (28)	Sunshine	2010	42	42	70	0.17	2010	2030
Regenesis Power	Thermal Solar	Solar Water Heaters (71)	Sunshine	2011	107	107	178	0.17	2011	2031
SunEdison	Lakeland Center	Solar PV	Sunshine	04/10	0.25	0.25	426	0.17	3/10	3/30
SunEdison	Airport Phase 1	Solar PV	Sunshine	12/11	2.3	2.3	91	0.17	12/11	12/36

15. Please provide a description of each existing utility-owned renewable generation resource and each renewable purchased power agreement planned during the 2012 through 2021 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 type, fuel type, commercial in-service date, net capacity (even if not considered firm capacity), and average annual energy generation. For purchased power agreements, also provide the contract start and end dates. For small (less than 100 kW) distributed generating units, please make a single summary entry which includes the total number of distributed generating units of that type. Please complete the tables below and provide an electronic copy (in Excel).

Planned Renewables for 2012 through 2021

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
N/A							

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
N/A							

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
N/A										

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Regenesis Powe	Thermal Solar	Solar Water Heaters (10,000)	Sunshine	2011-2016	15	15	25	0.17	2011 - 2016	2031 - 2036
SunEdison	TBD	Solar PV	Sunshine	2011-2017	24	24	31,200	0.17	2011-2017	2031-2037

16. Please provide a description of the costs associated with each utility-owned renewable generation resource, and each renewable purchased power agreement during 2011. 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 the description of the unit's generator type, fuel type, seasonal net capacity (even if not considered firm capacity), and annual energy generation. For utility-owned resources, also provide the annual capital revenue requirements, operations & maintenance (O&M) costs, fuel costs, and total cost of the facility. For purchased power agreements, also provide the amount of capacity payments, energy payments, and total payments to the facility. Please note if payment information to a renewable provider is confidential, and exclude confidential information from your response. Please complete the tables below and provide an electronic copy (in Excel).

Renewable Costs and/or Payments for the Year Ending December 31, 2011.

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
N/A									

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
N/A									

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
N/A									

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
Regenesis Power	Thermal Solar	Solar Water Heaters	Sunshine	149	149	248	N/A	$ 39,145	$ 39,145
SunEdison	Lakeland Center	Solar PV	Sunshine	0.25	0.25	426	N/A	$ 123,114	$ 123,114
SunEdison	Airport Phase 1	Solar PV	Sunshine	2.3	2.3	91	N/A	$ 17,290	$ 17,290

17. 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 name of the facility or owner, description of the unit's location, generator type, fuel type, commercial in-service date, seasonal net capacity (even if not considered firm capacity), and annual energy generation. Please exclude from this response net-metering installations or other small distributed generation systems. Please complete the table below and provide an electronic copy (in Excel).

Facility Name	County	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)
N/A								

18. Please refer to the list of planned utility-owned renewable resource additions and renewable PPAs with an in-service date for the renewable generator during the 2012 through 2021 period outlined above. Please discuss the current status of each project.

Lakeland is not currently budgeting for the deployment of any utility-owned solar / renewable facilities.

19. 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 solar hot water heaters, please use kilowatt-equivalent and kilowatt-hour-equivalent units. Please complete the table below and provide an electronic copy (in Excel).

Customer Class	Residential			Commercial		
Renewable Type	# of Connections	Installed Capacity (kW)	Annual Output (MWh)	# of Connections	Installed Capacity (kW)	Annual Output (MWh)
Solar PV	33	151.6	212.2	35	200.7	281
Solar Thermal (Water)	Unavailable					
Wind Turbine						

20. Please provide the annual output for the company's renewable resources, including utility-owned, firm purchases through a PPA, non-firm purchases (through a PPA or as-available energy contract), or customer-owned generation, for the period 2011 through 2021. Please complete the table below and provide an electronic copy (in Excel).

Annual Output (GWh)	Actual	Projected									
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Utility	N/A										
Firm PPA	N/A										
Non-Firm	3.565	8.975	13.45	18.825	24.525	34.675	46.775	56.2	56.2	56.2	56.2
Customer	0.46	0.55	0.66	0.79	0.95	1.14	1.37	1.64	1.97	2.36	2.84
Total	4.02	9.52	14.11	19.62	25.47	35.81	48.14	57.84	58.17	58.56	59.04

21. [Investor-owned Utilities Only] Provide, on a system-wide basis, the historical annual average as-available energy rate in the Company's service territory for the period 2002 through 2011. Also, provide the forecasted annual average as-available energy rate in the Company's service territory for the period 2012 through 2021. Please complete the table below and provide an electronic copy (in Excel).

Year		As-Available Energy ($/MWh)
Actual	2002	
	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
	2011	
Projected	2012	
	2013	
	2014	
	2015	
	2016	
	2017	
	2018	
	2019	
	2020	
	2021	

22. Please discuss whether the Company uses any renewable fuels in its existing fossil units, or has plans to do so within the planning period. Also, please identify whether the Company has conducted or is planning to conduct any studies relating to co-firing renewable fuels (such as biomass or biogas) in existing or planned fossil units.

Lakeland Electric currently has no studies planned for the cofiring of renewable fuels with fossil fuels

23. 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?

Lakeland Electric had explored the concept of co-firing renewable fuels with fossil fuels. This concept will not be pursued unless a regulatory or legislative mandate occurs

24. Please provide a list of all changes from January 1, 2011 to January 1, 2012 to existing or planned utility-owned renewable projects or purchased power agreements, including delays in in-service date, modifications of project size or contract terms, and expirations of purchased power agreements without renewal. N/A

TRADITIONAL GENERATION

25. Please provide the cumulative present worth revenue requirement of the Company's Base Case for the 2012 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. N/A

26. 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

27. Please complete the following table detailing unit specific information on capacity and fuel consumption for 2011. For each unit on the Company's system, provide the

following data based upon historic data from 2011; the unit's capacity, annual generation, capacity factor, estimated annual availability factor, unit average heat rate, and average energy cost for the unit's production. For dual fuel units, please report each fuel separately. Please complete the table below and provide an electronic copy (in Excel).

Plant	**Unit #**	**Unit Type**	**Fuel Type**	**Net Capacity (MW)**		**Annual Generation**	**Capacity Factor**	**Avail. Factor**	**In-Service Date**	**Heat Rate**	**Unit Fuel Cost**
				Sum	Win	(MWh)	(%)	(%)		(BTU/kWh)	(¢/kWh)

See Accompanying Spreadsheet Tables

28. For each of the planned generating units contained in the Company=s Ten-Year Site Plan, please discuss the Adrop 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.

29. 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, 2012, and including nuclear units, nuclear unit uprates, combustion turbines, and combined-cycle units. For each planned unit, provide the date of the Commission's Determination of Need and Power Plant Siting Act certification (if applicable), and the anticipated in-service date. Please complete the table below and provide an electronic copy (in Excel).

Planned Unit Additions for 2012 through 2021

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				
Combined Cycle Unit Additions				
Steam Turbine Unit Additions				

****Lakeland Electric has nothing in place at this time****

30. For each existing and planned unit on the Company's system, provide the following data based upon historic data from 2011 and forecasted capacity factor values for the period 2012 through 2021. Please complete the tables below and provide an electronic copy (in Excel).

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual	Projected									
				2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021

*****See Accompanying Spreadsheet Tables*****

31. Please complete the table below, providing a list of all of the Company's steam units or combustion turbines that are potential 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. Please complete the table below and provide an electronic copy (in Excel).

Plant Name	Unit Type	Fuel Type	Summer Capacity (MW)	In-Service Date	Potential Conversion

No current studies for repowering

32. [Investor-owned Utilities Only] Please provide the system average heat rate for the generation fleet for each year for the period 2002 through 2011. Please complete the table below and provide an electronic copy (in Excel).

Year		System Average Heat Rate (BTU/kWh)
Actual	2002	9586
	2003	9405
	2004	9087
	2005	9858
	2006	9779
	2007	9630
	2008	9944
	2009	9126
	2010	9044
	2011	8531

CY2011 MOS - NET

33. Please provide the average cost of a residential customer bill, based upon a monthly usage of 1200 kilowatt-hours, for the period 2002 through 2011. Please complete the table below and provide an electronic copy (in Excel).

Year		Residential Bill ($/1200-kWh)
Actual	2002	112.9
	2003	118.94
	2004	123.25
	2005	133.52
	2006	149.71
	2007	157.94
	2008	157.01
	2009	148.87
	2010	151.15
	2011	142.83

34. Please complete the following table detailing the Company's planned changes to summer capacity. In addition to providing the net change for the current year's Ten-Year Site Plan, please also provide the net change based on last year's Ten-Year Site Plan. Please complete the table below and provide an electronic copy (in Excel).

Fuel Type	**Unit Type**	**Summer Capacity Changes (MW)**	
		2011 TYSP (2011-2020)	**2012 TYSP (2012-2021)**
Natural Gas	Combined Cycle		
	Combustion Turbine		
	Steam		
Coal	Steam		
	Integrated Coal Gasification		
Oil	Combustion Turbine & Diesel		
	Steam		
Nuclear	Steam		
Firm Purchases	Independent Power Producer (IPP)		
	Interchange		
	Non-Utility Generator (NUG)		
	Renewables		
NET CAPACITY ADDITIONS			

35. Please complete the table below describing the status of the company's generating units during each month's peak demand, for the years 2009 through 2011. As part of this response, include the actual values at monthly peak for installed capacity, scheduled maintenance, forced outages, available capacity, and net firm peak demand. Please complete the table below and provide an electronic copy (in Excel).

Capacity / Demand at Time of Monthly Peak (MW)						
Year	Month	Installed Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
2009	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					
2010	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					
2011	1					
	2					
	3					
	4					
	5					
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	7					
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	10					
	11					
	12					

POWER PURCHASES / SALES

36. 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).

Existing Purchased Power Agreements as of January 1, 2012

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

Planned Purchased Power Agreements for 2012 through 2021

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

******Lakeland Electric has nothing in place at this time******

37. 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).

Existing Power Sales as of January 1, 2012

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

Planned Power Sales for 2012 through 2021

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

******Lakeland Electric has nothing in place at this time******

38. 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.****Lakeland Electric has nothing in place at this time****

ENVIRONMENTAL ISSUES

39. Please discuss the impact of existing environmental restrictions, relating to air or water quality or emissions, on the Company's system during the 2011 period, such as unit curtailments. As part of your discussion, please include the potential for existing environmental restrictions to impact unit dispatch or retirement during the 2012 through 2021 period.

40. 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 2002 through 2021. Please complete the table below and provide an electronic copy (in Excel).

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2002										
	2003										
	2004										
	2005										
	2006										
	2007										
	2008										
	2009										
	2010										
	2011										
Projected	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
	2019										
	2020										
	2021										

41. Please identify if your company has developed a compliance strategy for the new or proposed EPA Rules listed below. If so, please provide a copy of the document for each rule and discuss the compliance strategies your company intends to employ. If not, explain the timeline for completion of the compliance strategy, including any regulatory approvals, for each rule.

- Mercury and Air Toxics Standards (MATS) Rule
- Cross-State Air Pollution Rule (CSAPR)
- Cooling Water Intake Structures Rule (CWIS)
- Coal Combustion Residuals Rule (CCR), both for classification of coal ash as a "Non-Hazardous Waste" and as a "Special Waste"

42. Please identity, for each unit impacted by one or more of the EPA's new or proposed rules, what the impact is for each Rule, including unit retirement, curtailment, installation of additional emissions controls, fuel switching, or other impact identified by the Company. As part of this response, please provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Type of New or Proposed EPA Rules Impacts				
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste

43. Please identify, for each unit impacted by one or more of the EPA's new or proposed rules, what the estimated cost is for implementing each Rule over the course of the planning period. As part of this response, please provide the unit's name, type, fuel type, and net summer generating capacity. Please complete the table below and provide an electronic copy (in Excel).

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Cost of New or Proposed EPA Rules Impacts ($ million)					
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	Total Cost

44. Please identify, for each unit impacted by one or more of the EPA's new or proposed rules, when and for what duration units would be required to be offline due to retirements, curtailments, installation of additional emissions controls, or additional maintenance related to emissions controls. Please also include important dates relating to each rule. Please complete the table below and provide an electronic copy (in Excel).

Unit	Unit Type	Fuel Type	Net Sum Capacity (MW)	Estimated Timing of New or Proposed EPA Rules Impacts (Month/Year – Duration)				
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste

45. Please provide a preliminary estimate of the cost required for your company to comply with each EPA Rule over the planning period (2012 – 2021). As part of this response, please detail the amount of capital costs, operations & maintenance (O&M costs, and fuel costs). Please also provide a description of the majority share of each of these costs (such as replacement generation, retrofitting of existing facilities, fuel switching, etc.).

46. From a system-wide perspective, provide a preliminary estimate of the cost associated with each EPA Rule over the planning period, 2012 through 2021. As part of this response, please include the estimated additional capital cost expenditures, O&M costs, and fuel costs associated with each rule. Please complete the table below and provide an electronic copy (in Excel).

EPA Rule	Capital Costs ($ Millions)	O&M Costs ($ Millions)	Fuel Costs ($ Millions)	Total Costs ($ Millions)
Mercury and Air Toxics Standards (MATS) Rule				
Cross-State Air Pollution Rule (CSAPR)				
Cooling Water Intake Structures Rule (CWIS)				
Coal Combustion Residuals Rule (CCR)				

47. Please discuss any expected reliability impacts resulting from each of the EPA Rules listed below. As part of this discussion, include the impact of transmission constraints and units not modified by the rule, that may be required to maintain reliability if unit retirements, curtailments, additional emissions control upgrades, or longer outage times are impacts of the EPA Rules.

- Mercury and Air Toxics Standards (MATS) Rule
- Cross-State Air Pollution Rule (CSAPR)
- Cooling Water Intake Structures Rule (CWIS)
- Coal Combustion Residuals Rule (CCR)

48. Please describe the process your company employs to develop a compliance strategy for proposed Environmental Protection Agency (EPA) rules.

49. Please describe the process your company employs to develop a compliance strategy when EPA finalizes a rule.

50. Please explain how your company determines its optimum environmental compliance strategy, given that EPA's rules are in various stages of being revised or finalized.

51. Please describe and provide the capital costs for any significant environmental compliance investments made by your company in response to environmental regulations within the past five years. How will these investments affect your company's compliance with recently finalized or proposed EPA regulations?

52. Please provide a copy of any comments your company has filed with EPA during EPA's rule development proceedings for the following:

- Mercury and Air Toxics Standards
- Cross-State Air Pollution
- Cooling Water Intake Structures
- Coal Combustion Residuals
- Greenhouse Gas Emissions

53. On December 30, 2011, the U.S. Court of Appeals issued an order to stay the EPA's implementation of the final Cross-State Rule. Has the Court's order to stay implementation of the Cross-State Rule impacted your compliance strategies? If so, how?

54. Does your company intend to participate in the allowance trading market associated with the rule? If so, do you expect to be a net seller or net buyer of allowances?

55. Please discuss your company's current coal residue disposal practices for each coal generating facility.

56. Please discuss your company's efforts to facilitate the recycling of coal waste into beneficial products. What percentage of your company's coal waste is used for beneficial purposes?

57. EPA has proposed two regulatory schemes to regulate coal combustion residuals. Proposal one would regulate coal ash as "special waste" under Subtitle C of the Resource Conservation and Recovery Act; while under the second proposal, coal ash would be considered "non-hazardous waste" under Subtitle D of the Act. Please discuss any modifications that would be required at each of your company's coal facilities to comply with each of these two proposed regulatory schemes. Provide any available compliance strategies and expected costs for each facility and the timing of implementation of these compliance strategies. Provide the generating capacity for each unit that will require modifications.

58. Please discuss how your company takes the potential for greenhouse gas regulations into account in its resource planning process and environmental compliance planning process.

FUEL SUPPLY & RELIABILITY

59. Please provide, on a system-wide basis, the historic annual fuel usage (in GWh) and historic average fuel price (in nominal $/MMBTU) for each fuel type utilized by the company in the period 2002 through 2011. Also, provide the forecasted annual fuel usage (in GWh) and forecasted annual average fuel price (in nominal $/MMBTU) for each fuel type forecasted to be used by the Company in the period 2012 through 2021. Please complete the table below and provide an electronic copy (in Excel).

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2002				1.90		3.80		4.17		5.48
	2003			1369	1.85	1344	5.82	206	4.77	30	6.34
	2004			1140	2.03	1703	6.52	90	5.22	11	7.18
	2005			1572	2.42	806	9.15	175	6.52	12	9.91
	2006			1447	2.46	1154	9.34	20	8.55	3	11.99
	2007			1502	2.46	1498	8.21	12	8.74	3	13.92
	2008			1507	2.95	898	10.82	2	11.20	2	13.34
	2009			964	3.62	41664	5.79	1	11.13	0	15.48
	2010			843	3.83	1826	5.67	0	10.64	5	15.70
	2011			821	4.40	2346	4.69	0	15.91	0	21.36
Projected	2012			800	4.20	2796	2.95	0	15.12	0	20.50
	2013			925	4.22	2474	3.80	0	15.51	0	20.93
	2014			892	4.45	2811	4.23	0	15.72	0	21.16
	2015			1007	4.67	2497	4.51	0	15.74	0	21.18
	2016			923	4.76	2826	4.76	0	15.99	0	21.46
	2017			1042	4.86	2712	5.01	0	16.76	0	22.30
	2018			1019	4.96	2534	5.24	0	17.51	0	23.11
	2019			976	5.05	2683	5.49	0	18.13	0	23.78
	2020			1046	5.16	2855	5.75	0	18.66	0	24.37
	2021			1140	5.26	2728	6.01	0	19.05	0	24.79

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

RESPONSE / COAL: Lakeland Electric is involved in many outside groups such as the Eastern Fuel Buyers Conference and American Coal Council where industry experts present their latest independent forecasts of coal metrics and economies including trends of production, consumption, transport markets and factors affecting useage in all markets of interest to Lakeland Electric. In addition to these LE has specific studies done under contract with firms such as HellerWorx of Boston, Mass and others. LE also studies the output of DOE-EIA Annual Energy Forecast which is compiled from their analysis of the National Energy Modeling several local. Regional and national groups where natural *gas industry experts present their latest independent forecasts of natural gas a petroleum metrics and economies including trends of production, consumption, transport (incl. pipeline capacity and regulatory regime) markets and factors affecting useage in all products markets of interest to Lakeland Electric. In addition LE has specific studies done under contract with firms such as HellerWorx of Boston, Mass and others. LE also studies the output of DOE-EIA Annual Energy Forecast which is compiled from their analysis of the National Energy Modeling System. LE also subscribes, receives and reviews professional services industry market reviews that update latest trends described above on a weekly basis*

61. For each fuel type (coal, natural gas, nuclear fuel, etc.), please discuss in detail the expected industry trends and factors for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

RESPONSE / COAL: Coal prices are expected to moderate through the period from their recent high levels because of a continuing shift to lower cost production west of the Mississippi River; however, they remain higher than in earlier periods due to the change in surface mining regulation in Central Appalachia which is causing more rapid depletion of remaining reserves with lower mining costs. As a result Florida may become more reliant on coal from other regions. Traditional import sources of Colombian coal are tighter dues to shifting demand patters of seaborne coal trade.

Although, no comprehensive Federal policy has yet been enacted, growing concerns about GHG emissions appear to be affecting investment decisions in energy markets, particularly in the electricity sector. One large element is a near moratorium of building base-load coal generating plants U.S. electric power companies are operating in an especially challenging planning environment and so decisions for new generating plants already are being affected by the potential impacts of policy changes that could be made to limit or reduce GHG emissions.

These concerns and the eventual outcome will set the pace for total and regional US coal demand and the subsequent pace of development of the capacity to mine coal.

RESPONSE / NATURAL GAS: Average lower 48 wellhead prices for natural gas generally increase in the reference case, as more expensive domestic resources are used to meet demand. Prices decline for a brief period after the Alaska pipeline begins operation in 2020, but the market quickly absorbs the additional natural gas supplies from Alaska, and prices resume their rise (Figure 64).

Henry Hub spot market prices and delivered end-use natural gas prices generally follow the trend in lower 48 wellhead prices; however, delivered prices also are subject to *variation in average transmission and distribution rates and resulting margins, as reflected in the difference between the average delivered price and the average supply price for natural gas. Some new pipelines are built to bring supplies to market and to reach new customers, but the bulk of the pipeline system is already in place and revenue requirements for those segments decline as capital is depreciated. Consequently, transmission and distribution margins for natural gas delivered to the industrial and electric power sectors either remain flat or decline.*

The extent to which natural gas prices may rise depends on assumptions about economic growth rates and the rate of improvement in natural gas exploration and production technologies. Technology improvements reduce drilling and operating costs and expand the economically recoverable resource base.

Technology improvement is particularly important in the context of growing investment in production of natural gas from shale formations, which generally can be produced more efficiently than the natural gas contained in conventional formations, but which require relatively high capital expenditures.

During the forecast period unconventional natural gas sources will become the largest contributor to the growth in U.S. natural gas production, as rising prices and improvements in drilling technology provide the economic incentives necessary for exploitation of more costly resources. Unconventional natural gas production will increase as natural gas in tight sand formations becomes the largest source of unconventional production, but production from shale formations is the fastest growing source.

RESPONSE: Petroleum / Liquid Fuels :The long-term decline in total U.S. crude production has slowed over the past few years, as higher world oil prices have spurred drilling. Total U.S. domestic crude oil production, which has been falling for many years, has begun to increase. Most of the near-term increase is from the deepwater offshore. Growth is limited after 2010, however, because newer discoveries are smaller, and capital expenditures rise as development moves into deeper waters.

A number of deepwater discoveries in the Gulf of Mexico have begun to ramp up production recently or are expected to begin production shortly. The largest include Shenzi, Atlantis, Blind Faith, and Thunder Horse. Expiration of the Congressional moratoria on the Eastern Gulf of Mexico, Atlantic, and Pacific regions of the OCS also allow crude oil production to increase in the Atlantic and Pacific OCS after 2014.

How these factors and trends will affect Lakeland Electric

LE is aware of the fundamental issues involved relative to how these trends may affect the future pricing and availability of fuels. The changes that have the most effect are results of public policy and legislation. It is very difficult to forecast the timing and degree of these policy elements. Because of this LE policy for fuel planning is to *prudently prepare in ways that incorporate the highest degree of fuel flexibility so that we are not highly dependent on one type of fuel.*

62. What steps has the Company taken to ensure gas supply availability and transport over the 2012 through 2021 planning period?

Lakeland Electric is constantly taking action and making plans to assure for the availability and transport of natural gas during the planning period. Professional market services are maintained through a contract with The Energy Authority and other services which provide a strong presence on the pulse and rhythm of the natural gas commodity and transportation markets. In addition to this LE maintains a strong affiliation of professional collaborative efforts with the Florida municipal electric and gas network.

On at least an annual basis LE formalizes it's then current assessment of the market and the projected needs for natural gas and executes a plan to secure gas commodity volumes for the forward period. At the same time LE re-evaluates and makes necessary adjustments to a longer term need for natural gas transportation.

Florida Gas Transmission system has "open access" status for their natural gas pipeline on August 1, 1990. This pipeline is an underground pipeline running from the Mobile Bay area of the Gulf Coast across the Florida Panhandle and down through the center of the state. The majority of the FGT supply comes from land-based wells. The City holds firm transportation rights on the FGT pipeline that varies by month, and falls under two rate classifications; FTS-1 and FTS-2, both under the jurisdiction of the Federal Energy Regulatory Commission. Thirty-seven percent (37%) of the City's FGT firm transportation rights are under the less expensive FTS-1 rate, and sixty-three percent (63%) is under FTS-2. The two contracts under FTS-1 expire in 2020 and the two contracts under FTS-2 expire in 2015 and 2017.

The City of Lakeland's also receives natural gas through transport serviced of the Gulfstream Pipeline which operates a pipeline crosses the Gulf of Mexico starting from the Mobile Bay region and making landfall just south of Tampa, Florida near Port Manatee. Unit 2008, most of the supply sources for the Gulfstream pipeline were offshore, but new pipeline interconnects by Gulfstream have increased the supply of on-shore originating gas supply. Lakeland Electric is also connected to and has purchased firm transportation rights through Gulfstream pipeline which provides a second source of natural gas and gives it access to additional gas suppliers. Also, this second pipeline reduces the risk of interruption of the gas supply. Gulfstream has only one jurisdictional rate under the Federal Energy Regulatory Commission for firm transportation service, and the City has contracted for a fixed volume for each month. The contract is in effect until 2022.

63. Regarding existing and planned natural gas pipeline expansion projects, including new pipelines, affecting the Company for the period 2012 through 2021, please identify each project and discuss it in detail.

RESPONSE: Florida Gas Transmission Company is an interstate natural gas pipeline company that has been transporting natural gas to the Gulf Coast and Florida for nearly 50 years and is Florida's leader and trusted partner in providing clean energy solutions, safely and reliably.

• The company operates nearly 5,000 miles of underground pipeline from South Texas to Miami, Fla., providing natural gas to large companies such as electric utilities and local natural gas distribution companies, as well as smaller industrial and commercial customers.

Florida Gas Transmission is proposing to expand its natural gas pipeline system to meet the growing energy needs of the Gulf Coast and Florida.

This FGT "Phase VIII Expansion Project" will consist of approximately 483.2 miles of multi diameter pipeline in Alabama, Mississippi and Florida with approximately 365.8 miles built parallel to existing pipelines. The project will add 213,600 horsepower of additional mainline compression with one new compressor station to be built in Highlands County, Fla. The project will provide an annual average of 820,000 MMbtu/day of additional firm transportation capacity. FGT estimates the total cost of the project will be $2,455 million.

The project will increase the Florida Gas Transmission Company's natural gas capacity by 36 percent and in addition to pipe addition it also involves upgrading 8 existing compressor stations and the installation of a new station in Highlands County, FL.

Installation details are as follows:

• Loop 3 – 40.0 miles of 36-inch diameter pipeline in Santa Rosa, Okaloosa and Walton Counties, FL. Includes the removal of previously abandoned 24-inch diameter pipeline.

• Loop 4 – 46.8 miles of 36-inch diameter pipeline in Washington, Bay, Jackson and Calhoun Counties, FL. Includes the removal of previously abandoned 24-inch diameter pipeline.

• Loop 5 – 56.3 miles of 36-inch diameter pipeline in Gadsden, Leon and Jefferson,Counties, FL.

• Loop 6 – 19.0 miles of 36-inch diameter pipeline in Taylor and Lafayette Counties, FL.

- *Loop 7 – 12.8 miles of 36-inch diameter pipeline in Suwannee and Gilchrist Counties, FL.*

- *Loop 8 – 46.1 miles of 36-inch diameter pipeline in Levy and Citrus Counties, FL, ending at the Lecanto compressor station.*

- *Loop 9 – 42.9 miles of 36-inch diameter pipeline in Hernando, Pasco and Hillsborough Counties, FL.*

- *Loop 10 – 24.1 miles of 36-inch diameter pipeline in Hillsborough County., Fl. beginning at the Thonotosassa compressor station.*

- *Loop 11 – 6.6 miles of 24-inch diameter looping pipeline in Miami, Dade Co. FL.*

- *Greenfield 1 – (Suwannee Lateral) 20 miles of 20-inch diameter pipeline in Lafayette, Madison and Suwannee counties, FL.*

- *Greenfield 2 – (Manatee Lateral) 16.1 miles of 24-inch diameter pipeline in Manatee County, FL.*

- *Greenfield 3 – Consists of two segments. The first segment is 47.8 miles of 30-inch diameter pipeline in DeSoto and Highlands counties, FL, ending at the new compressor station in Highlands Co., FL. The second segment is 42.0 miles of 30-inch diameter pipeline in Highlands, Okeechobee and Martin counties, FL, beginning at the new Highlands Co. compressor station and ending at the Florida Power & Light Martin Power Plant.*

- *Acquisition 1 – 22.7 miles of an already existing 20-inch diameter pipeline in Martin Co., FL. No new construction or any ground disturbing activities are associated with the acquisition.*

- *Compressor Station 12 – Increase horsepower at existing compressor station in Santa Rosa Co., FL.*

- *Compressor Station 13 – Increase horsepower at existing compressor station in Washington Co., FL.*

- *Compressor Station 14 – Increase horsepower at existing compressor station in Gadsden Co., FL.*

- *Compressor Station 15 – Increase horsepower at existing compressor station in Taylor Co., FL.*

- *Compressor Station 24 – Increase horsepower at existing compressor station in Gilchrist Co., FL.*

• *Compressor Station 26 – Increase horsepower at existing compressor station in Citrus Co., FL.*

• *Compressor Station 27 – Increase horsepower at existing compressor station in Hillsborough Co., FL.*

• *Compressor Station 29 – Construct new compressor station at site to be determined in Highlands County, FL.*

64. 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

RESPONSE: In regard to Florida Gas Transmission pipeline the planned Phase IV project (described above in response to Question 39) involves associated pipeline projects, affecting FGT's natural gas pipeline capacity in the State of Florida several of these affiliated FGT Phase IV projects are outside of the State of Florida.

Installation details are as follows:

• *Loop 1 – 25.5 miles of 42-inch diameter pipeline in Mobile Co., AL, ending at the Mt. Vernon compressor station.*

• *Loop 2 – 37.2 miles of 36-inch diameter pipeline in Baldwin and Escambia Counties, AL, and Escambia Co. Fl.*

• *Compressor Station 11 – Increase horsepower at existing compressor station in Mobile Co., AL.*

65. Regarding unconventional natural gas production (shale gas, tight sands, etc.), please discuss in detail the expected industry factors and trends for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

Although unconventional gas resources are abundant, they are generally more costly to produce. Their exploitation was boosted in the late 1980s and early 1990s with the successful implementation of tax incentives designed to encourage their development. Since then, technologies developed and advanced in the pursuit of unconventional gas resources have contributed to continued growth in production even in the absence of the tax incentives (which generally are unavailable for production from wells drilled after

December 31, 1992). Indeed, increasing production from unconventional gas resources has actually offset a decline in conventional gas production in recent years. Over the next two decades the role of unconventional gas in meeting the US's energy needs is projected to expand to 28 percent of total production, or about 7.5 trillion cubic feet per year. Behind these projections are important assumptions about future technological

Natural gas in tight sand formations is the largest source of unconventional production, and production from shale formations is the fastest-growing source, with an assumed 267 trillion cubic feet of undiscovered technically recoverable resources. DOE-EIA projected production of natural gas from shale increases from 1.1 trillion cubic feet in 2006 to 4.2 trillion cubic feet, or 18 percent of total U.S. production, in 2030. The expected growth in natural gas production from shale is far from certain, however, and continued exploration is needed to provide additional information on the resource potential.

RESPONSE: How these factors and trends will affect the Company.

LE is aware of the fundamental issues involved relative to how these trends may affect the future pricing and availability of fuels. The changes that have the most effect are results of public policy and legislation. It is very difficult to forecast the timing and degree of these policy elements. Because of this LE policy for fuel planning is to prudently prepare in ways that incorporate the highest degree of fuel flexibility so that we are not highly dependent on one type of fuel.

66. Regarding liquefied natural gas (LNG) imports to the United States, please discuss in detail the expected industry factors and trends for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

In the United States in total , LNG are expected to peak at 1.5 trillion cubic feet in 2018 before declining to 0.8 trillion cubic feet during the 2020s, despite projected U.S. re-gasification capacity of 5.2 trillion cubic feet. The near-term increase is the result of growth in world liquefaction capacity, which temporarily exceeds world demand, making LNG available to the U.S. market— particularly in the summer to fill storage facilities. In the longer term, high LNG prices (which are tied to oil prices in many markets) and ample domestic natural gas supplies reduce U.S. demand for LNG imports; however, the amount of LNG available to U.S. markets could change if world natural gas consumptiondiffers from the levels projected

In the Florida market specifically the Port Dolphin, offshore LNG import terminal has been one of the primary issues.

The Florida Public Service Commission (FPSC) has forecast steadily rising demand for natural gas in the state while several planned coal-fired power plants have been canceled with the state increasingly turning to natural gas for electric power production

Recently Federal Energy Regulatory Commission (FERC) has issued a certificate of public necessity and convenience to build and operate an on-shore pipeline to connect to its deepwater liquefied natural gas (LNG) port off the West Coast of Florida. The FERC order marks another successful milestone in the project. In late 2009 the U.S. Maritime Administration and U.S. Coast Guard gave approval to the Port Dolphin project. This action followed the formal approval of the proposed project in September by Florida

Port Dolphin's deepwater port will have peak send out capacity of up to 1.2 billion cubic feet per day, enough to power more than one million homes. When fully operational, Port Dolphin will have enough capacity to meet 15 percent of Florida's natural gas needs. Construction of the port is set to begin in 2012 with completion in 2013.

Port Dolphin is a subsidiary of Hoegh LNG, a worldwide leader in the developer of floating solutions in LNG. The company is developing several deepwater LNG terminals based on SRV/Floating Storage and Re-gasification Unit technology around the world, including Port Dolphin. Located 28 miles off Tampa Bay, the new deepwater port will -- with its specially designed LNG vessels -- deliver natural gas through an undersea pipeline to connect with the state's pipeline system four miles inland from Port Manatee. The LNG will be returned to a gaseous state onboard the vessels and fed into the pipeline to serve customers across Florida.

RESPONSE: How these factors and trends will affect the Company.

LE is aware of the fundamental issues involved relative to how these trends may affect the future pricing and availability of fuels. The changes that have the most effect are results of public policy and legislation. It is very difficult to forecast the timing and degree of these policy elements. Because of this LE policy for fuel planning is to prudently prepare in ways that incorporate the highest degree of fuel flexibility so that we are not highly dependent on one type of fuel.

67. Regarding the potential for liquefied natural gas (LNG) exports from the United States, please discuss in detail the expected industry factors and trends for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

There is potential for liquefied natural exports to grow in the period of 2012 through 2021. This is due to the incorporation of shale gas to the overall natural gas production in the USA which has kept natural gas prices in this country at the lowest levels for the last decade while in the rest of the World gas prices are much higher.

RESPONSE: How these factors and trends will affect the Company.

LE is aware of the fundamental issues involved relative to how these trends may affect the future pricing and availability of fuels. The changes that have the most effect are results of public policy and legislation. It is very difficult to forecast the timing and degree of these policy elements. Because of this LE policy for fuel planning is to prudently prepare in ways that incorporate the highest degree of fuel flexibility so that we are not highly dependent on one type of fuel.

68. Regarding the potential for liquefied natural gas (LNG) exports from the United States, please discuss the potential impacts for natural gas prices within the US and how this would affect the Company.

Increased exports for liquefied natural gas from the United States could eventually increase, not in the immediate future, down the road the overall pricing structure of natural gas in the USA, This will happen due to the willingness of other World countries to pay premium prices for exported LNG.

RESPONSE: How these factors and trends will affect the Company.

LE is aware of the fundamental issues involved relative to how these trends may affect the future pricing and availability of fuels. The changes that have the most effect are results of public policy and legislation. It is very difficult to forecast the timing and degree of these policy elements. Because of this LE policy for fuel planning is to prudently prepare in ways that incorporate the highest degree of fuel flexibility so that we are not highly dependent on one type of fuel.

69. Please discuss in detail the Company's plans for the use of firm natural gas storage for the period 2012 through 2021.

Lakeland Electric does not have direct access to control or manage injection or withdrawal of natural gas from storage. However contracts LE holds or are offered contain provisions which facilitate required storing services of gas near origin or in-transit to move in and out of storage. In addition, at times the transporting pipelines allow a condition known as 'line-pack' which allows for LE to 'store' marginal volumes of gas en-route essentially by allowing the operating pressure of the lines to increase for later flow.

Most storage of natural gas is in underground salt "caverns" or porous underground formations Florida's geology is unsuitable for in-ground gas storage, so the state has previously had to look to neighboring states for their storage needs.

A business entity known as Floridian Natural Gas Storage will build an above-ground gas storage tank in an industrial area of Indiantown (MartinCounty) site.

Power and gas companies would be able deliver gas to the FGS facility through their existing pipeline capacity during off-peak periods. FGS will refrigerate the gas until it becomes a liquid and store the liquid in the tank at normal atmospheric pressure until it is needed. Then, on peak days or during unexpected outages like hurricanes, utility companies will call to have the process reversed and the gas delivered from FGS to their power plants.

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

In recent years Lakeland Electric has done several things to promote competition within the transportation modes available for delivery of coal:

i. *Monitored and participated in activities with other interested parties concerning rail competition, regulation and re-regulation including potential legislative, regulatory and legal action.*

ii. *Participated in alternate coal transport modes including movements of imported coal to dock in Tampa and furtherance by truck. LE will also investigate potential movements of Illinois Basin coal via similar water-truck (non-rail) routes.*

iii. *LE continues to aggressively seek best, low cost markets for supply and transport of natural gas to displace coal generation and thus apply competitive pressure to the coal transport markets.*

iv. *LE, especially through affiliation with its municipal electric associations, continues to aggressively seek best, low cost markets of inter-pool and extra-pool electricity to displace coal generation and thus apply competitive pressure to the coal transport markets.*

71. Regarding coal transportation by rail, please discuss the expected industry trends and factors for the period 2012 through 2021. 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.

RESPONSE: Routes for coal transportation of coal are well established with most of the movement itinerary being mainlines which also serve all various freight. All Class I US railroads moving coal continue to improve efficiency in hauling coal. The primary method of gaining efficiency has come in the form of increased weight of lading (cargo). This is accomplished in two ways, first by using the highest ratable capacity per car the second by increasing the length of the train. Lakeland Electric is working in collaboration with its coal carrier, CSX transport, to implement these improvements. During 2010 a transition will be made to higher per car load capacity cars and the length of the train will be increased with the goal of reaching 110 cars per train. Some portion of the net improvements in efficiency will be shared between customer and carrier. In additions – with these larger movements per train cycle – the need for rail equipment will be marginally improved.

There are no expected changes to the terminal and port facilities for coal that are available for movement of coal to Lakeland Electric with the possible exception of changes at TECO's Big Bend in-bound port facility. During 2009 that TECO plant began to first receive rail coal and plans to move 50 % of its ongoing coal needs by rail. As a result TECO will be using the in-bound port terminal less and thus potentially have a higher ability to use that port to move and store coal for other in-bound destination is conceivable that LE may, in the future, become one of those destinations.

72. Regarding coal transportation by water, please discuss the expected industry trends and factors for the period 2012 through 2021. 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.

73. As discussed above the historic primary source of waterborne coal to Lakeland Electric has been imported coal from South America, primarily Colombian coal. In more recent times a trend has developed that will probably affect the prices of Colombian coal for sometime in the future. With the high industrial growth in Asia and China as the largest example world demand for all commodities are strong. Colombian coal prices landed in Western Europe are much higher offsetting the lack of South African coal which is being *purchased into the Indian Ocean and Asian market. This will affect the ability and competitiveness, for example, of Colombian coal in-bound to Tampa ports with potential furtherance to Lakeland Electric. Terminal and port facilities are addressed above in response to Question 48.*

74. 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 2012 through 2021.

Lakeland Electric in not involved in Nuclear power

75. For the period 2012 through 2021, 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 short-term and long-term storage, dry cask storage, and litigation involving spent nuclear fuel, and the future of the Nuclear Waste Disposal Act.

NA

76. Regarding uranium production, please discuss the expected industry trends and factors for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

Residual fuel oil, the heavy fuel used to run boilers for power generation and to propel tankers and other large vessels, once accounted for as much as 30 percent of the oil burned in stationary uses, and 20 percent of all United States oil use. By 1997, those shares had fallen to 7 percent and 4 percent, respectively. During residual fuel oil's heyday, the 1970's, represented a particular time in energy markets. The market for residual fuel oil has eroded by a variety of factors, including price competition with (newly available) natural gas and environmental restrictions and its use in electric generation was limited to a few utilities in Florida and the Northeast. The market in Florida was dominated by Florida Power & Light' generators which have now mostly been converted to using natural gas or new NG fired capacity has displaced the need for the older residual oil fired units.

77. Regarding the transportation of heavy fuel oil and distillate fuel oil, please discuss the expected industry trends and factors for the period 2012 through 2021. As part of this discussion, please include how these factors and trends will affect the Company.

TRANSMISSION

78. 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. Please complete the table below and provide an electronic copy (in Excel).

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

******Lakeland Electric has nothing in place at this time******

Year	Month	Peak Demand (MW)	Date	Hour	Temperature (F)
2009	1	710	22-Jan	700	27
	2	703	5-Feb	800	27
	3	546	3-Mar	800	43
	4	471	24-Apr	1700	88
	5	568	11-May	1800	90
	6	625	22-Jun	1700	96
	7	601	16-Jul	1700	92
	8	608	11-Aug	1800	93
	9	579	21-Sep	1700	90
	10	587	8-Oct	1700	95
	11	444	1-Nov	1600	84
	12	505	29-Dec	900	45
2010	1	804	11-Jan	800	28
	2	624	26-Feb	700	33
	3	645	5-Mar	700	35
	4	451	24-Apr	1800	87
	5	578	3-May	1700	93
	6	619	16-Jun	1500	98
	7	638	28-Jul	1600	92
	8	621	3-Aug	1700	95
	9	597	13-Sep	1700	90
	10	528	28-Oct	1600	93
	11	435	3-Nov	1700	86
	12	709	14-Dec	800	31
2011	1	665	13-Jan	800	32
	2	501	14-Feb	800	47
	3	434	30-Mar	1600	70
	4	552	28-Apr	1700	89
	5	568	12-May	1700	93
	6	609	23-Jun	1700	96
	7	591	25-Jul	1600	89
	8	611	12-Aug	611	97
	9	563	20-Sep	1700	88
	10	482	11-Oct	1600	87
	11	429	16-Nov	1600	84
	12	383	8-Dec	800	45

Total Retail Energy Sales Forecasts (GWh)					
Year	2007	2008	2009	2010	2011
2011 TYSP					2918
2010 TYSP				2849	2875
2009 TYSP			2947	2993	3034
2008 TYSP		2980	3023	3065	3106
2007 TYSP	2885	2951	2990	3035	3080
2006 TYSP	2950	3014	3067	3123	3177
2005 TYSP	3014	3086	3153	3221	
2004 TYSP	3019	3087	3156		
2003 TYSP	NA	NA			
2002 TYSP	NA				

Fuel Type	Renewable Resource Capacity (MW)	
	Existing (2012)	Planned (2021)
Solar	2.837	44
Wind		
Biomass		
Municipal Solid Waste		
Waste Heat		
Landfill Gas		
Hydro		
Total		

Existing Renewables as of January 1, 2012

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
N/A							

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
Thermal Solar	Solar Water heaters (57)	Sunshine	1998-2002	86	86	142	0.17

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
N/A										

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Regenesis Power	Thermal Solar	Solar Water Heaters (28)	Sunshine	2010	42	42	70	0.17	2010	2030
Regenesis Power	Thermal Solar	Solar Water Heaters (71)	Sunshine	2011	107	107	178	0.17	2011	2031
SunEdison	Center	Solar PV	Sunshine	10-Apr	0.25	0.25	426	0.17	10-Mar	30-Mar
SunEdison	Airport Phase 1	Solar PV	Sunshine	11-Dec	2.3	2.3	91	0.17	11-Dec	Dec-36

Planned Renewables for 2012 through 2021

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
N/A							

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)
N/A							

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
N/A										

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor	Contract Start Date	Contract End Date
-	-	-	-	(MM/YY)	Sum	Win	(MWh)	(%)	(MM/YY)	(MM/YY)
Regenesis Powe	Thermal Solar	Solar Water Heaters (10,000)	Sunshine	2011-2016	15	15	25	0.17	2011 - 2016	2031 - 2036
SunEdison	TBD	Solar PV	Sunshine	2011-2017	24	24	31,200	0.17	2011-2017	2031-2037

Renewable Costs and/or Payments for the Year Ending December 31, 2011.

Utility-Owned Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
N/A									

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
N/A									

Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
N/A									

Non-Firm Renewable Purchased Power Agreements

Owner Name	Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capacity Payments	Energy Payments	Total Payments
-	-	-	-	Sum	Win	(MWh)	($)	($)	($)
Regenesis Power	Thermal Solar	Solar Water Heaters	Sunshine	149	149	248	N/A	$39,145	$39,145
SunEdison	Lakeland Center	Solar PV	Sunshine	0.25	0.25	426	N/A	$123,114	$123,114
SunEdison	Airport Phase 1	Solar PV	Sunshine	2.3	2.3	91	N/A	$17,290	$17,290

Facility Name	County	Unit Type	Fuel Type	Commercial In-Service Date	Net Capacity (MW)		Annual Generation	Capacity Factor
-	-	-	-	(MM/YYYY)	Sum	Win	(MWh)	(%)

Customer Class	Residential			Commercial		
Renewable Type	**# of Connections**	**Installed Capacity**	**Annual Output**	**# of Connections**	**Installed Capacity**	**Annual Output**
	(-)	(kW)	(MWh)	(-)	(kW)	(MWh)
Solar PV	33	151.6	212.2	35	200.7	281
Solar Thermal (Water)	Unavailable					
Wind Turbine						

Annual Output	Actual	Projected									
(GWh)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Utility	N/A										
Firm PPA	N/A										
Non-Firm	3.565	8.975	13.45	18.825	24.525	34.675	46.775	56.2	56.2	56.2	56.2
Customer	0.46	0.55	0.66	0.79	0.95	1.14	1.37	1.64	1.97	2.36	2.84
Total	4.02	9.52	14.11	19.62	25.47	35.81	48.14	57.84	58.17	58.56	59.04

Year		As-Available Energy ($/MWh)
Actual	2002	
	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
	2011	
Projected	2012	
	2013	
	2014	
	2015	
	2016	
	2017	
	2018	
	2019	
	2020	
	2021	

No Data Available

Plant	Unit #	Unit Type	Fuel Type	Net (MW)		Annual Generation	Capacity Factor	Avail. Factor	In-Service Date	Heat Rate	Unit Fuel Cost
				Sum	Win	(MWh)	(%)	(%)		(BTU/kWh)	(¢/kWh)
McIntosh	MS1	Daily	Ng	85	85	0	0.12	42.83	02/1972	-	
McIntosh	MS1	Daily	Fuel oil	85	85						
McIntosh	MS2	Periodic	Ng	103	103	10,171	1.40	89.88	06/1976	15,793	
McIntosh	MS2	Periodic	Fuel oil	106	106						
McIntosh	MS3	Base Load	Coal	342	342	1,368,125	47.12	85.09	09/1982	10,764	
McIntosh	MGT1	Peaker	Ng	16	19	154	0.09	90.80	05/1973	27,956	
McIntosh	MD1	Peaker	Fuel oil	2.5	2.5	0	0.00	0.00	10/1969	13,985	
McIntosh	MD2	Peaker	Fuel oil	2.5	2.5	11	0.05	85.71	10/1969	-	
McIntosh	MO5	Periodic	Ng	322	354	2,290,757	71.58	89.72	05/2002	7,062	
Larsen	LO8	Periodic	Ng	102	121	45,609	5.00	98.61	07/1992	11,809	
Larsen	LO8	Periodic	Fuel oil	105	124						
Larsen	LGT2	Peaker	Ng	10	14	38	0.05	95.47	11/1962	32,952	
Larsen	LGT3	Peaker	Ng	9	13	26	0.04	96.65	10/1962	27,850	
Winston	Win	Peaker	Fuel oil	50	50	-	0.19	99.70	12/2001	-	

CY2011 MOS - NET

Planned Unit Additions for 2012 through 2021

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

****Lakeland Electric has nothing in place at this time****

Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual 2011	Projected 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
McIntosh	MS1	Daily	Ng	0	-	-	-	-	-	-	-	-	-	-
McIntosh	MS1	Daily	Fuel oil											
McIntosh	MS2	Periodic	Ng	1	0	0	0	0	0	1	0	0	1	1
McIntosh	MS2	Periodic	Fuel oil											
McIntosh	MS3	Base Load	Coal	47	46	50	53	53	54	55	56	57	59	59
McIntosh	MGT1	Peaker	Ng	0	-	-	-	-	-	-	-	-	-	-
McIntosh	MD1	Peaker	Fuel oil	0	-	-	-	-	-	-	-	-	-	-
McIntosh	MD2	Peaker	Fuel oil	0	-	-	-	-	-	-	-	-	-	-
McIntosh	MO5	Periodic	Ng	72	83	85	84	85	84	87	86	85	85	85
Larsen	LO8	Periodic	Ng	5	10	10	12	12	12	12	12	13	14	14
Larsen	LO8	Periodic	Fuel oil											
Larsen	LGT2	Peaker	Ng	0	-	-	-	-	-	-	-	-	-	-
Larsen	LGT3	Peaker	Ng	0	-	-	-	-	-	-	-	-	-	-
Winston	Win	Peaker	Fuel oil	0	-	-	-	-	-	-	-	-	-	-

TYSP MODEL - Capacity Factor

Plant Name	Unit Type	Fuel Type	Summer Capacity	In-Service Date	Potential Conversion
(-)	(-)	(-)	(MW)	(MM/YY)	

No current studies for repowering

Year		System Average Heat Rate
		(BTU/kWh)
Actual	2002	
	2003	
	2004	
	2005	
	2006	
	2007	
	2008	
	2009	
	2010	
	2011	

Year		Residential Bill ($/1200-kWh)
Actual	2002	112.9
	2003	118.94
	2004	123.25
	2005	133.52
	2006	149.71
	2007	157.94
	2008	157.01
	2009	148.87
	2010	151.15
	2011	142.83

Fuel Type	Unit Type	Summer Capacity Changes (MW)	
		2011 TYSP (2011-2020)	2012 TYSP (2012-2021)
Natural Gas	Combined Cycle		
	Combustion Turbine		
	Steam		
Coal	Steam		
	Integrated Coal Gasification		
Oil	Combustion Turbine & Diesel		
	Steam		
Nuclear	Steam		
Firm Purchases	Independent Power Producer (IPP)		
	Interchange		
	Non-Utility Generator (NUG)		
	Renewables		
NET CAPACITY ADDITIONS			

Capacity / Demand at Time of Monthly Peak (MW)						
Year	Month	Installed Capacity	Scheduled Maintenance	Forced Outages	Available Capacity	Peak Demand
2009	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					
2010	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					
2011	1					
	2					
	3					
	4					
	5					
	6					
	7					
	8					
	9					
	10					
	11					
	12					

Existing Purchased Power Agreements as of January 1, 2012

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 2012 through 2021

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

****Lakeland Electric has nothing in place at this time****

Existing Power Sales as of January 1, 2012

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

Planned Power Sales for 2012 through 2021

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

****Lakeland Electric has nothing in place at this time****

Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2002										
	2003										
	2004										
	2005										
	2006										
	2007										
	2008										
	2009										
	2010										
	2011										
Projected	2012										
	2013										
	2014										
	2015										
	2016										
	2017										
	2018										
	2019										
	2020										
	2021										

Unit	Unit Type	Fuel Type	Net Summer Capacity (MW)	Type of New or Proposed EPA Rules Impacts				
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste

Unit	Unit Type	Fuel Type	Net Summer Capacity (MW)	Estimated Cost of New or Proposed EPA Rules Impacts ($ million)					
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste	Total

Unit	Unit Type	Fuel Type	Net Summer Capacity (MW)	Estimated Timing of New or Proposed EPA Rules Impacts (Month/Year – Duration)				
				MATS	CSAPR	CWIS	CCR Non-Hazardous Waste	CCR Special Waste

EPA Rule	Capital Costs	O&M Costs	Fuel Costs	Total Costs
	($ Millions)	($ Millions)	($ Millions)	($ Millions)
Mercury and Air Toxics Standards (MATS) Rule				
Cross-State Air Pollution Rule (CSAPR)				
Cooling Water Intake Structures Rule (CWIS)				
Coal Combustion Residuals Rule (CCR)				

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2002				1.9		3.8		4.17		5.48
	2003			1369	1.85	1344	5.82	206	4.77	30	6.34
	2004			1140	2.03	1703	6.52	90	5.22	11	7.18
	2005			1572	2.42	806	9.15	175	6.52	12	9.91
	2006			1447	2.46	1154	9.34	20	8.55	3	11.99
	2007			1502	2.46	1498	8.21	12	8.74	3	13.92
	2008			1507	2.95	898	10.82	2	11.2	2	13.34
	2009			964	3.62	41664	5.79	1	11.13	0	15.48
	2010			843	3.83	1826	5.67	0	10.64	5	15.7
	2011			821	4.4	2346	4.69	0	15.91	0	21.36
Projected	2012			800	4.2	2796	2.95	0	15.12	0	20.5
	2013			925	4.22	2474	3.8	0	15.51	0	20.93
	2014			892	4.45	2811	4.23	0	15.72	0	21.16
	2015			1007	4.67	2497	4.51	0	15.74	0	21.18
	2016			923	4.76	2826	4.76	0	15.99	0	21.46
	2017			1042	4.86	2712	5.01	0	16.76	0	22.3
	2018			1019	4.96	2534	5.24	0	17.51	0	23.11
	2019			976	5.05	2683	5.49	0	18.13	0	23.78
	2020			1046	5.16	2855	5.75	0	18.66	0	24.37
	2021			1140	5.26	2728	6.01	0	19.05	0	24.79

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

****Lakeland Electric has nothing in place at this time****

History and Forecast of Summer Peak Demand
High 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:									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
FORECAST:									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									

We do not perform this analysis

History and Forecast of Summer Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
FORECAST:									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									

We do not perform this analysis

History and Forecast of Winter Peak Demand
High 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:									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09									
2009/10									
2010/11									
FORECAST:									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									
2020/21									

We do not perform this analysis

History and Forecast of Winter Peak Demand
Low Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Residential Load Management	Residential Conservation	C / I Load Management	C / I Conservation	Net Firm Demand
HISTORY:									
2001/02									
2002/03									
2003/04									
2004/05									
2005/06									
2006/07									
2007/08									
2008/09									
2009/10									
2010/11									
FORECAST:									
2011/12									
2012/13									
2013/14									
2014/15									
2015/16									
2016/17									
2017/18									
2018/19									
2019/20									
2020/21									

We do not perform this analysis

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

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Total	Residential Conservation	C / I Conservation	Retail	Wholesale	Utility Use & Losses	Net Energy for Load	Load Factor (%)
HISTORY:								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
2011								
FORECAST:								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								

We do not perform this analysis

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:								
2002								
2003								
2004								
2005								
2006								
2007								
2008								
2009								
2010								
2011								
FORECAST:								
2012								
2013								
2014								
2015								
2016								
2017								
2018								
2019								
2020								
2021								

We do not perform this analysis

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
Charles Larsen Memorial	2			2.19		97.48		29,775	
	3			2.71		96.85		30,125	
	8ST			6.34		88.34			
	8CT			0.20		97.24		14,063	
Winston Peaking Station	1-20			0.10		98.19		(16,698)	
C.D. McIntosh Jr.	D1			98.68		1.32		0.00	
	D2			1.02		93.77		15,035	
	GT1			4.81		94.21		18,939	
	1			83.15		15.27		(853)	
	2			1.69		90.99		13,942	
	3			14.78		71.20		10,651	
	5ST			1.62		88.72			
	5CT			1.98		87.39		11,172	

NOTE: Historical - average of past three years 2009 - 2011
Projected - average of next ten years ***We do not perform this analysis***

*NOTE: negative HR numbers due to high station service

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:									
2009									
2010									
2011									
FORECAST:									
2012		16.78			13.45				
2013		17.18			13.85				
2014		17.38			14.05				
2015		17.40			14.07				
2016		17.66			14.33				
2017		18.43			14.10				
2018		19.18			15.85				
2019		19.79			16.46				
2020		20.33			17.00				
2021		20.72			17.39				

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:									
2009									
2010									
2011									
FORECAST:									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									

ASSUMPTIONS: heat content, ash content

We do not perform this analysis

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:									
2009									
2010									
2011									
FORECAST:									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									

ASSUMPTIONS: heat content, ash content

We do not perform this analysis

Nominal, Delivered Distillate Oil and Natural Gas Prices
Base Case

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Distillate Oil			Natural Gas		
			Escalation			Escalation
Year	$/BBL	c/MBTU	%	c/MBTU	$/MCF	%
HISTORY:						
2009						
2010						
2011						
FORECAST:						
2012		20.50		2.95		
2013		20.93		3.80		
2014		21.16		4.23		
2015		21.18		4.51		
2016		21.46		4.76		
2017		22.30		5.01		
2018		23.11		5.25		
2019		23.79		5.49		
2020		24.37		5.75		
2021		24.79		6.01		

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		
Year	$/BBL	c/MBTU	Escalation %	c/MBTU	$/MCF	Escalation %
HISTORY:						
2009						
2010						
2011						
FORECAST:						
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						

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

We do not perform this analysis

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:						
2009						
2010						
2011						
FORECAST:						
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						

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

We do not perform this analysis

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:												
2009						NA						
2010						NA						
2011						NA						
FORECAST:												
2012						4.30						
2013						4.34						
2014						4.36						
2015						4.41						
2016						4.46						
2017						4.50						
2018						4.55						
2019						4.59						
2020						4.64						
2021						4.69						

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:												
2009												
2010												
2011												
FORECAST:												
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												

ASSUMPTIONS: type of coal, heat content, ash content

We do not perform this analysis

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:												
2009												
2010												
2011												
FORECAST:												
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												

ASSUMPTIONS: type of coal, heat content, ash content

We do not perform this analysis

Nominal, Delivered Nuclear Fuel and Firm Purchases

(1)	(2)	(3)	(4)	(5)
	Nuclear		Firm Purchases	
		Escalation		Escalation
Year	c/MBTU	%	$/MWh	%
HISTORY:				
2009				
2010				
2011				
FORECAST:				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				

NA

Financial Assumptions
Base Case

AFUDC RATE		5.12 %
CAPITALIZATION RATIOS:		N/A
	DEBT	%
	PREFERRED	%
	EQUITY	%
RATE OF RETURN		N/A
	DEBT	%
	PREFERRED	%
	EQUITY	%
INCOME TAX RATE:		NA
	STATE	%
	FEDERAL	%
	EFFECTIVE	%
OTHER TAX RATE:		6.8 %
DISCOUNT RATE:		5.1 %
TAX		NA
DEPRECIATION RATE:		3.3 %

Financial Escalation Assumptions

(1)	(2)	(3)	(4)	(5)
Year	General Inflation %	Plant Construction Cost %	Fixed O&M Cost %	Variable O&M Cost %
2012	3.0	3.0	3.0	3.0
2013	3.0	3.0	3.0	3.0
2014	3.0	3.0	3.0	3.0
2015	3.0	3.0	3.0	3.0
2016	3.0	3.0	3.0	3.0
2017	3.0	3.0	3.0	3.0
2018	3.0	3.0	3.0	3.0
2019	3.0	3.0	3.0	3.0
2020	3.0	3.0	3.0	3.0
2021	3.0	3.0	3.0	3.0

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)
2012						
2013						
2014						
2015						
2016						
2017						
2018						
2019						
2020						
2021						

We do not perform this analysis

REVIEW OF THE 2012 TEN-YEAR SITE PLANS: DATA REQUEST #2

Please provide an electronic copy of all responses in Adobe PDF format, with tables to be provided in an Excel (.xls file format) document, unless otherwise specified in the question.

1. Please discuss whether the company included plug-in electric vehicle loads in its demand and energy forecasts for the 2012 Ten-Year Site Plan. If yes, please discuss the methodology used to estimate the number of vehicles operating in the company's service territory and their cumulative impact on system demand and energy consumption, and include the following information if available: an estimate of the number of electric vehicles, by year, and the estimated demand and energy impacts, by year.

   The impacts of electric vehicles are not currently being factored into the long term forecast.

Year	Number of Electric Vehicles	Cumulative Impact		
		Summer Demand	Winter Demand	Annual Energy
	(-)	(MW)	(MW)	(GWh)
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018				
2019				
2020				
2021				

2. Does the company anticipate developing load management programs relating to plug-in electric vehicles within the ten-year period? If yes, is this reflected in the company's forecasted impact of electric vehicles on the company's system demand?

   At present there is nothing in place or being discussed.