FPL

Florida Power & Light Company, 215 S. Monroe Street, Suite 810, Tallahassee, FL 32301

Jessica Cano
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May 1, 2012

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VIA HAND DELIVERY

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Ms. Ann Cole
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

RE: Staff's First Data Request; Florida Power & Light Company's 2012 Ten Year Power Plant Site Plan

Dear Ms. Cole:

Enclosed are an original and five copies of a compact disc containing Florida Power & Light Company's responses to Staff's First Data Request, Question Nos. 2-77. Also enclosed are an original and five copies of FPL's responses to Question Nos. 4-77 (hard copies of FPL's responses to Nos. 2 and 3 have been omitted, pursuant to Staff's request).

If you have any questions or concerns please feel free to call me.

Sincerely,

Lynne A. Adams

for Jessica A. Cano

Enclosure
cc: Charles Murphy

COM ____
APA ____
ECR ____
GCL 1+1CD
RAD 4+5CD's
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FPSC-COMMISSION CLERK

Q.
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.

A.
See Attachment No. 1.

Q.

[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 **<u>not</u>** provide a hardcopy of this response.

A.

See Attachment No. 1.

Q.

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.

A.

On a year-over-year basis, customer growth remained stable throughout 2011. The average number of customers for the year 2011 increased over 2010 for the second consecutive year following the decline in customers experienced in 2009.

Customer growth in the residential and commercial sectors was steady during 2011, remaining in a narrow range during the year. This was consistent with the economy in general. During the fourth quarter year-over-year growth in both the residential and commercial sectors began to increase modestly. The industrial sector is also showing some improvement. While the number of industry customers is still declining, the rate of decline is easing.

Q.

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.

A.

FPL began the transition from electro-mechanical meters to digital meters in 1992. In 2007, FPL began to replace over 4 million single-phase, non-demand digital and electro-mechanical meters with smart meters. This project is expected to be completed in 2013.

As part of the Energy Smart Florida initiative, FPL will pilot the installation of demand, poly-phase, time of use, and net smart meters for commercial/industrial customers in Miami-Dade County. This pilot program includes the installation of approximately 83,000 smart meters and is expected to begin in the 2nd quarter of 2012 and be completed by 2013. This project is fully funded by a grant from the Department of Energy.

Currently, we do not have any new or planned meter installations that are part of DSM programs.

Below are the numbers as of March 2012:

Customer Class	Digital / "smart" / Electro-mechanical	# of Current Installations	Current Penetration Level	# of Planned Installations
Residential	Digital	0.2 MM	5%	0
	Smart	2.9 MM	69%	1.3 MM
	Electro-mechanical	1.1 MM	26%	0
	Total	4.2 MM		
Commercial	Digital	0.2 MM	36%	0
	Smart	0.2 MM	33%	0.2 MM
	Electro-mechanical	0.2 MM	31%	0
	Total	0.6 MM		
Industrial	Digital	4 K	44%	0
	Smart	2 K	26%	2 K
	Electro-mechanical	3 K	30%	0
	Total	9 K		

Q.

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.

A.

The single phase, non-demand standard service meter is the GE I-210+ Digital meter (smart meter) with 2-way communication. Smart meter capabilities include remote reading and connection and disconnection capabilities. The meters also include "flags" which are useful for the determination of outage, restoration and theft. Register reads are obtained daily by schedule and available by on-demand request. Interval energy consumption data is recorded at the meter hourly and retrieved every four hours.

The table below provides the meter information for meters to be considered standard service for the remaining meter population.

Application	Manufacturer	Model	Type	Commun.	Meter Capabilities	Interval Reads	Billable Reads
Demand	Elster/ABB	A1D	Digital	n/a	kWh, demand	n/a	monthly
	Landis & Gyr	DXS2, AXS4e	Digital	n/a	kWh, demand	n/a	monthly
	GE	M90AE	Digital	n/a	kWh, demand	n/a	monthly
	Itron	Sentinel	Digital	n/a	kWh, demand	n/a	monthly
Time of Use	Elster/ABB	A1T, A1T+, A3	Digital	n/a	kWh, demand	n/a	monthly
	Landis & Gyr	AXS4e, Focus AX	Digital	AMR 1-way	kWh, demand	n/a	monthly
Load Profile	Elster/ABB	A3	Digital	Remote Read	kWh, demand, interval consumption	15 minute	monthly
	Landis & Gyr	AXS4e	Digital	Remote Read	kWh, demand, interval consumption	15 minute	monthly

Q.

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.

A.

In 2007, FPL began the deployment of smart meters to over 4 million single phase, non-demand metered customers. The smart meters are General Electric I-210+ Digital single phase, non-demand meters that are equipped with two-way communications, remote reading, and connection and disconnection capabilities. The meters also include "flags" which are useful for the determination of outage, restoration and theft. The project is expected to be completed in 2013 at a capital cost of approximately $650 million. Register reads are obtained daily by schedule and available by on-demand request. Interval energy consumption data is recorded at the meter hourly and retrieved every four hours.

Q.

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

A.

At this time, FPL is utilizing the remote reading capabilities that smart meters provide to replace manual reads for only existing tariffs and programs.

FPL is also conducting its Energy Smart Florida In-Home Technology Pilot Project, in fulfillment of its commitment to the Department of Energy. The pilot project allows FPL to collect data to better understand the technical feasibility, economic merit, and customers' acceptance of emerging in-home smart-grid technologies and dynamic pricing. Results of the pilot will be available in 2013.

Q.

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

A.

At this time, FPL is utilizing smart meter data/capabilities to perform remote reading (replacing manual reads) and to automatically generate leads for meter tampering investigations. The remote readings are also utilized by customers with smart meters through an online energy dashboard where they can see how much energy they are using by the hour, day, and month. Customers can also see what they are spending for electricity during those time intervals and obtain a projection of their next bill. Customers can also use the recently enhanced interactive voice response system (IVR) to get energy usage and other smart meter information. All of this information allows customers to make informed choices and better manage their energy usage. Additionally, FPL is gradually implementing other capabilities which, when fully implemented, will include remote connect/disconnect functionality, real-time outage/restoration verification and meter status, specific customer voltage information, and faster identification/location of failed devices (e.g., service, transformer, lateral and/or feeders).

Q.

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.

A.

The installation of smart meters is expected to result in lower line losses. However, any direct impact on net energy for load or summer peak is likely to be minimal at least in the short-term. The Company will continue to monitor any impacts on our peaks and energy from the installation of smart meters.

Regarding enhanced identification of outages/faults and voltage concerns, see FPL's response to Staff's 1st DR No. 9.

Regarding impact to DSM programs, please note that FPL does not currently offer any DSM programs which include time-differentiated pricing such as a TOU rate as part of the program. FPL is currently conducting a pilot that will allow us to collect data to better understand the technical feasibility, economic merit, and customers' acceptance of emerging in-home smart-grid technologies and dynamic pricing. Results of the pilot will be available in 2013.

Q.

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).

A.

See Attachment No. 1.

Please note, temperatures shown in Attachment No. 1 are the system-wide hourly temperatures during the monthly peak hour. System-wide temperatures are calculated using hourly temperatures across FPL's service territory. Miami, Ft. Myers, Daytona Beach, and West Palm Beach are the locations from which temperatures are obtained. In developing the system-wide hourly temperatures, these regional temperatures are weighted by regional energy sales.

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2012 Ten Year Site Plan - Staff's Data Request No. 1
Request No. 11
Attachment No. 1
Tab 1 of 1

Year	Month	Peak Demand (MW)	Date	Hour	Temperature (F)
2009	1	19,378	1/22/2009	7-8 AM	38
	2	20,081	2/5/2009	7-8 AM	35
	3	15,347	3/16/2009	5-6 PM	80
	4	17,145	4/6/2009	3-4 PM	88
	5	19,210	5/11/2009	3-4 PM	88
	6	22,351	6/22/2009	4-5 PM	95
	7	21,138	7/17/2009	3-4 PM	91
	8	21,015	8/20/2009	4-5 PM	89
	9	20,334	9/22/2009	4-5 PM	88
	10	21,014	10/8/2009	4-5 PM	90
	11	19,226	10/29/2009	4-5 PM	85
	12	16,122	12/9/2009	6-7 PM	78
2010	1	24,346	1/11/2010	7-8 AM	35
	2	16,488	2/17/2010	7-8 AM	46
	3	17,748	3/5/2010	7-8 AM	46
	4	15,480	4/25/2010	4-5 PM	84
	5	19,217	5/7/2010	4-5 PM	86
	6	21,901	6/16/2010	3-4 PM	93
	7	21,633	7/28/2010	3-4 PM	92
	8	22,256	8/19/2010	3-4 PM	92
	9	20,738	9/13/2010	4-5 PM	89
	10	19,099	10/27/2010	4-5 PM	84
	11	17,127	10/29/2010	3-4 PM	86
	12	21,126	12/15/2010	7-8 AM	40
2011	1	18,552	12/29/2010	7-8 AM	44
	2	14,483	2/22/2011	7-8 PM	74
	3	16,088	3/27/2011	5-6 PM	85
	4	19,615	4/27/2011	4-5 PM	85
	5	19,747	5/11/2011	4-5 PM	87
	6	21,222	6/23/2011	3-4 PM	91
	7	21,377	7/25/2011	3-4 PM	92
	8	21,619	8/5/2011	4-5 PM	91
	9	20,035	9/11/2011	4-5 PM	90
	10	18,757	10/12/2011	4-5 PM	86
	11	16,831	11/16/2011	2-3 PM	83
	12	14,575	12/23/2011	6-7 PM	75

Q.

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).

A.

See Attachment No. 1.

Florida Power & Light Company
2012 Ten Year Site Plan - Staff's Data Request No. 1
Request No. 12
Attachment No. 1
Tab 1 of 1

Total Retail Energy Sales Forecasts (GWh)					
Year	2007	2008	2009	2010	2011
2011 TYSP					102,257
2010 TYSP				100,668	102,340
2009 TYSP			101,078	101,029	102,514
2008 TYSP		109,137	112,715	116,537	120,948
2007 TYSP	107,673	112,519	116,375	120,337	124,322
2006 TYSP	108,959	113,918	118,116	122,111	124,920
2005 TYSP	109,852	114,036	117,813	121,038	123,550
2004 TYSP	109,010	111,680	113,748	116,262	118,610
2003 TYSP	109,010	111,680	113,748	116,262	118,609
2002 TYSP	108,752	111,360	113,973	116,736	119,282

Note: Consistent with Schedule 2.2 of the Ten-Year Site Plan, the forecast values above do not include the impact of incremental conservation.

Q.

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		
Wind		
Biomass		
Municipal Solid Waste		
Waste Heat		
Landfill Gas		
Hydro		
Total		

A.

Please see Attachment No. 1.

Florida Power & Light Company
2012 Ten Year Site Plan - Staff's Data Request No. 1
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Attachment No. 1
Tab 1 of 1

Fuel Type	Renewable Resource Capacity (MW)	
	Existing (2012)	Planned (2021)
Solar	110.35	110.35
Wind	0	0
Biomass*	86.6	88.6
Municipal Solid Waste	192.5	262.5
Waste Heat	0	0
Landfill Gas	22.9	22.9
Hydro	0	0
Total		

* Includes Pulp & Paper

Q.

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)(%)

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)(%)

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)

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)

A.

A description of utility-owned and existing renewable purchased power agreements as of January 1, 2011, with both firm and non-firm capacity, have been included in Attachment No. 1.

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Request No. 14
Attachment No. 1
Tab 1 of 1

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)	(%)

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)	(%)
DeSoto Solar	PV	SUN	10/09	25	25	52476	24
Space Coast Solar	PV	SUN	04/10	10	10	17890	20.4
Martin Solar	Thermal	SUN	12/10	75	75	137265	20.9
FPL Juno Beach Living Lab	PV	SUN	Various /10-11	0.021	0.021	0.033	17

* Average annual generation and capacity factor projected for the period from 2012 - 2021. Annual generation for the Living Lab is estimated.

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)
Wheelabrator Technologies	Broward North	ST	MSW	Apr-92	11	11	95414	99.0%	9/20/1991	12/31/2026

Wheelabrator Technologies	Broward South	ST	MSW	Apr-87	3.5	3.5	30098	98.2%	9/20/1991	12/31/2026
Solid Waste Authority of Palm Beach County	SWA	ST	MSW	Jan-89	40	40	315360	90.0%	1/2/1987	4/1/2032

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)
GES Port Charlotte	Port Charlotte Landfill	IC	LFG	Oct-11	4.2	4.2	237	0.6%	N/A	N/A
Georgia Pacific Corporation	Georgia Pacific	ST	Other (Pulp)	Jul-95	56.8	56.8	2015	0.4%	N/A	N/A
New Hope Power	Okeelanta	ST	AB	Sep-91	130	130	172050	15.1%	N/A	N/A
MMA Bee Ridge	Rothernberg Park	PV	SUN		0.25	0.25	323	14.7%	N/A	N/A
Wheelabrator	Broward North	ST	MSW	Apr-92	48.5	48.5	258309	60.8%	N/A	N/A
Wheelabrator	Broward South	ST	MSW	Apr-87	60.6	60.6	216511	40.8%	N/A	N/A
WM Renewable Energy	Broward North Landfill	IC	LFG	Apr-89	11.5	11.5	59719	59.3%	N/A	N/A
First Solar	First Solar Miami	PV	SUN	Mar-10	0.103	0.103	9	1.0%	N/A	N/A
WM Renewable Energy	Collieer County Landfill	IC	LFG	May-11	7.2	7.2	18046	28.6%	N/A	N/A

* Projects delivering to FPL under as-available tariff

** Energy delivered to FPL

Q.

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)(%)

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)(%)

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)

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)

A.

FPL is interpreting this request as seeking information related to planned utility-owned facilities (not "existing" utility-owned facilities, as stated in the question) and planned PPAs. See Attachment No. 1.

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Attachment No. 1
Tab 1 of 1

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)	(%)

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)	(%)

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)
Solid Waste Authority of Palm Beach County	SWA Expansion	ST	MSW	04/16	70	70	521220	85	12/11	4/34

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)
INEOS Bio	Indian River BioEnergy Center	ST	Biomass	06/12	2	2	8760	50	NA	NA

Q.

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)	($)	($)	($)($)

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)	($)	($)	($)($)

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)	($)	($)($)

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)	($)	($)($)

A.

See Attachment No. 1.

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Request No. 16
Attachment No. 1
Tab 1 of 1

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	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Utility-Owned Non-Firm Renewable Resources

Facility Name	Unit Type	Fuel Type	Net Capacity (MW)		Annual Generation	Capital Expenses	O&M Expenses	Fuel Expenses	Total Expenses
-	-	-	Sum	Win	(MWh)	($)	($)	($)	($)
DeSoto Solar (1)	PV	SUN	25	25	51,560	$17,896,016	$902,831	$0	$18,798,847
Space Coast	PV	SUN	10	10	18,720	$8,484,553	$451,894	$0	$8,936,447
Martin Solar (1)	Thermal	SUN	75	75	28,982	$48,350,515	$4,741,968	$0	$53,092,483

Note: (1) The Annual Generation, Capital, O&M, Fuel and Total Expense are 2011 actuals (source Dec. 2011 Solar Plant Operation Status Report page 3 of 3)

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)	($)	($)	($)
Wheelabrator	Broward North	ST	MSW	11	11	95,414	$ 3,297,493	$ 2,677,427	$ 5,974,920
Wheelabrator	Broward South	ST	MSW	3.5	3.5	30,098	$ 1,162,140	$ 846,858	$ 2,008,998

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)	($)	($)	($)
Port Charlotte		IC	LFG	4.2	4.2	237	n/a	$ 5,438	$ 5,438
Georgia Pacific		ST	Other	56.6	56.6	2,015	n/a	$ 59,221	$ 59,221
New Hope Power	Okeelanta	ST	AB	130	130	172,050	n/a	$ 5,445,146	$ 5,445,146
MMA Bee Ridge		PV	SUN	0.25	0.25	323	n/a	$ 13,359	$ 13,359
Wheelabrator	Broward South	ST	MSW	64	64	258,309	n/a	$ 8,430,769	$ 8,430,769
Wheelabrator	Broward North	ST	MSW	59	59	216,511	n/a	$ 7,189,075	$ 7,189,075
WM Renewable Energy		IC	LFG	11.5	11.5	59,719	n/a	$ 1,883,060	$ 1,883,060
Solid Waste Authority of Palm Beach County	SWA	ST	MSW	55	55	364,719	n/a	$11,259,505	$11,259,505
First Solar		PV	SUN	0.1	0.1	9	n/a	$ 218	$ 218
WM Renewable Energy	Naples	IC	LFG	7.2	7.2	18,046	n/a	$ 557,551	$ 557,551

Q.

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)	(%)

A.

See Attachment No. 1.

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Renewable Generators the FPL Currently Does not have a PPA with

Facility Name[1]	County	Unit Type	Fuel Type	Commercial In-Service Date	Summer Capacity (MW)	Winter Capacity (MW)	Annual Output[3] (MWh)	Capacity Factor
Brevard Landfill	Brevard	IC	LFG	Apr-08	9.6	9.6	75,521	89.8%
Georgia Pacific[2]	Putnam	ST	Other	Jul-95	56.8	56.8	2,015	0.4%
Lee County Resource Recovery #1	Lee	ST	MSW	Oct-92	39.7	39.7	0	0.0%
Lee County Resource Recovery #2	Lee	ST	MSW	Jul-07	21.0	21.0	0	
Dade County Resource Recovery	Dade	ST	LFG	Sep-91	77.0	77.0	0	0.0%
Tomoka Farms[2, 5]	Palm Beach	IC	LFG	Apr-99	3.8	3.8	0	0.0%
Okeelanta #1[2]	Palm Beach	ST	AB	Sep-91	74.0	74.0	172,050	14.1%
Okeelanta #2[2]	Palm Beach	ST	AB	Jul-04	65.0	65.0	for both facilities	
Seminole Landfill	Seminole	IC	LFG	Apr-08	6.4	6.4	0	0.0%
Broward Resource Recovery - North[2]	Broward	ST	MSW	Est April 1992	59.5	59.5	311,925	59.8%
Broward Resource Recovery - South[2]	Broward	ST	MSW	Feb-87	64.1	64.1	288,407	51.4%
Broward North Landfill[4]	Broward	IC	LFG	Est April 1989	11.5	11.5	59719	59.3%
First Solar Miami Projectl[2]	Dade	PV	SUN	after 3/2010	0.1	0.1	9	1.0%
Collier County Landfill[2]	Collier	IC	LFG	May-11	7.2	7.2	18046	42.8%
Port Charlotte Landfill[2]	Charlotte	IC	LFG	Est 10/1/2011	4.3	4.3	237	2.5%

Notes :

1) All of the facilities listed have an interconnection agreement with FPL
2) FPL purchases energy from these facilities under its "as-available" tariff, however there is no contract
3) Annual Output in MWh is for historical year 2011 and is provided only for facilities FPL purchases from.
4) Energy deliveries from this facility began in January, 2010
5) No longer making sales to FPL starting January, 2011

NOTE - Some Unit Ratings are specified in MVA in the interconnection agreements instead of MW. Assumed that the equivalent MW rating would be at 85% of the MVA rating. This applies to ratings shown for Georgia Pacific and the Palm Beach Solid Waste Resource Recovery Unit.

Other Comments -

Original Interconnection Agreement for the Metro Dade Resource Recovery unit was dated December 1981.
Ga Pacific sells only random net metered deliveries to FPL on an as-available basis, FPL does not receive generation data from Ga Pacific.
Brevard Energy LLC, Seminole Energy LLC and the two Lee County Resource Recovery facilities sell their total output to Seminole Electric Cooperative
GES Port Charlotte sells total output to Orlando Utility Commission, however some "as-available" energy was sold to FPL in 2011
MM Tamoka Farms, LLC sells total output to Reedy Creek Utilities
Metro Dade County Resource Recovery total output is sold to Florida Power Corporation

Q.

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.

A.

Because no legislation supporting utility development of new solar power generation facilities has been passed at this time, FPL has not fully developed specific solar projects at specific power plant sites for utility owned renewable generators. Rather, FPL has identified potential sites for solar development and performed initial permitting and due diligence with respect to available solar and other renewable power technologies that may be used depending upon the outcome of supporting legislation..

In regards to the SWA facility expected to be on-line in 2015, construction has started on the facility and it is expected to meet its anticipated schedule. The INEOS Bio facility is under construction and should also meet its schedule.

Q.

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						
Solar Thermal (Water)						
Wind Turbine						

A.

See Attachment No. 1.

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Customer Class	Residential			Commercial		
Renewable Type	# of Connections	Installed Capacity (DC kW)	Estimated Annual Output (MWh)	# of Connections	Installed Capacity (DC kW)	Estimated Annual Output (MWh)
Solar PV	1,344	7,038	7.081	235	7,014	7,362
Solar Thermal (Water)	Unknown					
Wind Turbine	5	14	4.5	1	1.5	0.08

Q.

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											
Firm PPA											
Non-Firm											
Customer											
Total											

A.

See Attachment No. 1.

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Annual Output (GWh)	Actual	Projected									
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Utility	70.69	194.68	209.24	208.77	185.62	208.35	191.71	206.93	206.48	199.86	205.58
Firm PPA	125.51	475.91	475.91	510.60	535.40	535.40	535.40	535.40	535.40	535.40	535.40
Non-Firm	757.61	727.20	727.20	727.20	727.20	727.20	727.20	727.20	727.20	727.20	727.20
Customer	18.62	29.26	45.22	67.83	98.42	143.64	170.24	202.16	242.06	293.93	364.42
Total	972.43	1427.05	1457.57	1514.40	1546.64	1614.59	1624.55	1671.69	1711.14	1756.39	1832.60

Q.

[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	

A.

See Attachment No. 1.

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2012 TYSP Supplemental Data Request - Question 21

Year		As-Available Energy	South	Southeast	Northeast South	Northeast North	West
		($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
Actual	2002		18.01	17.79	17.18	16.73	17.01
	2003		21.63	21.63	20.76	19.78	20.43
	2004		21.49	21.33	20.38	19.69	20.12
	2005		32.41	32.21	30.62	29.44	29.91
	2006		27.33	27.14	25.95	24.85	25.20
	2007		28.21	28.41	27.25	26.24	26.57
	2008		34.24	34.52	33.36	31.92	32.34
	2009		17.55	17.83	17.65	16.95	17.23
	2010		21.46	21.28	21.51	20.54	19.63
	2011		31.53	31.24	31.77	30.36	30.57
Projected	2012	40.80					
	2013	38.50					
	2014	40.20					
	2015	41.70					
	2016	48.20					
	2017	52.30					
	2018	56.40					
	2019	60.10					
	2020	67.20					
	2021	73.00					

Note : FPL historically keeps track of avoided costs on a regional basis but forecasts avoided costs on an system average basis

Q.

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.

A.

FPL has not conducted any studies regarding combining renewable and existing fossil fuel units. The Martin Next Generation Solar Energy Center, which became commercial in December 2010, is the world's first "hybrid" solar energy facility – integrating a 75MW solar thermal facility with an existing natural gas combined cycle unit. At this time, FPL has not identified the potential for other similar projects.

Q.

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?

A.

Over the last five years FPL has had frequent discussions regarding potential new renewable generation as well as the potential for contracts with existing renewable generators. These did not come to fruition for a variety of reasons. Some of these projects include the St. Lucie Plasma Gasification facility, the Sarasota County Landfill gas facility, new contracts or extension of contracts at the Broward North and South waste management facilities, as well as numerous developers of small solar facilities. In the case of newly built generation, the combination of highly efficient gas fired avoided units and low natural gas costs resulted in poor economic prospects for the potential projects. In the case of existing projects, the ability to sell at "as-available" rates to FPL without a contract provides an attractive option. They therefore can elect to receive revenues while awaiting a change in the market which would provide better long term economics.

Q.

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.

A.

The following changes occurred regarding purchased power agreements for renewable generation:

1. The refurbishment of the existing Palm Beach SWA facility, subject of a contract extension, was completed effective January 1, 2012. As a result, the facility moved from providing "as-available" energy to providing 40 MW of firm power under the PPA. This completion was four months ahead of schedule, however the firm capacity provided under the contract was at the lower limit of the contract range;

2. The Palm Beach SWA expansion contract was approved by the Commission, and all conditions precedent were achieved. The SWA has declared that the firm capacity of the unit will be 70 MW. Construction has started; and

3. Effective January 1, 2011, the 1992 contract with Broward North for 45 MW of firm capacity from a MSW facility expired, the contract was not renewed or extended. Broward North continues to deliver the energy to FPL on a non-firm (as-available) basis.

Q.

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.

A.

The projected cumulative present value of revenue requirements (CPVRR) for the resource plan presented in FPL's 2012 Ten Year Site Plan is approximately $111,879 million in 2012$ for the years 2012-2043 assuming a 7.29% discount factor. (This CPVRR value includes no capital costs for increased nuclear capacity from FPL's nuclear uprates within the 2012–2021 time frame addressed by the 2012 Site Plan or from FPL's planned two new nuclear units at Turkey Point that are projected to be added after this time frame. Please refer to Note 1 on Schedule 9 of FPL's 2012 Ten Year Site Plan.)

Q.

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.

A.

The load forecast that is presented in FPL's 2012 Site Plan was developed in September 2011. The only load forecast sensitivities analyzed during 2011/early 2012 were high load forecast sensitivities developed solely to analyze the quality of FPL's future reserves and the projected frequency at which load control might be implemented. These analyses are on-going and the load forecast sensitivities have not been used to determine potential changes to the resource plan that was presented in the Site Plan.

Q.

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)

A.

See Attachment No. 1.

2011 Unit Information

Plant	Unit #	Unit Type	Fuel Type	Net Capacity (MW) Summer	Net Capacity (MW) Winter	Annual Generation* (MWh)	Capacity Factor (%)	Availability Factor (%)	In-Service Date	Heat Rate (BTU/kWh)	Unit Fuel Cost (¢/kWh)
FT. MYERS	# 2	CC	GAS	1,432	1,490	6,990,424	59.4	82.1	Jun-02	7,348	4.29
	#3A	CT	GAS	158	176	275,546	21.5	93.6	Jun-03	10,852	6.33
	#3A		#2 OIL			909					20.68
	#3B	CT	GAS	158	176	272,547	21.5	93.2	Jun-03	15,832	9.18
	#3B		#2 OIL			2,998					18.67
LAUDERDALE	# 4	CC	#2 OIL	442	483	934	68.9	91.4	May-93	8,122	19.09
	# 4		GAS			2,621,677					4.74
	# 5	CC	#2 OIL	442	483	1,046	66.5	89.2	Jun-93	8,057	12.63
	# 5		GAS			2,529,478					4.70
MANATEE	# 1	ST	#6 OIL	812	822	147,886	16.4	90.7	Oct-76	11,401	14.19
	# 1		GAS			973,025					6.67
	# 2	ST	#6 OIL	812	822	143,045	18.1	66.4	Dec-77	11,153	13.96
	# 2		GAS			1,116,131					6.51
	# 3	CC	GAS	1,111	1,168	5,769,671	62.8	77.4	Jun-05	7,075	4.14
MARTIN	# 1	ST	#6 OIL	826	832	83,302	21.3	93.0	Dec-80	10,964	14.50
	# 1		GAS			1,412,164					6.39
	# 2	ST	#6 OIL	826	832	76,203	19.3	91.6	Jun-81	11,110	14.27
	# 2		GAS			1,271,020					6.49
	# 3	CC	GAS	469	489	2,586,053	70.2	87.1	Feb-94	7,466	4.35
	# 4	CC	GAS	469	489	2,426,230	66.1	86.7	Apr-94	7,448	4.34
	# 8	CC	#2 OIL	1,132	1,219	(A) 6,163	67.1	81.9	Jun-05	7,024	12.07
	# 8		GAS			6,101,794					4.10
PT EVERGLADES	# 1	ST	#6 OIL	213	214	(913)	-0.1	100.0	Jun-60	0	-
	# 1		GAS			(913)					-
	# 2	ST	#6 OIL	213	214	(1,307)	-0.2	100.0	Apr-61	0	-
	# 2		GAS			(1,307)					-
	# 3	ST	#6 OIL	387	389	29,000	6.9	93.2	Jul-64	12,605	13.96
	# 3		GAS			194,938					7.37
	# 4	ST	#6 OIL	374	376	32,229	6.0	98.5	Apr-65	12,663	14.46
	# 4		GAS			161,152					7.37
SANFORD	# 3	ST	#6 OIL	138	140	(2,844)	-0.5	100.0	May-59	0	-
	# 3		GAS			(2,844)					-
	# 4	CC	GAS	958	1,040	5,668,565	72.6	92.6	Oct-03	7,344	4.28
	# 5	CC	GAS	954	1,037	5,519,269	71.0	94.4	Jun-02	7,375	4.30
TURKEY POINT	# 1	ST	#6 OIL	396	398	131,184	13.1	88.8	Apr-67	13,459	16.00
	# 1		GAS			307,123					7.92
	# 2	ST	#6 OIL	(B) 0	(B) 0	(7,589)	-0.5	84.8	Apr-68	0	4.63
	# 2		GAS			(7,589)					1.66
	# 5	CC	# 2 OIL	1,148	1,156	6,575	62.8	87.0	May-07	7,115	11.38
	#5		GAS			5,788,380					4.15
WEST COUNTY	#1	CC	# 2 OIL	1,219	1,335	12,108	66.9	81.7	Aug-09	6,881	14.77
	#1		GAS			7,112,343					4.02
	#2	CC	# 2 OIL	1,219	1,335	76,391	68.7	85.5	Nov-09	6,952	15.81
	#2		GAS			7,226,028					4.06
	#3	CC	# 2 OIL	1,219	1,335	0	67.4	98.5	(B)	6,776	-
	#3		GAS			7,149,210					3.87
CUTLER	# 5	ST	GAS	68	69	(752)	-0.1	100.0	Nov-54	0	-
	# 6	ST	GAS	137	138	(752)	-0.1	100.0	Jul-55	0	-
FT MYERS	1-12	GT	#2 OIL	648	710	5,510	0.1	99.6	May-74	15,035	24.79
LAUDERDALE	1-12	GT	#2 OIL	420	459	504	0.9	89.6	Aug-70	16,819	27.38
	1-12		GAS			25,999					9.85
	13-24	GT	#2 OIL	420	459	2,303	0.8	96.5	Aug-72	18,203	29.65
	13-24		GAS			20,142					10.57
EVERGLADES	1-12	GT	#2 OIL	420	459	2,465	1.3	96.4	Aug-71	17,807	N/A
	1-12		GAS			36,335					10.41
PUTNAM	# 1	CC	#2 OIL	249	265	351	22.3	81.6	Apr-78	10,530	14.27
	# 1		GAS			462,274					6.13
	# 2	CC	#2 OIL	249	265	3,455	18.3	70.8	Aug-77	10,320	17.33
	# 2		GAS			377,089					6.03

2011 Unit Information

Plant	Unit #	Unit Type	Fuel Type	Net Capacity (MW) Summer	Net Capacity (MW) Winter	Annual Generation* (MWh)	Capacity Factor (%)	Availability Factor (%)	In-Service Date	Heat Rate (BTU/kWh)	Unit Fuel Cost (¢/kWh)
ST JOHNS	# 1	ST	COAL	(C) 127	(C) 125	(C) 677,063	61.4	87.2	Mar-87	(D) 10,089	4.26
	#1		GAS			4,836					8.10
	# 2	ST	COAL	(C) 127	(C) 125	(C) 703,696	63.7	96.1	May-88	(D) 10,040	4.27
	# 2		GAS			2,546					8.23
SCHERER	# 4	ST	COAL	(C) 672	(C) 678	(C) 4,253,247	76.3	91.0	Jul-89	(D) 10,277	2.47
	# 4		#2 OIL			1,275					20.62
DESOTO		PV	SOLAR	25	25	51,845	23.5	-	Oct-09	-	-
SPACE COAST		PV	SOLAR	10	10	18,842	21.4	-	Apr-10	-	-
TURKEY POINT	# 3	ST	NUCLEAR	693	717	5,875,936	95.9	93.4	Nov-72	11,011	0.77
	# 4	ST	NUCLEAR	693	717	5,137,785	83.8	81.5	Jun-73	11,009	0.65
ST LUCIE	# 1	ST	NUCLEAR	839	853	6,301,442	84.9	84.0	May-76	10,869	0.60
	# 2	ST	NUCLEAR	*** 745	*** 757	*** 5,627,034	**** 66.2	**** 63.1	Jun-83	*** 9,130	0.54

* FPL converted from reporting generation on a fiscal basis to a calendar basis in July 2011, hence data reported is from December 29, 2010 to December 31, 2011

*** Excludes participants

**** Includes participants

(A) Includes generation from Martin Solar contribution as reported on FPL's Solar Plant Operation Status Report as of December 2011.
(B) This generating unit is currently serving as a synchronous condenser.
(C) FPL share.
(D) Calculated on generation received net of line losses.
Heat rate is calculated based on the generation and fuel reported on the Schedule A4 and may be different than the actual heat rate.
Net capacity is as of December 31, 2011.

Q.

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

A.

FPL's 2016 Port Everglades Next Generation Clean Energy Center is the only new generating unit listed in FPL's 2012 Ten Year Site Plan that is currently projected to provide firm capacity within the time horizon of the Plan, and for which construction of the facility had not started at the end of 2011.

Construction/pre-construction activities have begun at 7 other units/sites: Turkey Point 3 (uprates), Turkey Point 4 (uprates), St. Lucie 1 (uprates), St. Lucie 2 (uprates), Cape Canaveral (modernization), and Riviera (modernization).

The Attachment No. 1 timeline provides FPL's current projections of the approximate time periods for the permitting, engineering, demolition and construction phases of the new generating unit at Port Everglades. FPL has received need determination approval for this project from the PSC. The decision to proceed with construction of this unit has already occurred. FPL will continue to report to the Commission the status of the Port Everglades Next General Clean Energy Center, consistent with the Commission's need determination approval.

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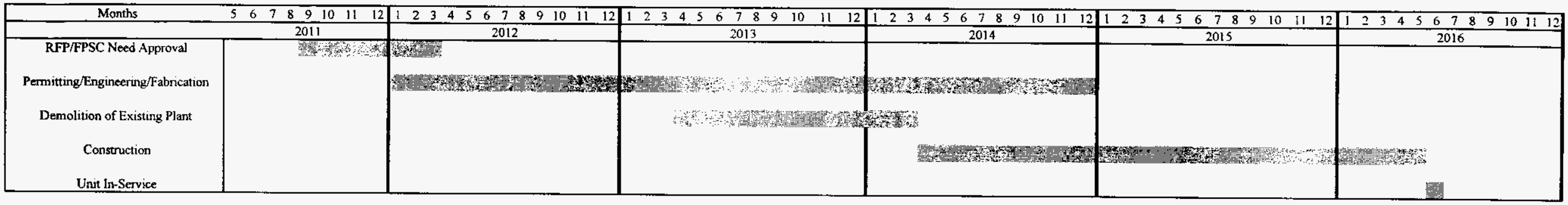
Port Everglades CC Unit - 2016

(Dates shown are approximate and are subject to change)



Q.

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).

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				

A.

See Attachment No. 1.

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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				
St. Lucie Unit #1 Uprates	129	September-08	September-08	5/31/2012
Turkey Point Unit # 3 Uprates	123	September-08	October-08	6/30/2012
St. Lucie Unit #2 Uprates *	84	September-08	September-08	10/31/2012
Turkey Point Unit # 4 Uprates	123	September-08	October-08	2/28/2013
Turkey Point Unit #6	1,100			6/1/2023
Turkey Point Unit #7	1,100			6/1/2024
Combustion Turbine Unit Additions/Upgrades				
Fort Myers 2 **	51	n/a	n/a	8/1/2015
Manatee 3 **	39	n/a	n/a	9/1/2014
Martin 8 **	35	n/a	n/a	12/1/2012
Sanford 4 **	38	n/a	n/a	4/1/2013
Sanford 5 **	38	n/a	n/a	9/1/2013
Turkey Point 5 **	33	n/a	n/a	3/1/2014
Combined Cycle Unit Additions				
Cape Canaveral Next Generation Clean Energy Center	1,210	September-08	October-09	6/1/2013
Riviera Beach Next Generation Clean Energy Center	1,212	September-08	November-09	6/1/2014
Port Everglades Next Generation Clean Energy Center	1,277	April-12	March-13	6/1/2016
Steam Turbine Unit Additions				

* 31 MW of St. Lucie Unit #2 uprates have already been achieved in 2011.

** Date shown for the CT upgrades represents last date of phased CT upgrades at the site.

Q.

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

A.

See Attachment No. 1.

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Projected Unit Information – Capacity Factor (%)

Plant	Unit #	Unit Type	Fuel Type	Actual 2011	Projected 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CAPE CANAVERAL 3	3	CC	OIL/GAS	0	0	52.88	88.67	85.7	90.17	82.01	86.85	86.56	88.16	88.07
DESOTO SOLAR (PV)	-	PV	SOLAR	23.54	24.66	24.51	24.35	24.19	24.03	23.88	23.72	23.57	23.41	23.26
EVERGLADES 1-12	-	GT	OIL/GAS	1.32	0	0.48	0	0	0.13	0.03	0.03	0.13	0.33	0.56
EVERGLADES 3	3	ST	OIL/GAS	6.88	13.29	0	0	0	0	0	0	0	0	0
EVERGLADES 4	4	ST	OIL/GAS	6.04	4.37	0	0	0	0	0	0	0	0	0
FORT MYERS 1-12	-	GT	OIL/GAS	0.11	0	0.07	0	0	0.02	0	0	0.01	0.02	0.06
FORT MYERS 2	2	CC	GAS	59.43	76.82	42.7	45.5	43.89	47.58	42.41	46.31	45.4	46.57	48.37
FORT MYERS 3A_B	3	CT	OIL/GAS	21.54	2.14	2.34	1	0.28	0.97	0.74	0.51	0.82	1.35	2.36
LAUDERDALE 1-24	-	GT	OIL/GAS	0.88	0.13	0.7	0.03	0	0.16	0.09	0.07	0.15	0.23	0.33
LAUDERDALE 4	4	CC	OIL/GAS	68.85	31.34	27.16	15.66	21.51	13.54	11.14	9.14	9.44	10.06	12.9
LAUDERDALE 5	5	CC	OIL/GAS	66.52	33.26	21.54	18.28	16.28	11.41	13.52	10.87	11.13	11.99	15.23
MANATEE 1	1	ST	OIL/GAS	16.41	12.92	6.14	4.7	7.56	8.46	8.12	6.87	7.35	7.99	10.91
MANATEE 2	2	ST	OIL/GAS	18.06	6.81	5.28	2.54	4.43	5.04	4.33	4.35	4.79	3.26	6.2
MANATEE 3	3	CC	GAS	62.76	83.7	75.38	56.65	65.33	41.66	53.14	49.92	49.13	50.32	53.72
MARTIN 1	1	ST	OIL/GAS	21.3	16.34	3.41	6.83	6.85	8.31	7.57	6.72	7.5	8.81	10.44
MARTIN 2	2	ST	OIL/GAS	19.3	9.5	4.95	0.85	1.86	2.47	2.98	2.19	2.1	3.98	5.17
MARTIN 3	3	CC	GAS	70.19	48.79	37.82	26.38	29.13	21.37	21.22	20.09	19.68	21.47	24.64
MARTIN 4	4	CC	GAS	66.06	42.71	32.39	21.91	23.86	18.04	16.6	15.31	15.92	16.7	19.97
MARTIN 8*	8	CC	OIL/GAS	67.08	80.04	74.33	70.01	58.19	59.26	55.23	63.37	62.11	63.91	65.05
PEEC		CC	OIL/GAS	0	0	0	0	0	54.41	92.91	95.25	95.26	95.36	95.39
PUTNAM 1	1	CC	OIL/GAS	22.28	20.73	9.47	5.41	6.84	7.78	7.43	5.66	5.83	6.78	9.28
PUTNAM 2	2	CC	OIL/GAS	18.3	19.67	8.3	5.04	6.09	4.45	6.25	4.87	5.19	5.87	7.96
RIVIERA 5	5	CC	OIL/GAS	0	0	0	52.64	90.35	84.98	90.79	89.71	89.6	90.68	90.94
SANFORD 4	4	CC	GAS	72.58	52.54	49.01	44.68	40.65	27.46	30.71	30.61	29.95	32.84	34.08
SANFORD 5	5	CC	GAS	71.01	51.61	61.1	51.24	37.93	36.87	30.91	35.87	36.06	39.1	41.46
SCHERER 4	4	Coal	COAL	76.29	77.18	96.42	86.58	96.41	86.24	96.16	85.61	95.9	86.39	96.25
SPACE COAST SOLAR (PV)	-	PV	SOLAR	21.37	21.02	20.89	20.76	20.62	20.48	20.35	20.22	20.09	19.95	19.83
ST JOHNS 1	1	Coal	COAL	61.43	32.17	23.76	36.39	56.03	86.78	85.01	92.01	85.67	93.55	86.03
ST JOHNS 2	2	Coal	COAL	63.71	31.23	30.24	36.44	69.35	80.75	92.72	85.09	93.01	86.11	93.21
ST LUCIE 1	1	Nuclear	Nuclear	84.89	70.06	87.35	97.5	87.35	90.04	97.5	90.02	90.02	97.5	90.02
ST LUCIE 2	2	Nuclear	Nuclear	66.24	67.4	97.5	87.35	87.35	97.5	90.02	90.02	97.5	90.04	90.02
TURKEY POINT 1	1	ST	OIL/GAS	13.14	0.89	1.28	0.48	0.12	0	0	0	0	0	0
TURKEY POINT 2	2	ST	OIL/GAS	0	0	0	0	0	0	0	0	0	0	0
TURKEY POINT 3	3	Nuclear	Nuclear	95.92	54.88	87.35	97.5	87.35	90.04	97.5	90.02	90.02	97.5	90.02
TURKEY POINT 4	4	Nuclear	Nuclear	83.76	82.58	77.73	87.35	87.35	97.5	90.02	90.02	97.5	90.04	90.02
TURKEY POINT 5	5	CC	OIL/GAS	62.76	77.59	57.23	61.72	59.78	55.5	45.64	57.93	57.69	60.67	65.04
WCEC 1	1	CC	OIL/GAS	66.88	92.61	84.9	77.42	81.04	72.88	67.06	74.71	74.39	74.19	77.13
WCEC 2	2	CC	OIL/GAS	68.69	87.24	91.58	83.39	75.88	77.09	78.8	80.38	80.09	80.85	82.16
WCEC 3	3	CC	OIL/GAS	67.44	89.33	83.85	85.73	79.87	72.65	76.54	77.52	77.38	77.72	80.14

* The generation values for Martin 8 include energy from steam generated at the Martin solar thermal facility.
Capacity factor values are not seperately available for the Martin Solar Thermal site.

Q.

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

A.

All existing conventional steam generating units and the combustion turbine units at Fort Myers are capable of being converted to combined cycle operation. The list of such units on FPL's system, in alphabetical order, which are potential candidates for repowering or conversion are:

- Cape Canaveral Units 1 and 2
- Cutler Units 5 and 6
- Ft. Myers Combustion Turbines Units 3A and 3B
- Manatee Units 1 and 2
- Martin Units 1 and 2
- Port Everglades Units 1, 2, 3, and 4
- Riviera Units 3 and 4
- Sanford Unit 3
- Turkey Point Units 1 and 2

Included in the above list are eight units which FPL received FPSC approval to convert into new combined cycle units. These units are Cape Canaveral Units 1 and 2 (currently planned to be converted in 2013), Riviera Units 3 and 4 (currently planned to be converted in 2014), and Port Everglades Units 1, 2, 3, and 4 (currently planned to be converted in 2016). In practice, there are a number of considerations that are taken into account when analyzing whether to convert an existing conventional steam generating unit to a combined cycle unit. Some of these considerations can be thought of as feasibility issues (such as whether there is sufficient land at the existing site for this type of unit) while other issues are typically thought of as economic issues. Any of these considerations could potentially become a major obstacle to a plant conversion at a specific site.

The considerations listed below are examples of issues typically addressed in analyses of potential conversions. However, other issues may also enter into analyses of conversions for specific sites:

- Physical site limitations
- Available water quantity, quality and cost
- Permitting issues
- Projected environmental compliance costs for the existing units and/or for the FPL system
- Projected on-going O&M and capital replacement costs for the existing units
- Projected fuel and environmental compliance costs
- Projected fixed and variable costs for new generating units
- Net capacity addition (after removing existing capacity and adding the new 3 x 1 advanced CT CC capacity)
- Impacts to FPL system reserve margin after removing the existing units
- Feasibility and cost of securing adequate additional firm natural gas to the site (especially for those sites with significant urbanization around them)
- Feasibility and cost of transmission upgrades to bring increased capacity and energy from the site (especially for those sites with significant urbanization around them)

See Attachment No. 1.

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Plant Name	Fuel & Unit Type	Summer Capacity (MW)	In-Service Date	Potential Conversion Type
Cape Canaveral Unit 1	FO6/NG, ST	0		CC
Cape Canaveral Unit 2	FO6/NG, ST	0		CC
Cutler Unit 5	NG, ST	68	Nov-54	CC
Cutler Unit 6	NG, ST	137	Jul-55	CC
Ft. Myers Combustion Turbines Unit 3A	NG/FO2, CT	158	Jun-03	CC
Ft. Myers Combustion Turbines Units 3B	NG/FO2, CT	158	Jun-03	CC
Manatee Unit 1	FO6/NG, ST	812	Oct-76	CC
Manatee Unit 2	FO6/NG, ST	812	Dec-77	CC
Martin Unit 1	FO6/NG, ST	826	Dec-80	CC
Martin Unit 2	FO6/NG, ST	826	Jun-81	CC
Port Everglades Unit 1	FO6/NG, ST	213	Jun-60	CC
Port Everglades Unit 2	FO6/NG, ST	213	Apr-61	CC
Port Everglades Unit 3	FO6/NG, ST	387	Jul-64	CC
Port Everglades Unit 4	FO6/NG, ST	374	Apr-65	CC
Riviera Unit 3	FO6/NG, ST	0		CC
Riviera Unit 4	FO6/NG, ST	0		CC
Sanford Unit 3	FO6/NG, ST	138	May-59	CC
Turkey Point Unit 1	FO6/NG, ST	396	Apr-67	CC
Turkey Point Unit 2	FO6/NG, ST	392	Apr-68	CC

Note: Cape Canaveral 1 and 2 and Riviera 3 and 4 show 0 MW of summer capacity and no in-service date since these units are currently being modernized to combined cycle generators. Although Port Everglades 1, 2, 3, and 4 have been approved for modernization by FPSC, the units have not been decommissioned and therefore the summer capacity remains.

Q.

[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	9,739
	2003	9,454
	2004	9,301
	2005	9,117
	2006	9,057
	2007	8,916
	2008	8,963
	2009	8,866
	2010	8,705
	2011	8,402

A.

Please see completed table and Attachment No. 1, an electronic copy in Excel.

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Year		System Average Heat Rate (BTU/kWh)
Actual	2002	9,739
	2003	9,454
	2004	9,301
	2005	9,117
	2006	9,057
	2007	8,916
	2008	8,963
	2009	8,866
	2010	8,705
	2011	8,402

Q.

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).

A.

See Attachment No. 1.

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	Year	Residential Bill ($/1200 kWh-mo.)
Actual	2002	93.43
	2003	99.40
	2004	104.07
	2005	110.39
	2006	133.36
	2007	127.20
	2008	130.31
	2009	133.87
	2010	114.99
	2011	116.70

Q.

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).

		Summer Capacity Changes (MW)	
		2011 TYSP	2012 TYSP
Fuel Type	**Unit Type**	**(2011-2020)**	**(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			

A.

See Attachment No. 1.

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Fuel Type	Unit Type	Summer Capacity Changes (MW)	
		2011 TYSP (2011-2020)	2012 TYSP (2012-2021)
Natural Gas [1/]	Combined Cycle	6,370	3,901
	Combustion Turbine	---	---
	Steam	---	---
Coal [1/]	Steam	26	(30)
	Integrated Coal Gasification	---	---
Oil [1/]	Combustion Turbine & Diesel	---	---
	Steam	(2,883)	(399)
Nuclear [1/]	Steam [3/]	433	459
Firm Purchases [2/]	Independent Power Producer (IPP)	(1,461)	(1,733)
	Interchange	---	
	Non-Utility Generator (NUG)	---	---
	Renewables [4/]	145	70
	Unspecified Purchase [5/]	---	250
	NET CAPACITY ADDITIONS	**2,630**	**2,518**

Notes:

1/ The values shown for the 2011 TYSP and the 2012 TYSP for Natural Gas, Coal, Oil and Nuclear represent the total of those MWs shown in Schedule 8 of the respective site plans .

2/ The value shown for the 2011 TYSP and the 2012 TYSP for Firm Purchases represents the difference in the values shown in Table 1.B.1 of the respective site plans.

3/ The 2011 Site Plan Nuclear value projected an increase of 433 MW (to a total of 450 MW) above the projected 17 MW expected in 2011. The 2012 site plan nuclear value projects an increase of 459 MW (to a total of 490 MW) above the 31 MW achieved in 2011.

4/ The 2011 Site Plan renewable value of 145 MW was based on two contracts with Palm Beach SWA of 55 MW and 90 MW that were projected to start in 2012 and 2015, respectively. The 2012 Site Plan renewable value of 70 MW is based on the additional contract for 70 wit Palm Beach SWA in 2016.

5/ Unspecified Purchase is reflected in the 2012 Ten Year Site Plan in Col (2) Firm Installed Capacity.

Q.

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					
	6					
	7					
	8					
	9					
	10					
	11					
	12					

A.

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Capacity (6) / Demand at Time of Peak (MW)						
Year	Month	Installed Capacity (1)	Scheduled Maintenance (2)	Forced Outages (3)	Available Capacity (4)	Peak Demand (5)
2009	1	23,358	48	120	23,190	19,378
	2	23,358	2,008	585	20,765	20,081
	3	23,358	2,568	122	20,668	15,347
	4	22,088	2,387	0	19,701	17,145
	5	22,088	2,095	406	19,587	19,210
	6	22,088	43	226	21,819	22,351
	7	22,088	398	1,201	20,489	21,138
	8	23,307	756	787	21,764	21,015
	9	23,307	2,422	1,294	19,591	20,334
	10	24,671	2,454	5	22,211	21,014
	11	25,791	1,516	41	24,233	19,226
	12	25,791	4,646	30	21,114	16,122
2010	1	25,835	934	428	24,473	24,346
	2	25,835	2,462	56	23,317	16,488
	3	25,835	2,699	0	23,136	17,748
	4	24,505	3,589	481	20,435	15,480
	5	24,505	3,608	160	20,737	19,217
	6	23,713	1,402	299	22,012	21,901
	7	23,713	1,152	534	22,027	21,633
	8	23,713	470	505	22,738	22,256
	9	23,713	1,107	7	22,599	20,738
	10	23,713	2,758	82	20,873	19,099
	11	24,982	3,150	732	21,100	17,127
	12	24,982	1,721	1,297	21,964	21,126
2011	1	24,191	582	62	23,547	18,552
	2	24,191	3,825	0	20,366	14,483
	3	24,191	4,102	140	19,949	16,088
	4	23,139	3,112	1,412	18,615	19,615
	5	24,358	3,451	285	20,622	19,747
	6	24,358	1,969	383	22,005	21,222
	7	24,396	760	227	23,409	21,377
	8	24,396	862	456	23,078	21,619
	9	24,396	1,482	603	22,311	20,035
	10	24,396	2,864	16	21,516	18,757
	11	25,583	4,328	-	21,255	16,831
	12	25,640	1,988	96	23,556	14,575

Notes:

(1) FPL-owned generating units' projected monthly long-term firm peak capability ratings (excluding solar) for summer months (April-October) and winter months (November-March). This "Installed Capacity" includes MW capability for the inactive reserve units.

(2) Scheduled Maintenance MW is based on the "Installed Capacity" in column 1 multiplied by the percent of time during the peak day that all FPL owned generating units were in a planned and maintenance outage (including units in inactive reserve). FPL maintains the practice of using available capacity year-round for scheduling maintenance of its fossil-fueled units as opportunities arise.

(3) Forced Outage MW is based on the "Installed Capacity" in column 1 multiplied by the percent of time during the peak day that all FPL owned generating units were in a forced outage (including units in inactive reserve).

(4) This "Available Capacity" has been calculated as MW = Installed Capacity MW - Scheduled Maintenance MW - Forced Outage MW. This Available Capacity was not adjusted for peak day ambient conditions.

(5) Peak Demand is based on the actual peak MW system demand reported over the peak hour.

(6) This information in columns 1-4 relate to FPL-owned generating units only.

Q.
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	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)	

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Existing Purchased Power Agreements as of January 1, 2012

Seller	Contract Term		Contract Capacity (MW)		Annual Generation (Note 1)	Capacity Factor (Note 2)	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Southern Co	6/1/2010	12/31/2015	584	584	1,942,549	38%	Natural Gas	Harris
Southern Co	6/1/2010	12/31/2015	185	185	554,864	34%	Natural Gas	Franklin
Southern Co	6/1/2010	12/31/2015	159	159	1,206,848	87%	Coal	Scherer 3
Oleander	6/1/2007	5/31/2012	155	180	209,777	15%	Natural Gas	---
Wheelabrator Technologies	1/1/1993	12/31/2026	11	11	95,414	89%	MSW	Broward North
Wheelabrator Technologies	1/1/1993	12/31/2026	3.5	3.5	30,093	93%	MSW	Broward South
Cedar Bay Generating Co.	1/25/1994	12/31/2024	250	250	1,188,649	96%	Coal	---
Indiantown Cogen, LP	12/22/1995	12/1/2025	330	330	987,003	98%	Coal	---
DeSoto	1/1/2012	12/31/2012	305	305	585,600	22%	Natural Gas	Tolling
TECO	1/1/2012	12/31/2012	125	75	240,000	22%	---	System
Seminole	4/1/2012	5/31/2012	150	150	288,000	22%	---	System
Solid Waste Authority of Palm Beach	1/1/2012	4/1/2032	40	40	364,719	85%	MSW	---
SJRPP *	4/2/1982	4/1/2017	375	383	2,093,916	64%	Coal	---

* Contract End Date shown does not represent the actual contract date. Instead, this date represents a projection of the date at which FPL's ability to receive further capacity and energy from this purchase will be suspended due to IRS regulations.

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)	
Solid Waste Authority of Palm Beach	6/1/2016	6/1/2034	70	70	613,200	85%	MSW	---

Note 1 - Where historical data is available, values reflect purchases for year 2011 as reported in the FERC Form 1
Note 2 - Calculations are based on Summer Contract Capacity

Q.

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	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)	

A.

Please see Attachment No. 1, which provides information related to existing and planned power sales reflected in FPL's 2012 TYSP.

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Existing Power Sales as of January 1, 2012

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Load Factor *	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Florida Keys Long Term Agreement	February 7, 2011	December 31, 2051	139 - 164	109 - 127	799,598 - 1,027,600	71.5%	System Average	Fulll Requirements
Key West Long Term Agreement	June 1, 1993	May 31, 2013	45	45	238,016	60.4%	System Average	Partial Requirements
Lee County Partial Requirements Agreement	January 1, 2010	December 31, 2013	233	244	1,224,177 - 1,242,539	58.1%	System Average	Partial Requirements
City of Wauchula	October 1, 2011	December 31, 2016	13	13	66,164	58.1%	System Average	Fulll Requirements
Metro-Dade Transmission Service Agreement	July 9, 1996	October 31, 2013	1	1	6,640	75.8%	System Average	Transmission Losses

Planned Power Sales for 2012 through 2021

Purchaser	Contract Term		Contract Capacity (MW)		Annual Generation	Load Factor *	Primary Fuel	Description
	Begins	Ends	Summer	Winter	(MWh)	(%)	(if any)	
Lee County Full Requirements Agreement	January 1, 2014	December 31, 2053	833 - 1135	915 - 1244	3,919,089 - 5,375,341	49.3%	System Average	Full Requirements
Seminole Electric Cooperative	June 1, 2014	May 31, 2021	200	200	489,600 - 835,200	47.7%	Natural Gas	Heat Rate Call Option

* Load Factor calculations use the highest annual generation and peak annual contract capacity values forecast during the contract period.

Q.

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.

A.

The MW impact of all of FPL's long-term firm capacity contracts is shown in Table I.B.1 and Table I.B.2 in Chapter 1 of FPL's 2012 Ten Year Site Plan.

FPL projects that two long term contracts will begin to add capacity during the 2012-2021 time period. The first of these contracts is with the Solid Waste Authority (SWA) of Palm Beach County and is scheduled to provide 40 MW of firm capacity with a start date of 1/1/2012. This contract is a revision of an earlier contract which ended 3/31/2010. This revised contract was approved by the FPSC in Docket No. 090150. Under the second contract, an additional 70 MW of firm capacity is scheduled to begin on 4/1/2016.

Additionally, three shorter term contracts for firm capacity have been added: TECO, and DeSoto Units 1 & 2 for 2012. These capacity additions have a projected summer capacity of 125 MW, 150 MW and 155 MW, respectively, and are intended to provide support to FPL's system as units are off for extended periods for nuclear uprates and environmental modifications.

The following long-term firm capacity contracts presented in Tables I.B.1 and I.B.2 of FPL's 2012 Ten Year Site Plan have contract end dates that fall within the 2012-2021 time period addressed by this Site Plan:

- UPS Replacement contract with a summer capacity of 928 MW and a contract end date of 12/31/2015;
- SJRPP with a summer capacity of 375 MW and a "contract end date" (which is actually an energy delivery suspension date as explained below) of 4/1/2017; and
- Oleander with a summer capacity of 155 MW and a contract end date of 5/31/2012.

The UPS Replacement contract for 928 MW began on 6/1/2010 and will remain in place through 12/31/2015. No extension of that contract is currently projected by FPL.

The amount of firm capacity that FPL receives under the SJRPP contract is subject to an energy "cap" regarding the cumulative total MWh that FPL may receive consistent with Internal Revenue Service regulations. Once this energy cap has been reached, FPL cannot receive additional energy under the contract. The sustained downturn in natural gas prices has made gas-fired generation more attractive relative to the energy cost for SJRPP energy and hence has reduced FPL's recent utilization of SJRPP. Thus, whereas FPL expected until recently to reach the SJRPP energy cap before the 2016 summer peak period, FPL currently projects that the energy cap will not be reached until April 2017 at the earliest. The date shown in the table as the "contract end date" conservatively reflects April 2017 as the earliest date when the suspension of capacity and energy could occur.

In regard to the Oleander purchase listed above, this contract was entered into shortly after FPL experienced the large increase in peak load in the Summer of 2005. This contract provided near-term capacity that is no longer needed due to the addition of FPL's Turkey Point 5 and WCEC units.

For purposes of its resource planning, FPL assumes that all of its existing long-term firm capacity purchases shown in Table I.B.1 and Table I.B.2 in Chapter 1 of its 2012 Site Plan will remain in place to the Contract End Date shown in these tables. Individual contracts may have options with which one or both parties may either terminate earlier than the listed contract end date or extend this date. In addition, these contracts may be subject to renegotiation with mutual consent of both parties. As dictated by changes in resource needs, economic conditions, regulatory changes, and/or performance under the contract, FPL may examine such options available under the contract.

Discussion of all of FPL's long term sales forecasts can be found in Chapter 2, Section C of FPL's 2012 Ten Year Site Plan.

Q.

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.

A.

FPL operates its Electric Generating Units in compliance with all applicable federal, state and local regulations that limit impacts to air and water quality. Compliance with permit requirements requires FPL to monitor and operate facilities within specific allowable limits at all times. Environmental restrictions relating to air or water quality and emissions from facility operations are incorporated within those permits, and operating procedures are implemented at FPL's facilities to ensure compliance. Regulatory changes which impose environmental restrictions are ultimately incorporated within the operating permits as changes to existing limits or new requirements. Compliance with existing permits and new requirements is continuous, on a unit and fleet-wide basis. Changes to operations of facilities to comply with existing and new requirements are included in both existing and planned operating costs, and are reflected as unit generating performance impacts that are used for unit dispatch and production costing modeling. Impacts to operation of facilities include, but are not limited to, the installation of new pollution controls (which may impact unit efficiency and generation output), purchase of emission allowances, changes to fuels that can be combusted, and use of alternative products where applicable.

FPL has evaluated the impact of all existing regulations on the operation of its generating units and has developed compliance plans to limit, or avoid, impacts to generating unit operation. During the 2011 period, impacts from air and water environmental restrictions to generating units included the following environmental requirements: 1) Use of "environmental" natural gas during startup of FPL's oil/gas steam units; 2) Compliance with Clean Air Interstate Rule (CAIR) will require the use of emission allowances and the operation of the Selective Catalytic Reduction (SCR) at SJRPP; 3) Compliance with the Georgia Multi-Pollutant Rule requirements at Plant Scherer through operation of sorbent injection / bag-house control for mercury; and 4) Operation of temporary heaters at Riviera and Cape Canaveral plants when needed to provide warm water for manatees in compliance with manatee protection plan.

To comply with the CAIR FPL implemented several projects as the most cost effective strategy, which included: 1) The 800 MW Cycling Project at the Martin 1&2 and Manatee 1&2 units to improve the ability of the units to be economically dispatched to meet system demand and allow the removal of "must run" status; 2) Installation of SCR and Scrubber on Plant Scherer Unit 4 (also required by the Georgia Multi-pollutant rule); 3) Installation of SCR on SJRPP Units 1 & 2; and 4) Purchase of emission allowances as needed. Though denied recovery under the Fuel and ECRC clauses, in 2011 FPL pursued and completed the installation of an HP Turbine upgrade to improve unit efficiency and restore unit capability on Scherer Unit 4 that would have been lost as a result of the parasitic load from installation of emission controls. During the 2012 through 2021 period FPL is aware of two final regulations, and several evolving regulations, which could potentially affect generating unit dispatch or retirement.

On July 6, 2010, the EPA published a proposed Clean Air Transport Rule (CATR) to replace the CAIR rule that had been remanded to EPA by the Court. EPA subsequently withdrew the proposed CATR and on July 6, 2011, EPA made public its Cross State Air Pollution Rule (CSAPR) as the replacement to CAIR to be implemented January 1, 2012. On December 30, 2011 the DC Circuit Court of Appeals issued a stay of the rule and set an abbreviated schedule for submittal of briefs. On April 13, 2012 oral argument to assess the merits of a continuing stay and remand of the rule to EPA. FPL anticipates that the court's decision could come early this summer but we cannot know the outcome of that decision. In accordance with the December 23, 2008 Court decision, CAIR remains in effect until a replacement rule is finalized by the EPA. FPL's construction of the West County Plant, and the modernizations of the Cape Canaveral and Riviera Beach facilities have reduced, and will reduce, FPL system emissions to avoid the need for future purchase of emission allowances necessary to comply with the requirements of either CSAPR or CAIR as currently promulgated.

The other final air regulation for which FPL has new compliance obligations is the Mercury and Air Toxics Standards (MATS) rule. The rule finalizes the coal- and oil fired Maximum Achievable Control Technology (MACT) standards that the EPA had proposed to reduce emissions of Hazardous Air Pollutants (HAPs). FPL does not anticipate any adverse impacts to operation of its generating units to comply with the MATS rule at this time. FPL began its planned installation of ESPs on its 800 MW oil fired units at Manatee and Martin plants in 2011 to plan for compliance within the required time period using existing planned outages and additional system capacity additions from the modernization projects. FPL does not anticipate any additional changes to its remaining oil fired steam electric generating units as a result of existing planned unit retirements and the use of the rules limited oil use provisions until planned unit retirements.

The several environmental regulations which FPL anticipates becoming final in the 2012 through 2021 period include: 1) 316(b) Cooling Water Intake Rule; 2) Coal Combustion Residuals Rule; 3) Steam Electric Effluent Guidelines; 4) Greenhouse Gas Performance Standards for Existing Sources; 5) Regional Haze Reasonable Further Progress requirements for visibility improvement; 6) EPA Waters of the U.S. Guidance Document; and 7) future revisions to the National Ambient Air Quality Standard (NAAQS) for the criteria pollutants. While FPL does not yet know what requirements would be included in each final rule, we have made a preliminary determination using publically available information that the anticipated compliance requirements for FPL would not impact generating unit capability or reliability to meet projected system demand.

Q.

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										

A.

See Attachment No. 1.

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Year		SOX		NOX		Mercury		Particulates		CO2e	
		lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons	lb/MWh	Tons
Actual	2002	2.781	117,611	1.402	59,278	*	*	*	*	979	41,406,953
	2003	2.871	126,640	1.243	54,828	*	*	*	*	988	43,606,284
	2004	2.770	120,018	1.150	49,850	*	*	*	*	1009	43,630,249
	2005	2.570	118,289	1.150	52,883	*	*	*	*	976	44,930,742
	2006	1.370	66,443	0.850	41,417	*	*	*	*	878	42,683,702
	2007	1.400	68,441	0.810	39,735	*	*	*	*	896	43,826,364
	2008	1.010	47,976	0.679	32,375	*	*	*	*	851	40,444,387
	2009	0.847	40,790	0.574	27,618	*	*	*	*	845	40,706,301
	2010	0.688	34,419	0.448	22,409	*	*	*	*	818	40,912,209
	2011	0.395	20,149	0.325	16,554	*	*	*	*	799	40,711,094
Projected	2012	0.188	10459	0.233	12,935	*	*	*	*	711	39,568,000
	2013	0.095	5309	0.146	8,183	*	*	*	*	662	37,202,000
	2014	0.084	4949	0.115	6,765	*	*	*	*	644	37,888,000
	2015	0.106	6364	0.119	7,159	*	*	*	*	665	39,832,000
	2016	0.119	7214	0.115	6,951	*	*	*	*	657	39,873,000
	2017	0.120	7350	0.116	7,127	*	*	*	*	677	41,551,000
	2018	0.113	7029	0.110	6,820	*	*	*	*	682	42,283,000
	2019	0.117	7323	0.113	7,098	*	*	*	*	683	42,855,000
	2020	0.119	7595	0.114	7,304	*	*	*	*	676	43,287,000
	2021	0.132	8626	0.126	8,239	*	*	*	*	692	45,327,000

* FPL does not currently calculate or report actual or projected Particulate or Mercury air emission releases for all units or on a system basis.

Q.

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"

A.

MATS

The Mercury and Air Toxics Standards (MATS) rule finalizes the Maximum Achievable Control Technology (MACT) standards that EPA had proposed for the reduction of emissions of Hazardous Air Pollutants (HAPs) from coal- and oil fired electric steam generating units. FPL must demonstrate compliance with the rule requirements by April of 2015 for its affected coal- and oil fired electric steam generating units. FPL evaluated its compliance options for its oil units and decided the best compliance strategy for the rule would be the installation of ESPs on its Martin and Manatee 800 MW units, a limit on oil operation at its Turkey Point fossil steam units to current levels of operation, and the limitation on oil firing or retirement of the Sanford fossil steam unit by the 2015 deadline. FPL has received air construction permits from the State of Florida that are required for installation of the ESPs. FPL's coal fired unit at plant Scherer was required to install controls to comply with the Georgia Multi-Pollutant rule which will also meet the compliance requirements of MATS which will be completed by second quarter 2012. The evaluation of compliance strategies for the St. John's River Power Park coal units was initiated in March of 2012 following the release of EPA's final MATS rule and is anticipated to be completed by third quarter 2012. Attached are FPL's April 2012 Supplemental CAIR/CAMR/CAVR Filing, and FPL's June 2011 response to the Commission's inquiry regarding EPA's Air Toxics and 316b Rules that describe FPL's compliance plan projects.

CSAPR

The EPA Cross-State Air Pollution Rule (CSAPR) was finalized in 2011 to replace the vacated CAIR. FPL's compliance plan for the CSAPR cap-and-trade program included only the capital costs for controls installed at Plant Scherer for GMPR, the controls installed at SJRPP and the Martin and Manatee 800 MW Cycling Project for CAIR compliance, and the addition of the West County generating units to meet demand growth. FPL, along with industry groups including the Florida Coordinating Group, petitioned EPA to reconsider various aspects of its final rule. In December 2011 the DC Circuit Court of Appeals issued a stay for the implementation of CSAPR and ordered that CAIR be implemented while the Court considered the merits of a continuing stay and remand of CSAPR. While the regulatory certainty of CSAPR is unknown at this time, FPL's compliance plan to meet the rule requirements was the plan that had been implemented for compliance with the CAIR and Georgia Multi-Pollutant rules.

FPL will continue to evaluate its compliance strategy including emission allowance market prices and whether further cost-effective reductions from generating units would provide its customers with reductions in environmental compliance costs through revenue from the sale of excess emission allowances. Additionally, FPL will continue to participate in responses to EPA and the DEP during the review of CSAPR and the Court ordered replacement of CAIR. Attachment No. 1 is FPL's April 2012 Supplemental CAIR/CAMR/CAVR Filing that describes FPL's compliance plan projects for CAIR, CAMR and the Georgia Multi-Pollutant Rule that are included as FPL's CSAPR compliance plan .

CWIS

The final requirements of the 316 (b) Rule are not yet certain as the final Rule is not expected to be issued until at least July 27, 2012. FPL anticipates that EPA will make numerous revisions to the draft rule based on additional data and comments that will be submitted to the rulemaking record. As proposed, the rule would require each affected facility to develop compliance plans and comprehensive studies to determine the appropriate compliance measures to achieve the Best Technology Available (BTA) and meet entrainment and impingement reduction requirements. As proposed by the rule, the timeline to complete these analyses, studies and ultimate agency review and approvals may take up to eight years beyond the effective date of the rule. Until these studies and compliance options are reviewed, it is not possible to determine what the exact compliance controls and costs will be for each power plant affected by the rule. Generally, the implementation of the 316 (b) rule must take into account the site specific characteristics of each generating facility, the water body types that supply the intake structure and the types of aquatic organisms in the vicinity.

EPA's analyses presented in the draft Rule indicate that cooling towers may be BTA to reduce the impacts of cooling water intake structures. Though the addition of cooling towers could be required at some facilities under the proposed rule, they are not feasible at many locations due to impacts to endangered species such as manatees, spatial limitations and disproportionate costs versus benefits and therefore were no declared BTA for all facilities. FPL operates 10 (not including Cutler Power Plant) power plants in Florida that may be affected by the proposed 316 (b) rule and may require comprehensive studies to determine the BTA to meet the 316 (b) rule. If each of the six (6) power plants (not including Sanford Unit 3 3) that currently don't employ closed-cycle cooling (i.e., cooling towers or cooling ponds) were required to install cooling towers at each of these facilities, it is anticipated that the capital cost could be as high as $1.5 billion, based on costs estimates from the Electric Power Research Institute. However, we anticipate that, based on the current draft rule, most FPL facilities will not require to retrofit their cooling systems with cooling towers and will be able to meet the determinations of BTA by installing alternative controls such as wedge wire screens, advanced travelling screens with fish returns or reductions of intake flow velocities that would meet impingement criteria. If each facility affected by the proposed 316 (b) rule were capable of reducing intake flow velocities to meet the 0.5 feet per second rule requirements for intake flow velocities the costs for FPL plants to comply would be approximately $170 million, as compared to the approximately $1.5 billion estimated for cooling towers at these facilities.

FPL is also a co-owner of the Scherer Unit 4 and SJRPP coal-fired units. Both Scherer Unit 4 and SJRPP already have cooling towers to reduce the impacts of entrainment as required under the proposed 316 (b) rule. However, each of these facilities may have to evaluate the installation of additional impingement controls under the requirements included in the currently proposed rule. FPL does not agree with this requirement for additional impingement controls if a facility already meets the definition of a closed cycle cooling system through the use of cooling towers. We will include this comment in the record when we file comments with EPA. Since the rule is not final and these facilities have not completed their comprehensive studies to evaluate the type of impingement control that may be necessary we cannot provide a reasonable cost estimate to comply. Attachment No. 2 is FPL's June 2011 response to the Commission's inquiry regarding EPA's Air Toxics and 316b Rules that describe FPL's compliance plan.

CCR

FPL does not operate any coal-fired power plants and hence is not directly responsible for coal combustion residual storage or disposal. However, FPL is a co-owner of two coal-fired units that are operated by others: Scherer Unit 4, which is operated by Georgia power Company (GPC); and the St. Johns River Power Park (SJRPP), which is operated by JEA. By contractual arrangement FPL requires that all management activities be conducted in full compliance with existing regulations and prudent industry practices. FPL expects the operating partner to manage coal by-product storage and disposal programs consistent with prudent industry practices and in full compliance with any federal, state and local regulations. It is anticipated that whenever practical coal by-products will be beneficially used rather than placed for long term storage. EPA published the proposed rule in June 2010 and has since received over 450,000 comments from the public. FPL's current strategy to manage the CCR process includes the participation with various industry groups in petitioning EPA to maintain the current designation of coal combustion residuals as non-hazardous waste under the Federal Resource Conservation and Recovery Act (RCRA) Subtitle D (as EPA "D Prime" proposal) regulation, and to work with legislators in support of maintaining designation as non-hazardous. FPL advocates the development of a non-hazardous waste standard implemented by the states with the continued use of existing ash impoundments through their remaining useful life. For new facilities FPL supports the use of dry ash handling and lined landfill disposal. Compliance strategies will be developed in cooperation with the co-owners and operators of FPL's co-owned coal fired generating units once a final rule has been promulgated.

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 120007-EI
ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/CAMR/CAVR FILING
APRIL 2, 2012

Per Order No. PSC-11-0553-FOF-EI, issued on December 7, 2011, the discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR)/ Best Available Retrofit Technology (BART) Projects.

CAIR Compliance Project Update:

Status of CAIR Rule Revision – On July 11, 2008 the United States Circuit Court of Appeals for the District of Columbia (the Court) issued an opinion vacating the United States Environmental Protection Agency's (EPA) CAIR. On December 23, 2008, the Court issued an opinion on rehearing of the July 11 decision and remanded CAIR to the EPA without vacatur, instructing EPA to remedy the CAIR flaws in accordance with the Court's July 11 opinion. This results in CAIR remaining in effect in its current form until it is revised for the July 11 opinion. On July 6, 2010 EPA published a proposed Clean Air Transport Rule (CATR) to replace the CAIR rule that had been remanded to EPA by the Court. EPA subsequently withdrew the proposed CATR and on July 6, 2011 EPA made public its Cross State Air Pollution Rule (CSAPR) as the replacement to CAIR. Interested parties filed petitions for reconsideration with EPA and also filed petitions for judicial review of CSAPR. FPL joined the Florida Coordinating Group in its petition to EPA for reconsideration of several issues through which the affected Florida generating units would receive additional emission allowances under CSAPR. On December 30, 2011 the DC Circuit Court of Appeals issued a stay on the rule and set an abbreviated schedule for submittal of briefs and oral argument to assess the merits of a stay and remand of the rule to EPA. All parties have filed briefs and oral argument is set for April 2012. In the Court's decision to stay the rule, the CAIR requirements are now in effect for all affected states. FPL anticipates that the court's decision could come early this summer but we cannot know the outcome of their decision. In accordance with the December 23, 2008 Court decision, CAIR remains in effect until a replacement rule is finalized by EPA.

St. Johns River Power Park (SJRPP) Selective Catalytic Reduction Systems (SCR) and Ammonia Injection Systems – The construction and installation of SCR and Ammonia Injection Systems on SJRPP was accomplished in 2009 with the controls on both units being placed into service in 2010. The total CAIR capital cost for installation of the SCR and Ammonia Injection System for FPL's ownership share of SJRPP is $55.3 million.

Estimated CAIR O&M expenses for 2012 are $0.6 million and estimated annual O&M expenses beginning 2013 are approximately $0.6 million (FPL 20% ownership). Ongoing

O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment.

Scherer SCR and Wet Flue Gas Desulfurization (FGD) - Current capital cost estimates for FPL's share of the installation of the FGD, Scrubber and SCR with Ammonia Injection System on Scherer Unit 4 is $363.9 million. The planned construction activities in 2012 include the installation of instrumentation for the FGD and SCR controls on Unit 4, by-product and reagent facility common storage, and final tie-in of controls during the spring planned outage.

Unit specific engineering and design work on the FGD and SCR for Unit 4 was completed in 2008 and procurement of materials needed for the construction of the equipment began in 2009. Foundation work for the FGD and SCR and for the new chimney at the output from the FGD was completed in 2008. Project work accomplished in 2009 included: delivery and initial installation of SCR structural steel; delivery and installation of SCR ammonia storage facility; initial construction of FGD chimney liner and absorber foundation activities; Scherer common FGD facility work including limestone handling prep equipment, tanks, piping, and electrical; and initial construction activities for FGD gypsum waste disposal facility. The 2010 project work included the erection of the scrubber vessel and stack/liner. Unanticipated, persistent inclement weather increased the original planned construction schedule. Project work in 2010 also included the SCR support structure and Unit 4 FGD absorber vessel. Additionally, construction was substantially completed in 2010 for SCR and FGD project common facilities (e.g., unloading and storage facilities for ammonia and limestone and limestone grinding facilities). Construction activities completed in 2011 included the completion of FGD absorber fill, recycle pump alignments, SCR damper completion, SCR ash system, and CEMS sample lines. FPL estimates its share of the Scherer Unit 4 CAIR capital costs to be $29.7 million in 2012 and $7.4 million in 2013. FPL has preliminarily estimated annual O&M for operation of the SCR, FGD, and common plant facilities supporting the controls at $3.4 million for 2012 when the FGD and SCR are projected to be in-service and $5.6 million in 2013 for the first full year of controls operation. O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

800 MW unit cycling project –FPL witness Randall R. LaBauve introduced this project in his September 1, 2006 testimony and subsequently provided an estimate for implementation of the projects with a total capital cost of $104.8 million. FPL had originally planned completion of the 800 MW unit cycling project in 2010 at the Martin and Manatee Plants utilizing existing planned outage windows to complete project work. As a result of changes to the Manatee Unit 2 outage schedule to accommodate system load requirements, completion of remaining boiler and associated drain work was accomplished in 2011.

Total capital costs for the 800 MW unit cycling project are $115.2 million and total O&M expenses to date are $4.1 million. Completed work in 2011 included the Super Heat (SH) Spray Upgrade, Extraction Control/Mass Blowdown on Manatee Unit 2, the implementation of rotor stress monitors on all four 800 MW units, and the remaining boiler work at Manatee Unit 2. Projected O&M expenses for 2012 are $0.540 million and 0.549 million in 2013 for treatment of condenser tube fouling.

Continuous Emissions Monitoring System (CEMS) Plan for Gas Turbines (GT) - The Low Mass Emitting (LME) CEMS under 40 CFR Part 75 have been installed, tested, and are now in operation at the Fort Myers, Port Everglades, and Fort Lauderdale Gas Turbine Parks, as required by the CAIR and by the CSAPR.

FPL has projected O&M expenses of $5,000 per year that will be required for routine maintenance of these CEMS systems. It should be noted that the LME option is available for a GT only if its emissions remain under EPA-prescribed thresholds. If any GT emits more than 50 tons of NOx or 25 tons of SO2 in a given calendar year, the testing for that GT will be required every year, instead of every five years. That would increase the testing costs for non-qualifying GTs to $65,000 per year, along with $5,000 per year for maintenance. FPL has not projected operation of any GT to exceed the LME limits.

Purchases of allowances – To comply with the CAIR Ozone Season NOx program requirements, FPL purchased CAIR allowances that were needed for compliance at a total cost of $98,325 for compliance year 2009. The 855 CAIR Ozone season allowances, in addition to the 12,418 allowances allocated to FPL by the EPA, were needed to comply with CAIR requirements for fossil generating unit emissions during the May through September 2009 Ozone Season. As a result of the lower than previously projected system load, and changes in FPL's generation plan mentioned above, FPL had sufficient allowances for compliance with the 2010 and 2011 CAIR NOx Ozone Season and had sufficient allowances for compliance with the CAIR 2010 and 2011 NOx Annual programs without purchasing additional allowances. Future purchases of allowances will be made as needed for compliance with the annual and ozone season NOx requirements under CAIR and the CSAPR. While FPL has received allocations to its existing CAIR fossil generating units, FPL has projected, but does not know precisely, the number of allowances it will be allocated under the CAIR NOx Annual and Ozone Season new source set-aside program for the West County Energy Center generating units.

FPL has evaluated the proposed allowance allocations under CSAPR and has projected that it will have sufficient allocated allowances to cover projected emissions in 2012 and 2013 and has not projected a need to purchase allowances under CSAPR or CAIR.

Actual CAIR capital costs through 2011 were $949.0 million.

CAIR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	0.0	0.0	55.3
Scherer-SCR/FGD	29.7	7.4	363.9
800 MW Unit Cycling - Martin	0.0	0.0	58.3
800 MW Unit Cycling - Manatee	0.0	0.0	56.9
CEMS at GTs	Capital project completed	Capital project completed	Capital project completed
Allowances	N/A	N/A	N/A

Actual CAIR O&M expenses through 2011 are $6.6 million.

CAIR O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	0.6	0.6	0.6 (2012+ annual operating costs are on-going)
Scherer-SCR/FGD	3.4	5.6	3.4 (2012+ annual operating costs are on-going)
800 MW Unit Cycling – Martin	0.300	0.300	0.305 (2012+ annual operating costs are on-going
800 MW Unit Cycling – Manatee	0.240	0.249	0.249 (2012+ annual operating costs are on-going
CEMS at GTs	0.005	0.005	0.005 (2012+ annual operating costs are on-going)
Allowances	0	0	N/A

CAMR Compliance Project Update:

On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury (Hg) emissions from coal-fired power plants for the first time. In response to the EPA CAMR, the Georgia Environmental Protection Division (EPD) promulgated two major rules to implement Hg reductions within Georgia: a rule to adopt the CAMR federal Hg cap and trade program: Rule 391-3-1-.02(15) – "*Georgia Mercury Trading Rule*" and a Georgia state specific Multipollutant Rule: Rule 391-3-1-.02(2)(sss) – " *Multipollutant Control for Electric Utility Steam Generating Units*" which became effective June 1, 2008. The Multipollutant Rule was promulgated to specify the implementation of specific air pollution control equipment for reductions in Hg, sulfur dioxide (SO2), and nitrogen oxides (NOx) emissions from identified coal-fired Electric Generating Units (EGUs) within Georgia. Section 4(i) of the Multipollutant Rule requires that Scherer Unit 4 may not be operated after April 30, 2010, unless it is equipped and operated with sorbent injection and a baghouse for the control of Hg emissions.

Installation of the Hg controls, and associated continuous Hg emission monitoring that would have been needed to comply with the CAMR requirements remain necessary to comply with the requirements of the Georgia Multipollutant Rule; therefore installation of Hg controls on Plant Scherer Unit 4 must continue. The vacatur of CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. In addition, on December 16, 2011 EPA published its final Mercury and Air Toxics Standards (MATS) Rule as a replacement for CAMR. EPA's MATS Rule sets limits on emissions of Toxic Metal Hazardous Air Pollutants (HAPs), including Hg, limits on emissions of acid gasses, and work practice standards for emissions of Organic HAPs. FPL has reviewed the compliance requirements of the MATS rule and believes that controls installed on Scherer Unit 4 for compliance with CAIR, CAMR, and the Georgia Multi-Pollutant Rule, will allow the unit to meet the rule's emission specifications for Hazardous Air Pollutants. Specifically, FPL is complying with the Hg reduction requirements of the Georgia Multipollutant Rule and EPA's MATS Rule by using the following projects identified previously under CAMR:

1. Installation of Fabric Filter Baghouse and Mercury Sorbent Injection System on Scherer Unit 4 (completed 2010).
2. Installation of HgCEMS on Scherer Unit 4 (completed 2009).
3. Installation of HgCEMS on SJRPP Units 1 & 2 (completed in 2008 prior to the vacatur of CAMR). Hg CEMS are required to comply with MATS Rule.

Total capital costs to date for the CAMR project are $107.3million. Projected annual O&M associated with operation of the Hg controls includes purchase of new sorbent, disposal of spent sorbent, replacement of filter bags, and maintenance activities associated with the baghouse and sorbent injection system, and the maintenance costs associated with FPL's share of the Scherer Unit 4 Hg CEMS. Projected CAMR capital expenses for plant Scherer are $0.133 million for 2012 and $0.111 million for 2013 for anticipated capital equipment component replacements. Projected CAMR O&M expenses for plant Scherer are $3.3 million for 2012 and $4.2 million for 2013 primarily for purchase and disposal of sorbents and replacement of bags.

FPL's cost associated with the installation of Hg CEMS at SJRPP represented a total capital cost of $0.4 million. FPL does not yet know whether SJRPP will meet all applicable emission specifications of the MATS rule. FPL and JEA have recently initiated a study of the potential impacts of MATS and other proposed rules on the SJRPP units to develop the appropriate compliance strategy.

Actual CAMR capital costs through 2011 are $107.3million.

CAMR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	0.0	0.0	0.40
Scherer-Sorbent Injection/Baghouse/ Mercury CEMS	0.133	0.111	106.9

Actual CAMR O&M expenses through 2011 are $3.5 million.

CAMR O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2012**	**2013**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	0	0	0.0
Scherer-Sorbent Injection/Baghouse/ HgCEMS	3.31	4.15	(2012+ annual operating costs are on-going)

CAVR / BART Project Update:

FPL successfully concluded negotiations with the Florida Department of Environmental Protection (FDEP or the Department) regarding Turkey Point Units 1 & 2 in February 2009, with the Department accepting FPL's proposed plan to comply with the BART requirements under the Regional Haze program. In 2011 FPL negotiated with DEP changes to its compliance plan at Turkey Point to address changes to the state's plan as a result of the CSAPR impact on the regional haze State Implementation Plan (SIP). FPL proposed to remove the requirement to install new multi-cyclone dust collectors and instead proposed to reduce emissions of SO_2 through use of 0.7% Sulfur residual fuel oil and to commit to no longer burning fossil fuels in the Unit 2 boiler effective immediately, and to take a significant reduction in fuel oil firing in Unit 1 boiler beginning in 2013. FPL projects that there will be no associated capital costs or increased O&M for compliance with the BART permit at Turkey Point. In 2011 FDEP identified that there were concerns with the analysis of the Putnam units which they were projecting exceedances of the criteria. FPL retained a consultant in 2012 to prepare modeling required by the state to demonstrate that the Putnam plant does not exceed the criteria thresholds. FPL will recover those costs through the CAVR ECRC project.

EPA has told FDEP that it will not approve Florida's Draft CAVR SIP, primarily due to the FDEP Reasonable Progress Control Technology (RPCT) Rule which uses a permit application process that EPA finds unacceptable. FDEP has indicated that it will withdraw the RPCT Rule from the Florida Administrative Code (FAC) and delete the RPCT provision from the SIP. FDEP contends that visibility improvements at Florida's Class 1 Areas will meet the Reasonable Progress glide slope in 2018 by way of existing air rules promulgated previously. At this time, FDEP has determined that no additional rulemaking will be needed. Until EPA rules on the FDEP CAVR SIP, FPL cannot know if controls will be required beyond 2018.

When EPA issued its CSAPR, Florida was no longer included in the particulate matter portion of the rule removing previously affected units from the annual NOx and SO2 requirements. Because of the regulatory uncertainty from the status of CSAPR and CAIR, FPL must undergo a full 5-factor BART Determination for SO2 and NOx. Turkey Point Units 1&2, Manatee Units 1&2, and Martin Units 1&2 are affected by this change. Consultant costs for BART Determinations for these facilities are estimated to be $30,000.

Actual CAVR capital costs through 2011 are $0.

Actual CAVR O&M expenses through 2011 are $0.041 million. FPL has projected a preliminary estimated O&M total cost of $0.030 million in 2012 for the required modeling of the Putnam facility.

CAVR/BART O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	2012	2013	TOTAL PROJECT*
Reasonable Process Control Technology	.030	0	0.071

** Through 2012*

FPL Responses to PSC Questions regarding EPA Air Toxics and Cooling Water Intake Structure--Section 316 (b) Rule

1. Provide a current cost estimate to comply with each of the rules

Air Toxics Rule—The proposed EPA Air Toxics Rule was released March 16, 2011 and is required by court order to be final by November 2011. Though the details of the Air Toxics Rule are not yet final, FPL anticipates that EPA's final rule will generally follow the proposed rule in requiring reductions of hazardous air pollutant (HAP) emissions from coal and oil fired steam electric generating units.

1. **Oil-fired electric generating units**--EPA's proposed rule requirements confirm information provided by the agency and anticipated in the rulemaking process that oil fired electric generating units operating on residual oil will be required to meet Maximum Achievable Control Technology Limits establish based on emissions data collected during the 2010 EPA Information Collection Request. The rule proposes limits for liquid oil-fired unit emissions on total HAPs metals (including mercury), Hydrogen Chloride (HCL) and Hydrogen Fluoride (HF).
    a) **FPL Manatee and Martin 800 MW Units**—As previously reported to the Commission in the ECRC docket, FPL will need to install electrostatic precipitators to meet the compliance requirements of the Air Toxics Rule and maintain the ability to burn 100% residual oil in the four 800 megawatt units operated at these Manatee and Martin Plants. FPL estimated in the ECRC docket that the costs of installing the electrostatic precipitators will be $303 million. These costs will be incurred between 2011 and 2015. If controls for HCL emissions were required for the 800 MW units it likely would be in the form of injecting hydrated lime into the flue gas stream in front of the ESPs. The cost to add hydrated lime injection to the four 800 MW units is estimated to be approximately $8.0 million.

    b) **Other FPL residual oil fired EGUs**—In the Air Toxics Rule proposal EPA requests comments on a "limited use provision" that would exclude low capacity oil fired electric generating units from the requirements to add HAPs controls if these units operate under enforceable permit restrictions that limit the capacity factor of these units to 10%. Though FPL is not yet certain whether EPA will adopt the limited use provision or at what capacity factor threshold it will apply, this option may eliminate the need to install electrostatic precipitators at other FPL residual oil fired units. Without the limited use provision FPL anticipates that ESPs may be required to maintain oil fired operation at Turkey Point Unit 1 (Turkey Point Unit 2 is operating only as a synchronous condenser for the foreseeable future and hence will not need emission controls). A rough estimate of the costs to add an ESP at Turkey Point Unit 1 is $100 million.

2. **Coal Fired electric generating units**—EPA's proposed Air Toxics Rule establishes emissions limits for Total HAPs metals, a separate limit for mercury, Hydrogen Chloride and Hydrogen Fluoride emissions.
    a) **FPL ownership of Unit 4, at Plant Scherer operated by Georgia Power Company near Macon Georgia**—Pollution control equipment now installed and currently being installed at Scherer Unit 4 was required to meet the State of Georgia's multi-pollutant emission reduction regulation. Installation of these controls includes a wet scrubber, selective catalytic reduction (SCR), activated carbon injection and a baghouse. When the installation of these controls is complete, FPL expects that Unit 4 will also meet the emissions requirements of the proposed EPA Air Toxics Rule. No other additional pollution control equipment is anticipated as a result of the pending Air Toxics Rule.

    b) **FPL ownership at St. Johns River Power Project (SJRPP)**--Though the facility already has a scrubber for SO2 and acid gas controls, SJRPP will likely have to evaluate additional options for further reductions of sulfur emissions to meet the more stringent limits of the proposed rule. SO2 limits are included for coal as a surrogate for acid gas emissions. The mercury and particulate emissions limits may require the installation of an activated carbon injection system and baghouse at SJRPP. FPL and its ownership partner at the facility have not yet determined the best approach to achieve compliance with the Air Toxics Rule and are reviewing potential pollution control equipment options and costs. Therefore, no estimate of compliance costs for SJRPP can be provided at this time.

Cooling Water Intake Structure--Section 316 (b) Rule-- The proposed Cooling Water Intake Structure Rule (316 (b) Rule) was published in the Federal Register April 20, 2011. Comments are due by July 19, 2011. A Consent Decree requires EPA to sign the Final Rule by July 27, 2012 and, assuming that occurs, the final Rule will become effective in October 2012. The 316 (b) rule as proposed will regulate Cooling Water Intake Structures from power plants and industries that withdraw threshold limits of cooling water from waters of the U.S. The rule requirements are designed to reduce adverse environmental impacts that result from the impingement and entrainment of aquatic organisms by requiring facilities to install Best Technology Available to reduce the impacts of cooling water intakes.

The final requirements of the 316 (b) Rule are not yet certain. FPL anticipates that EPA will make numerous revisions to the rule based on additional data and comments that will be submitted to the rulemaking record.

As proposed the rule would require each affected facility to develop compliance plans and comprehensive studies to determine the appropriate compliance measures to achieve the Best Technology Available and meet entrainment and impingement reduction requirements. As proposed by the rule the timeline to complete these analyses, studies and ultimate agency review and approvals may take up to eight years beyond the effective date of the rule. Until these studies and compliance options are reviewed it is not possible to determine what the exact compliance controls and costs will be for each power plant affected by the rule. Generally, the implementation of the 316 (b) rule must take into account the site specific characteristics of each generating facility, the water body types that supply the intake structure and the type of aquatic organisms in the vicinity.

EPA's analyses indicate that cooling towers may be the Best Technology Available to reduce the impacts of cooling water intake structures is the installation of cooling towers. Though the addition of cooling towers could be required at some facilities under the proposed rule, they are not feasible at many locations due to impacts to endangered species such as manatees, spatial limitations and disproportionate costs versus benefits.

FPL operates 10 power plants in Florida that will be affected by the proposed 316 (b) rule and will require comprehensive studies to determine the Best Technology Available to meet the 316 (b) rule. If each of those power plants were required to install cooling towers at each of these facilities it is anticipated that the capital cost could be as high as $1.5 billion, based on costs estimates from the Electric Power Research Institute. However, we anticipate that as the rule is proposed now, most FPL facilities will not require cooling towers and will be able to meet the determinations of Best Technology Available by installing alternative controls such as wedge wire screens, advanced travelling screens with fish returns or reductions of intake flow velocities that would meet impingement criteria. If each facility affected by the proposed 316 (b) rule were capable of reducing intake flow velocities to meet the 0.5 feet per second rule requirements for intake flow velocities the costs for FPL plants to comply would be approximately $170 million, as compared to the approximately $1.5 billion estimated for cooling towers at these facilities.

FPL is also a co-owner of the Scherer Unit 4 and SJRPP coal-fired units. Both Scherer Unit 4 and SJRPP already have cooling towers to reduce the impacts of entrainment as required under the proposed 316 (b) rule. However, each of these facilities may have to evaluate the installation of additional impingement controls under the requirements included in the currently proposed rule. FPL does not agree with this requirement for additional impingement controls if a facility already meets the definition of a closed cycle cooling system through the use of cooling towers. We will include this comment in the record when we file comments with EPA. Since the rule is not final and these facilities have not completed their comprehensive studies to evaluate the type of impingement control that may be necessary we cannot provide a reasonable cost estimate to comply.

2. **Please discuss any expected reliability impacts resulting from EPA's proposed Air Toxics and Cooling Water Intake Structures rules.**

Air Toxics Rule—FPL does not anticipate any system reliability impacts associated with the compliance requirements of the Air Toxics Rule. In light of FPL's investment in efficient, clean combined cycle gas fired generation and the modernization of older oil fired generation to combined cycle gas fired generation we are well positioned to meet the compliance requirements of the Air Toxics Rule without significant impact to the majority of our fossil fired fleet. Further, because the Commission has authorized FPL to move forward with the installation of electrostatic precipitators at the Martin and Manatee Plant 800 MW oil fired units we will be able to stagger the installation of the ESP controls on a schedule that meets the compliance dates of the rule in 2015 and maintains reliable access to generation from our portfolio.

As a result of having the 800 MW units in compliance with the Air Toxics Rule if additional controls are required at Turkey Point Plant Unit 1FPL anticipates that we will have sufficient generation margin to take this unit off line as needed to install additional controls, if and when required.

Cooling Water Intake Structure--Section 316 (b) Rule—The 316 (b) rule as proposed does not have a strict prescription for each type of control technology that will be required to achieve the performance requirements of "Best Technology Available". Furthermore, FPL anticipates that EPA will make substantial changes to the proposed 316 (b) Rule prior to publication of the final rule in 2012. For these reasons it is unclear what the reliability impacts to specific generating units will be as a result of the final rule.

However, if the final rule requires a significant number of cooling tower installations, FPL believes that the currently proposed timeline for the rule's implementation could result in overlapping requirements for generating units to be off line at the same time. The proposed rule would require entrainment studies and agency approval on an eight year schedule from the effective date of the rule. This schedule may find facility owners competing for the same contractor services and equipment suppliers. FPL believes that EPA should tailor the compliance schedules to the due dates of each facility's five year NPDES permit renewal. This option would stagger when units come in for compliance associated with the 316 (b) rule and would avoid the higher costs associated with competing for vendors and equipment and would reduce the potential reliability impacts associated with units going off line to add control equipment.

Several models have predicted that numerous power plants, particularly small, inefficient and older coal and natural gas-fired units will be required to retire if forced to install cooling towers to achieve compliance with the entrainment and or impingement criteria established by the pending 316 (b) rule. Again it is much too soon to predict how the final rule will impact the generation fleet; however, as currently proposed the 316 (b) includes several requirements that are unnecessarily burdensome and could drive several plant retirements throughout Florida and the U.S. Specifically, the current rule proposes numeric impingement Mortality (IM) limits that FPL believes are overly stringent and in many cases are infeasible. As proposed, facilities affected by the rule would have to meet impingement Mortality criteria that limit the mortality of species of concern to 12% annually or 31% in any given month. This "one size fits all" approach to compliance is not workable for many power plants throughout the country. In fact EPA has based these numeric criteria on data from only three power plants out of more than 600 plants that will be affected by the rule. Of these three facilities evaluated, all were in one region of the country and only one was on a saltwater body. FPL believes it is impractical to attempt to apply these unrealistic IM criteria to all power plants. To achieve this criteria EPA offers a menu of control options that also are not always practical at various power plants. We are hopeful that our advocacy efforts during rulemaking will result in alternatives that will prevent the requirement to install costly cooling towers to meet IM limits. However, if we are unsuccessful and the IM numeric criteria cannot be achieved, the proposed rule would require closed cycle cooling through the installation of the most expensive and operationally complex control option--cooling towers.

FPL believes that EPA .should revise the impingement mortality portion of their rule to establish presumptive 'Best Technology Available" options that are assumed to achieve the goal of reducing adverse environmental impacts. If these presumptive BTA options are not feasible EPA should allow cost benefit analysis and site specific considerations to be coordinated by the State Permitting Director (Florida Department of Environmental Protection) for. The cost benefit analysis and site specific considerations are already available for the determination of BTA for entrainment and should also be allowed for impingement evaluations.

Though we believe FPL will identify alternative control options for our facilities, FPL believes that without these revisions to the proposed 316 (b) rule several power plants throughout the state may be required to add cooling towers unnecessarily and due to the costs and operational complexities of these cooling towers some facilities may be forced to retire. Though Florida does not currently have projections of power plant retirements associated with the 316 (b) rule a recent study by ERCOT in Texas projects that the rule would result in the retirement of 8,100 MW of older combined cycle natural gas fired plants.

3. **Discuss compliance strategies your company intends to employ to comply if EPA's proposed Air Toxics and Cooling Water Intake Structures rules are implemented, including but not limited to plant retirements, fuel switching, and the type and timing of replacement units, if necessary.**

Air Toxics Rule

Oil-Fired Generating Units--As noted above, FPL is pursuing the installation of ESPs at the 800 MW oil fired generating units at Martin and Manatee Plants. These ESPs will meet the proposed Hazardous Air Pollutant Total Metals limits proposed by EPA. FPL has secured contractor guarantees that the ESPs to be installed at these facilities will meet the EPA proposed emissions limits. If the final rule requires a limit on HCL emissions FPL may be required to install hydrated lime injection ports to reduce the formation of acid gas. However, if comments and additional information presented to EPA convince the agency to permit the use of best management practices for the control of HCL emissions, then FPL would be able to comply without the installation of any additional emission control equipment and instead would simply comply with additional monitoring and recordkeeping requirements associated with operation and maintenance of the plants.

As requested by EPA, FPL will comment on the option of a Limited Use Provision that reduces or eliminates control requirements for low capacity factor oil fired generating units. We would plan to apply this option to Turkey Point Plant Unit 1. If the Limited Use Provision is not incorporated in the final rule FPL will review the options of installing an ESP at this generating unit.

An additional compliance burden expected at all affected generating units, based on requirements in the proposed rule, is a significant increase in emissions and fuel sampling and analysis. This additional activity may require additional stack test sampling crews, contractors and electronic data base monitoring and reporting capabilities to track emissions data. FPL anticipates that the magnitude of data management associated with the Air Toxics Rule, the pending Clean Air Transport Rule and EPA's already adopted GHG Reporting Rule may require a commercially available information management system as these numerous additional tasks will exceed the capabilities of each plant's existing personnel.

Until the rule is final, we are unable to accurately assess whether additional controls beyond those required at the 800 MW units are necessary nor are we able to determine whether units will be required to retire or be replaced.

Coal fired units—As noted above, Scherer Unit 4 is in the process of adding controls that will meet the emissions limits established under the currently proposed rule and expected in the final Air Toxics Rule. The primary additional impact to the facility will be increased testing, and monitoring criteria and record keeping for HAPS metals, mercury and acid gases.

Also as noted above, FPL and our ownership partner at SJRPP are evaluating the optimum methods for meeting the compliance requirements of the Air Toxics Rule. No decisions for compliance have yet been made.

Cooling Water Intake Structure--Section 316 (b) Rule—Because of uncertainty over the form of the final 316 (b) Rule and the extensive evaluation process that is likely to be required under any final form of the rule, FPL is currently unable to project which generating units would be required to install impingement controls, the types of impingement controls that will be required or whether cooling towers will be required. Each facility would require generally five years of study and comprehensive plans to determine a recommendation of the Best Technology Available to meet impingement and entrainment Criteria. An additional three years is likely for agency review, comment, and construction of the approved compliance option.

4. **Discuss what would be required, on a unit by unit basis, to comply with EPA's proposed Air Toxics and Cooling Water Intake Structures rules. Provide any available compliance strategies or expected costs for each unit.**

Air Toxics Rule—See answers to above questions for discussion on what would be required to respond to the Air Toxics Rule. On a plant-by-plant cost the estimates are listed below.

Plant	Control Technology	Costs Estimate	Comments
Manatee Units 1 and 2	ESPs	$154 million	
Martin Units 1 and 2	ESPs	$149 million	
Turkey Point Unit 1	ESPs	$ 77 million	Only likely if Limited Use Provision is not adopted in Final Rule
St. Johns River Power Park	Control requirements uncertain, still under review	Unknown	Some additional method of SO2 and HCL and mercury controls likely

Cooling Water Intake Structure--Section 316 (b) Rule—As noted above, FPL cannot predict the actual requirements for the installation of Best Technology Available controls at specific power plants at this time. The rule will first need to be finalized and extensive comprehensive studies will be required at each facility before the necessary controls will be approved by the state permitting director. Options for responding to the rule would include the most conservative response including closed cycle cooling tower installations. One of the lower costs options for compliance may be the installation of additional intake structure bays to reduce the velocity of intake water flow to 0.5 feet/second. An estimate of facility costs for cooling towers and additional intake bay construction is provided in the two tables below. The cost for cooling towers was developed by the Electric Power Research Institute.

Note: the installation of cooling towers or the addition of additional intake bays may not feasible or cost effective at each facility. The determination of the Best Technology Available will require site specific cost benefit analysis.

Costs Estimates to Install Cooling Towers*
Source: Electric Power Research Institute

Plant	Control Option	Low to High Costs	Issues/Concerns
Cape Canaveral	Cooling Towers	$88-$228 million	Manatees/Spatial limits
Ft. Myers	Cooling Towers	$81-$210 million	Manatees
Fort Lauderdale	Cooling Towers	$41-$106 million	
Port Everglades	Cooling Towers	$139-$361 million	Spatial limits/Airport
Riviera Beach	Cooling Towers	$63-$163 million	Manatees/Spatial limits
St. Lucie Nuclear	Cooling Towers	$156-$404 million	Velocity cap should be BTA

Estimated costs to construct additional intake bays to achieve 0.5 fps intake flow velocity*

Plant	Intake Velocity feet/second	# of new bays/screens required	Estimated Costs
Cape Canaveral	2.9	10	$ 44 million
Ft. Myers	1.4 to 2.4	6	$ 27 million
Fort Lauderdale	1.7-	5	$ 22 million
Port Everglades	1.9-2.9	9	$ 40 million
Riviera Beach	2.6	8	$ 35 million
St. Lucie			New intake bays not practical/Velocity cap should be BTA

*Martin and Manatee Units 1 and 2 receive cooling water from closed cycle cooling ponds. Though these facilities may need some impingement controls additional intake bays or cooling towers are impractical. FPL will comment to EPA that closed cycle cooling ponds are BTA and should require no further controls. Cutler Plant and Sanford Unit 3 are not shown due to scheduled 2012 retirement.

5. **Does your company intend to file comments on EPA's proposed Air Toxics rule, Cooling Water Intake Structures rule, or both rules? If so, when does your company expect to have these comments completed?**

Yes, FPL will file comments on both the Air Toxics and 316 (b) rules. Comments for the Air Toxics Rule are due July 5, 2011. Comments for the 316 (b) Rule are due July 19, 2011. Note: FPL and several others have requested a 60 day extension to the comment period for the 316 (b) rule. We do not expect to have the comments completed until the due dates for each rule.

Q.

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 on-Hazardou Waste	CCR Special Waste

A.

See Attachment No. 1.

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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
Cape Canaveral 3	CC	NG, ULSD	1219	N/A	Emission Allowance Management	Installation of additional controls	N/A	N/A
Cutler 5	ST	NG	64	N/A	Emission Allowance Management	N/A	N/A	N/A
Cutler 6	ST	NG	137	N/A	Emission Allowance Management	N/A	N/A	N/A
Fort Myers Gas Turbines 1-12	GT	DFO	552	N/A	Emission Allowance Management	N/A	N/A	N/A
Fort Myers 2	CC	NG	1349	N/A	Emission Allowance Management	Installation of additional controls	N/A	N/A
Fort Myers CT's	GT	NG, ULSD	296	N/A	Emission Allowance Management	N/A	N/A	N/A
Lauderdale 4	CC	NG	438	N/A	Emission Allowance Management	Installation of additional controls	N/A	N/A
Lauderdale 5	CC	NG	438	N/A	Emission Allowance Management	Installation of additional controls	N/A	N/A
Lauderdale Gas Turbines 1-12	GT	NG, DFO	342	N/A	Emission Allowance Management	N/A	N/A	N/A
Lauderdale Gas Turbines 13-24	GT	NG, DFO	342	N/A	Emission Allowance Management	N/A	N/A	N/A
Port Everglades Gas Turbines 1-12	GT	NG, DFO	342	N/A	Emission Allowance Management	N/A	N/A	N/A
Port Everglades 1	ST	NG, RFO	203	ESP Already Installed	Emission Allowance Management	N/A	N/A	N/A
Port Everglades 2	ST	NG, RFO	203	ESP Already Installed	Emission Allowance Management	N/A	N/A	N/A

Port Everglades 3	ST	NG, RFO	370	ESP Already Installed	Emission Allowance Management	N/A	N/A	N/A
Port Everglades 4	ST	NG, RFO	370	ESP Already Installed	Emission Allowance Management	N/A	N/A	N/A
Port Everglades 5	CC	NG, ULSD	1219	N/A	Emission Allowance Management	Installation of additional controls	N/A	N/A
Riviera 5	CC	NG, ULSD	1219	N/A	Emission Allowance Management	Installation of additional controls	N/A	N/A
Sanford 3	ST	NG, RFO	138	Limited Oil Use	Emission Allowance Management	N/A	N/A	N/A
Sanford 4	CC	NG	910	N/A	Emission Allowance Management	Additional controls not likely to be required	N/A	N/A
Sanford 5	CC	NG, DFO	896	N/A	Emission Allowance Management	Additional controls not likely to be required	N/A	N/A
Turkey Point 1	ST	NG, RFO	385	Limited Oil Use	Emission Allowance Management	N/A	N/A	N/A
Turkey Point 2	ST	NG, RFO	0	N/A	Emission Allowance Management	N/A	N/A	N/A
Turkey Point 3	PWR	NUC	693	N/A	N/A	N/A	N/A	N/A
Turkey Point 4	PWR	NUC	693	N/A	N/A	N/A	N/A	N/A
Turkey Point 5	CC	NG, ULSD	1049	N/A	Emission Allowance Management	N/A	N/A	N/A
Manatee 1	ST	NG, RFO	792	ESP Installation 2013	800 MW Cycling Project Complete	Additional controls not likely to be required	N/A	N/A
Manatee 2	ST	NG, RFO	792	ESP Installation 2012	800 MW Cycling Project Complete	Additional controls not likely to be required	N/A	N/A
Manatee 3	CC	NG	1054	N/A	Emission Allowance Management	Additional controls not likely to be required	N/A	N/A
Martin 1	ST	NG, RFO	795	ESP Installation 2014	800 MW Cycling Project Complete	Additional controls not likely to be required	N/A	N/A
Martin 2	ST	NG, RFO	799	ESP Installation 2015	800 MW Cycling Project Complete	Additional controls not likely to be required	N/A	N/A

Martin 3	CC	NG, RFO	423	N/A	Emission Allowance Management	Additional controls not likely to be required	N/A	N/A
Martin 4	CC	NG	423	N/A	Emission Allowance Management	Additional controls not likely to be required	N/A	N/A
Martin 8	CC	NG, ULSD	1070	N/A	Emission Allowance Management	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Martin 9	ST	SUN	75*	N/A	N/A	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
St. Lucie 1	PWR	NUC	839	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
St. Lucie 2	PWR	NUC	745*	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
Putnam 1	CC	NG, DFO	239	N/A	Emission Allowance Management	No additional controls expected	N/A	N/A
Putnam 2	CC	NG, DFO	239	N/A	Emission Allowance Management	No additional controls expected	N/A	N/A
West County Energy Center 1	CC	NG, ULSD	1219	N/A	Emission Allowance Management	N/A	N/A	N/A
West County Energy Center 2	CC	NG, ULSD	1219	N/A	Emission Allowance Management	N/A	N/A	N/A
West County Energy Center 3	CC	NG, ULSD	1219	N/A	Emission Allowance Management	N/A	N/A	N/A
SJRPP 1	ST	BIT	127**	Study Underway	SCR Installed	No additional controls expected	On-Site Disposal & Loss of By-Product Sales	Off-Site Disposal & Loss of By-Product Sales
SJRPP 2	ST	BIT	127**	Study Underway	SCR Installed	No additional controls expected	On-Site Disposal & Loss of By-Product Sales	Off-Site Disposal & Loss of By-Product Sales
Scherer 4	ST	SUB	648**	Hg Control Installed 2010, FGD Installation 2012	SCR & FGD Installed 2012	No additional controls expected	On-Site Disposal & Loss of By-Product Sales	On-Site Haz Disposal & Loss of By-Product Sales
Space Coast Solar Energy	PV	SUN	10	N/A	N/A	N/A	N/A	N/A
Desoto Solar Energy	PV	SUN	25	N/A	N/A	N/A	N/A	N/A

Unit Type: ST = Steam Turbine, GT = Gas Turbine, CC = Combined Cycle, PV = Photovoltaic
Fuel Type: NG = Natural Gas, DFO = Distillate Fuel Oil, RFO = Residual Fuel Oil, ULSD = Ultra-Low Sulfur Distillate, BIT = Bituminous Coal, SUB = Sub-Bituminous Coal, SUN = Solar (PV & thermal), NUC = Nuclear

Notes: * Unit capability also included in Martin Unit 8 Net Summer Capability
** FPL Ownership Share only

Q.

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

A.

Please see confidential Attachment No. 1.

Q.

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

A.

Table provided as Attachment No. 1. Schedule for rule implementation is as follows:

MATS Key Dates:

EPA Secretary Jackson signs final rule:	December 21, 2011
Final rule is published in federal Register:	March 16, 2012
Final Rule is Effective (60 days after publication):	May 15, 2012
Compliance with emission standards :	May 15, 2015
(For units adding emission controls):	May 15, 2016

CSAPR Key Dates:

EPA Secretary Jackson signs final rule:	July 6, 2011
Final rule is published in federal Register:	August 8, 2011
Technical adjustments (incl. Florida)	October 6, 2011
DC Circuit Court of Appeals stay issued:	December 30, 2011
CAIR Reinstated (while is stay in effect)	January 1, 2012
Briefs by parties to DC Circuit:	March 1, 2012
Oral Argument:	April 13, 2012
Court decision on CSAPR stay:	June – November 2012

CWIS Key Dates:

EPA Secretary Jackson signs final rule:	July 27, 2012
Final rule is published in federal Register (estimated):	August 24, 2012
Final Rule is Effective (60 days after publication):	October 23, 2012
Various studies required:	2012-2017
Compliance with Impingement Mortality Standards (5- 8 years after rule is effective):	October 23, 2020
Compliance with Entrainment Standards	No set date:

CCR Key Dates:

Final rule is published in federal Register:	June 21, 2010
Final rule is published in federal Register:	March 16, 2012
Third party lawsuit to compel EPA to issue final rule:	April 5, 2012
Final Rule (estimated):	Late 2012 – Early 2013

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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
Cape Canaveral 3	CC	NG, ULSD	1219	N/A	N/A	1/2013 - Completed during construction	N/A	N/A
Cutler 5	ST	NG	64	N/A	N/A	N/A	N/A	N/A
Cutler 6	ST	NG	137	N/A	N/A	N/A	N/A	N/A
Fort Myers Gas Turbines 1-12	GT	DFO	552	N/A	N/A	N/A	N/A	N/A
Fort Myers 2	CC	NG	1349	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
Fort Myers CT's	GT	NG, ULSD	296	N/A	N/A	N/A	N/A	N/A
Lauderdale 4	CC	NG	438	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
Lauderdale 5	CC	NG	438	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
Lauderdale Gas Turbines 1-12	GT	NG, DFO	342	N/A	N/A	N/A	N/A	N/A
Lauderdale Gas Turbines 13-24	GT	NG, DFO	342	N/A	N/A	N/A	N/A	N/A
Port Everglades Gas Turbines 1-12	GT	NG, DFO	342	N/A	N/A	N/A	N/A	N/A
Port Everglades 1	ST	NG, RFO	203	N/A	N/A	N/A	N/A	N/A
Port Everglades 2	ST	NG, RFO	203	N/A	N/A	N/A	N/A	N/A
Port Everglades 3	ST	NG, RFO	370	N/A	N/A	N/A	N/A	N/A

Port Everglades 4	ST	NG, RFO	370	N/A	N/A	N/A	N/A	N/A
Port Everglades 5	CC	NG, ULSD	1219	N/A	N/A	2016 - Completed during construction	N/A	N/A
Riviera 5	CC	NG, ULSD	1219	N/A	N/A	2014 - Completed during construction	N/A	N/A
Sanford 3	ST	NG, RFO	138	N/A	N/A	N/A	N/A	N/A
Sanford 4	CC	NG	910	N/A	N/A	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Sanford 5	CC	NG, DFO	896	N/A	N/A	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Turkey Point 1	ST	NG, RFO	385	N/A	N/A	N/A	N/A	N/A
Turkey Point 2	ST	NG, RFO	0	N/A	N/A	N/A	N/A	N/A
Turkey Point 3	PWR	NUC	693	N/A	N/A	N/A	N/A	N/A
Turkey Point 4	PWR	NUC	693	N/A	N/A	N/A	N/A	N/A
Turkey Point 5	CC	NG, ULSD	1049	N/A	Emission Allowance Management	N/A	N/A	N/A
Manatee 1	ST	NG, RFO	792	09/2012 - 7 months	800 MW Cycling Project Complete	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Manatee 2	ST	NG, RFO	792	10/2011 - 7 months	800 MW Cycling Project Complete	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Manatee 3	CC	NG	1054	N/A	N/A	If requirred - 2018 - No impact to plant operation	N/A	N/A
Martin 1	ST	NG, RFO	795	06/2013 - 9 months	800 MW Cycling Project Complete	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Martin 2	ST	NG, RFO	799	03/2014 - 9 months	800 MW Cycling Project Complete	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Martin 3	CC	NG, RFO	423	N/A	N/A	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A

Martin 4	CC	NG	423	N/A	N/A	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Martin 8	CC	NG, ULSD	1070	N/A	N/A	If required - 2017-2020 time frame - No impact to plant operation	N/A	N/A
Martin 9	ST	SUN	75*	N/A	N/A	N/A	N/A	N/A
St. Lucie 1	PWR	NUC	839	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
St. Lucie 2	PWR	NUC	745*	N/A	N/A	2017-2020 time frame - Completed during normal outages	N/A	N/A
Putnam 1	CC	NG, DFO	239	N/A	N/A	N/A	N/A	N/A
Putnam 2	CC	NG, DFO	239	N/A	N/A	N/A	N/A	N/A
West County Energy Center 1	CC	NG, ULSD	1219	N/A	N/A	N/A	N/A	N/A
West County Energy Center 2	CC	NG, ULSD	1219	N/A	N/A	N/A	N/A	N/A
West County Energy Center 3	CC	NG, ULSD	1219	N/A	N/A	N/A	N/A	N/A
SJRPP 1	ST	BIT	127**	Study Underway	N/A	No impacts expected	No impacts expected	Study Underway, completed during normal outages
SJRPP 2	ST	BIT	127**	Study Underway	N/A	No impacts expected	No impacts expected	Study Underway, completed during normal outages
Scherer 4	ST	SUB	648**	Underway, installation to be completed by June 2012	N/A	No impacts expected	No impacts expected	Study Underway, completed during normal outages
Space Coast Solar Energy	PV	SUN	10	N/A	N/A	N/A	N/A	N/A
Desoto Solar Energy	PV	SUN	25	N/A	N/A	N/A	N/A	N/A

Unit Type: ST = Steam Turbine, GT = Gas Turbine, CC = Combined Cycle, PV = Photovoltaic
Fuel Type: NG = Natural Gas, DFO = Distillate Fuel Oil, RFO = Residual Fuel Oil, ULSD = Ultra-Low Sulfur Distillate, BIT = Bituminous Coal, SUB = Sub-Bituminous Coal, SUN = Solar (PV & thermal), NUC = Nuclear
Notes: * Unit capability also included in Martin Unit 8 Net Summer Capability
** FPL Ownership Share only

Q.

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.).

A.

Please see FPL's response to Staff's 1st DR No. 46.

Q.

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)				

A.

Please see Attachment No. 1.

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EPA Rule	Capital Costs ($ Millions)	O&M Costs ($ Millions)	Fuel Costs ($ Millions)	Total Costs ($ Millions)
Mercury and Air Toxics Standards (MATS) Rule*	$223	$6	(N/A)***	$226
Cross-State Air Pollution Rule (CSAPR)**	$0	$7	(N/A)***	$0
Cooling Water Intake Structures Rule (CWIS)	$95-$1339	$27-$176	(N/A)***	$122 - $1515
Coal Combustion Residuals Rule (CCR)	Waiting for Final Rule	Waiting for Final Rule	(N/A)***	Waiting for Final Rule

Note: * Includes O&M costs for complaince with CAMR & Georgia Multi-Pollutant Rule
** Includes O&M costs for complaince with CAIR & Georgia Multi-Pollutant Rule
*** FPL has not currently forecasted changes to unit operation or dispatch that would result in fuel changes

Q.

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)

A.

FPL does not anticipate any system reliability impacts associated with the compliance requirements of the MATS Rule, CSAPR Rule, CWIS Rule or the CCR Rule including generating unit reliability, transmission system constraints, and installation of controls on units not regulated by these rules, nor does FPL anticipate early retirement of units in response to these regulations. FPL evaluates the potential impacts to unit operation based on proposed and draft rule language that identifies compliance requirements for environmental regulations. For the final MATS and CSAPR rules FPL has not identified any impacts to unit or system reliability, or capability, from its planned compliance strategy. With the Court's stay of the CSAPR, the EPA was required to implement the CAIR requirements instead of CSAPR until the stay is lifted or a replacement rule is promulgated. FPL's CAIR compliance plan has not, and will not, impact generating unit or system reliability or capability. FPL's projected compliance plan is based on current fuel availability and price forecasts, planned generating unit availability, purchase power contracts, and projected system load. However, should future actual conditions vary significantly from projection assumptions, reliability impacts could occur.

For the CWIS and CCR rules FPL has evaluated anticipated compliance requirements based on EPA and industry comments, but cannot yet know the appropriate compliance strategy until the final rules are promulgated. FPL has evaluated the potential requirements and developed a range of costs associated with the various compliance requirements that we anticipate could be included in the final rules. Impacts for CWIS will vary based on the level of modifications required by the final rule and the results of subsequent studies and negotiations with FDEP permit writers. Should, as is currently expected, modified Ristroph type traveling screens and fish return systems, along with the possibility of variable speed drive circulating (cooling) water pumps be required, for most facilities (those without cooling ponds or cooling towers), the impacts should be minimal where installations could be accommodated during scheduled maintenance outages. Under the anticipated rule requirements for CWIS, FPL has not identified system reliability impacts which would be anticipated to occur. FPL's compliance plan for the proposed CCR regulations depends on the final form of the regulation and the outcome of any legal challenges, and cannot be determined at this time given the breadth of requirements being considered under the three approaches proposed by EPA. While FPL, and the co-owners of its coal fired generating units, maintain that the appropriate designation of CCR's continue as non-hazardous, additional regulation of coal combustion by-products could have a significant impact on management, beneficial use, and disposal of such by-products. Impacts for compliance with changes in the regulatory status of CCR's for FPL's co-owned coal units are not anticipated to create impacts to the reliability of any generating unit or FPL's system.

Q.

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

A.

FPL operates its Electric Generating Units in compliance with all applicable federal, state and local regulations that limit impacts to waste generation and disposal, air emissions and water quality impacts. Compliance with permit requirements requires FPL to monitor and operate facilities within specific allowable limits at all times. Environmental restrictions relating to air quality, water quality or waste from facility operations are incorporated within those permits, and operating procedures are implemented at FPL's facilities to ensure compliance.

FPL reviews proposed and final federal environmental regulatory requirements, and proposed legislation, on a routine basis to evaluate potential impacts to existing unit operation and generation expansion planning. FPL's evaluation includes both a regulatory review of rules to determine the appropriateness of proposed rule language and also a review of FPL system or unit changes which may be required to comply with the rule requirements. As part of the rule language review FPL participates in reviews with other Florida utilities, including members of the Florida Coordinating Group, and on a national level with various organizations including the Edison Electric Institute, The Business Roundtable, Utility Solid Waste Activity Group, Utility Water Act Group, the Class of '85 Regulatory Response Group, and the Clean Energy Group. Where warranted, FPL files comments either in support of rule language that benefits our customers or opposing rule language that does not.

During the review of rule compliance requirements, potential impacts to facility operation or generating unit equipment are evaluated to determine what changes would be required for compliance. Where significant changes to existing system or unit operations might be required for compliance with new requirements, FPL initiates engineering studies to evaluate potential changes to existing unit operation including emissions, efficiency, reliability, and operational flexibility. FPL then evaluates the impacts of identified compliance strategies on system generation costs through the use of production cost modeling and sensitivity analyses. Effects to FPL unit operations can be quantified and evaluated to determine customer impacts from changes in fuel costs and revenue requirements from the identified compliance strategies and to identify those which provide the greatest customer benefit. Compliance strategies are then reviewed to determine if regulatory timelines for compliance would impact system reliability or existing planned outages.

Q.

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

A.

FPL reviews the language of final EPA rules to assess the impact of any changes in the final version from proposed rule language. If changes to rule language are identified, a review of the compliance strategy is conducted to determine whether modifications to planned projects are necessary and potential associated costs are evaluated. In those instances where FPL believes that the EPA has proposed rule language which we believe will adversely impact our goal of providing affordable clean energy, FPL either files on its own or participates in groups that file petitions for reconsideration and/or petitions for judicial review to ensure our customers' interests are represented.

Regulatory changes which impose environmental restrictions are ultimately incorporated within the operating permits as changes to existing limits or as new requirements. Compliance with existing permits and new requirements is continuous, on a unit and fleet-wide basis. Changes to operations of facilities to comply with existing and new requirements are included in planned operating costs, and in unit generating performance impacts, for unit dispatch and production costing modeling. Impacts to operation of facilities include, but are not limited to, the installation of new pollution controls (which may impact unit efficiency and generation output), purchase of emission allowances, changes to fuels that can be combusted, unit operating restrictions including changes to the number of allowable operating hours and unit capacity, use of alternative products where applicable, and unit retirement/replacement.

FPL cannot project future impacts to its generating unit operation that would result from future environmental regulations which EPA and States have not yet proposed or provided information related to planned changes to federal and state implementation plans. However, to the extent possible, FPL evaluates its compliance with the various air, water and waste regulations affecting electric generating facilities in its compliance plans. As an example, FPL includes the evaluation of impacts to water resources, air quality and off-site impacts during its annual planning process which includes potential future CO_2 emission costs and SO_2 and NO_x allowance costs. Final compliance strategies which require additional environmental capital and O&M costs that are identified for new air, water, and waste compliance requirements are included as new projects, or as modifications to existing projects, for recovery by FPL through the Environmental Cost Recovery Clause (ECRC).

Q.

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.

A.

FPL cannot know what EPA will ultimately require for compliance until a final rule is published in the Federal Register. However, during the evaluation of proposed EPA rules, FPL works diligently with other utilities and regulatory response groups to help inform EPA on the appropriateness of rule requirements during the rulemaking process. FPL includes those compliance requirements in its evaluation of proposed rules that we, and the electric utility industry, believe are most likely to be included in final rule language. As discussed in FPL's response to Staff's DR Nos. 48 & 49, strategies are identified through the use of engineering studies and production cost modeling using the best information available on the final and proposed rules for new environmental requirements and most recent projections assumptions. Reviews of impacts of environmental regulations include the effects on purchase power agreements and energy purchases where impacts to generating units are known. FPL evaluates the results of studies to determine those strategies which provide low production costs and maintain fuel flexibility, generating unit and system reliability. Those strategies which provide the best long term benefit for customers are identified as the optimum compliance strategy. As new environmental regulations are promulgated, FPL includes in its analysis existing environmental compliance costs to identify strategies which include the overall cost to comply with new and existing regulations.

Q.

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?

A.

FPL's significant costs for compliance with environmental regulations during the past 5 years include the following projects:

1. EPA Clean Air Interstate Rule (CAIR);
2. EPA Clean Air Mercury Rule (CAMR);
3. Georgia Multi-Pollutant Rule (GMPR);
4. Cross-State Air Pollution Rule (CSAPR); and
5. EPA Mercury and Air Toxics Standards (MATS) Rule.

FPL considers capital costs in excess of $1 million as a significant cost related to operation and maintenance of generating units. In its response FPL has not included other significant environmental costs but rather has provided those costs in response to environmental regulations. Examples of significant environmental costs that were not in response to EPA regulation include the construction of the Desoto and Space Coast solar generating stations, and the 2007 & 2008 costs for installation of Electro-Static Precipitators (ESPs) at Port Everglades required by their revised air operating permit.

CAIR

Capital compliance costs for CAIR include the 800 MW Cycling project, installation of SCR at SJRPP Units 1 & 2, installation of SCR and Flue Gas Desulfurization (FGD) Scrubber on Scherer Unit 4, and installation of CEMS on the Gas Turbine Peaking Units. Total actual capital costs for installation of these projects through 2011 are $949 million. Installation of SCR and FGD on Scherer Unit 4 by December 2012 is also required by the Georgia Multi-Pollutant Rule. As discussed in its response to Interrogatory 41, FPL's plan for compliance with CAIR requirements are also included as our strategy to comply with the CSAPR and a portion of the Georgia Multi-Pollutant Rule. The Court's decision to remand CSAPR and once again implement CAIR until the stay is lifted or a replacement rule is promulgated does not affect FPL's CAIR compliance strategy.

CAMR

FPL's compliance with CAMR, which was vacated by the court after FPL began implementation of compliance requirements, is limited to the SJRPP and Scherer Unit 4 coal-fired generating units. CAMR required FPL to install mercury emission monitoring systems on all 3 units and to meet emission standards for mercury which required installation of a bag-house / sorbent injection system on Scherer Unit 4. Prior to the Court's vacatur of CAMR, the State of Georgia finalized the Georgia Multi-Pollutant Rule (GMPR) that required the installation of mercury emission controls on Scherer Unit 4 no later than December 2010. FPL's capital cost for implementation of its CAMR project was $107.3 million through 2011.

CAMR emission specifications for coal fired electric generating units have effectively been incorporated into the MATS rule for mercury and installation of the baghouse – sorbent injection system at Plant Scherer, also required under GMPR, provides sufficient mercury reduction on Unit 4 to meet that MATS requirement.

GMPR

To address specific concerns related to the emission of mercury, and to limit impacts of the emission of ozone and fine particulate matter precursors from coal plants in Georgia, the Environmental Protection Division promulgated the Georgia Multi-Pollutant Rule (GMPR). The GMPR required specific emission controls, or retirement in the alternative, for all coal generating units within the state by specific dates. Installation of controls for the GMPR had already been included within FPL's implementation of its compliance plant for CAIR and CAMR. Costs to meet GMPR are included in the CAIR and CAMR projects discussed above.

CSAPR

The EPA Cross-State Air Pollution Rule (CSAPR) was finalized in 2011 to replace the vacated CAIR. The CSAPR requires FL facilities to comply only with the Ozone Season cap-and-trade program. FPL, along with industry groups including the Florida Coordinating Group (FCG), petitioned EPA to reconsider various aspects of its final rule.Specifically FPL and FCG believe that EPA did not allocate sufficient allowances to Florida to accommodate future growth in generation within the state needed to meet demand. In December 2011 the DC Circuit Court of Appeals issued a stay for the implementation of CSAPR and ordered that CAIR be implemented while the Court considered the merits of a final stay. FPL's compliance plan for the CSAPR cap-and-trade program included only the surrender of emission allowances allocated to FPL as necessary and purchase of future allowances should the state choose to allocate allowances differently than EPA has done. Controls installed at Plant Scherer for GMPR, the controls installed at SJRPP and the Martin and Manatee 800 MW Cycling Project for CAIR compliance, and the addition of the West County generating units to meet demand growth have significantly reduced FPL's NOx emissions currently regulated under CSAPR. While the final terms of CSAPR are unknown at this time, FPL expects that the capital investments it has made to comply with earlier rules will also allow FPL to comply with CSAPR.

MATS

EPA proposed its Air Toxics rule on March 16, 2011 for the control of emissions of Air Toxics from oil- and coal fired steam electric generating units. At that time EPA proposed emission standards for mercury emissions from coal fired units that would require use of mercury controls for sub-bituminous coal units, acid gas standards that would require installation and use of FGD for all coal units, and Electro-Static Precipitators (ESPs) on oil fired units for control of toxic metal particulate emissions. At that time FPL conducted a study of its generating units and concluded that the installation of the Sorbant Injection / Baghouse and FGD on Scherer Unit 4 for compliance with the GMPR would meet MATS emission standards and that ESPs would be needed on the 800 MW generating units at Martin and Manatee to maintain fuel diversity and meet required particulate emission standards. FPL actively worked with EPA to inform that agency on alternative work practices for the proposed acid gas standard for oil fired units.

FPL proposed its compliance plan for its 800 MW unit ESP project to the Commission as the most cost effective compliance option available to the company and that the company would need to start construction beginning in 2011 to meet the tight compliance timelines allowed under the Clean Air Act. FPL was given approval to begin construction for the first control installation and that if EPA's final rule required ESPs the company could seek recovery of costs under the ECRC process. EPA promulgated its final rule on March 16, 2012 which established the final standards where compliance with standards will be required by May 2015. FPL's actual costs in 2011 for implementation of the 800 MW ESP project was $32.5 million. In its August 2020 filing for recovery of the ESP project under ECRC, FPL estimated the total capital cost at $303 million. FPL's current capital cost estimate for installation of the ESP's on the 800 MW units at Martin and Manatee plants is $222.5 million. FPL and JEA have initiated a study to review compliance and fuel flexibility options at SJRPP to meet MATS and comply with upcoming standards under 316b and Steam Electric Effluent Guidelines for waste water discharge.

Q.

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

A.

FPL has included, as attachments (See Attachment Nos. 1-16), comments filed directly by the Company and those filed by industry groups in which FPL participated in drafting and reviewing comments.

NEXTera ENERGY

October 1, 2010

Docket ID No. EPA–HQ–OAR–2009–0491
EPA Docket Center, EPA West (Air Docket)
Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
(submitted through www.regulations.gov)

Re: Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone—Proposed Rule

To Whom It May Concern:

Provided below are NextEra Energy, Inc.'s (formerly FPL Group, Inc.) comments on the Environmental Protection Agency's (EPA's) proposed *Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone* ("Transport Rule") published in the Federal Register on August 2, 2010 (75 FR 45210).

NextEra Energy is a leading clean-energy company with 2009 revenues of more than $15 billion, nearly 43,000 megawatts of generating capacity, and more than 15,000 employees in 28 states and Canada. Headquartered in Juno Beach, Florida, NextEra Energy's principal subsidiaries are NextEra Energy Resources, LLC, the largest generator in North America of renewable energy from the wind and the sun, and Florida Power & Light Company (FPL), which serves approximately 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country. FPL has been recognized as having one of the most successful energy-efficiency programs in the nation. Through its subsidiaries, NextEra Energy collectively operates the third largest U.S. nuclear power generation fleet.

NextEra Energy has one of the cleanest energy profiles in the electric sector. Since 1990, while the Company's power generation has increased by 230 percent, our nitrogen oxides (NOx) emissions rate has decreased by 88 percent, our sulfur dioxide (SO_2) emissions rate has decreased by 87 percent and our carbon dioxide (CO_2) emissions rate has decreased by 31 percent. Notwithstanding the Company's clean energy profile, NextEra Energy owns and operates a substantial amount of fossil fuel-fired electric generation in the Eastern U.S. that will be subject to the proposed Transport Rule. Therefore, we have a keen interest in the final outcome of the rule.

General Comments on the Proposed Transport Rule

Overall, NextEra Energy supports EPA's proposed Transport Rule because it will achieve important air quality and health benefits. In our view, it is critical that EPA implement the rule as expeditiously as practicable, and we are committed to supporting EPA's implementation of the Transport Rule by January 1, 2012.

The fundamental purpose of the Transport Rule is to address the Section 110(a)(2)(D)(i)(I) requirement that states do not contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary national ambient air quality standard (NAAQS). Several of NextEra Energy's power plants operate in downwind states where the transport of emissions from upwind states contribute significantly to nonattainment with the ozone and fine particulate ($PM_{2.5}$) NAAQS. Our company has made substantial investments in clean energy technologies and advanced emission control technologies to improve the air quality in the areas in which we operate. Despite these efforts, however, transported pollution from upwind states prevents many of these areas from meeting air quality standards.

The framework proposed by the Transport Rule would take necessary and important steps toward improving air quality in the eastern U.S. As EPA notes in the preamble and supporting materials for the Transport Rule, the Agency's air quality modeling demonstrates that the Transport Rule would help many areas in the Eastern U.S. attain the current NAAQS. The proposal would also establish a framework that would allow EPA to address any transport problems associated with future NAAQS revisions (e.g., revisions to the 8-hour ozone NAAQS expected in October).

With the possible exception of EPA's proposed allowance allocation approach (see discussion beginning on Page 3 of our comments), NextEra Energy believes that the proposed Transport Rule satisfactorily addresses the legal requirements set out in the D.C. Circuit's decision vacating the Clean Air Interstate Rule (CAIR), *North Carolina v. EPA*. As noted above, the Clean Air Act requires states to ensure they do not significantly contribute to downwind states' nonattainment and interference with maintenance. We believe that the proposed rule satisfies that legal obligation and addresses the additional flaws identified by the D.C. Circuit.

The use of a Federal Implementation Plans (FIP) to implement the program is authorized under the Clean Air Act. While states have authority to, and may, submit State Implementation Plans (SIPs) to replace the FIP, we agree with EPA's assertion that due to time concerns, states are unlikely to be able to complete these plans before implementation of the Transport Rule on January 1, 2012.

Specific Comments on the Proposed Transport Rule

NextEra Energy supports EPA's preferred methodology for developing state budgets.

From NextEra Energy's perspective, EPA appropriately uses a multi-step process that includes both air quality and cost modeling to calculate state contributions to downwind nonattainment and interference with maintenance. As EPA discusses in the preamble to the proposed Transport Rule, it is important to require that emission reductions are achieved as expeditiously as possible. Under EPA's preferred methodology for determining the 2012 state budgets, the Agency uses a mix of Integrated Planning Model (IPM) modeling, reported emissions, and adjustments to both modeled and reported emissions based on pollution control technologies installed or projected to be installed before 2012. By using this methodology, EPA intends to avoid backsliding from the progress made in response to CAIR in the control of emissions from units in the Transport Rule region. Under the unique circumstances resulting from the vacatur of CAIR, NextEra Energy supports this methodology for establishing initial state budgets for annual NOx, ozone season NOx, and 2012 SO_2 in both Group 1 and 2 states. In our view, this methodology would *not* be appropriate for future rulemakings because it would not result in the most cost-effective emissions reductions. However, NextEra Energy understands that the vacatur of CAIR creates a unique situation for EPA and agrees that the proposed approach is appropriate for the initial state budgets.

NextEra Energy also supports EPA's exclusive use of IPM runs to set state budgets for 2014 Group 1 SO_2 emissions using pollution control cost thresholds. NextEra Energy understands and supports that this methodology would be the basis for establishing any revised state budgets in any of the four programs (e.g., ozone season NOx, annual NOx, Groups 1 and 2 SO_2) as necessary to comply with future NAAQS revisions.

EPA should abandon its proposed allowance allocation methodology based on the lower of projected 2012 emissions or actual 2009 emissions and adopt either a historic generation output-based allocation approach or a historic heat input-based approach.

EPA proposes to distribute, to sources in each state covered under the proposed Transport Rule, a number of emissions allowances equal to the SO_2, annual NOx, and ozone-season emissions budgets for that state, without variability, minus a three percent set-aside of allowances for new units. EPA would distribute four discrete types of emissions allowances for four separate cap and trade programs: SO_2 group 1 allowances, SO_2 group 2 allowances, NOx annual allowances, and NOx ozone season allowances.

EPA proposes that, for 2012, each existing unit in a given state receive allowances commensurate with the unit's emissions reflected in whichever total emissions amount is lower for the state, 2009 actual emissions or 2012 base case emissions projections. In either case, the allocation is adjusted downward, if the unit has additional pollution controls projected to be on-line by 2012. EPA proposes to use this same method to allocate allowances for each of the four trading programs (SO_2 group 1, SO_2 group 2, NOx annual, and NOx ozone season).

For states with lower SO_2 budgets in 2014 (SO_2 group 1 states), each unit's allocation for 2014 and later would be determined in proportion to its share of the 2014 state budget, as projected by IPM.

EPA's proposed approach for allocating allowances under the Transport Rule is different than the NOx allowance allocation methodology adopted for existing units in CAIR, which was based on a unit's baseline heat input, *adjusted for fuel type* (with proportionately more allowances provided to unit's burning higher-emitting coal and proportionately fewer allowances allocated to units burning lower emitting oil and natural gas). In its July 2008 decision temporarily vacating CAIR, the D.C. Circuit Court determined the NOx allowance allocation methodology reflected in the rule to be arbitrary and capricious "[b]ecause the fuel-adjustment factors shifted the burden of emission reductions solely in pursuit of equity among upwind states—an improper reason…" The court explained that EPA's [CAIR] rule essentially allocated more allowances to states having mostly coal-fired electric generating units because states that use more gas and oil can control emissions more cheaply. The court agreed with petitioners that fairness had nothing to do with the state's obligation to prohibit significant contributions to downwind nonattainment.

While EPA's proposed allowance allocation methodology in the Transport Rule does not rely on baseline heat input or fuel adjustment factors, NextEra Energy believes that the practical effect of the proposed methodology is very similar to the effect of the fuel-adjusted, heat input-based methodology rejected by the D.C. Circuit in the CAIR litigation because the methodology awards proportionately greater allowances to electric generating units (EGUs) burning inherently higher-emitting fuels (e.g., coal) and proportionately fewer allowances to EGUs burning inherently lower-emitting fuels (e.g., oil and natural gas).

Moreover, NextEra Energy believes that EPA's proposed allowance allocation methodology discriminates against companies that will have substantially reduced their emissions by 2012 by installing pollution control technologies, compared to companies that have done little or nothing to control their emissions in that timeframe, *regardless of the fuel they burn.*

While the proposed allowance allocation methodology in the Transport Rule may or may not pass legal muster since it does not explicitly rely on fuel-adjusted heat input values, NextEra Energy strongly believes it is a poor public policy choice since it sends the wrong messages to companies contemplating taking early steps to reduce emissions from their electric generation fleet and will likely discourage such actions in the future. The proposed allowance allocation methodology rewards companies that have continued to burn higher emitting fuels and/or have not installed emission control technology (by 2012) with proportionately greater allowance allocations. Conversely, companies that have (1) installed new EGUs designed to burn cleaner fuels, (2) converted existing units to burn cleaner fuels and/or (3) taken steps to install advanced emission control technologies on their units would be allocated proportionately fewer allowance allocations. For example, under EPA's proposed allowance allocation methodology, a company that continued to operate an old, inefficient coal or oil/gas-fired steam unit would receive substantially greater SO_2 and NOx allowances than a company that voluntarily repowered the unit with state-of-the art gas combined-cycle technology prior to 2012. Similarly, an existing coal-fired unit that installed advanced flue gas desulfurization equipment for SO_2 emissions control and selective catalytic oxidation for NOx emissions control prior to 2012 would receive substantially fewer SO_2 and NOx allowances than the same unit that did nothing to control emissions prior to 2012. NextEra Energy believes that this sends the wrong messages to companies contemplating taking early steps to reduce emissions from their electric generation fleet and will discourage such actions in the future. NextEra Energy believes that basing allowance allocations on source emissions (future projected or historic emissions) is the *worst* approach for allocating allowances, from a public policy perspective, because it sends the wrong message to companies that want to do the right thing and violates the "polluter pays" principle

Proponents of EPA's proposed allowance allocation methodology are likely to use the argument that units with higher emission rates (e.g., coal versus natural gas, or uncontrolled coal units versus controlled coal units) need a proportionately greater share of allowances because they bear a greater cost burden to control emissions. This is *exactly* the same argument that EPA used in CAIR in support of the fuel-adjusted heat input NOx allowance allocation contained in the Model Rule that was determined to be illegal by the D.C. Circuit "[b]ecause the fuel-adjustment factors shifted the burden of emission reductions solely in pursuit of equity among upwind states—an improper reason…" . As indicated above, this argument is not only flawed from a legal perspective but is misplaced from a public policy standpoint. What this argument is saying is that owners that continue to operate plants with higher emitting fuels and without emission controls are somehow entitled to a proportionately greater share of allowances (to help defray the costs they now face to comply with the Transport Rule) than companies that have already invested in clean energy technologies and pollution control technologies. In NextEra Energy's view, it is not in the public interest to reward companies that have done little or nothing to reduce their emissions prior to implementation of the rule in 2012 at the expense of companies like NextEra Energy that have taken early action to replace old, inefficient, high-emitting units with clean and efficient energy technologies such as natural gas combined-cycle units or to install emission control technologies.

EPA states in the preamble of the proposed Transport Rule that it believes that it is appropriate to allocate individual unit allowances consistent with the approach used in the development of the state budgets but acknowledges that there are many ways of linking unit allowance allocations directly to the way the state budgets were developed and, thus, significant contribution was defined. Aside from linking individual unit allowance allocations to the state budgets that EPA has established based on its analysis of significant contribution, then, (which EPA acknowledges can be accomplished with alternative allocation approaches) there is no apparent reason for EPA proposing that units receive allowances equal to the lower of 2009 actual emissions or 2012 projected emissions other than an equity rationale, something the D.C. Circuit found to be an "improper reason" in *North Carolina v. EPA*.

As indicated above, NextEra Energy supports the derivation of state emission budgets based on analyses of significant contribution and the cost-effectiveness of emission reduction opportunities, as proposed in the rule. However, once these state emission budgets are established, NextEra Energy recommends that all units within a state be treated as a single group and the state emission budgets be allocated to affected EGUs in 2012, 2014 and future re-calculations *based on each source's proportional share of total baseline state generation output.* NextEra Energy suggests that each unit's share of total state generation output should be determined on the basis of the average of each affected unit's annual generation output during the latest three calendar years of operation (e.g., 2007-2009).

The goal of output-based environmental regulations is to encourage the use of fuel conversion efficiency and clean energy as air pollution control measures. Output-based regulations can be an important tool for promoting an array of innovative energy technologies that will help achieve national environmental and energy goals by reducing fuel use. Output-based emission limits do not favor any particular technology and do not increase emissions. Output-based regulations simply level the playing field by establishing performance criteria and allowing energy efficiency and clean energy sources to compete on an equal footing with any other method of reducing emissions (e.g., combustion controls and add-on controls).

If EPA decides, for whatever reason, to reject the option of allocating allowances on the basis of generation output, NextEra Energy recommends that the Agency adopt a modified version of the alternative allowance allocation methodology discussed in the preamble of the proposed Transport Rule, which is to treat all units within a state as a single group and distribute allowances equal to a state's emissions budget, without variability, to each covered source in the state (in effect, distributing the responsibility for eliminating significant contribution and interference with maintenance) based on each source's proportional share of total state heat input. But rather than basing allocations on each units share of *projected* state heat input for the initial year of the program, NextEra Energy strongly recommends that the allocation be based on each unit's share of *baseline* state heat input. Baseline heat input would be determined based on the average of each affected unit's heat input during the latest three years of operation (e.g., 2007-2009).[1]

The IPM model is an excellent *planning* tool for analyzing the potential cost and energy impacts associated with various policy initiatives. However, NextEra Energy does not believe that this model was ever intended for, nor is capable of, providing projections that are anywhere near accurate enough (particularly for individual units) for basing something as important as allowance allocations on. Similar to other predictive models, IPM relies on a multitude of economic, energy-related and other assumptions that are subject to various degrees of uncertainty. The additive effect of this uncertainty is greater than the uncertainty associated with the individual assumptions.

Power plant owners, transmission system owners, and power system operators plan and operate their systems according to numerous federal, state and local regulations, policies and protocols, applying planning requirements designed to ensure electricity suppliers have adequate resources to meet current and future demand, and operational standards to ensure power is available when consumers turn on the lights. The IPM model appropriately determines how much a particular unit will operate in the future on an economic dispatch basis. However, the model does not consider a range of non-economic factors that influence a company's decision to operate a particular EGU such as grid stability considerations (e.g., voltage support), contractual generation commitments, reliability must-run requirements and fuel availability constraints. As a result, using the IPM model to project unit operations can create unrealistic scenarios such as running natural gas combined- cycle units at higher utilization than can be accommodated by the available natural gas pipeline network or not running oil-fired units that are required to operate to meet capacity requirements. These distortions of the electricity market may be masked when data are aggregated at the regional level or state level for setting state emission budgets, but can result in erroneous projections when used at the unit level to allocate allowances to individual units. Specific examples of these erroneous projections for a single electric generating fleet (NextEra Energy's) are presented in Appendix A of NextEra Energy's comments..

[1] While NextEra Energy could support EPA adoption of an historic heat-input based allowance allocation methodology for SO_2 and NOx in the Transport Rule, this does not mean or imply that the Company could support such a methodology in future air quality control programs. For example, if CO_2 emissions from EGUs are regulated in the future under a market-based cap-and-trade program, it would be important to design the program to incentivize the adoption of energy efficiency measures as a cost-effective control option. A heat-input based allowance allocation approach does not provide the proper incentives to encourage the adoption of energy efficiency measures. Therefore, in this case, NextEra Energy would strongly support a generation output-based allowance allocation methodology.

Not only does basing allowance allocations based on IPM model projections raise potentially serious technical and policy issues, but NextEra Energy believes that this approach will subject the proposed Transport Rule to a much higher degree of risk from a legal perspective. NextEra Energy believes it is important for EPA to propose a rule that withstands, and preferably forestalls, litigation and that can be implemented as quickly and smoothly as practicable. We believe that using modeled projections as the basis for allocating allowances to affected EGUs has the potential for significant flaws that could cause the program to be deemed arbitrary and capricious. *Accordingly, NextEra Energy believes that the methodology for establishing allowance allocations should be based on actual (i.e., historic) data that has been verified by EPA.*

As noted above, there are no legal or policy reasons that the methodology for determining state budgets and the methodology for distributing allowances to affected EGUs need to be the same. The historic generation output and heat-input allowance allocation approaches advocated by NextEra Energy are consistent with the D.C. Circuit's decision on CAIR because they do not alter the state budgets, which are based on each state's significant contribution. In addition, these allowance allocation approaches are fuel neutral and would not raise concerns similar to those identified by the D.C. Circuit regarding CAIR's use of fuel adjustment factors. The court rejected the fuel adjustment factors because they placed a disproportionate burden on downwind sources compared to the upwind sources contributing to the nonattainment problems. In NextEra Energy's view, adoption of a historic generation output- or heat input-based allowance allocation approach would provide greater insulation for the rule against litigation that could threaten implementation of the rule beginning January 1, 2012.

An historic generation output- or heat-input-based allowance allocation methodology would also address NextEra Energy's public policy concerns with EPA's preferred approach. Most significantly, it would not be based on modeled future emissions with its known inaccuracies but, rather, on verified data EPA already has obtained from companies. Additionally, it would correct the proposed methodology's disadvantages for early actors that EPA acknowledges in the preamble to the proposed rule. It would put all EGUs on equal footing and take the timing aspect of when emission reductions are achieved (i.e., prior to or after 2012) out of the allowance allocation equation.

Inaccuracies identified in the NEEDS database and EPA's modeling assumptions for NextEra Energy's EGUs need to be corrected

Upon reviewing EPA's modeling assumptions and results, including data the Agency relied on from the NEEDS database, NextEra Energy has noted a number of incorrect assumptions/data associated with EGUs operated by its FPL subsidiary. These inaccuracies in EPA's modeling assumptions/data are identified in the attached spreadsheet (Appendix A).

In addition to the corrections for FPL generating units identified in Appendix A, the most recent IPM projections show gas only operation for FPL's dual fuel-fired fossil steam generating units. With respect to the FPL units which IPM projects operation for in 2012, we have calculated that there would be a potential system demand for natural gas use in excess of 132,125 MMBtu/hr. FPL currently has under contract a maximum daily demand of 1,596,000 MMBtu/day for both Gulfstream and FGT pipelines which is an equivalent hourly demand of 66,374 MMBtu/hr. FPL also has under contract a 2011 expansion of FGT capacity of an additional 400,000 MMBtu/day, which would give FPL a total hourly pipeline capacity of approximately 83,040 MMBtu/hr. Currently there is only 210,000 MMBtu/day of unsubscribed pipeline capacity in 2010, or roughly an additional 8,750 MMBtu/hr that could be available. Even if FPL could obtain all of the available pipeline capacity we would have only 69% of the gas needed to meet system demand under the natural gas unit operations that the IPM model is projecting for FPL's units.

A review of the IPM model and its assumptions shows that EPA relies on adjusted price curves to address fuel supply and does not model physical constraints resulting from limited pipeline capacity for electric generation. While other utilities have identified issues with the IPM not modeling of their "must run" units at designated load constraint areas, NextEra Energy has not identified any of the FPL units being designated as such. We believe that the only units in our system that might be designated as must run on oil would be the Turkey Point fossil steam units where gas availability constraints would likely prohibit operation on oil during times of system peak demand.

During a July 7, 2010 EPA briefing hosted by the Edison Electric Institute (EEI), EPA staff acknowledged that IPM has difficulty handling dual-fuel units because there are non-economic reasons that a company must run such units that are not considered by the model such as grid stability considerations, contractual generation commitments, reliability must-run requirements and fuel availability constraints. NextEra Energy strongly encourages EPA to correct this modeling limitation through adjustments to the model or through post-modeling adjustments to unit emissions.

Florida should remain a Group 2 state for SO_2 in the final rule based on EPA's multi-factor assessment using the air assessment tool

The methodology EPA proposes to use to quantify significant contribution in the Transport Rule is a multi-factor approach that accounts for both cost and air quality improvement. In step one, EPA identifies what emissions reductions are available at various costs, quantifying emissions reductions that would occur within each state at ascending costs per ton of emissions reductions. In step two, EPA uses a simplified air quality assessment tool to estimate the impact that the combined reductions available from upwind contributing states and the downwind state, at different cost-per-ton levels, would have on air quality at downwind air quality monitoring sites that had nonattainment and/or maintenance problems. While less rigorous than the air quality models used for attainment demonstrations, EPA believes that this air quality assessment tool is acceptable for assessing the impact of numerous options on upwind reductions in the process of identifying upwind state significant contribution. It allows the Agency to analyze many more potential scenarios in a shorter timeframe than the time-and-resource-intensive more refined air quality modeling would permit (More refined air quality modeling can take several months, while multiple scenarios can be evaluated using the air quality assessment tool in a single day).

EPA did, however, conduct more refined air quality modeling of select emissions budgets to serve as a check on the appropriateness of the simplified method. This check confirmed the directional conclusions of the air quality assessment tool and largely confirmed the more detailed results of the air quality assessment tool, but there were some instances where EPA identified discrepancies between the results of the simplified air quality assessment tool and the more refined air quality modeling

For the annual $PM_{2.5}$ standard, the air quality assessment tool projected that, after implementation of the proposed FIP, only one area (Allegheny County, PA) would have a continuing NAAQS air quality problem under the maintenance criteria. The results of the refined air quality modeling were very similar. This modeling projected similar annual $PM_{2.5}$ reductions in downwind states and projected that Allegheny County, PA would remain in nonattainment and that Birmingham, AL would exceed the threshold for "maintenance" by a slight amount (less than 0.1 ug/m 3). For this reason, EPA is taking comment on whether Florida, the one group 2 state that was identified as linked to Birmingham, should be moved from Group 2 to Group 1.

Since the refined air quality modeling projects that Birmingham, AL will exceed the maintenance criteria by only an extremely slight amount and because reductions from nearby point sources will reduce local emissions in the area, NextEra Energy does not believe the refined air quality modeling demonstrates that upwind reductions beyond those in the proposed FIP are required to address significant contribution and interference with maintenance of the annual $PM_{2.5}$ NAAQS in Birmingham. On this basis, supports EPA's proposal to include Florida as a Group 2 state for SO_2

NextEra Energy believes that the industry is fully capable of installing the emission control technologies in the timeframes necessary to comply with the rule.

In determining the initial phase of SO_2 emission reductions required under the Transport Rule, EPA only took into account emission reductions that could be made through (1) the operation of existing scrubbers, (2) scrubbers that are expected to be built by 2012 and (3) the use of low sulfur coal. With respect to determining the 2012 annual and ozone season NOx budgets, EPA used the same general methodology. EPA assumed only reductions achievable from the year-round operation of existing selective catalytic reduction (SCR) units and SCR units expected to be installed by 2012 in establishing the 2012 NOx budgets.

In the preamble to the proposed rule, EPA estimates that approximately 14 gigawatts (GW) of SO_2 scrubbers and less than 1 GW of SCR for NOx control will be required for the electric sector to comply with the proposed 2014 emission caps. This amount of retrofits is significantly less than the industry has added in recent construction cycles. For example, according to the NEEDS database, approximately 56 GW of scrubbers was installed between 2006 and 2009, including 15 GW across 50 to 60 sites in 2009. EPA projects that an additional 19 GW of scrubbers will come online in 2010.

Moreover, the industry's past successful installation of pollution controls on numerous units underscores its ability to schedule and sequence any required unit outages in an efficient and reliable manner. To help ensure reliability, generators and transmission owners provide reasonable advance notice of any planned outages to the respective transmission authorities. In turn, the transmission authorities develop a coordinated outage schedule to prevent any deliverability problems. This illustrates a key benefit of a fully integrated national transmission system.

NextEra Energy believes that the air quality benefits of the proposed Transport Rule can be achieved without jeopardizing reliability of the electric system.

As indicated above, EPA estimates that approximately 14 GW of SO_2 scrubbers and less than 1 GW of SCR for NOx control will be required for the electric sector to comply with the proposed 2014 emission caps. In addition, EPA projects that, relative to base case projections (i.e., business-as-usual), about 1.2 GW of coal-fired capacity (less than 1 percent of all coal-fired capacity in the Transport Rule states) may become uneconomic to continue operating by 2014 as a result of the cost of compliance with the Transport Rule. According to EPA, these units are, for the most part, small and infrequently used generating units that are dispersed throughout the states covered in the Transport Rule and that, in practice, units projected to be uneconomic to maintain may be "mothballed," retired, or kept in service to ensure transmission reliability in certain parts of the grid.

Some third-party analysts have concluded that the proposed Transport Rule, along with other upcoming rulemakings that will regulate air emissions from fossil fuel-fired power plants, such as the Electric Utility Hazardous Air Pollutant Maximum Achievable Control Technology (MACT) Rule could result in the retirement of a significantly greater amount of the nation's 1,030 GW of electric generating capacity than EPA has projected with respect to the Transport Rule. This has raised concerns about the combined effects over the next five years of anticipated power plant retirements and outages required to install new pollution control equipment on the ability of the industry to maintain reliability of the electric system.

NextEra Energy does not believe the Transport Rule, as proposed, would significantly increase electric system reliability risks. Reserve margins throughout the Transport Rule region are well in excess of target reserve levels, suggesting that the system has the capacity to absorb additional retirements and compensate for scheduled outages for purposes of installing pollution control technologies. Further, if there are isolated reliability issues in areas of heavy demand as a result of implementing the Transport Rule or additional rules affecting the electric sector, existing risk management procedures under the Clean Air Act, the Federal Power

Act, and other statutes already provide EPA, the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the President tools to address unforeseen impacts on electric system reliability on an individual basis.

This viewpoint is supported by a recent analysis performed by M.J. Bradley and Associates and the Analysis Group of the potential impact of EPA's upcoming air regulations (including the proposed Transport Rule), with a focus on the issue of possible power plant retirements on electric reliability.[2] This analysis reached the following three conclusions:

1. Even though some units likely will retire in lieu of complying with the new regulations, electric system reliability will not be compromised if the industry and its regulators proactively manage the transition to a cleaner, more efficient generation fleet. When assessing reliability impacts, not only must generation capacity and availability be considered but consumption levels and patterns, and transmission capacity and use must be taken into account as well. According to the analysis, existing power system capacity well in excess of minimum reserve levels, relatively modest projections of load growth over the next several years, a large amount of proposed generating resources, and the availability of load management practices indicate that the electric system can handle the level of projected EGU retirements. The industry has a proven track record of adding new generating capacity and transmission solutions when and where needed and of coordinating effectively to address reliability concerns. In the three years between 2001 and 2003, the electric industry built over 160 GW of new generation—about four times what some analysts project will retire over the next five years as a result of the Transport Rule and other upcoming EPA air regulations..

2. Concerns that it will cost the industry too much to comply with EPA's proposed air regulations, that pollution controls cannot be installed soon enough, or that the EPA regulations will lead to the closure of otherwise economically healthy power plants are without merit. The proven technologies for controlling air pollution emissions, such as NOx, SO_2, mercury and acid gases, are commercially available and have already been, or soon will be, installed on the majority of the nation's coal plants (65 percent with scrubbers; 50 percent with advanced NOx controls), demonstrating that the costs can be managed. The industry also has a demonstrated ability to schedule and sequence unit outages in an efficient and reliable manner and is capable of installing additional pollution control systems to comply with the Transport Rule and Utility MACT Rule. Many of the coal units that are the most likely candidates to shut down are smaller, 40 to 60 year old units, which are nearing the end of their design life expectancy and are already economically challenged. Additionally, the retirement of some existing generating capacity will create room on the transmission grid to accommodate additional power flows, or new generating capacity, without requiring attendant upgrades in transmission, thus mitigating reliability concerns while reducing the cost of transitioning to a cleaner, more efficient generation fleet.

3. EPA, FERC, DOE and State utility regulators, both together and separately, have an array of tools to moderate impacts on the electric industry:
   - EPA may, and if needed should, exercise its statutory authority under the Clean Air Act to grant, on a case-by-case basis, extensions of time to complete pollution control installations, where appropriate.
   - To the extent that its legal authority allows, EPA should adopt regulatory approaches that allow for cost-effective compliance, such as the emissions trading mechanism proposed in the Transport Rule.

[2] M.J. Bradley & Associates, LLC and the Analysis Group. *Ensuring a Clean, Modern Electric Generating Fleetwide Maintaining System Reliability.* August 2010.

- In circumstances in which power plant retirements trigger localized reliability concerns, EPA and DOE should follow established precedent, including use of consent decrees, to permit continued operation for reliability purposes only, pending necessary upgrades or generation additions. Additionally, the various federal agencies and offices with responsibility for assuring reliability for the nation's electricity capability should work together to help support the industry and states in complying with EPA's new air regulations.
- Transparent, well-established market rules approved by FERC and overseen by independent market monitors, particularly the forward capacity markets relied on by some Regional Transmission Operators, as well as state regulatory agency oversight, provide additional safety nets to help ensure adequate capacity. Although EPA is under court order to promulgate its air regulations, the Agency can and should coordinate the implementation of anticipated water regulations under Section 316(b) of the Clean Water Act and new waste regulations to avoid possible reliability concerns.

NextEra Energy encourages EPA to coordinate the proposed rulemaking with other regulations affecting the electric sector.

The Transport Rule is one of several rules affecting the electric sector that EPA will be implementing over the next five to ten years. Each of these rules will impact the industry and companies' long term planning decisions. To enable companies to make decisions consistent with EPA's long-term vision, NextEra Energy encourages EPA to coordinate the upcoming regulations to the extent EPA has the legal authority to do so. We also support the coordination of regulations among EPA's air, water, and solid waste offices in order to allow EPA and industry to assess the interrelated impacts of all regulations affecting the electric sector. This will ensure maximum co-benefits while avoiding potential unintended consequences (e.g., stranded investments) and without delaying important environmental, public health, and economic benefits.

NextEra Energy recommends revisions to the assurance provisions proposed in the Transport Rule.

Although NextEra Energy has significant concerns about EPA's use of projected emissions to allocate allowances to emission units, we strongly support the overall framework of the preferred option, including unlimited intrastate trading and limited interstate trading using the variability and assurance level provisions proposed in the rule. We support EPA's proposal to determine assurance provisions' surrender requirements at the owner level, rather than the plant or unit level, because this would allow companies to optimize the management of their plants as a fleet. This allows much-needed flexibility while resulting in equal or lower emissions. The preferred option manages to allow some interstate trading while staying within the constraints of the D.C. Circuit decision by ensuring the necessary emissions reductions occur in the states identified as contributing to nonattainment or interfering with maintenance in other states. At the same time, the preferred option allows owners to use market mechanisms to buy and sell allowances. Allowance markets are essential to promoting cost-effective reductions.

NextEra Energy believes that the assurance provisions proposed in the Transport Rule will create a powerful incentive to operate pollution control equipment rather than buying allowances. With a sufficient allowance price, the requirement that a unit owner surrender two allowances for every ton by which it exceeds the variability limit if a state exceeds its limit will likely result in companies limiting their reliance upon purchased allowances. Instead, companies will look to achieve further emissions reductions. This will ensure reductions occur in the necessary states so as to meet the requirements of Section 110, clarified in the D.C. Circuit decision.

If EPA agrees with NextEra Energy's recommendation to change the unit allocation methodology to a historic basis while maintaining the existing methodology for the setting the state budget, EPA will need to evaluate whether that requires a change to the assignment of responsibility for the assurance provisions to owners. NextEra Energy has considered this issue and, if EPA uses the allocation methodology supported by NextEra Energy, we recommend and support that EPA use the revised allocations as the basis for calculating the owner's share. That is, we believe that variability limits at the owner-level should be based on allocation. If an owner operates in a state where the variability is ten percent of the state budget, the owner's variability should be ten percent of the owner's allocation. Any emissions above the owner's allocation plus variability would be used to calculate the owner's portion of the additional surrender requirement if the state exceeds the state budget plus variability limit.

EPA should establish a small auction under EPA's preferred limited trading option

Under EPA's preferred, limited trading option, NextEra Energy recommends that EPA establish a small auction of allowances that is similar in size to the proposed new unit set aside of three percent. Similar to the small auction in the Acid Rain Program, the auction would help for price discovery and liquidity purposes. Although NextEra Energy believes that market manipulation would be a greater risk under EPA's proposed Alternative 1 (*intra*-state trading only), we are also concerned that limited trading under the preferred option could result in market manipulation in isolated areas.

EPA should use freed up allowances from retired units to increase the auction pool over time

NextEra Energy supports EPA's proposal to continue to allocate allowances to retired units for six years after ceasing operations. The six-year period ensures that companies make the retirement decisions independent of any allocation and allowance value. However, rather than placing these allowances in the new unit pool or redistributing these allowances at the end of the six-year period, NextEra Energy recommends that EPA use these allowances to increase the auction pool recommended above over time.

NextEra Energy appreciates the opportunity to comment on EPA's proposed Transport Rule. If you have any questions, please do not hesitate to contact me at (561) 691-7001 or Ray Butts of my staff at (561) 691-7040.

Sincerely,

Randall R. LaBauve
Vice-President, Environmental Services

COMMENTS OF THE CLASS OF '85 REGULATORY RESPONSE GROUP

ON THE DETERMINATION THAT THE TRANSPORT RULE IS AN ALTERNATIVE TO BEST AVAILABLE RETROFIT TECHNOLOGY FOR REGIONAL HAZE

EPA Docket No. EPA-HQ-OAR-2011-0729

I. INTRODUCTION

On December 30, 2011, the U.S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 76 Fed. Reg. 82219, a proposed rule ("Proposed Rule") that would allow states to substitute participation in the Transport Rule[1] for source-specific Best Available Retrofit Technology ("BART") to address regional haze and visibility ("Regional Haze Rule"). The Proposed Rule determines that the Transport Rule's trading programs achieve greater reasonable progress towards the national goal of achieving natural visibility conditions than source-specific BART for sulfur dioxide ("SO_2") and/or nitrogen oxides ("NOx") emissions from power plants in those states covered by the Transport Rule. The Proposed Rule also disapproves regional haze State Implementation Plans ("SIPs") that relied on the requirements of the Clean Air Interstate Rule ("CAIR"), the precursor to the Transport Rule, and implements Federal Implementation Plans ("FIPs") to replace reliance on CAIR with reliance on the Transport Rule.

The Class of '85 Regulatory Response Group ("Class of '85" or "Group") respectfully submits these comments on the Proposed Rule.[2] The Class of '85 is a voluntary ad hoc coalition of approximately 30 electric generating companies from around the country that has been actively involved in the development of regulations to implement the Clean Air Act ("CAA" or "Act"), including the Transport Rule and the Regional Haze Rule. Members of the Class of '85 own and operate electric generating units ("EGUs") subject to both the Transport Rule and the Regional Haze Rule and, thus, will be directly affected by any final rule issued by EPA.

II. COMMENTS

The Class of '85 supports the Transport Rule as an alternative to source-specific BART requirements for EGUs, but recommends that EPA take additional steps that will assist States in developing SIPs for the Regional Haze Rule. The steps recommended by the Group will provide affected sources with greater regulatory certainty without diminishing improvements in visibility achieved by the Proposed Rule.[3]

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[1] *See* Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208 (Aug. 8, 2011) (referred to as the "Transport Rule").
[2] Attached is a list of the Class of '85 members who are supporting these comments.
[3] While the Group supports the Proposed Rule, these comments do not constitute an expression of support for the Transport Rule by the Group as a whole or individual Group members.

A. The Class of '85 Supports the Transport Rule as an Alternative to Source-Specific BART Requirements.

The Class of '85 supports EPA's efforts to address the Clean Air Act's overlapping regulatory initiatives and reduce the regulatory burden imposed on EGUs subject to the Transport Rule. In Executive Order 13563, President Obama affirmed the need to improve the regulatory process. Among other things, Executive Order 13563 mandates improved integration and coordination of rulemaking processes, requiring that:

> Some sectors and industries face a significant number of regulatory requirements, some of which may be redundant, inconsistent, or overlapping. Greater coordination across agencies could reduce these requirements, thus reducing costs and simplifying and harmonizing rules. In developing regulatory actions and identifying appropriate approaches, *each agency shall attempt to promote such coordination, simplification, and harmonization.*[4]

The Regional Haze Rule substantially overlaps with the Transport Rule because regional haze is believed to be caused in part by SO_2 and NOx. As a result, making reasonable progress toward improving visibility is advanced through participation in the Transport Rule. The Class of '85 believes that a determination that participation in the Transport Rule's trading programs as an alternative to source-specific BART is necessary to prevent redundancy and possible inconsistency of regulation between the Transport Rule and the Regional Haze Rule and is required by Executive Order 13563.

The Proposed Rule also would provide affected sources with important flexibility to achieve the emissions reductions required under the Regional Haze Rule. The Regional Haze Rule's BART requirements call for the installation of emissions controls determined on a source-by-source basis. By contrast, the Transport Rule allows sources to control emissions through a flexible and cost-effective trading program. The Group supports EPA's recognition that compliance with the Transport Rule's trading programs will achieve greater environmental and health benefits than source-specific BART, while providing affected sources with much needed flexibility to install cost-effective emissions controls.

B. EPA Reasonably Determined the Transport Rule's Trading Programs Achieve Greater Reasonable Progress than BART.

The Class of '85 agrees with EPA's determination that compliance with the Transport Rule's trading programs is a reasonable alternative to source-specific BART to address regional haze and visibility. For a trading program to be considered an alternative to source-specific BART, it must achieve greater reasonable progress in improving visibility than BART, demonstrated through a two-pronged visibility assessment.[5] By comparing emissions reductions achieved by the nationwide application of BART controls to all BART-eligible EGUs with the emissions reductions achieved by the Transport Rule and the application of BART controls to

[4] Improving Regulation and Regulatory Review, 76 Fed. Reg. 3,821, 3,822 at § 3 (Jan. 21, 2011) (emphasis added).
[5] *See* 40 C.F.R. § 51.308(e)(3) (greater reasonable progress is attained if "(1) Visibility does not decline in any Class I area, and (2) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas").

eligible EGUs elsewhere, EPA conducted an appropriate analysis of the visibility conditions attributable to the Transport Rule. Based on this analysis, EPA reasonably concluded that participation by EGUs in the Transport Rule's trading programs achieves greater reasonable progress in improving visibility than source-specific BART.

The Proposed Rule provides that participation in the Transport Rule's seasonal NOx trading program is an alternative to source-specific BART for NOx. In the technical analysis supporting its determination, EPA accounted for the limited duration of the seasonal NOx trading program and still concluded that the Transport Rule achieves greater reasonable progress than source-specific BART for NOx. Because EPA relied on emissions reductions achieved through the seasonal NOx trading program, EPA reasonably determined that participating in the Transport Rule's seasonal NOx program satisfies the BART requirements of the Regional Haze Rule.

C. EPA Should Adopt the Transport Rule's Cost Thresholds as the Upper Bounds of BART Compliance Costs

The Class of '85 urges EPA to use the range of cost-effectiveness thresholds defined in the Transport Rule to set the upper bounds of cost-effectiveness thresholds for BART. The Regional Haze Rule provides States the authority to determine source-specific BART for eligible sources based on several statutory factors, including the costs of compliance.[6] According to EPA guidelines, states should assess the costs of compliance in part by calculating the average cost effectiveness of the technology, measured in terms of total annualized costs of control divided by annual emissions reductions.[7] Although EPA provides states the tools for calculating average cost-effectiveness,[8] EPA has been inconsistent in applying cost thresholds to state BART determinations, leaving states with uncertainty as to what cost levels are appropriate and will not result in EPA imposing more expensive BART requirements. Setting the cost thresholds developed for the Transport Rule as the upper bounds of source-specific BART requirements would alleviate this uncertainty.[9]

In the Transport Rule, EPA conducted a thorough cost analysis to determine how different cost thresholds impact air quality. Based on this analysis, EPA concluded that NOx emissions reductions were cost-effective at \$500 per ton, and that SO_2 emissions reductions were cost-effective at \$2,300 per ton for Group 1 states starting in 2014, and \$500 per ton for Group 2 states. In the Transport Rule, EPA concluded that technologies resulting in costs above the cost thresholds did not achieve significant emissions reductions in comparison to cost. EPA should reach the same conclusions in reviewing source-specific BART determinations because the Regional Haze Rule is an aesthetic, rather than public health, standard. It would be nonsensical for EPA to apply cost-effectiveness thresholds to source-specific BART determinations that are more costly than the cost-effectiveness thresholds for the Transport Rule. Therefore, the Group

[6] 42 U.S.C. § 7479(3).
[7] 40 C.F.R. Part 51, Appendix Y.
[8] *See, e.g.,* Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 Fed. Reg. 39,104, 39,135 (Jul. 6, 2009) (stating that the BART presumptive limit for NOx from coal-fired units was less than \$1,500 per ton).
[9] *See* Letter from Senator Max Baucus & Senator Jon Tester, U.S. Senate, to the Honorable Lisa P. Jackson, Administrator, U.S. Environmental Protection Agency (Feb. 17, 2012).

urges EPA to adopt the Transport Rule's cost-effectiveness thresholds as part of the guidance on BART determinations, and to propose that BART is not cost-effective at costs greater than the Transport Rule's thresholds.

D. EPA Should Not Disapprove Regional Haze SIPs that Rely on CAIR.

EPA should not disapprove Regional Haze SIPs that rely on CAIR while litigation challenging the Transport Rule is pending. As a result of the U.S. Court of Appeals for the D.C. Circuit's order staying implementation of the Transport Rule,[10] CAIR is currently in effect, and, depending on the outcome of the litigation, CAIR may remain in effect for some time. Given the current stay, it is premature for EPA to disapprove SIPs that are fully consistent with CAIR.[11] The Class of '85 urges EPA to postpone taking action on these SIPs until litigation on the Transport Rule has been resolved.[12]

E. States Have Primary Authority to Make Source-Specific BART Determinations.

If EPA does not finalize the Proposed Rule or the Transport Rule is vacated by the D.C. Circuit, states will continue to be entitled to significant discretion in their determinations of what technology constitutes source-specific BART. As the D.C. Circuit noted in *American Corn Growers Ass'n. v. EPA*, "states . . . play the lead role in designing and implementing the regional haze program." In this role, states submit implementation plans detailing a particular state's approach to making reasonable progress in achieving the goals of the Regional Haze Rule. Included in these SIPs is the state's determination of what technology constitutes source-specific BART. In the absence of an approved alternative program such as the Transport Rule, EPA must respect source-specific BART determinations made by states pursuant to the Regional Haze Rule.

III. CONCLUSION

The Class of '85 appreciates the opportunity to comment on the Proposed Rule. The Group supports EPA's efforts to proactively recognize that participation in the Transport Rule's trading programs is a reasonable alternative to source-specific BART, and believes the actions recommended in these comments will assist EPA in its efforts.

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[10] *See EME Homer City Generation v. EPA*, No. 11-1302 (D.C. Cir. Dec. 30, 2011) (order granting stay of implementation).
[11] *See* 76 Fed. Reg. at 82,221.
[12] Through these comments, neither the Class of '85 nor any individual member is commenting upon the relative merits of CAIR or the Transport Rule or of the pending challenges to the Transport Rule.

Respectfully submitted,

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Dated: February 28, 2012

CLASS OF '85 REGULATORY RESPONSE GROUP

AES Corporation

Alliant Energy Corporation

Arkansas Electric Cooperative Corporation

City of Lakeland

City of Tallahassee

Cleco Corporation

Dairyland Power Cooperative

Entergy Services, Inc.

Florida Municipal Electric Association

Florida Municipal Power Agency

Gainesville Regional Utilities

Great River Energy

Indianapolis Power & Light Company

Integrys Energy Group

JEA

National Grid

NextEra Energy, Inc.

OGE Energy Corp.

Orlando Utilities Commission

PowerSouth Energy Cooperative

PPL

Public Service Enterprise Group

Tampa Electric Company

Western Farmers Electric Cooperative

Wisconsin Public Service Corporation

Xcel Energy Inc.

NEXTera ENERGY

June 7, 2011

BY FIRST-CLASS MAIL AND
ELECTRONIC SUBMISSION

Water Docket
U.S. Environmental Protection Agency
Mail Code 4203M
1200 Pennsylvania Ave., N.W.
Washington, DC 20460

RE: Docket ID No. EPA–HQ–OW–2008–0667 – Request for Extension of Comment Deadline

To Whom It May Concern:

On behalf of NextEra Energy, Inc., I am writing to request a 60-day extension of the comment period for the proposed "National Pollutant Discharge Elimination System – Cooling Water Intake Structures at Existing Facilities and Phase I Facilities" rule published in the Federal Register on April 20, 2011("Proposed Rule"). NextEra Energy recognizes that EPA faces court deadlines for this rulemaking, and thus we do not make this request without due consideration. Because of the exceedingly complex nature of the Proposed Rule, the massive size of the record, and the questions that have arisen to date, the current comment period is inadequate to allow affected sources the time necessary to review and analyze the Proposed Rule and meaningfully respond to the Agency's request for comments. Accordingly, NextEra Energy must request that EPA extend the public comment period by 60 days, from July 19, 2011 to September 19, 2011.

NextEra Energy operates steam electric generating facilities covered by the Proposed Rule, and thus will be directly affected by any final rule issued by EPA. The regulatory scheme finalized by EPA will have a significant impact on NextEra Energy's business, including long-term business planning, the computation of consumer rates, and the day-to-day operation of electric generating units. It is of the utmost importance that NextEra Energy and other affected sources be given adequate time to fully analyze the Proposed Rule and provide the Agency with constructive feedback through detailed comments.

NextEra Energy's first concern is that an adequate review of the record cannot be completed in the time allotted because of the massive size of the record, totaling over 1,800 documents. As we approach the half-way mark of the current comment period, new documents are still being added to the docket, and crucial questions regarding the record remain unanswered. Affected sources, our industry group representatives, and our contractors will need additional time and assistance to master all of the underlying data and fully understand the implications of EPA's decisions. In addition, access to numerous documents in the record by our Utility Water Act Group ("UWAG") industry workgroup has been delayed due to password protection issues, and while EPA has worked quickly to respond to document requests, the delayed access reduces the amount of time available to review and analyze these documents. EPA was also forced to remove key information in certain documents to protect confidential business information, and while we appreciate the need for this protection, the result is additional delay as individual companies make separate requests for the information. NextEra Energy very much appreciates the Agency's willingness to work with potentially affected sources on certain record issues, and the fairness and adequacy of the commenting process will be preserved by the granting of additional time for comment.

In addition to the time necessary to adequately review the massive record and receive additional information regarding the record, NextEra Energy is also concerned about potential timing inconsistencies between the Proposed Rule and the revised Information Collection Request (ICR) that EPA intends to issue with a separate 60-day comment period. See 76 Fed. Reg. 22,263, col. 2. It is clear Congress intended that public review of a proposed ICR occur at the same time as the public review of the rule itself. This will allow the quality, value, and effort of the proposed ICR to be considered in light of the Proposed Rule. Thus, the comment period of the rule should be extended, at a minimum, to coincide with the 60-day comment period for the revised ICR.

As EPA is well aware, the Proposed Rule involves complex biological, technological, and economic analysis with significant consequences to NextEra Energy's steam electric generating facilities, as well as more than a thousand power plants and manufacturing facilities nationwide. Developing a full and accurate record at the proposal stage is in the best interest of the public, this Administration, and the electric power industry. When opportunities for obtaining meaningful comment are foreclosed, the result is missed opportunities for valuable information exchange. This leads to wasted Agency resources and time. EPA has the discretion to extend the comment period for the Proposed Rule, and doing so would benefit the Agency, States, and the regulated community. Given the exceedingly complex nature of the Proposed Rule, the massive size of the record, and the questions that have arisen to date, additional comment time is necessary to ensure a full and fair comment period.

NextEra Energy appreciates the opportunity to submit comments on the Proposed Rule. If you have any questions regarding this request for an extension of the comment period, please contact me at Ray.Butts@fpl.com or 561-691-7040.

Sincerely,

Rayburn L. Butts
Director, Environmental Services

cc: Ms. Mary T. Smith

FPL GROUP

Environmental Services, 700 Universe Blvd, Juno Beach, FL 33455
Ph: 561-691-7040

Submitted to: a-and-r Docket@epa.gov

November 28, 2008

Joe Dougherty
Air and Radiation Docket and Information Center
Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Docket ID No. EPA-HQ-OAR-2008-0318

Re: Advance Notice of Proposed Rulemaking on Regulating Greenhouse Gas Emissions under the Clean Air Act

Dear Mr. Dougherty,

FPL Group appreciates the opportunity to comment on EPA's Advance Notice of Proposed Rulemaking (ANPR) relating to regulating greenhouse gas emissions under the Clean Air Act (CAA). FPL Group is a member of and endorses the comments filed in this docket by the Clean Energy Group (CEG), the Class of 85 Regulatory Response Group, and the Edison Electric Institute.

FPL Group

FPL Group, is nationally known as a high quality, efficient, and customer-driven organization focused on energy-related products and services. With a growing presence in 27 states, it is widely recognized as one of the country's premier power companies. Its rate-regulated subsidiary, Florida Power & Light Company, serves approximately 4.5 million customer accounts in Florida. FPL Energy, LLC, an FPL Group competitive energy subsidiary is the nation's No. 1 producer of wind energy, with 58 projects in 16 states capable of producing more than 5,800 megawatts of emissions-free electricity. FPL Energy is also the nation's No. 1 producer of solar energy. We operate the largest solar-thermal plant in the world in California's Mojave Desert, the 310-megawatt Solar Electric Generating System. FPL Group has one of the lowest emissions profiles of any power company in the nation. More than 50 percent of our electricity comes from natural gas, more than a quarter from nuclear, and 7 percent from wind. Just 5 percent comes from coal, compared with an average of 50 percent nationwide. Additional information is available on the Internet at www.FPLGroup.com, www.FPL.com and www.FPLEnergy.com.

FPL Group recommends comprehensive federal legislation over Clean Air Act regulation

FPL Group has long supported the passage of comprehensive legislation that would establish a national policy for the orderly reduction of GHG emissions in the U.S. As participants in the U.S. Climate Action Partnership, the Clinton Global Climate Initiative and the World Wildlife Fund's PowerSwitch Program we have consistently called for Congress to quickly implement legislation that would begin the reduction of GHG emissions in the U.S. This reduction should be achieved through an economy-wide emissions reduction program that prices carbon in the economy in a manner that effectively reduces emissions without harming the U.S. economy. In addition to a price for carbon, GHG emissions reduction legislation should include a safety valve or cost containment mechanism that will protect the economy from dramatic increases in GHG allowance cost. The legislation should include options for the use of offsets, banking and borrowing of allowances to allow companies the opportunity to weigh the timely use of allowances against the future development of carbon reduction technologies. FPL Group also supports the development of federal and state programs to promote energy efficiency projects, research, development and deployment of renewable generation, nuclear generation and carbon capture/sequestration projects. The effective reduction of GHG emissions in the U.S. will require numerous technological, economic and policy related tools to reach the desired reductions of GHG emissions.

FPL Group does not believe that the regulation of GHGs under the current CAA provides the authority for EPA to implement all of the necessary strategies described above. Thus, FPL Group does not support unilateral action by EPA to regulate GHG emissions under the CAA. We suggest that EPA should instead continue to work with Congress to pursue comprehensive GHG reduction legislation. Several Federal agencies that have weighed-in on the ANPR have taken this same position and highlighted the futility in trying to regulate greenhouse gases through the existing Clean Air Act. Even EPA's Administrator, Stephan Johnson notes in the ANPR that the CAA is not the most effective tool for regulating greenhouse gas emissions.

The Clean Air Act does not authorize EPA to collect carbon fees or implement an auction

The current form of the CAA fails to provide EPA with ample opportunity to establish efficient methods to price carbon in the economy. FPL Group believes that greenhouse gas emissions will best be controlled under a national policy developed through comprehensive Congressional legislation. Reducing greenhouse gas emissions effectively will require changing behaviors by pricing carbon throughout the economy. The most efficient and transparent mechanism for implementing this cost for carbon is through a carbon fee, applied either at the emissions source or upstream in the economy. Increasingly, policy makers and world renowned economists such as, Al Gore, Alan Greenspan, and William Nordhaus have expressed support for a carbon fee as the best method to price carbon in the economy. A carbon fee that is properly recycled into the economy provides several benefits over a traditional cap and trade based allowance allocation method, including:

- Assignment of a predictable price on carbon economy-wide
- Provision for a progressive and measured implementation over time
- Easy and much less expensive administration
- Clear cost transparency to all parties
- Avoidance of cap & trade pitfalls, such as market manipulation, windfall profits, price volatility and regressive impacts on low income consumers
- Incentives for the capture and reduction of emissions, the development of cleaner generation, including nuclear and renewables and creates a price signal encouraging energy conservation
- Certainty for long term investments and economic benefit for early action
- Options for funding R&D for lower carbon technologies and the protection of internationally competing industries and recycles the bulk of revenue back to consumers
- Easily allows border adjustment – tariffs on imports, credits on exports

The current form of the CAA does not offer EPA the authority to implement a carbon fee or to redistribute revenues from the fee back into the economy.

In the ANPR EPA indicates that the CAA may offer the option for implementing a cap and trade program for GHG allowances. If a cap and trade program were implemented in lieu of a carbon fee approach FPL Group supports a 100% auction of allowances where the proceeds from the auction are recycled back into the economy through the development of energy efficiency projects, deployment of additional renewable technologies or offsets of detrimental impacts associated with GHG regulation affecting low income families or business. Auctions provide a pay as you go option for pricing carbon into the economy. An auction based allowance distribution system, similar to the auction program currently being implemented by the states participating in the Regional Greenhouse Gas Initiative (RGGI), does not create winners and losers, or result in windfall profits such as those seen in historical forms of cap and trade programs that include free allowance allocations. An auction-based allocation program would incentivize companies to reduce emissions or utilize lower carbon emissions technologies. As an example, in the first quarterly RGGI auction, held in September, 2008, over $38 million worth of allowances were auctioned. These auction revenues will result in significant quarterly funding to the participating states for use in the development of clean, alternative energy programs, energy efficiency programs or assistance to low income families and businesses affected by the regulations. A similar auction format applied nationally could assist in the deployment of new technologies, energy efficiency programs, renewable energy and fund the development of carbon capture and sequestration technology to reduce GHG emissions.

The current CAA neither provides authority for EPA to implement an allowance auction nor does it provide direction for the agency to distribute the proceeds that may be collected through an auction.

A GHG cap and trade program will likely face court challenges

If EPA chooses to regulate GHG emissions using the , FPL Group would recommend the implementation of a market based cap and trade system for the distribution of GHG allowances. This system should be based on carbon intensity (lbs/MWh) in order to incentivize energy efficiency and promote the development of low and non-emitting electric generation. However, in light of recent court decisions on the Clean Air Interstate Rule and the Clean Air Mercury Rule it is uncertain whether EPA will be able to successfully implement a cap and trade program to meet emissions limits. Without a market-based cap and trade system the regulation of GHGs under the CAA would force EPA to regulate GHGs through a strict command-and-control system establishing hard emissions limits and control technology requirements. Without a cap and trade program it is uncertain how regulated facilities would meet the new GHG limits since there are currently no commercially available GHG capture and sequestration technologies on the market. A command-and-control emissions reduction program without market-based trading would lead to extensive fuel switching and the likely shutdown of numerous electric generating facilities that could not meet the new emissions limits. This approach would likely have a dramatic impact to the economy and the reliability of the nation's electric generation system.

GHG regulation under the CAA will increase leakage

An additional downside to the economy-wide regulation of GHGs under the CAA is the negative impact to U.S. businesses that will be competitively disadvantaged by the cost of GHG regulation when other countries do not impose GHG reduction requirements on their businesses and products. This additional cost would likely lead some industries and businesses to relocate overseas to countries that do not impose GHG regulation. The results of this costly regulation will include additional leakage of GHGs from other countries. This phenomenon further highlights the need for Congressional legislation that could impose border taxes on imports from countries not imposing GHG regulations or legislation that could provide assistance to U.S. businesses having to compete with overseas companies. Carbon fee revenues or auction proceeds would be an efficient form of funding for this assistance. These are options not available to EPA under the current CAA.

EPA's Options for Regulating GHG Under the Clean Air Act

In the ANPR EPA requested comments on the possible options for regulating GHG emissions under the Clean Air Act. These regulatory options include New Source Performance Standards (NSPS), National Ambient Air Quality Standards (NAAQS), and Hazardous Air Pollutants (HAPs). EPA also requested commenter's views on the impacts of Prevention of Significant Deterioration (PSD)/New Source Review (NSR) programs as a result of GHG regulation. FPL Group addresses each of these regulatory options below:

New Source Performance Standards (NSPS)

If EPA is compelled to regulate GHG emissions from stationary sources under the CAA, FPL Group contends that the NSPS option is the only appropriate regulatory option as compared to the other sections of the CAA. Section 111 of the CAA provides opportunity for EPA to determine appropriate source categories, in addition to electric utility sources, that should be regulated. Section 111 also allows EPA to establish emissions limits for individual units or for overall facilities including output basis standards that promote efficiency and conservation. Furthermore, under Section 111(d) EPA may have the authority to establish NSPS for existing sources .

Section 111 also directs EPA to take into account the cost of achieving emissions reductions. This option allows EPA to evaluate the most cost effective emissions standards seeking the lowest economic cost. With regard to standards promulgated on electric utility sources, the ability to take into consideration the cost of emissions reduction could allow EPA to mitigate some impact to the reliability of electric generation.

In the ANPR EPA indicates that the agency may have the authority to establish a traditional cap and trade program under Section 111. The use of an allowance cap and trade program is likely to result in litigation as evidenced by the litigation surrounding the now vacated Clean Air Interstate Rule and Clean Air Mercury Rule. Furthermore, FPL Group does not believe the CAA provides EPA the authority to establish an allowance auction program or the authority to collect and distribute auction revenues. The potential limitations to establish market-based allowance trading programs represents a significant shortcoming to the use of Section 111 of the CAA to regulate GHGs.

Finally, FPL Group believes that the most limiting concern for establishing existing facility or New Source Performance Standards under Section 111 is the lack of emission control options that would allow facilities to achieve lower emissions standards. Today and for the foreseeable future there are no commercially available controls to reduce GHG emissions or sequester carbon once it is captured. This lack of control options is of particular concern given the uncertainty surrounding EPA's authority to implement a cap and trade program and the agency's lack of authority to utilize offsets to achieve GHG reduction compliance.

National Ambient Air Quality Standards (NAAQS)

The regulation of GHG emissions under Section 110 of the CAA is likely the most untenable option available to EPA. Since GHG concentrations are relatively uniform globally it is uncertain how EPA would establish attainment or non-attainment areas of the country. Even less certain is how individual State's would prepare their State Implementation Plans (SIP) without clear attainment goals that could be reached by their efforts. If the entire country were deemed to be in non-attainment it is unclear how rural states with relatively minimal contributions to GHG emissions would be able to reach attainment. In fact, it is unlikely that the nation could reach attainment status during the maximum 10 year limit for achieving the primary NAAQS given the influences of GHG emissions globally.

It is unlikely that EPA could establish NAAQS without additional legislative authority and significant revision to the CAA.

Hazardous Air Pollutants (HAPs)

If EPA determines that GHGs have "an adverse environmental effect" they could then regulate under Section 112 of the CAA. However, the thresholds established under Section 112 would require numerous stationary sources to be regulated as major sources. Regulation under Section 112 of the CAA would require EPA to designate GHGs as HAPs, thus forcing the establishment of strict emissions standards. The most likely option would include Maximum Achievable Control Technology (MACT) standards. MACT controls are generally required for all new HAP emissions sources and would be rapidly phased-in for existing emissions sources. FPL Group is unaware of a reasonable, cost effective or commercially available control technology for reducing GHG emissions that would meet the requirements of MACT. Another option would include the development of an alternative standard under Section 112 (h) that would establish an efficiency or output-based standard. Neither of these regulatory options includes the opportunity to use a cap and trade program, offsets, or cost containment.
FPL Group opposes regulation under Section 112 as this option would pose the greatest risk to electric generation reliability and likely the greatest cost for compliance.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

FPL Group believes the use of the CAA in its current form will result in an unworkable regulatory program burdened with inefficiencies and costly requirements that will not necessarily be applied to the appropriate sectors for regulation. In fact, the facility-based application of the current CAA will result in tens, if not hundreds of thousands of new, smaller facilities that will be regulated under the Act as a result of extremely low regulatory thresholds. Even EPA has acknowledged that applying "major source" thresholds to GHGs would "increase the number of Prevention of Significant Deterioration (PSD) permits by an order of magnitude -- from 200-300 per year to thousands of PSD permits each year." If GHGs become subject to PSD, even the smallest changes at commercial and industrial sources may require a lengthy pre-construction permit. Thousands of otherwise insignificant projects would be subject to PSD review based solely on GHG emissions, inflicting extremely burdensome requirements on industry and permitting authorities alike.

The PSD permitting program regulates stationary sources that either emit or have the potential to emit 250 tons per year (tpy) of a regulated pollutant or, if they are included on the list of source categories, at least 100 tpy of a regulated pollutant. These thresholds are extremely low when considered with respect to GHGs. For example, carbon dioxide (CO_2) emissions from a typical

200,000 square foot commercial building may approach 1,000 tpy. The ANPR acknowledges that regulation of GHGs under the CAA could result in the regulation of "small commercial or institutional establishments and facilities with natural gas-fired furnaces." This could include large single family homes, small businesses, schools, or hospitals heated by natural gas.

Already permittees affected by the PSD program can expect a single permit to take months if not years to complete, costing hundreds of thousands or millions of dollars. As noted above regulation of GHGs under the CAA would result in significant increases in the number of PSD permits required. The costs and administrative burdens to both permittees and regulatory agencies would be significant. Moreover, permitting under the PSD program would require EPA to establish permit limits reflecting the Best Available Control Technology (BACT) or Lowest Achievable Control Technology (LAER). FPL Group is unaware how the agency could establish either BACT or LAER as no commercially available technologies for carbon capture and sequestration have yet been deployed.

The use of the CAA's current NSR program for the regulation of GHGs seems unworkable. FPL Group suggests that EPA would need to seek legislation that would either limit the applicability of NSR or limit the emissions levels that would trigger NSR. Otherwise the number of facilities that would be burdened by NSR requirements would skyrocket. Further, as noted there are no currently available carbon capture or sequestration technologies that could meet the requirements of BACT or LAER.

EPA should support expanded use of electric vehicles

Finally, in Section VI of the ANPR, EPA addressed the increased use of plug-in hybrid electric vehicles in the future. FPL Group agrees with EPA's assessment that the nationwide use of grid electricity can result in significant reductions of transportation tailpipe GHG emissions. EPA also notes that wide usage of PHEVs will increase the demand for electricity and increase GHG emissions from the electric sector.

FPL Group supports the increased use of PHEVs as an obviously more efficient method of fueling the nation's transportation needs and reducing GHG emissions. However, the increased load growth to the electric sector would have to be taken into account when developing sector caps and allowance allocations. FPL Group suggests that EPA seek legislative support from Congress to eliminate barriers to the development and deployment of PHEVs outside of the CAA GHG regulation process.

Conclusions

In summary, FPL Group does not support the use of the current CAA for the regulation of GHG emissions. The uncertainties and apparent inefficiencies of using the CAA will likely lead EPA into yet another string of protracted rule challenges that will only delay implementation of real GHG reductions. FPL Group does recognize that EPA's role in regulating GHG emissions in the future is necessary and preferred in order to achieve an effective program. As members of EPA's Climate Leaders program FPL Group is well aware of the agency's knowledge and understanding of GHG emissions issues and emissions sources. However, EPA's future role should be initiated through comprehensive legislation that establishes a streamlined national policy with clear goals and strategies for achieving successful GHG reduction. Regulation under the current form of the CAA will not achieve this goal. We are also aware that EPA is compelled by a recent court decision to make an endangerment finding that may lead the agency to regulate GHG emissions under the CAA. If this inefficient regulatory approach becomes necessary, FPL Group encourages EPA to implement a broad and transparent stakeholder process. Further, to the extent emissions modeling is necessary to establish regulatory limits, we advise a robust and timely process of sharing data and models with stakeholders.

If you have any questions or need additional information from FPL Group please contact me at 561-691-7040.

Sincerely,

Rayburn L. Butts
Director, Strategic & Regulatory Planning
Environmental Services

cc: Randall R LaBauve, V.P.
FPL Environmental Services

NextEra Energy Comments on the Proposed Section 316(b) Existing Facilities Rule

Docket EPA-HQ-OW-2008-066

Submitted by:

Name: Randall R. LaBauve
Title: Vice-President – Environmental Services
Date: August 17, 2011

These comments have been prepared by NextEra Energy and reflect its concerns, opinions, and suggestions. NextEra Energy has also participated in the Clean Energy Group's 316(b) Initiative that includes Constellation Energy, Exelon Corporation, National Grid, NextEra Energy, PG&E Corporation, and Public Service Enterprise Group, Inc. The Clean Energy Group's 316(b) Initiative has included preparation of comments as well as a proposed BTA Framework to Replace EPA's Proposed Impingement Mortality Standard under Section 316(b). NextEra Energy also endorses the comments and BTA Framework developed by the Clean Energy Group's 316(b) Initiative.

Executive Summary

NextEra Energy is pleased to submit these comments on EPA's proposed 316(b) Rule for existing facilities. The following comments are organized around five topics:

- Suggested changes to the proposed Rule's thresholds;
- Support to EPA's position that closed-cycle cooling should not be considered Best Technology Available (BTA);
- Suggested changes to the proposed Rule's specialized definitions;
- Comments and suggested changes to EPA's proposed approach to BTA for impingement mortality; and
- Comments on EPA's proposed site-specific evaluation of BTA for entrainment.

Our comments close with a brief response to EPA's request for specific comments made in Section IX(B) of the proposed Rule's preamble. In most cases, these brief comments provide reference to NextEra Energy's previous comments.

While NextEra Energy has several specific comments, our major concerns are summarized in the following bullet points:

- NextEra Energy strongly endorses EPA's finding that closed-cycle cooling is not BTA under Section 316(b) (see Comment B.1).
- NextEra Energy also endorses the evaluation of BTA for entrainment on a site-specific basis and makes several suggestions regarding EPA's proposed implementation process (see Comments E.1 through E.6).
- NextEra Energy provides several comments regarding EPA's proposed BTA for impingement mortality. The most significant comments are:
    - While EPA intended to provide flexibility in the implementation of BTA for impingement, the proposed regulatory language provides very little flexibility and defines rule requirements that will be unachievable at many facilities including some of NextEra Energy's. NextEra Energy's primary concerns regarding the proposed regulatory language are: 1) the numerical performance goals (e.g., no more than 12% impingement mortality for modified Ristroph screens) will be impossible to achieve at some facilities and could drive the perceived need to retrofit to closed-cycle cooling (see Comment D.4); 2) the need to control carry-over of shellfish in tidal settings is not demonstrated by EPA and will be infeasible and/or extremely costly to achieve (see Comment D.11).
    - EPA's proposed Rule provides no means to account for a variety of impingement and impingement mortality control measures that have been demonstrated to be effective and which may already be in place at a number of facilities. As described in Comment D.6, NextEra Energy's facilities successfully apply offshore velocity caps and acoustic

deterrents to substantially reduce impingement rates. While EPA discusses these measures in favorable terms in the preamble and even appears to use them as the assumed basis of compliance in developing costs of the Rule, the regulatory language provides no opportunity to account for their benefit. NextEra Energy believes that crediting these and other effective measures is reasonable, will make the Rule more efficient with lower costs, and is consistent with EPA's goals.

- Several of the Rule's provisions are redundant and will result in unjustified costs with little or no environmental benefit (see Comment D.3). In particular, facilities employing closed-cycle cooling should be viewed as fully compliant with the rule (see Comment D.9), and those facilities in which the intake structure has a through-structure velocity of 0.5 fps or less should also be fully compliant (see Comment D.3).
- NextEra Energy recommends that the Rule be based on preapproved BTA technologies (i.e., through-screen velocities below a specified target; advanced traveling water screens with a fish return) and comparable BTA technologies (i.e., other effective technologies such as offshore velocity caps) that can achieve comparable reductions in impingement and impingement mortality (see Comment D.9).
- The concept of entrapment within the cooling water intake structure is ill-defined, unsound, and will result in significant yet unquantified costs (see Comment D.23).
- The impingement mortality performance standard is flawed in two primary aspects: 1) as discussed in Comments D.5, D.6, and D.7, focusing on impingement mortality rather than impingement and impingement mortality leads to inappropriate solutions; and 2) the derivation of the quantitative performance goals uses too small a data set and contains errors (see Comments D.13 through D.16).
- The cost-to-monetized benefits calculated in support of the Rule are flawed in several ways. NextEra Energy believes that the actual costs of the proposed Rule have been underestimated and its benefits overestimated (see Comment D.18). The proposed Rule suggests that pending information on non-use benefits will greatly increase the monetizable benefits of the Rule. Basing a proposal on an analysis that is yet to be completed and has an uncertain outcome precludes development of complete comments on the Rule (see Comment D.21). Finally, the nominal cost-to-monetized benefits presented for the selected regulatory option (i.e., 21.3 for Option 1) results in costs that are wholly disproportionate with monetized benefits, consistent with EPA's own finding in the Phase III Rule (see Comment D.20).
- NextEra Energy believes that an economic variance must be available on a site-specific basis in order to ensure that, on a site-specific basis, the costs of implementation of impingement controls are not wholly disproportionate with the monetized benefits (see Comment D.32).

- NextEra Energy recommends several changes to the definitions included in the proposed Rule. The most important of these are relative to "closed-cycle cooling" (Comment C.1) and "cooling pond" (Comment C.2).

A. The Proposed Thresholds for Application of the 316(b) Rule Should be Refined

A.1 The Threshold for Cooling Water Flow for Inclusion in the Proposed Rule (2 MGD) is Far Too Low.

Under the Phase II and Phase III rulemakings (69 FR 41578 and 71 FR 35015) for existing facilities, EPA determined that BPJ was the appropriate approach for selecting BTA for existing facilities that withdraw less than 50 MGD and facilities in industry segments other than the power generation sector. This was determined based on EPA's "...judgment that the monetized costs associated with the primary option under consideration are wholly disproportionate to the monetized environmental benefits" (71 FR 35017). It is not clear on what basis EPA is reversing this decision with the proposal of this Rule.

In fact, EPA's cost and benefits values presented in the rule preamble provide a clear indication that the costs to benefit ratio for facilities with flows between 2 and 50 MGD are nearly three times higher than facilities with greater than 50 MGD withdrawals (Table 1). As discussed in Comment D.20 below, the cost:benefit ratio of Option 1 is troublesome for a number of reasons. A cost to benefit ratio of nearly three times higher is substantially more so.

Table 1:
EPA's Estimates of Costs and Monetized Benefits for Impingement Mortality Controls Including Inference of Costs and Monetized Benefits for Facilities with DIF < 50 MGD

EPA Rulemaking Option	Social Costs ($MM/yr)	Quantified Monetized Benefits ($MM/yr)	Costs/Monetized Benefits
1: IM Mitigation with DIF > 2 MGD	384	18	21.3
4: IM Mitigation with DIF > 50 MGD	327	17	19.2
IM Mitigation 2 MGD < DIF < 50 MGD	57	1	57.0

Inclusion of facilities with less than 50 MGD raises a number of additional concerns. Many facilities that withdraw such low volumes are likely to impinge very small number of organisms. Implementation of expensive modifications and monitoring is unjustified in these cases. EPA estimates Option 4 would achieve 98.9% of the monetized benefits of Option 1 while impacting many fewer small businesses and having much lower costs (76 FR 22208). In addition, this low volume threshold will include a significant number of facilities that have employed closed-cycle cooling.

Instead of requiring categorical standards for these lower flow facilities, EPA should adopt its previous position that requirements should be established on a case-by-case, best professional judgment basis. Such an approach allows regulatory agencies the flexibility to impose substantial requirements to reduce impingement mortality and entrainment mortality when justified without imposing needless requirements on facilities that have much lower impacts. In addition, it allows agencies the discretion to ensure that the costs of required measures are commensurate with their benefits. Finally, it has a strong potential to reduce the burden on NPDES agencies by reducing the scope of the 316(b) effort at several hundred facilities nationwide.

A.2 EPA Should Use Actual Intake Flow, Rather Than Design Intake Flow, As The Threshold For Inclusion In The Rule.

We recommend the use of Actual Intake Flow (AIF) as the threshold for inclusion in the Rule rather than Design Intake Flow (DIF). EPA indicates in the preamble (76 FR 22195) that it based the threshold on design intake flow rather than actual intake flow to provide clarity on which facilities are covered, account for the magnitude of "possible environmental impact", and avoid the need for monitoring to confirm facility status. NextEra Energy believes that these drawbacks are minimal and/or unfounded. To account for potential variations in withdrawal rates, the rule could require review of the actual intake flow during permit renewal. For those facilities that report AIF above the rule threshold during permit renewal, the rule's requirements could be applied at that time on a schedule identified in the rule starting at the effective date of the rule and permit. This would be a clear way of determining which facilities are covered by the rule. Although it would require monitoring withdrawal rates, most facilities already are required by NPDES permits to monitoring withdrawal and/or discharge rates. Therefore, this would not impose an additional significant burden.

EPA's position that the DIF is representative of the possible magnitude of environmental impact (76 22195) neglects that fact that the actual environmental impact should be the relevant metric. As stated elsewhere in the preamble to the draft rule "Environmental impacts, particularly entrainment and entrainment mortality, result from actual water withdrawals, and not the maximum designed withdrawals." Based on this, the thresholds for inclusion in the rule should be based on actual intake flows rather than design intake flows. This approach would avoid the application of the rule to facilities that withdraw less than the selected threshold. The preamble states that using actual intake flow as the threshold for conducing entrainment characterization studies "...may encourage some facilities to reduce their flows..." The incentive provided by using actual intake flow for determining inclusion in the rule would be stronger and likely result in substantial water savings nationwide. These benefits outweigh the minor drawbacks outlined by EPA.

A.3 Closed-cycle Cooling Should not Be the Presumptive BTA for New Units at Existing Facilities.

NextEra Energy believes that it is inefficient and unnecessary to hold existing and new units at an existing facility to different standards of BTA. The majority of site-specific factors at a given site (e.g., Species of Concern, population densities, waterbody characteristics, space constraints, most costs of construction and operation) are identical between existing and new units at a given site. While the proposed Rule allows for variance when the costs of compliance are wholly disproportionate to the costs estimated by EPA, the nine factors that the proposed Rule considers when evaluating the site-specific BTA for impingement and entrainment should be considered for a new unit within the context of the site constraints. To presume that closed-cycle cooling is BTA will result in inconsistent regulatory outcomes under very similar circumstances and would result in inconsistent and unjustified costs of compliance.

B. EPA is Correct in Finding that Closed-cycle Cooling Does Not Represent BTA for Existing Facilities

B.1 The Proposed Rule Properly Finds that Closed-cycle Cooling is Not BTA.

NextEra Energy strongly endorses EPA's proposal that closed-cycle cooling is not available or appropriate as BTA for existing facilities. NextEra Energy believes that such a finding is well within the agency's authority to apply cost-benefit analysis consistent with the U.S. Supreme Court's decision in *Entergy Corp. v. Riverkeeper Inc.* In particular, the Supreme Court notes that BTA may "refer to that which produces a good at the lowest per-unit cost, even if it produces a lesser quantity of that good than other available technologies." Thus, even though flow reduction commensurate with closed-cycle cooling may result in greater reductions in impingement and entrainment, the Supreme Court finds that BTA may be a measure that produces lower levels of reductions at a lower per-unit cost.

The EPA also properly highlights that four important factors generally limit a facility's ability to retrofit to closed-cycle cooling:

- Energy Reliability: EPA correctly concludes that a broad-based requirement to retrofit to closed-cycle cooling would affect the reliability of the electrical supply grid. The adverse affects would be associated with idling of generation resources during the retrofitting process; loss of net generation capacity due to reduced generation efficiency and new parasitic loads; and the lack of electricity transmission infrastructure to supplement power within regional power markets.
- Air Emissions: EPA is correct in noting that retrofit to closed-cycle cooling can have significant air quality impacts associated with new generation to replace power lost or consumed by new cooling system as well as release of particulates from the cooling towers. EPA indicates that these air quality impacts are local but increased emissions of Greenhouse Gases present a global issue. These air emissions are very likely to trigger reopening of permits issued under the Prevention of Significant Deterioration program, potentially placing the permit in jeopardy.

  In one analysis performed for NextEra Energy's Port Everglades plant, it was estimated that switching from once-through to closed-cycle cooling would result in increased fuel consumption caused by the parasitic load of cooling tower pumps and fans. The annual parasitic load from supplying electricity to additional fans, pumps, and ancillary equipment associated with the cooling towers was estimated to be 1.4 percent of generating capacity. Resulting emissions of four criteria pollutants (in tons per year) as well as volatile organic compounds (VOCs) and carbon dioxide were estimated as follows:

  - SO_2: 675 TPY;
  - NO_x: 202 TPY;
  - PM_{10}: 56.8 TPY;
  - VOCs: 0.9 TPY; and
  - CO: 21 TPY.

In addition, CO_2 (a greenhouse gas but not a criteria pollutant) emissions are estimated to increase by a rate of 103,176 TPY.

Operation of cooling towers would also increase particulate emissions, particularly when salt or brackish water is used to make up the cooling towers. For example, at NextEra Energy's Seabrook plant, freshwater supplies do not have the required capacity to provide makeup to a cooling tower thus sea water would have to be used in the cooling towers. The operation of a salt water cooling tower would create particulate emission levels that would exceed all current NHDES air quality thresholds for new or modified sources and the ability to obtain permits from them is uncertain.

- Space Availability: EPA is correct in concluding that the space necessary to retrofit to closed-cycle cooling is unavailable at many facilities. A number of NextEra Energy's plants are located on sites that are highly constrained by waterways and urban infrastructure. Examples include the Port Everglades and Riviera plants which are located in heavily industrialized maritime port complexes, with petroleum and cargo shipping and storage as well as cruise ship terminals. Figure 1 (see Attachment 1) shows the extensive port operations and petroleum storage and transfer facilities that surround the Port Everglades site, as well as the premium on available space within the property boundary that would restrict the ability to retrofit cooling towers.

Figure 2 (see Attachment 1) illustrates the space constraints as well as conflicts with neighboring land uses at NextEra Energy's Riviera Beach site, for which a modernization project is currently being undertaken. The figure shows the potential layout of the new combined cycle facility and depicts the relative size of a potential cooling tower footprint that would be required to satisfy the cooling demand for the new configuration. Space within the site boundary for the new plant footprint was at a premium and resulted in very little open area, most of which has been utilized to provide a visual buffer for the residences to the south. The property to the north of the site is owned by the Port of Palm Beach and has active port and cargo handling activities. Commercial properties to the west include petroleum and cargo storage and transfer operations, thus there is no opportunity to site a cooling tower on adjacent parcels.

The Canaveral plant location is also tightly constrained within a narrow strip of land between the Indian River Lagoon and US Highway 1, and bordered on the other sides by residential and commercial development. Figure 3 (Attachment 1) depicts the site layout and surrounding land use at the Canaveral site, which is also currently undergoing modernization to a combined cycle operation. Space within the site boundary for the new plant footprint was at a premium, and adjacent parcels consist of residential lots to the south and retail/commercial properties to the north and to the west across US Highway 1.

- Remaining Facility Life: EPA is right in determining that the age of several generation plants are such that a significant investment in closed-cycle cooling is not economical.

In addition to these four factors, NextEra Energy believes that several other important issues support that closed-cycle cooling is not BTA. These include:

- Challenges to Obtaining Appropriate Federal, State, and Local permits. Retrofitting to closed-cycle cooling would involve a very significant construction effort and would trigger a variety of environmental permits. Construction of dozens of cooling tower cells would require several acres of land. Given the importance of wetlands, waterways, and other natural habitats near many generating facilities (examples include the Point Beach, St. Lucie, and Seabrook plants all of which are surrounded by coastal and wetlands resources), impacts to wetlands and waterways would be impossible to avoid and will require extensive permitting and substantial mitigation. Many of the natural areas in close proximity to the plants provide habitat for state and federally protected species, thus it is not certain that obtaining the necessary permits would be successful.
- Loss of Beneficial Aspects of the Thermal Effluent. Five of NextEra Energy's steam electric generating plants in Florida (Cape Canaveral, Riviera, Port Everglades, Lauderdale, and Fort Myers) maintain thermal refuges for manatees during the winter months as required by their NPDES permits. These refuges have been observed to harbor several hundred manatees at a time and provide critical protection against cold-induced mortality. In the event that closed-cycle cooling became BTA, NextEra Energy could not maintain these refuges, putting many hundreds of manatees at risk. Operation of dedicated heaters to provide thermal refuges in the absence of cooling water discharge would be very costly and result in additional air emissions.
- Increase in Noise Impacts. Mechanical-draft, evaporative towers generate a substantial amount of noise associated with several moving parts as well as cascading water. Installation of closed-cycle cooling is likely to increase the noise level in the facility of the plant leading to impacts on the neighboring properties. As depicted in Figures 2 and 3 (Attachment 1), residential areas abutting the Riviera Beach and Cape Canaveral plant sites would be likely be impacted by increased noise and drift impacts associated with potential cooling tower retrofits at these two sites.
- Saltwater Drift. Most of NextEra Energy's facilities that employ once-through cooling are located on tidal waterbodies and use saltwater to carry away waste heat. Due to the unavailability of extensive freshwater resources as well as priority of other uses for freshwater, most of these facilities would use salt water for cooling tower makeup. Recirculation of salt water in cooling towers generates "drift" or the dispersion of droplets of salt water from the tower. Such drift can adversely affect nearby habitats, vegetation, soils, and human infrastructure. Particularly notable is the potential for saltwater drift to induce arcing and corrosion in electrical switchyards.
- Impacts of Fogging. Evaporated water from the cooling tower often results in the generation of a visible vapor plume or fog. While generation of a visible plume is an aesthetic issue, it can also result in obscured vision leading to unacceptable risks for automobiles and aircraft. This is an important issue at several of NextEra Energy's plants that are located near major roadways and airports. For example, NextEra Energy's Port Everglades plant is located only 0.5 mile north of the eastern approach to Fort Lauderdale International Airport.

- Increased Water Consumption. Evaporative cooling towers rely on the latent heat of vaporization to dissipate most of the heat. Therefore, it is common for evaporative cooling towers to lose a significant portion of the water (e.g., 80 to 90% is not uncommon) that is withdrawn from the environment. While NextEra Energy would likely use seawater at many of its plants, adoption of closed-cycle cooling at most power plants would result in significant water losses to the atmosphere. Depending on the nature of the hydrologic system, such water losses may adversely affect aquatic resources or human uses of the water.
- Potential Adverse Impacts to Water Quality. As water is evaporated from the cooling tower, salts and other conservative materials present in the recirculated water accumulate at higher concentrations than those present in the source water. The presence (and concentration) of constituents in the source water commonly complicates the discharge of cooling tower blow-down under the NPDES program. In some cases, toxic constituents present in the intake water reach high enough concentrations that adverse aquatic impacts might occur. In most cases, the need to resort to use of salt water for cooling tower makeup at NextEra Energy's near-coastal power plants would require mixing zones to discharge the salts in the makeup water concentrated by evaporation in order to comply with state water quality standards. Obtaining regulatory approval of such mixing zones may be difficult due to limitations in the implementation procedures as well as the Water Quality Standards.
- Highly Adverse Cost to Monetized Benefit Ratio. As shown in Exhibit X-1 of the proposed Rule, EPA estimates that the cost of installation of closed-cycle cooling far exceeds the monetized benefits. EPA estimates that the annualized costs associated with Option 2 considered in the rulemaking (i.e., closed-cycle cooling for facilities with Design Intake Flow of 50 MGD or greater) as $4,463,000,000/year. In contrast, EPA estimates the monetized benefits at $121,000,000/year. The ratio of costs to monetized benefits is 36.9, indicating that under Option 2, $36.9 would be spend for every dollar of monetized benefit. Note that these figures include the costs and monetized benefits for the relatively low cost option of controlling impingement mortality (i.e., Option 1). If these costs and monetized benefits are removed from Option 2, the resulting cost to monetized benefit ratio rises to 39.6. NextEra Energy believes strongly that a cost to monetized benefit ratio of this magnitude is unreasonable and that the costs are wholly disproportionate to the monetized benefits.

Again, NextEra Energy endorses EPA's finding that closed-cycle cooling is not generally available and it should not be considered to be BTA. This conclusion is supported by several lines of evidence and is consistent with the authority that EPA has to consider several different factors when defining BTA including the costs and monetized benefit.

C. The Proposed Rule's Definitions Should be Refined

C.1 Definition of Closed-cycle Cooling

The draft rule's definition of a closed-cycle recirculating system at 40 CFR 125.92 is unnecessarily restrictive. The proposed definition indicates that closed-cycle cooling should not "rely upon continuous intake flows of water". The logic for this provision is not at all clear and we speculate that EPA intended to preclude the one-time passage of water through the condensers. It is common practice for cooling towers and cooling ponds to receive makeup water on a continuous or semi-continuous basis to offset evaportation, drift and blowdown but they receive makeup at a rate that is *greatly reduced relative* to once-through cooling systems (generally a 98% or better reduction). NextEra Energy does not perceive an ecological benefit of precluding continuous makeup given that the instantaneous rate of withdrawal is reduced consistent with closed-cycle cooling.

The draft definition at 40 CFR 125.92 also indicates that "New source (makeup water) is added to the system to replenish losses that occurred due to blow-down, drift, and evaporation." This aspect of the definition is also needlessly restrictive and similar language is included in the definition of a cooling pond (see below). It is common for cooling ponds to act as a source of other process water so that makeup water to the pond would also serve as a process water supply. Similarly, many CWIS divert part of their flow to process water uses. Continuation of this practice is consistent with the draft rule's anticipation that cooling water could be re-used and, when it is, would no longer be considered cooling water.

Make-up to cooling ponds also may go to three other sinks: 1) infiltration to groundwater; 2) unplanned but necessary release from the cooling pond associated with rainfall induced pond overflow; and 3) intended release from the pond to provide wetlands hydration and other beneficial uses. While the first two sinks are largely unintended, they are common and inevitable in most existing cooling pond systems which are unlined and contain emergency spillways to avoid overtopping following severe precipitation events. The intended release of water from a cooling pond is part of the routine operation of NextEra Energy's Martin power plant and is the result of permit/agreement conditions that obligates NextEra Energy to provide recharge water to nearby wetlands.

The draft rule specifies the number of cycles of concentration for facilities with cooling towers and the flow reduction that must be achieved when systems other than cooling towers are used. At a given facility, the number of cycles of concentration and the flow reductions are dictated by a complicated relationship between the source water chemistry, NPDES effluent limits applied to the discharge (blow-down), and operational factors specific to the facilities. As a result, not all facilities with closed-cycle cooling can be operated to be consistent with the draft rule's definition.

Despite this, these facilities achieve very high reductions in cooling water withdrawal from the environment relative to once-through systems. Employment of closed-cycle cooling towers will generally result in 90% reductions in water demand, a figure that is the target for impingement reduction under the Phase I Rule and is higher than the proposed impingement mortality performance goal in the existing facilities proposed Rule. Therefore, such facilities should not be excluded from the definition in closed-cycle cooling due to deviations from the operational parameters that would not result in significant changes in impingement mortality or entrainment mortality.

The definition of closed-cycle cooling should be based on the engineering of the system as closed-cycle; a system that relies on recirculating cooling water should be included regardless of the hypothetical reduction of water withdrawal. The definition should not include minimum cycles of concentrations or flow reductions as it places an undue burden on facilities that achieve the Rule's goals for substantial reduction in impingement and entrainment. The water withdrawn from the source waterbody is used to replace water lost to evaporation and infiltration. There is not a feasible way to reduce these losses short of lining the pond, which would be prohibitively expensive.

With these comments in mind, NextEra Energy proposes the following as an amended definition of closed-cycle recirculating system:

> *Closed-cycle recirculating system* means a system designed, using minimized make-up and blow-down flows, to withdraw water from a natural or other water source to support contact or noncontact cooling uses within a facility, or a system designed to include cooling ponds that are not themselves a waters of the U.S.. ~~and that does not rely upon continuous intake flows of water.~~ The essential feature of a closed-cycle recirculating system is that the cooling water is recirculated within the system (i.e., the cooling tower or the cooling pond) and is not employed only once to conduct heat prior to release back to the environment. New source water (make-up water) is added to the system to replenish losses that have occurred due to blow-down, drift, ~~and~~ evaporation, inadvertent infiltration and overflow, process water use, and beneficial re-uses of the water. *Closed-cycle recirculating system* includes, but is not limited to, wet or dry cooling towers and cooling ponds. ~~For cooling towers where the source for make-up water is freshwater or has a salinity equal to or less than 0.5 parts per thousand, minimized make-up and blow-down means operating at a minimum cycles of concentration of 3.0. For cooling towers where the source for make-up water is saltwater, brackish water, or has a salinity of greater than 0.5 parts per thousand, minimized make-up and blow down means operating at a minimum cycles of concentration of 1.5. For facilities with a closed-cycle recirculating system other than a cooling tower, minimized make-up and blow-down flows means a reduction in actual intake flow of 97.5 percent for freshwater, and 94.9 percent for salt water or brackish water.~~

<u>C.2 The Definition of Cooling Pond Must Allow for Other Uses of the Makeup Water as Water Stored in Cooling Ponds Does Not All End Up as "Blow-down, Drift, and Evaporation."</u>

As discussed above in the context of the definition of "Closed-cycle recirculating systems", the water balance for cooling pond makeup can and should include other sinks beyond "blow-down, drift, and evaporation". As previously stated, at NextEra Energy's Martin power plant, permit agreements with the State of Florida call for the transfer of water from the pond to hydrate adjacent wetlands. Similarly, water used for process purposes other than cooling (e.g., boiler makeup) is commonly withdrawn from cooling ponds. Increasing the rate of water use for other non-cooling purposes is discussed as a positive outcome by EPA and the inclusion of a 25% dedicated cooling water threshold in the proposed rule provides an incentive for re-use of cooling water. These other sinks do not change the status of the impoundment as a closed-cycle cooling pond nor do they in any way suggest that the system employs open cycle cooling. For these reasons, NextEra Energy suggests the following for an amended definition of cooling pond under 40 CFR 125.92:

> *Cooling pond* means a man-made canal, channel, lake, pond or other impoundment designed and constructed to provide cooling for a nearby electric generating or manufacturing unit. A cooling pond may comprise a closed-cycle recirculating system when water stored in the cooling pond is used multiple times for cooling and waters of the U.S. are withdrawn only for the purpose of replenishing losses of cooling water due to blow-down, drift, ~~and~~ evaporation, inadvertent infiltration and overflow, process water use, and beneficial re-uses of the water.

<u>C.3 The Average Water Depth is a More Appropriate Basis for Calculating the Through-screen Velocity to Determine Whether it is Less than 0.5 fps.</u>

Swimming speed data evaluated by EPA during the Phase I rulemaking showed that the species evaluated could endure a 1.0 fps velocity. EPA applied a safety factor of two to this value to derive the 0.5 fps threshold (66 FR 6527). This interpretation of this value as a through-screen velocity has further increased the conservative nature of this value; through-screen velocities are frequently 50% or more than approach velocities. The approach velocity is the relevant measure for determining whether organisms are able to swim away from the intake structure. Finally, this value is calculated based on the design intake flow of the facility. Many facilities, particularly in the non-power sector, seldom operate at full design capacity. Therefore, this measure has three conservative assumptions that make it very protective of aquatic organisms.

The draft rule requires that any demonstration that the intake velocity is less than 0.5 fps be based on the minimum ambient source water surface elevation (40 CFR 125.94(b)(2)(ii)). This specification provides yet another conservative component to the application of this threshold. The result is an overly protective application of this threshold. Many facilities that have intake velocities of less than 0.5 fps over a vast majority of the time would not be eligible for compliance based on intake velocity because their design parameters suggest they may exceed this value on rare occasions during extreme conditions. The average water surface elevation is the best representation of the long-term condition at the CWIS. Potential ecosystem impacts are best predicted by this long-term behavior.

In contrast, the minimum water level might occur at a very low frequency and be far below the typical or average condition. The limited frequency of these occurrences at many locations would minimize any reduction in effectiveness due to these exceedances. However, given the highly protective nature of the 0.5 fps threshold even during brief exceedances, facilities would likely continue to substantially limit the impingement mortality.

To address this, the rule should allow the director the discretion to determine what water level is most appropriate for determining whether a facility meets the 0.5 fps threshold or base the demonstration on the average water level. This would allow director to take into consideration the frequency that low water levels and maximum intake flows coincide and determine whether the intake is still protective despite rare exceedances of the 0.5 fps value.

When facilities achieve intake velocities of less than 0.5 fps a portion of the time, they should be able to credit the reductions in impingement achieved. The record supporting this and other rules clearly documents that low intake velocities achieve greater than 90% reductions in impingement mortality (76 FR 22202). Therefore, facilities should be encouraged to maintain low intake velocities to the extent possible. To do this, the rule should allow credit for even temporary reductions in intake velocities below the 0.5 fps threshold. This would require some modification to the impingement mortality limitations as discussed in Comment D.5.

C.4 More Guidance Should be Provided to the States Regarding Definition of Species of Concern.

The definition of Species of Concern is a critical part of defining nature of proposed performance monitoring as well as designing for and achieving the impingement mortality performance goals. EPA acknowledges this in several places in the proposed Rule's preamble as well as in the Technical Development Document (TDD) when it indicates that it would be unlikely that forage species that are very sensitive to handling would be included among Species of Concern. EPA staff has made similar statements in conversations with NextEra Energy's contractors when they were queried about the difficulty in meeting the proposed Rule's performance goals. EPA alludes to potential exclusion of alewife and bay anchovies from the Species of Concern in Section 6.9.4 of the TDD (EPA 2011[1]). EPA's apparent intention relative to Species of Concern is not stated with sufficient clarity in the regulatory text.

In addition, Species of Concern needs better definition to exclude unusual events, forage fish, invasive species, and organisms that are experience high impingement mortality even on state of the art travelling screens. As explained above, the literature consistently indicates that several forage fish species (e.g., clupeids and engraulids) are subject to very high rates of post-impingement mortality. These same species are also commonly impinged in one-time episodes (e.g., associated with seasonal cold shock or episodic schooling events) that can dominate annual rates of impingement at a facility. The loss of these organisms to impingement mortality frequently has no environmental significance as is the case at the Point Beach Facility (Kitchell 2009)[2]. A clear basis from excluding these species and unusual one-time events from the impingement mortality limits is necessary to make an impingement mortality limitation that is achievable.

While NextEra Energy concurs with EPA that it is likely to be appropriate to exclude very common, very sensitive forage fish as well as unusual episodes from the Species of Concern, it is NextEra Energy's experience that NPDES permit writers are likely to err on the side of including all species in the performance monitoring and in comparison to standards. For this reason, NextEra Energy requests that EPA include a definition of the Species of Concern that limits it to higher value fish and shellfish while

[1] EPA 2011. Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule. March 28, 2011. EPA-821-R-11-001.

[2] Kitchell, J.F. 2009. Assessment of Alewife Impingement Impact at Point Beach Nuclear Plant (PBNP) on Lake Michigan Fisheries. Prepared for NextEra Energy Energy Point Beach, LLC. March 2009.

providing concrete guidance and encouragement on excluding forage fish and other species of lower ecological and commercial value. EPA should explicitly state in 40 CFR 125.94(b)(1)(i) that the impingement mortality limitations only apply to Species of Concern. It should also be clearly stated that the Species of Concern can be defined to exclude particularly sensitive species with lower ecological value. These changes would provide the permit writer the discretion to select organisms that are of significant value to the local environment and the loss of which has potential to have adverse environmental impact.

NextEra Energy also notes that there is some ambiguity relative to the importance of shellfish in the definition of Species of Concern. Previous 316(b) rules were consistent in their reference to the protection of "fish and shellfish". Consistent with that precedent, 40 CFR 122.21 of the proposed rule calls for evaluation and documentation of "all life stages of fish and shellfish". Similarly, the proposed 40 CFR 125.92 provides the following definition of impingment:

> "Impingement means the entrapment of any life stages of fish and shellfish on the outer part of an intake structure or against a screening device during periods of intake water withdrawal."

In contrast, the proposed BTA Standards for Impingement Mortality (at 40 CFR 125.93(b)(1)(i)) indicate that the owner or operator must, "achieve the following impingement mortality limitations for all life stages of fish", without mentioning shellfish. The derivation of the Impingement Mortality performance goals also relies exclusively on finfish. NextEra Energy asks EPA to clarify the applicability of shellfish as Species of Concern relative to the BTA Standards for Impingement Mortality[3].

<u>C.5 The Definition of Invasive Species Should be Refined.</u>

The proposed Rule notes that invasive species may be excluded from the set of Species of Concern but it does not provide a tangible definition of what constitutes an invasive species. The "specified" invasive species listed at §125.92 is incomplete as it does not include fish species that are recognized as invasive species including alewife, common carp, Asian carp, white perch, and round goby that are commonly impinged at facilities on the Great Lakes and Midwest in general. NextEra Energy suggests that the rule adopt the definition of invasive species provided by Executive Order 13112: an invasive species is an "alien species whose introduction does or is likely to cause economic or environmental harm or harm to human health".

The final rule should clarify what is meant in the definition of all life stages, where it states "The Director may determine that all life stages of fish and shellfish does not include specified invasive species and naturally moribund species." It is unclear if this gives the Directors the latitude in specifying invasive species or if it only applies to those listed in the definition. If it is the latter, then EPA should provide a

[3] Later in this comment documents, NextEra Energy will evaluate the potential to meet the BTA Standards for Impingement Mortality at four of its facilities. For the purposes of this calculation, NextEra Energy has assumed that shellfish should be included in that calculation. We note that shellfish, particularly those used as surrogates in the calculation when species-specific survival rates were unavailable, tend to be relatively robust. Therefore, exclusion of the shellfish would result in lower rates of post-impingement survival.

more comprehensive listing of invasive species or preferably use the definition provided by Executive Order 13112.

D. The Proposed Rule's Requirements for Impingement Mitigation are Too Prescriptive, are Poorly Supported, and Do Not Allow Credit for Several Effective Means of Minimizing Impingement

D.1 The Proposed Rule Attempts to be Consistent with President Obama's Executive Order 13563, "Improving Regulation and Regulatory Review," but it Falls Short of the Goal by Being Too Prescriptive, by Setting Inappropriate Standards, and by Establishing Redundant Requirements.

On January 21, 2011, President Obama issued Executive Order 13563, Improving Regulation and Regulatory Review (76 FR 3821 to 3823). The order sets out general principles (e.g., the benefits of a regulation must justify its costs) as well as specific calls to include public participation, integration and innovation, flexible approaches, science, and retrospective analysis of existing rules during the rulemaking process.

Based on the proposed Rule's Fact Sheet as well as several statements in the preamble, EPA apparently intended to adhere to the Executive Order by proposing a Rule that was flexible and presented a reasonable net monetized benefit. As discussed in the next several comments, NextEra Energy believes that EPA has fallen short of the requirements of Executive Order 13563. In particular, the proposed Rule is remarkably prescriptive, has several redundant provisions that, in some ways, make it more stringent than the Phase I new facilities rule, and has a substantially negative net monetized benefit.

The following several comments provide more detail regarding this concern and make suggestions that, taken together, would provide for a much more workable approach to BTA for impingement mortality.

D.2 The Requirements for Modifying Travelling Screens are Overly Prescriptive

The draft Rule's requirements for mitigating impingement mortality are too prescriptive, and contrary to statements made in the preamble, do not provide facilities with the flexibility to install the most cost-effective measures for reducing impacts of their cooling water intake structures.

As drafted, all facilities with travelling screens are required to make a number of specific modifications to their screening systems:

> 40 CFR (125.94(b)(1)(iii)(B); 125.94(b)(2)(v)(B)) Incorporate protective measures including but not limited to: modified traveling screens with collection buckets designed to minimize turbulence to aquatic life, addition of a guard rail or barrier to prevent loss of fish from the collection bucket, replacement of screen panel materials with smooth woven mesh, a low pressure wash to remove fish prior to any high pressure spray to remove debris on the ascending side of the screens, and a fish handling and return system with sufficient water flow

to return the fish to the source water in a manner that does not promote predation or re-impingement of the fish.

This language is applied too broadly, minimizes flexibility, and contains specifics that are not consistent with industry practice and available science.

Specific technological requirements may be warranted if applied to facilities that are not subjected to numeric performance standards or other measures that ensure performance. Such an approach is discussed below at Comment D.9. In this case, such requirements should be carefully designed to ensure they only specify measures necessary to ensure performance. Additional requirements are unnecessary and have the potential to stifle innovation and development of new approaches. It is not clear from the record that all the measures specified by the rule are necessary. For example, there is no evidence in the record, or elsewhere that we are aware, that smooth woven mesh is necessary to reduce impingement mortality. Adding smooth woven mesh screens would be a significant cost for some facilities; therefore, the record should support the utility of this modification. Furthermore the specific requirements for a given facility should take into account local conditions. Therefore, significant discretion should be provided to the Director to determine the necessary modifications.

The requirement to install a low pressure spray wash on the ascending side of the screen is not consistent with available travelling screens or with the design portrayed in Fletcher (1990)[4]. Instead, screens with fish-friendly modifications provided by traveling screen vendors typically have low pressure spray washes on the descending side of the travelling screens, and before the high pressure wash. This arrangement is also illustrated in Fletcher (1990). Therefore, the language should be modified to indicate that the low pressure wash need not be on the ascending side as long as it precedes the high pressure spray wash.

D.3 Several of the Proposed Rule's Provisions are Redundant and will Result in Implementation Costs without Real Environmental Benefit.

The most important of these redundancies is the proposed Rule's requirement to retrofit traveling screens with modified Ristroph screens and a fish return even when the through-intake velocity is below 0.5 fps and/or the cooling system is closed-cycle. If EPA considered the reductions in impingement achieved by either the reduced through-intake velocity or the closed-cycle system, the cost-to-benefit ratio of requiring screen modifications would be extremely poor. As suggested below, both closed-cycle cooling and intake velocities of 0.5 fps should be considered fully compliant with the existing facilities rule.

D.4 Few Alternatives for Achieving Compliance

The rule's requirements at 40 CFR 125.94(b)(1) do not provide any apparent compliance path for facilities to use any technology other than modified traveling screens if their intake exceeds 0.5 fps. All facilities with intake velocities of greater than 0.5 fps are required to demonstrate achievement of

[4] Fletcher, I.W. 1990. Flow dynamics and fish recovery experiments: water intake systems. Transactions of the American Fisheries Society. 119: 393-415.

impingement mortality limitations. It is not clear how these limitations could be achieved and demonstrated using any technology other than travelling screens. This is despite the fact that EPA has previously concluded that a number of other technologies (including velocity caps, location in a less biologically active area, deterrents, variable speed pumps, wedgewire screens, and closed-cycle cooling) substantially reduce impingement and impingement mortality. EPA's apparent intention to allow flexibility is expressed in this discussion of the costing approach included in the preamble (76 FR 22214):

> Note that this [the selection of Ristroph screens and a fish return as BTA and as the cost basis] does not preclude the use of other technologies; EPA simply used the available performance data in deriving the performance requirements and excluded technologies that were either inconsistent performers or did not offer sufficient data for analysis in a national categorical regulation. EPA's research has shown that other technologies may also be capable of meeting the proposed requirements, but EPA did not opt to identify these technologies as the technology basis for today's proposal.

NextEra Energy does not find the same flexibility to select other technologies in the regulatory language in the proposed Rule. This is despite the fact that many facilities have already invested substantial resources into installing these measures and they should be able to credit the performance of these measures towards compliance with the rule.

<u>D.5 The Rule Should Focus on Control of Impingement First and, if Necessary, Impingement Mortality.</u>

The limited compliance alternatives are associated with the proposed Rule's focus on limiting impingement mortality as opposed to impingement and/or impingement mortality (40 CFR 125.94(b)(1)(i)). These standards are based solely on the fraction of the impinged organisms that are subjected to mortality. This measure is not the most direct way of considering adverse environmental impact of an intake structure. The impact of intakes is related to the overall impingement mortality caused by the intake; the overall mortality is a function of both the rate of impingement and the rate of mortality. Therefore the overall mortality can be reduced by minimizing the number of organisms that are impinged on the intake structure and/or by minimizing the mortality of those organisms that are impinged.

As currently structured, the rule provides no incentive to reduce the rate of impingement because no credit is provided towards the performance standard in the rule. In previous EPA rulemakings and materials in the docket, EPA has acknowledged that a number of measures are effective at reducing impingement, including flow reduction, velocity caps, intake location, and deterrents. However, these measures may not impact the proportion of impinged organisms that are subjected to mortality. Therefore the rule should be structured to encourage any measures that reduce impingement mortality regardless of whether they achieve reductions by minimizing impingement or by reducing impingement mortality.

The rule should be revised to focus on the more environmentally meaningful goal of reducing impingement rather than reducing only the proportion of impinged organisms that are subjected to mortality. This was achieved in the Phase II Rule by considering a facility-specific situation relative to the calculation baseline, or the worst-case, site-specific level of impacts. We believe that return to the calculation baseline is a useful approach and would allow for crediting measures that reduce impingement and impingement mortality.

NextEra Energy is aware of concerns that the calculation baseline was difficult to conceptualize and quantify at many facilities. NextEra Energy disagrees. We believe that the calculation baseline provided the applicant and the NPDES agency with a robust and flexible approach to evaluate the extent of mitigation at a given CWIS. It facilitated evaluation of several different approaches to impingement and entrainment mitigation using site-specific data (e.g., reductions in water use, spatial differences in fisheries populations, exclusion efficiency, post-impingement survival, etc.). Including this approach recognizes the reality of site-specific conditions, fosters innovation regarding protection measures, and allows credit for a variety of existing and effective mitigation measures.

D.6 The Rule should be Structured to Allow Credit for Any Effective Measures for Reducing Impingement and Impingement Mortality.

EPA should structure the rule to allow credit for measures with a demonstrated ability to reduce impingement and/or impingement mortality. Several existing and very cost-effective measures have been demonstrated to reduce impingement and/or impingement mortality. Examples of the effectiveness of these technologies are well documented in the materials supporting the proposed Rule and the Phase II Rule. The suitability of these approaches is also well demonstrated by efforts conducted at the individual facilities during the implementation of the Phase II Rule.

The potential to credit some of these measures (e.g., offshore velocity caps) is implied in the supporting documentation (e.g., Exhibits 8-1 and 8-2 of the TDD) but it is not clear how the performance of these measures could be credited towards the performance goals in the proposed regulatory text (i.e., 40 CFR 125.94).

Proposed regulatory language at 40 CFR 122.21(r)(ix) 4 and 5(iii) may be construed to invite demonstration of the effectiveness of other measures, including intake location, but other portions of the proposed Rule require installation and demonstration of other measures. In order to credit alternative measures, the impingement mortality performance goals at 40 CFR 125.94(b) must be modified to allow other approaches.

Flow reductions associated with operational measures, variable speed pumps, and/or closed-cycle cooling are relatively simple to quantify and lead to commensurate reductions in impingement mortality. Other measures, including velocity caps, intake location, and deterrents also have been demonstrated to be effective and their effectiveness has been quantified in a variety of ways. NextEra Energy believes that by working with the NPDES Director it will be possible to develop means of quantifying the effectiveness of a variety of measures aimed at reducing impingement and impingement mortality.

The performance of offshore velocity caps and sound/light deterrence measures in the context of three NextEra Energy facilities are discussed in the following sub-comments.

Offshore Intakes with Velocity Caps

Throughout the 316(b) rulemaking processes (i.e., the current draft existing facilities rule and the previous Phase I, II and III rules), EPA has reported on the effectiveness of offshore velocity caps in reducing impingement mortality (EPA 2011; EPA 2001[5]; EPA 2004a; EPA 2004b[6]). These reductions result from the avoidance response in fish triggered by the horizontal flow created by the velocity caps. Additional reductions in both impingement mortality and entrainment mortality can be realized by placement of the velocity cap in offshore waters in regions of reduced biological activity compared with shoreline environments, as well as by locating the intakes in deeper waters.

In several cases cited in these documents, the reductions in impingement mortality were substantial and met or exceeded the impingement mortality performance standard in the currently proposed rule. For example, EPA (2011) indicated that velocity cap studies at the Huntington Beach and El Segundo Generating Stations in California resulted in overall reductions in entrapment (equated to impingement mortality losses) of 80 to 90 percent. The El Segundo study compared entrapment rates before and after installation of the velocity cap, while the Huntington Beach study compared normal operations using the velocity caps with reverse flow operations that used the discharge (with no velocity cap) as the intake.

To eliminate potential artifacts in results due to differences in ambient fish densities near the intakes, entrapment rates at Huntington Beach were compared to ambient fish densities that were measured using hydroacoustic techniques supplemented by net sampling in the water column. This refined approach resulted in reductions as high as 99 percent reported for some periods at Huntington Beach.

Two studies at the Scattergood Generating Station included measurements conducted pre- and post-installation of velocity caps as well as more recent flow reversal studies (EPA 2011; LADWP 2007[7]). Results from the Scattergood study yielded an overall reduction of 83 percent. Studies at Ormond Generating Station conducted concurrently with the Huntington Beach studies resulted in overall reductions in entrapment of 61 percent during the night and 87 percent during the day.

EPA (2011) also cites impingement reductions at two facilities in England with velocity caps on one of two intakes. The intake equipped with a velocity cap at the Sizewell Power Station yielded a 50 percent reduction compared to the other intake, while the velocity cap at the Dungeness Power Station reduced impingement by 62 percent.

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[5] EPA 2001. Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities. Chapter 5 Efficacy of Cooling Water Intake Structure Technologies. EPA-821-R-01-036. November 2001.

[6] EPA 2004b. Technical Development Document for the Proposed Section 316(b) Phase III Rule. EPA-821-R-04-015.

[7] LADWP 2007. Scattergood Generating Station Clean Water Act Section 316(b) Velocity Cap Effectiveness Study. Los Angeles Department of Water and Power. June 28, 2007.

Performance at NextEra Energy's Seabrook Nuclear Power Station

Seabrook Station in New Hampshire utilizes three offshore intakes which, based on a 1975 ruling by EPA's Regional Administrator, were located approximately 7,000 feet offshore in 60 feet of water in an area of low biological activity. Each intake is equipped with 30-foot diameter circular velocity caps with 7-foot high openings. Vertical bars were retrofitted in 1999 into these openings to prevent seals from entering the velocity caps. The calculated approach velocity to the velocity caps at full load operation is approximately 0.5 feet per second, and the velocity increases to approximately 0.8 feet per second as it passes through the bars. The permitted limit through the velocity caps is 1.0 foot per second.

Regional case studies in EPA (2002)[8] compared the offshore velocity cap technology at Seabrook with the shoreline intake structure at Pilgrim Station in Massachusetts and concluded that the combination of intake location and velocity cap design at Seabrook reduced impingement losses by 68 percent and entrainment losses by 58 percent. An updated comparison for based on impingement monitoring data from the two plants from 2002 to 2006 showed a reduction in actual impingement losses of 81 percent attributable to the location and design of the Seabrook intake (NextEra Energy 2008)[9]. Estimated reductions from the calculation baseline for Seabrook Station under average flow conditions yielded an 83 percent reduction in impingement losses.

Actual impingement losses at Seabrook are extremely low, further documenting the effectiveness of the velocity cap. Estimated annual impingement rates for fish and shellfish under typical operation conditions for the period 2002 to 2006 averaged only 29,876 organisms. The most abundant fish impinged were Atlantic silverside (5,260; 18%), rock gunnel (3,602; 12%), and winter flounder (2,963; 10%). All other species each contributed less than 10% to the estimated total. To put these numbers into perspective, it is estimated that a small inshore commercial trawler can capture about 4,000 adult winter flounder in less than three days of fishing effort. Only 25 lobsters were estimated to be impinged on an annual basis over this period. With an annual circulating water pump capacity of approximately 205 billion gallons, these impingement rates would certainly qualify as *de minimis*, and the velocity cap design should be deemed best technology available for reducing impingement mortality.

Performance at NextEra Energy's St. Lucie Power Plant

The St. Lucie Nuclear Power Plant on Hutchinson Island, St. Lucie County, Florida utilizes three offshore intakes which are located approximately 1,200 feet offshore in 23 feet of water. After extensive baseline studies, the intakes were sited in an area of low biological activity (i.e., seaward of near-shore worm rock formations in areas of unconsolidated sediments devoid of reef structures, grass beds, and rock outcroppings) and isolated from major spawning grounds of most species of finfish and shellfish

[8] EPA 2002. Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule. Washington, DC: U.S. EPA. April 9.

[9] NextEra Energy Energy 2008. Cooling Water Intake Structure Information Document Seabrook Nuclear Power Station. Appendix A - Seabrook Nuclear Power Station EPA 316(b) Phase II Rule Project Revised Proposal for Information Collection. NextEra Energy Energy Seabrook LLC, July 2008.

taken in local recreational and commercial fisheries. The offshore location avoided impacts to the biologically sensitive Indian River estuary, which was initially considered as a potential source for cooling water.

The velocity caps consist of flat plates elevated about six feet above the vertical shaft of the intake structure by a series of concrete posts. Through-cap velocities are designed to be less than one foot per second. Water withdrawal at mid-depth reduces the potential for the entrapment of near-surface adults, juveniles, larvae and eggs or benthic organisms. The intake pipes were installed under the seafloor and pass under the near-shore work reefs, beach, and dunes, terminating in a headwall at the plant's 4,920-foot intake canal.

Sampling within the open channel intake canal provides the means to estimate the number of fish entrained in the velocity caps and entrapped within the canal. Comparison of gill net data from the intake canal and stations in the vicinity of the offshore intake structures indicated that the entrainment of fish and large motile crustaceans is relatively low, and major accumulations of these species do not occur within the intake canal. Catches of commercially important migratory species within the intake canal were very small.

Occurrences of larvae of sport and commercial species were infrequent and insignificant in the canal system, with the low entrainment rates attributed to the mid-depth location of the velocity caps. This layer consistently contains far fewer fish eggs and larvae than surface water.

NextEra Energy has been proactive in implementing programs to minimize and mitigate organisms entrapped by the intakes. In particular, NextEra Energy has a stringent program in place for recovery and release of entrapped sea turtles which are protected under the Endangered Species Act. The program was developed in consultation with the National Marine Fisheries Service and has been incorporated into the plant's Environmental Protection Plan. It is based on rapid detection, benign capture, and timely return to the sea. Two barrier nets were installed to retain turtles in the segment of the canal east of Highway A1A where they can be more effectively captured using buoyed tangle nets. These nets are typically deployed 7 days per week unless large quantities of jellyfish or seaweed accumulate on the nets, requiring temporary suspension of netting activity. The netting technique is supplemented with capture by hand (divers) and dip net. Biologists are on call for emergency rescue operation on a 24-hour basis.

There have been five occasions where endangered manatees have entered the intake system, the first of which occurred in 1991. NextEra Energy coordinates capture and evaluation of entrapped manatees with Florida's Fish and Wildlife Conservation Commission and, as required, assists in transporting ill or injured animals to approved rehabilitation facilities and/or releasing entrapped animals back into the wild.

NextEra Energy initiated measures in 1993 to remove entrapped fish and juvenile lobster from the intake canal. Fish are routinely captured using hook and line and with submerged traps. Over seven years, nearly 6,500 individuals representing 100 species have been caught and removed from the canal. The majority of these have been released back into the ocean or the Indian River Lagoon. The most frequently entrained species are those typically associated with reef and hard bottom systems, and it is likely that they entered the velocity caps to feed on organisms growing on the intake structure.

In summary, there are numerous examples of the effectiveness of offshore velocity caps in reducing impingement mortality. In certain cases where distance offshore and depth limit abundance and productivity, the data also indicate that substantial reductions in entrainment may occur. Each of these examples shows the effectiveness of this technology in achieving reductions in these metrics and thus should be given credit toward meeting the performance standards in the proposed rule.

Deterrents

Use of behavioral deterrents, including acoustics, strobe lights, and bubble curtains, is another widely used technology to reduce impingement mortality at cooling water intakes. Studies have shown the performance of these systems is often highly species-dependent and thus their application must be based on site-specific determinations of the target species and the effectiveness of the selected deterrent. This requirement for site-specific determinations of the efficacy of deterrents should not preclude their inclusion as a viable technology (either individually or as part of an integrated system) to achieve the proposed performance standards for impingement mortality. Where shown to be effective, their beneficial performance should be credited in the facility's overall compliance with the proposed rule.

NextEra Energy has one installed application of an acoustic deterrent system at its Point Beach Nuclear Plant on Lake Michigan in Wisconsin. The system was installed to reduce alewife impingement and consists of an acoustic array of 16 Integrated Projector Assemblies ("IPAs") uniformly spaced around the outer circumference of its 110-foot diameter submerged cooling water intake structure. The acoustic signal produced by the system consists of high frequency broad band (125 kHz) pulses, 0.5 second in duration, at one second intervals.

The 125 kHz frequency has been shown to be very effective at deterring alewife at other facilities, including the James A. FitzPatrick Nuclear Power Plant on Lake Ontario in New York that features a similar offshore intake structure. Prior to deployment of the system, alewife was responsible for approximately 80 percent of the annual impingement at the FitzPatrick plant (EPRI 2007) [10]. Following a series of pilot studies, the full-scale test system resulted in 85 to 88 percent decreases in alewife impingement Ross *et al* (1993 and 1996)[11]. The final design was accepted by the New York State Department of Environmental Protection as the best technology available for reducing impingement mortality at the plant (EPRI 2007).

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[10] EPRI, 2007. Fish Protection at Cooling Water Intake Structures: A Technical Reference Manual. EPRI Report Number: 1014934.

[11] Ross Q.E., D.J. Dunning, R. Thorne, J.K. Menezes, G.W. Tiller, and J.K. Watson. 1993. Response of alewives to high-frequency sound at a power plant intake on Lake Ontario. North American Journal of Fisheries Management 13: 291-303.

Ross Q.E., D.J. Dunning, J.K. Menezes, M.J. Kenna, and G, Tiller. 1996. Reducing impingement of alewives with high-frequency sound at a power plant intake on Lake Ontario. North American Journal of Fisheries Management 16: 548-559.

The acoustic deterrent system at Point Beach was installed in 2002 and is deployed only during the warmer months (May to October) in order to prevent ice damage to the equipment. This deployment period coincides with the peak period of alewife impingement which comprised 85 percent of annual impingement at Point Beach during monitoring conducted in 1975-1976 and as much as 99 percent of annual impingement in 2006 (at the time sections of the acoustic deterrent system were not fully operational).

Prior to the installation of acoustic deterrents, periodic and severe impingement events by alewife were relatively common. In fact, on two occasions, very large numbers of alewife were impinged and the plant "tripped" due to loadings on the traveling water screens. The deterrents were installed in 2002. During the Phase II impingement characterization study conducted in 2005 and 2006, the deterrents system was functioning poorly and is believed to have actually focused alewife around the CWIS (Kitchell, 2009). Consistent with that hypothesis, 1.5 million alewife were observed to be impinged during that study. The deterrence system was repaired and became fully functional in May of 2007 Since then, no major alewife impingement events have been recorded. In fact, between the onset of 2010 and June of 2011, only approximately 500 fish over six inches in length have been observed to be impinged.

<u>D.7 Demonstrated and Committed Reductions in Flow Should be Credited to Reductions in Impingement and Impingement Mortality</u>

Any flow reductions (including flow reductions from adoption of closed-cycle cooling, employment of variable speed pumps, retirement of units, or reduction in operation frequency) from the design intake flow result in proportional reductions in impingement and impingement mortality. For this reason, it is reasonable to credit such reductions in flow toward the performance goals of the proposed Rule. This is consistent with the Phase II's calculation baseline approach and would motivate water users to reduce water demand. Such an approach is also consistent with the proposed Rule's use of the Actual Intake Flow as a trigger for evaluation of BTA for entrainment.

<u>D.8 The Rule Should Allow a Variance from Impingement Performance Requirements when Rates are Found to be *De Minimis*.</u>

By virtue of the configuration, operation, and placement of some cooling water intake structures, some facilities have very low annual rates of impingement and impingement mortality. Implementation of the proposed Rule's full provisions would be needlessly burdensome. To avoid this, the NPDES Director should be given the discretion to define *de minimis* levels of impacts including consideration of actual versus design flow; the numerical rates of impingement (e.g., lbs/year); the operating characteristics of the plant; and/or cost-benefit considerations.

<u>D.9 The Rule should Reflect Two Tiers of Acceptable Impingement Technologies: Preapproved and Comparable.</u>

NextEra Energy believes that two technological approaches should be designated as "preapproved", similar to the application of wedgewire screens in riverine situations which was a preapproved technology under the 2004 Phase II Rule. In the proposed Rule, EPA has already defined two technologies (retrofit of traveling screens with advanced screens and fish return as well as reduced through-intake velocity of less than or equal to 0.5 fps) as high-performing technologies. NextEra Energy believes that proper installation, operation, and maintenance of either of these technologies should be considered to be fully compliant with the impingement reduction goals of the statute and rule. Therefore, these technologies would be considered to be "preapproved".

As noted above, NextEra Energy believes that several other intake technologies can greatly mitigate the effects of impingement and should be candidates for adoption as "comparable" technologies. Applications at a facility would be in consideration of all relevant site-specific factors and subject to review and approval of the NPDES Director. Such technologies should include but not be limited to: offshore velocity caps, deterrence systems based on light and/or sound; wedgewire screens; barrier nets; variable speed pumps or other forms of flow reduction; the position of the intake; restoration; etc. Evaluation of comparable technologies should include the ability to consider site-specific costs of potential retrofits relative to both the costs estimated by EPA for the preapproved technology at the site and/or the monetized benefits of the measure. Evaluation of potential system performance should be relative to the worst-case, site-specific effects (i.e., the calculation baseline) and, at the discretion of the NPDES Director, may be based on available literature and/or site-specific monitoring studies. Following review by the NPDES Director, only those measures for which the benefits justify the costs would be necessary to install and operate.

This proposed approach to finalizing the Rule is presented as a flow chart in Attachment 2. The flow chart integrates the comments made on the impingement mortality BTA in the form of an alternative compliance approach. It provides for categorical compliance in the event that a facility employs either: closed-cycle cooling, an intake velocity of less than 0.5 fps, or modified Ristroph screens and a fish return. The last two measures are designated preapproved. It also provides opportunities to demonstrate that existing or newly installed measures provide reductions in impingement or impingement mortality comparable with the preapproved technologies. Use of comparable BTA would trigger one year of performance monitoring. Results would be considered within the context of costs and monetized benefits of potential control measures. Finally, *de minimis* impacts would be considered when defining comparable BTA.

D.10 EPA Should Issue Guidance for Comparable BTA.

EPA should develop guidance for states based on a few (5 to 10) example facilities to illustrate the expected performance for preapproved BTA and comparable BTA technologies at specific sites. These examples should be based on a robust data set and reflect different situations that will affect impingement such as different water bodies, fragile species, facility sizes, and seasonal dynamics. The expected performance should be based on both fish mortality and biomass and account for actions that prevent fish impingement.

This guidance would facilitate permitting authorities' assessment of alternatives to the preapproved BTA technologies. It would not establish a national standard that would be applicable to all facilities. The guidance should also note that states should use a cost-benefit analysis when evaluating BTA for a facility if the facility is installing a comparable technology.

D.11 The Importance of Shellfish Carry-over on Traveling Water Screens is Undemonstrated and Has the Potential to Drive Significant Costs for Compliance

EPA proposes that facilities that withdraw from tidal waters must provide additional impingement control measures by preventing the transport of shellfish from the ascending side of the screen to the pump well due to their entanglement in the screen. To prevent such carry-over, EPA proposes that protection of shellfish commensurate with a barrier net must be installed. EPA offers that such measures could include barrier nets, dual-flow or disc screens, or wedgewire screens. EPA also considers an aquatic filter barrier (e.g., Gunderboom) as having performance commensurate with a barrier net. NextEra Energy believes that the Gunderboom system would be an unlikely choice to control shellfish carry-over due to its high cost and the operational difficulties associated with the fine mesh intended to exclude ichthyoplankton. For this reason, these comments will not discuss aquatic filter barriers.

NextEra Energy is very concerned with several aspects of EPA's proposal. First and foremost, EPA offers no quantitative data supporting that: 1) carry-over occurs on a common basis; 2) that if carry-over does occur, that it results in significant losses of shellfish; 3) that the monetized benefit of protecting such shellfish justifies the social costs of the installation of the protection measures. In the absence of these analyses, it is very difficult to argue that the proposal has merit.

As importantly, NextEra Energy believes that EPA underestimates the challenge of engineering approaches to prevent potential carry-over. Installation of any of three potential barrier technologies is fraught with installation, operation, and maintenance issues. Each of the three is also likely to be very costly relative to the monetized benefits.

Barrier nets themselves have been successfully deployed and maintained at a very small number of facilities (only 8 of 766 facilities responding to EPA's detailed questionnaire on the rule indicated use of barrier nets; EPRI (2007) reviews use of nets at seven steam electric generators). Many of the deployments are seasonal to avoid periods of high debris loading or ice formation. Only two of the net systems have been deployed in saltwater and neither of those was in marine setting (EPRI, 2007). Both of the estuarine deployments are in sheltered areas and one of those is no longer used due to clogging by silt and colonial algae. In certain settings (e.g., J.P. Pulliam Station in Wisconsin and Chalk Point in Maryland), two nets are deployed to facilitate the removal and cleaning of one while the other is left in place as a barrier. It is not uncommon to remove and clean one net on a twice-weekly basis. Barrier nets are subject to damage and failure during periods of high debris loading as well as heavy seas associated with storms. To our knowledge, no barrier net has been deployed in an offshore environment such as NextEra Energy's St. Lucie or Seabrook CWIS.

The challenges associated with the installation and maintenance of a barrier net are very substantial. Supporting and anchoring the net would involve innovative and costly technology particularly to ensure that the barrier is complete at the bottom. The net would frequently have to be removed, cleaned of organisms and debris, and redeployed. Net mesh sizes vary with the size of target organisms to be excluded (along with other factors) and typically range from 4 mm to 32 mm (EPRI 1999)[12]. Through-net velocities vary with these factors. While there are no firm guidelines on the target through-net velocity, EPA (2004) indicated that a very low through-net velocity (0.06 ft/s) is advisable based on design criteria from installed applications, thus resulting in a very large surface area.

The net would be subject to high currents as well as significant wave action. It would also present an obstacle to navigation. While no barrier net of this scale has been designed and installed to withstand a marine environment and the level of required maintenance, while high, is uncertain, a set of simple cost algorithms used in the context of sheltered waters provide an estimate of the annualized cost of such a barrier net system at St. Lucie. When annualized according to the Phase II procedures using $2009, the estimate is $2,200,000, which is likely a significant underestimate given the uncertainties in construction and maintenance. As well, a single net was assumed for the analysis and two nets would likely be required. This cost is completely unreasonable given the high performance of the existing offshore velocity caps, the fact that the cap is placed offshore in an area with low biological populations, and the lack of demonstrated carry-over at the plant.

Barrier nets would suffer from other problems at several of NextEra Energy's other plants that are located in and around harbors or tidal embayments. Given the relatively shallow water of these systems, the barrier net would be quite long to achieve target through-net velocities (estimated in some cases to be almost a half mile in length). This length complicates maintenance and also presents a significant impediment to navigation and a substantial risk to manatees and other endangered aquatic species.

EPA suggests that installation of wedgewire screens could result in a level of protection commensurate with barrier net. The screens would likely be sized to achieve a through-screen velocity of 0.5 ft/sec facilitating compliance with the overall Impingement Mortality approach. At that target velocity, several very large screens would be necessary to serve a plant like Seabrook (estimated to require 252 feet of 84-inch diameter screens using 6 mm slot size) or Port Everglades (estimated at 307 feet of 66-inch diameter screens using 9 mm slot size). Wedgewire screens are a demonstrated technology in freshwater but do not have wide application in seawater. In seawater, there is a much smaller installed base and there are significant concerns about fouling as well as corrosion (particularly at the welds). Wedgewire screen vendors have indicated to NextEra Energy that careful site-specific studies would be necessary to establish that the metallurgy of the screen is adequate for long-term exposure to seawater. The deployed screens would be an impediment to boat traffic, particularly in bays and harbors such as Port Everglades and Riviera. It is likely that the screens would have to be cleaned by divers on a frequent basis to control fouling. Placement of the screens would require a significant reconfiguration of the CWIS to include a very large diameter pipe that runs offshore as well as lateral manifolds to serve each screen. Approximate costs of such a system would be extremely high. Such a system at Port

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[12] EPRI 1999. Fish Protection at Cooling Water Intakes: Status Report. TR-114013. EPRI, Palo Alto, CA. Cited in EPA-821-R-11-001.

Everglades (if it were feasible) was preliminarily estimated to cost approximately $141 million. Such costs are far beyond those estimated by EPA in its evaluation of the social costs of the proposed Rule. Such costs would be wholly disproportionate with monetized benefits of reducing shellfish carry-over.

Dual flow or disc screens are suggested by EPA as a means of controlling carry-over. While these screens have the apparent advantage of not allowing carry-over (the screen face on which shellfish might be impinged always faces out and is never rotated into the pump well), it is not clear that entanglement of shellfish would be avoided with such a system. Instead of being subject to carry-over, shellfish that may become entangled in the wire mesh may remain there and not get routed to the fish return.

In response to verbal questions on the importance of carry-over, EPA staff indicated that staff intended to allow for no additional carry-over controls if the degree of carry-over can be shown to be small through site-specific sampling. If the requirement to control carry-over is included in the final Rule, this intention should be clearly stated in the regulatory language of the Rule. Guidance should also be provided as to the acceptable level of carry-over. Finally, NextEra Energy believes that a site-specific cost-benefit test should be allowed to evaluate whether the costs of potential carry-over controls are reasonably matched to the monetized benefits. If the costs are disproportionate with the benefits, a variance from the carry-over requirement should be available.

EPA proposes that CWIS on tidal systems be required to control carry-over to protect shellfish. NextEra Energy suggests that, if carry-over controls are included in the final Rule that those facilities on saline waters be included. There are several facilities on waterbodies that are influenced by tides but are most commonly freshwater and, therefore, have low numbers of shellfish.

D.12 Closed-cycle Cooling Should be Compliant with IM Requirements

Facilities that employ closed-cycle cooling typically achieve flow reductions of greater than 90% relative to the facilities with once-through cooling. As EPA has acknowledged in previous rulemakings (69 FR 41612), this flow reduction results in commensurate reductions in impingement mortality relative to open cycle facilities. NextEra Energy believes that the rule's impingement mortality standards should be re-structured to allow credit for flow reductions. This change would make facilities with closed-cycle cooling compliant with the IM reduction requirements.

Given the high performance of closed-cycle cooling at reducing impingement mortality, the requirements to retrofit travelling screens with fish protection features outlined in 125.94(b)(1)(iii)(B) and 125.94(b)(2)(v)(B) are unnecessary and result in an undue financial burden to the facility. Inclusion of such a requirement makes the proposed Rule more stringent than the 316(b) Phase I Rule that has no blanket requirement for traveling screens. It also requires a higher level of performance of closed-cycle facilities (i.e., reduction of flow by approximately 90% and further reduction of impingement mortality) relative to open cycle facilities (i.e., reduction of impingement mortality). The very low impingement mortality rates at closed-cycle facilities make the costs associated with screen modifications unwarranted as illustrated in the very poor cost to monetized benefit ratios that would be incurred.

The application of these requirements to facilities with closed-cycle cooling and intake velocities of less than 0.5 fps is particularly troublesome. EPA has concluded that intake velocities of less than 0.5 fps are protective of 96% of tested organisms (67 FR 17151; 66 FR 6527; and 69 FR41602) and therefore facilities with low intake velocities should be compliant with the impingement mortality requirement. Facilities with both low intake velocities *and* closed-cycle cooling have an even lower potential to result in impingement mortality.

For example, the combined reduction in impingement would be on the order of 99.6% (i.e., reduction in flow (0.9) + (reduction in impingement rate in the remaining flow) (0.1 * 0.96)). Requiring retrofit of traveling screens to address the minimal rate of impingement is simply unreasonable. Therefore, these facilities should not be required to also retrofit to their travelling screens and install a fish return. The benefits of such a requirement would be insignificant and the costs substantial. Furthermore, such a requirement would be more stringent than the requirements included in the Phase I rule for new facilities. Requiring higher performance for existing facilities than new facilities is illogical and inconsistent with EPA policy as stated in the preamble to the proposed Rule.

D.13 Achieving the Impingement Mortality Limitations is Unlikely to be Feasible at Many Facilities

The impingement mortality limitations in the proposed rule (40 CFR 125.94(b)(1)(i)) are likely to be unachievable at many facilities due to the inherent sensitivity of some fish species to handling, the amount of debris, and other factors. In the preamble to the draft rule, EPA quotes the 1977 section 316(b) guidance which states, "...the environmental-intake interactions in question are highly site-specific and the decision to the best technology available for intake design, location, construction, and capacity must be made on a case-by-case basis" (EPA 1977)[13]. The site-specific nature of the interaction between the environment and the intake structure makes the performance of any technologies for reducing impingement mortality or entrainment mortality vary significantly from plant to plant. This variation will make achievement of the rule's impingement mortality limitations infeasible at intakes in conditions that are different from those on which the performance standard is based.

Perhaps the most important factor that influences impingement mortality performance of available technologies is the species that are subjected to impingement. There is significant literature that clearly demonstrates that performance of modified traveling screens at limiting impingement mortality is highly species-specific (EPRI 2003)[14]. This is a very important phenomenon given the highly episodic nature of impingement events. For example, bay anchovy comprised 85 percent of annual fish impingement at NextEra Energy's Cape Canaveral plant during 2007, with one event in mid-August contributing 21 percent of the total annual fish impingement. Similarly, two species of anchovy comprised 67 percent of the annual fish impingement at NextEra Energy's Port Everglades plant that same year; however,

[13] EPA 1977. Draft Guidance for Evaluating the Adverse Impacts of Cooling Water Intake Structures on the Aquatic Environment. Section 316(b) P.L. 92-500. May 1, 1977.

[14] EPRI 2003. Evaluating the Effects of Power Plant Operations on Aquatic Communities. Summary of Impingement Survival Studies.

impingement of just one of the species (big-eye anchovy) during one event in early September contributed 25 percent of the annual total. While tomtate contributed only 37 percent of the total annual impingement at NextEra Energy's Riviera plant in 2007, during one event in February impingement of this species comprised 27 percent of the annual total.

An integrated summary of the estimated rate of impingement survival at four of NextEra Energy's plants is presented in Table 2 (see Attachment 3, including a description of the method employed to develop the estimate). As discussed below, many of the species impinged at these plants are sensitive to handling and the impingement mortality estimated from the literature exceeds the proposed Rule's performance standard of 12% impingement mortality at three of the four plants. NextEra Energy believes that these estimates are likely to be biased toward higher survival rates because several of the surrogate species used in the analysis (e.g., blue crabs, shrimp species) are tolerant of impingement. Therefore, NextEra Energy believes that several of its plants would have great difficulty achieving the proposed Rule's performance standards.

Some organisms are relatively durable and experience very low rates of mortality following impingement while others are extremely delicate and have very high rates of mortality even on travelling screens with state-of-the-art fisheries protection modifications. The data that the draft Rule's impingement mortality limitations are based on provide a clear illustration of the variable performance of the modified traveling screens that are the basis for the performance standards (see Table 3). As illustrated in that table, the relatively low rate of impingement mortality derived by EPA is critically driven by mixture of species impinged. If a different proportion of species had been impinged, which is very likely, the rate of impingement mortality could have been far higher.

Table 3:
Species-Specific Mortality Rates Following Impingement on Modified Travelling Screens at the Three Plants Used by EPA to Develop the Impingement Mortality Goals

Species Name	# Impinged That Died	# Impinged That Survived	Total # Impinged	% Impingement Mortality
Alewife	298	184	553	67%
Atlantic herring	336	100	436	77%
Gizzard shad	324	3837	4446	14%
Emerald Shiner	344	14841	15249	3%
Rock bass	4	676	684	1%
Threespine stickleback	2	1517	1519	0%

1. Data obtained from Exhibit 11C-1. Impingement Data Used to Develop the Proposed Limitations (EPA-821-R-11-001)

The implication of this variability is that facilities that impinge a high proportion of relatively sensitive species are unlikely to be able to achieve the rule's IM limitations regardless of the travelling screen modifications that are employed. To illustrate this case, the potential performance of the Point Beach facility was estimated based on the species mix that has historically been impinged at this facility and the assumption that survival rates similar to those in EPA's data could be achieved. Based on this analysis, the estimated impingement mortality at this facility, *using the data summarized by EPA*, would be 66% (Table 4). This is substantially higher than the draft rule's annual average performance standard for impingement mortality limitations of 12%. Therefore, it is unlikely that this facility could reduce its impingement mortality using Fletcher-type modifications to be compliant with the draft rule if the performance standard is applied to all species impinged.

Table 4:
Estimation of Impingement Mortality at FPL's Point Beach Plant Using Observed Rates of Impingement at the Facility and Data Used by EPA to Derive the Proposed IM Performance Goals

Species	Number[1]	Percentage	IM[2]	Weighted IM[3]
Alewife	1,595,015	99.26%	67%	66%
Rainbow Smelt	9,144	0.57%	27%	0.16%
Spottail Shiner	1,276	0.08%	4%	0.00%
Gizzard shade	738	0.05%	14%	0.0%
Yellow Perch	738	0.05%	1%	0.0%
Total	**1,606,911**	**100.00%**		**66%**

1. Numbers are values measured during the Phase II impingement investigation performedin 2005 and 2006.

2. Species specific impingement mortality calculated with data from Exhibit 11C-1 of EPA's Technical Development Document

3. Production of proportion of total and species-specific IM.

Other site-specific characteristics are also likely to substantially impact performance. For example, some facilities experience very high debris loads on their travelling screens. This has the potential to substantially increase impingement mortality. Impinged organisms are likely to be subjected to impact and abrasion from the debris resulting in increased mortality.

In addition, there is no evidence in the record for the draft rule that the modified travelling screens identified as BTA are able to separate debris and organisms effectively enough to achieve the impingement mortality limitations. It is well documented that a number of NextEra Energy facilities experience numerous events of heavy seagrass and drift algae entering the CWIS, often resulting from sustained onshore winds. During a number of impingement and entrainment sampling events conducted n 2006-2007, heavy loads of drift algae and detached seagrass were encountered on the traveling screens at several plants including Riviera Beach, Canaveral, and Cutler. These heavy debris loads greatly complicated sorting and enumeration of impinged organisms during the studies. NextEra Energy therefore has substantial concerns regarding the potential success for modified traveling screens to separate and safely return organisms impinged during these events. Provisions should be included in the rule that accommodate these natural events, similar to provisions on the former Phase II rule that provided accommodations for such unique events.

NextEra Energy's plants in Florida[15] also have NPDES permit conditions that prohibit the return of debris to the source waterbody. Returning organisms impinged at these facilities while maintaining compliance with the permit condition that prohibits discharge of debris would require complete separation of debris from organisms, which is infeasible. Furthermore, achieving compliance with the impingement mortality limitations would require very low rates of organisms being carried into the debris waste stream. Again, there is no evidence that this is achievable.

EPA indicates that they expect that operators will innovate and optimize the operation and configuration of their traveling water screens in order to achieve reduced rates of impingement mortality. This is one of the reasons that EPA finds it acceptable that an average annual rate of impingement mortality of 12% would result in one-half of their selected studies failing to achieve the standard. In reality, there is very little on a modified traveling water screen to modify or optimize. Among the operating parameters are: 1) rotation speed; 2) rotation frequency (e.g., intermittent vs. continuous); 3) spray wash pressure; and 4) spray wash angle. In most cases, these parameters will be fixed in order to maximize fish survival and the literature studies also reflect such optimized values.

For example, in settings where minimal mortality is desired, screens are rotated on a continuous basis. EPRI (2003) notes that this is an important factor in fisheries protection and NextEra Energy has selected its planning data from the literature to include only screens that are rotated continuously. The factors that are beyond the control of the operator are precisely the ones that most determine the rate of impingement mortality: the species impinged and the degree of concurrent debris loading. For these reasons, NextEra Energy does not believe that it will be possible to substantially improve traveling screen performance through optimization.

[15] This is a common NPDES permit condition in several states.

Given the evidence that not all facilities will be able to achieve the IM limitations, the draft rule must be revised to provide a feasible path to compliance when achieving the IM limitations is not feasible. As discussed in Comment D.9, such a workable path is presented in Figure 1, Attachment 2.

The difficulty of achieving the impingement mitigation standards would be mitigated by careful definition of Species of Concern to exclude particularly sensitive organisms with lower ecological value consistent with EPA's statements in the preamble and the TDD. As noted in Comment C.4, NextEra Energy requests that EPA modify the regulatory language to include a concrete definition of Species of Concern consistent with its statements in the preamble and the TDD.

The proposed requirement to return organisms to the waterbody alive may be in conflict with local or state ordinances that prohibit the return of invasive species to the source waterbody. Compliance with such requirements could require the separation of invasive plant and animal species from other species in the fish return system. This would be very challenging and costly to conduct and would subject impinged organisms to additional handling and stress. Retrofitting effective fish return systems is highly constrained at many existing facilities due to the plant configuration, distance to the waterbody and existing land uses between the plant and the waterbody. Examples at NextEra Energy facilities include St. Lucie, Seabrook, Riviera, and Port Everglades, (constraints at the latter are illustrated in Figure 1 in Comment B.1). As a result, achieving the impingement mortality limitations would be even less feasible.

D.14 The Basis for the Impingement Mortality Goals is Unsound

EPA's approach to developing the performance standard raises a number of concerns. As stated previously and acknowledged by EPA, the performance of technologies is highly dependent on a number of site-specific characteristics, including waterbody type, species encountered, debris loads, etc. Despite this variability, EPA relies on performance data from only three facilities within a single state. As importantly, the studies were relatively limited in time and are treated as aggregated data, substantially reducing the variation that was encountered. Therefore, these data do not represent the range of species, environmental conditions, and operating parameters that occur nationwide. Basing a national standard on them is inappropriate and results in a standard that is unachievable where conditions vary from those at the three facilities[16] that the draft standards are based on.

In addition, there are a number of inaccuracies and concerns with the approach used by EPA when calculating the impingement mortality limitations. Section 11.2.1 of the EPA TDD (EPA-821-R-11-001) provides two equations used by EPA in calculating the impingement mortality percentages. The first calculates the impingement mortality percentage based on the numbers of organisms killed relative to the number of organisms impinged:

[16] It is interesting to note that, while EPA adopts the technology advocated by Fletcher (1990), it rejects his data from the calculation of the performance standards due to his latent survival period being longer than 48 hours. Despite this, several important trends are evident in Fletcher's paper: 1) he notes that high debris loading in the form of vegetation lowers fish survival rates and complicates separating fish from debris; 2) fish are encountered in the debris sluice due to their imperfect separation from debris; and 3) the latent mortality rates of four of the six measured taxa exceed the EPA's proposed goal of 12% impingement mortality (the latent mortality of alewife is measured at 64% and white cat fish at 40%).

(1) impingement mortality percentage = (total number killed)/(total number impinged) x 100

The second calculates the performance based on the number that survive relative to the number impinged:

(2) Impingement mortality percentage = [1-(total number survived)/total number impinged)] x 100

If all organisms impinged are accounted for in either the survived and impinged values, both equations will result in the same impingement mortality percentages. However, close review of the data used by EPA in developing the performance standards indicates that this is not the case. To illustrate this we examined the data that are presented in Exhibit 11-3 of the TDD. This table presents the total number impinged, the total dead, and the percent impingement mortality calculated using equation 1. We used the supporting data for these facilities to consider how these values would differ if based on the survival values. This assessment clearly indicates that use of equation 2 leads to higher rates of impingement mortality (Table 5).

Table 5:
Comparison of Impingement Mortality Based on Alternative Calculation Approaches
From Exhibit 11-3 of the TDD.

Facility	Sampling Period	Total Impinged	Total Dead	Percent IM[1]	Number Survived[2]	Percent IM[3]	
Arthur Kill	Unit 20, 1994-1995	7,130	1,366	19.2%	Note 4	-	
	Unit 30, 1994-1995	3,408	235	6.9%	Note 4	-	
	Total	**10,538**	**1,601**	**15.2%**	***8,657***	***17.8%***	3%
Dunkirk	12/20/98 to 01/09/99	6,775	261	3.9%	***6,488***	***4.2%***	0%
	04/20/99 to 04/28/99	3,562	435	12.2%	***3,053***	***14.3%***	2%
	08/16/99 to 09/04/99	1,220	182	14.9%	***1,010***	***17.2%***	2%
	11/02/99 to 11/11/99	8,928	243	2.7%	***8,657***	***3.0%***	0%
Huntley	01/21/99 to 01/25/99	6,120	561	9.2%	***5,185***	***15.3%***	6%
	10/24/99 to 10/29/99	3,258	1,025	31.5%	***2,138***	***34.4%***	3%

Values in bold are from impingement data in docket. Remaining values are directly from Exhbit 11-3 of the TDD.

1. Value reported in Exhibit 11-3 of TDD. Total value reported for AK calculated as Dead/Total Impinged
2. Number survived from IM Survival Data provided in Docket
3. Value calculated based on 1-Total Survived/Total Number impinged
4. Data provided in docket does not differentiate between unit 20 and 30

The discrepancy between the two calculated impingement mortality percentages indicates that some organisms that were impinged were not included in either the survived or impingement mortality values. Review of the documents that were the source of this data indicated that this is the result of organisms that were stressed being discarded and not included in either the impingement mortality or survived category. For example, the study of the Huntley Steam Station indicates that 6,120 organisms were impinged during the January sampling period (Beak 2000)[17]. This value is consistent with that reported in Exhibit 11-3. Of these organisms, 87 were reported to be dead and 316 stressed upon collection. Following the latent survival assessment another 474 were dead. EPA reports the total number killed (impingement mortality) to be 561, the sum of initial dead and dead after latent survival studies. This value does not include those that were stressed upon collection and not included in the latent survival studies. As a result, the impingement mortality percentage is lower than if these organisms were accounted for. Since these organisms were visibly stressed and unlikely to survive they should be considered mortality for the purposes of the calculation. This can be accomplished by either using the impingement mortality value provided in Exhibit 11-3 or simply using equation 2 as illustrated in the table above. In either case the result is a higher impingement mortality value; in some cases significantly higher. As the table indicates, this was not an isolated occurrence. EPA must re-calculate the performances limits based on this approach to accurately account for the performance of the screens.

D.15 Use of the Beta Distribution to Predict Impingement Mortality Data is Ill-advised:

EPA derives its average annual and monthly maximum performance by fitting a statistical distribution to the rates of impingement mortality observed at three facilities (see Chapter 11 and Appendix D of the TDD). The beta distribution is fit to eight data points each representing the average rate of impingement mortality during sampling windows at the three selected facilities. We believe that the statistical analysis is flawed in three essential ways:

- As described in Appendix D of the TDD, the beta distribution can take a variety of very different forms depending upon the values of the two parameters employed in its calculation. For this reason, in the absence of an accepted theoretical basis that the form of the distribution is descriptive of the data, the "fit" of the data to the beta distribution provides very little assurance that the distribution is predictive of conditions outside of the data set. In effect, the beta distribution can be used to fit a variety of data, particularly when the data set is small. An example of this flaw is the fact that some species, and groups of species impinged at plants across the country, survive at very low rates even when impinged on post-Ristroph type screens, as supported by EPA's own analysis in the TDD and the impingement survival literature. In contrast, the beta distribution as fit by EPA would predict that the vast majority of fish would survive at rates greater than approximately 70%: low rates of survival are predicted to be exceedingly rare.
- The use of the statistical expected value (average) of the beta distribution for calculating that average annual limitation results in a limitation that approximately half of the samples would not achieve. Use of the average value indicates that half of samples would be expected to exceed this selected limitation. EPA indicates that no upward adjustment to this value would be necessary because facilities will "...have opportunities to modify the technology when necessary to achieve compliance with the annual average limitation" (section 11.2.3.2 of the TDD). However, there is no evidence in the record that there are available modifications to the

[17] Beak, 2000. Post-Impingement Survival at Huntley Steam Station (Winter and Fall, 1999).

technology identified as BTA that would improve the performance substantially and ensure that achievement of the annual impingement mortality limitation is feasible. In fact, the limited data sets do not allow calculation of an annual average; none of the data sets evaluated spans a calendar year of impingement mortality sampling at a given plant. Finally, while EPA also spends some time in an *ad hoc* post-analysis censoring of some of the data based on speculation regarding differences in screen size, etc., it is not clear that its potential explanations are valid or if the data are simply subject to variation.

- As noted above, the population of observed impingement mortality rates is far too limited. The population does not represent an adequate range of conditions, particularly different fisheries taxa including those of different geographical areas. EPA cannot claim that the sample of impingement mortality represents the range of conditions that will be encountered nationally. As described above, careful evaluation of the data provides concrete evidence that the rate of impingement mortality will be higher at plants where impingement is dominated by certain taxa. The means by which EPA aggregated impingement mortality rates masks the variation in impingement mortality and, by happenstance, sensitive taxa are poorly represented in the samples employed. These weaknesses in the data undercut the conclusions reached in the statistical analysis.

In Section 11.2.3.4 of the TDD, EPA evaluates the impingement mortality data from the three plants relative to its proposed performance standards. EPA attempts to explain that the performance goals are relevant and achievable even when the observed data appear to be inconsistent. EPA does this by *ad hoc* censoring and rationalization of apparent differences. It is precisely these differences that make general compliance with the performance standards so problematic and unlikely.

D.16 The Rule's Impingement Mortality Limitations Must be Removed or Recalculated.

NextEra Energy recommends that the numerical performance standards for impingement mortality be removed from the Rule. In the event that EPA maintains the numerical performance standards they must be recalculated. The calculation of the performance standards should be corrected to address the concerns described in Comment D.5. In addition, the impingement mortality limitations should account for the variation in performance that would be achievable under the wide range of site conditions encountered at facilities across the country.

EPA concluded in the Phase I rule that achieving performance that was 90% of the technology selected as BTA in that case (closed-cycle cooling) was considered comparable performance (40 CFR 125.86 (c)(2)(i)). This approach was accepted by the second circuit court (River Keeper *et al* v. US EPA, February 3, 2004). This conclusion was based on uncertainties in performance estimates and differences in ambient conditions (66 FR 65279). EPA should utilize a similar approach when setting impingement mortality performance limitations to account for some of the variability and uncertainty that will be encountered. The existing impingement mortality limitations expressed as reductions in impingement mortality are 88% on an annual basis and 68% on a monthly basis. Applying the same definition of "comparable" (i.e., within 10% of the performance) to these standards would result in an annual impingement mortality reductions of 80% and 61%; these correspond to impingement mortality limitations of approximately 20% and a monthly limitation of 39%.

This adjustment would not account for all variation that would be encountered at facilities across the country. However, it does provide a limitation that would provide some accounting for the variability in conditions to which it will be applied. This adjusted limit would likely substantially reduce violations of permit limits without reducing the environmental benefit of the rule's impingement mortality requirements. It is likely that in nearly all cases facilities would install the same technologies and operate them identically under the adjusted limits as they would under the draft impingement mortality limitation.

<u>D.17 The Rule's Requirements to Retrofit Travelling Screens are not Consistent with Standard Industry Practice or Available Technologies.</u>

The very specific requirements at (125.94(b)(1)(iii)(B) and 125.94(b)(2)(v)(B)) for modifying travelling screens are not consistent with the configuration of the travelling screens at the facilities at which the performance standards are based upon and are not consistent with many available and effective technologies. The draft rule's requirement that the low pressure spray wash system be located on the ascending side of the screen is particularly problematic. The configuration of screens available from existing vendors of which we are aware all have the low pressure spray wash located near the top of the descending side of the screen. In addition, this location is consistent with that portrayed in Fletcher (1990) referred to in the preamble and supporting documents. Furthermore, having the low pressure spray wash and fish return on the descending side of the screen is likely preferable for reducing mortality, since the collection buckets drain by gravity as the it passes from the ascending to descending side of the screen and the low pressure wash can be combined with the water to draining from the bucket.

Conversations with EPA staff on this issue suggest that the intention of this requirement was to ensure the low pressure spray wash precedes the high pressure spray wash, a configuration that we endorse. The language should be clarified to reflect this intention and to be consistent with available technology configurations. In addition, the draft rule contains language requiring the installation of a guard rail that could be misinterpreted. Clarification of these issues is provided in the suggested regulatory text below:

> (125.94(b)(1)(iii)(B); 125.94(b)(2)(v)(B)) Incorporate protective measures including but not limited to: modified traveling screens with collection buckets designed to minimize turbulence to aquatic life and capped at both ends to stop water and organisms from draining out when lifted above the water ~~addition of a guard rail or barrier to prevent loss of fish from the collection bucket~~, replacement of screen panel materials with smooth woven mesh, a low pressure wash to remove fish prior to any high pressure spray to remove debris ~~on the ascending side of the screens~~, and a fish handling and return system with sufficient water flow to return the fish to the source water in a manner that does not promote predation or re-impingement of the fish. Alternative approaches to the refitting of traveling water screens that

the facility and the NPDES Director agree offer a commensurate level of protection to the measures defined here may also be employed.

D.18 The Estimated Costs of Compliance with the Rule's Requirements are Likely Understated and Monetized Benefits Likely Overstated.

Recent quotes to install post-Ristroph-type traveling water screens with a fish return at one of NextEra Energy's plants indicate that actual costs can substantially exceed those estimated by EPA. The EPA cost estimating tool produces an estimated capital costs for installing modified travelling screens and fish return at this example facility of $4,500,000. The quotes for this effort provided by two vendors were $6,500,000 and $7,100,000, which are 44% and 58% higher than EPA's estimate, respectively. This is despite the fact that the facility has a relatively standard intake consisting of travelling screens located on the source waterbody and would have a short fish return. Many facilities with less typical intakes or longer returns requiring fish pumps, etc., are likely to face costs that exceed the cost estimated by EPA by an even greater margin.

As another example, NextEra Energy has estimated that an additional 16 bays of similar configuration to the eight existing bays would be required at its Port Everglades plant to attain a through-screen velocity of less than 0.5 fps. If equipped with Ristroph-type modifications and a fish return system, the preliminary estimate to construct these bays is $113.2 million. NextEra Energy has performed similar evaluations at its other Florida facilities and the resulting cost estimates are similar to those developed for Port Everglades.

NextEra Energy performed a preliminary cost-benefit analysis to compare the cost of traveling screen retrofits to reduce impingement mortality at the Port Everglades and Lauderdale plants to the benefit realized in terms of the value of fish and shellfish that would survive impingement as a result of the retrofits. The methodology for retrofit costs followed that used by the EPA during the Phase II 316(b) rulemaking (EPA 2004a)[18], updated to reflect costs based on the Engineering News-Record's (ENR's) November 2010 construction cost index.

Monetary values for available plant-specific impingement losses were based on National Marine Fisheries Service (NMFS) annual landings data for Florida and the Atlantic and Gulf States. The estimated values are based on annual landings for recreational and commercial fish and their cost per pound at the dock. A second source of fish valuation data included the Florida Fish and Wildlife Conservation Commission's (FWC) Marine Fisheries Information System. Estimated values for a variety of vertebrate and invertebrate species were obtained from the 2009 Annual Landings Summary and the 2009 Marine Life Landings Summary.

Assuming 100 percent mortality of impinged organisms, the monetized value (2010$) for the estimated annual impingement loss at Port Everglades using the NMFS landings data was $1,908, while the

[18] EPA 2004a. Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule February 12, 2004. EPA 821-R-04-007.

estimated annual loss using the landings data from the FWC was $13,635. Using an estimated annualized cost of $1.8 million for retrofitting and operating a fish return system at Port Everglades, the annual costs exceed the benefits by a factor of 948 using the NMFS valuation data, while the cost-benefit ratio using the FWC valuation data was 133.

The monetized value (2010$) for the estimated annual impingement loss at the Lauderdale plant using the NMFS landings data was $452, while the estimated annual loss using the landings data from the FWC was $1,634. Using an estimated annualized cost of $537,000 for retrofitting and operating a fish return system at Lauderdale, the annual costs exceed the benefits by a factor of 1,188 using the NMFS valuation data, while the cost-benefit ratio using the FWC valuation data was 328. These cost-benefit ratios are significantly higher than those assumed by EPA, and the costs must be considered wholly disproportionate to the benefit realized from the technology improvements. Such data highlight the need for a site-specific variance to avoid very high compliance-related expenditures with very small environmental and monetized benefits.

EPA develops estimates of the monetized benefits of the proposed rule based on estimated losses of commercial and recreational fisheries as well as non-use benefits and loss of threatened and endangered species. EPA uses a model facility approach to estimate the rate of impingement and entrainment losses at subject facilities. Unfortunately, the source of the impingement/entrainment data and the process used to map the rates of impingement/entrainment to the subject facility is not explained in a transparent fashion. Were data collected during the Phase II implementation process used to estimate impingement and entrainment rates? Given the timing and nature of that implementation process, those would appear to be the most relevant data to the process of estimating losses and benefits. Were data from a given plant used at that plant or was a more aggregated data set used?

We understand that impingement and entrainment data were stratified by region. Were all facilities within the region assumed to have the same rates of impingement and entrainment? We infer that the same rates were used across the entire region. If this is the case, the source of the data employed is critical. It must be current, representative, and scalable by CWIS flow rate. If the data are biased in any way, the monetized benefits will also be biased. Even if they are unbiased but aggregated, the monetized benefits at some plants will be overestimated. While we appreciate the challenges of estimating nationwide monetized benefits, we call for acknowledgement that the rates of losses at some plants are very low. This acknowledgement should include consideration of alternative measures as well as a site-specific variance based on local cost and benefit considerations.

EPA's underestimate of the costs of the rule is troublesome because the costs are already more than 20 times the monetized benefits defined in the proposal. For facilities with less than 50 MGD withdrawals the costs are nearly 60 times the monetized benefits (see Comment A.1). Although estimation of non-use benefits may increase the benefits estimates, EPA's underestimate of the costs of the rule call into question the conclusions on the costs relative to the benefits of the rule.

D.19 The Description of EPA's Cost Basis for the Impingement Mortality Control Portion of the Proposed Rule Appears to be Inconsistently Stated between the Preamble and the Technical Development Document (TDD)

The preamble to the proposed Rule indicates that the social costs were estimated based on the installation of modified traveling screens and a fish handling and return systems (76 FR 22214, emphasis added):

> For the impingement mortality requirements, EPA analyzed data from a wide variety of technologies and facilities and concluded that modified Ristroph (or equivalent) coarse mesh traveling screens are the most appropriate basis for determining the compliance costs. As discussed in Section VI of the preamble, a facility may also comply with impingement mortality requirements by meeting a maximum intake velocity limit. Based on facility-specific data, EPA made a preliminary assessment of which model facilities would not currently meet impingement mortality requirements through either approach, and *assigned technology costs based on the installation of modified traveling screens with a fish handling and return system*. This assigned technology is assumed to meet the BTA standard (see § 125.94(b)). However, some facilities might still incur costs for restructuring their intakes to avoid entrapment.

A footnote to this section of the preamble indicates that:

> Note that this does not preclude the use of other technologies; EPA simply used the available performance data in deriving the performance requirements and excluded technologies that were either inconsistent performers or did not offer sufficient data for analysis in a national categorical regulation. EPA's research has shown that other technologies may also be capable of meeting the proposed requirements, but EPA did not opt to identify these technologies as the technology basis for today's proposal.

In contrast to this description, Section 8.2.2 of the TDD indicates that several technologies and combinations of technologies were considered in developing the cost of rule compliance for impingement mortality (see, for example, Exhibit 8-1). It is interesting that the footnote indicates that selection of modified Ristroph screens "does not preclude the use of other technologies but, as noted above, the means of crediting these technologies is absent from the regulatory language of the proposed Rule.

Therefore, reconciling the approach to costing appears to involve clarification of the goals and implementation procedures of the rule itself. NextEra Energy believes that such a clarification should include the ability to credit the performance of several measures that represent a comparable BTA to the Preapproved BTAs of modified Ristroph Screens and CWIS intake velocity of less than 0.5 fps.

As importantly, clarifying the approach to costing and correcting any inconsistencies with the proposed Rule may have an effect on the costs estimated for rule implementation. While the presence of some existing measures (e.g., offshore velocity caps at the St. Lucie and Seabrook plants, acoustic deterrents at Point Beach) would lower the estimated costs of compliance (as well as the incremental monetized benefits) at some facilities, implementation of the costing rules set out in Exhibit 8-1 of the TDD is likely to increase the costs of implementation at several facilities.

D.20 The Estimated Costs of the Proposed Rule are Wholly Disproportionate with the Monetized Benefits.

In its 316(b) Phase III Rule, promulgated in 2006, EPA concluded the societal costs of regulating manufacturing facilities with CWIS flows greater than 50 MGD were wholly disproportionate with the estimated monetized benefit. On the strength of this finding, EPA chose not develop national performance goals for those facilities but to rely instead on implementation on a case-by-case Best Professional Judgment basis. The cost to monetized benefits ratio calculated by EPA for those manufacturing facilities was between 17 and 21, very similar to the ratio calculated for this proposed Rule (i.e., 21.3). While EPA notes that the full monetization of non-use benefits is pending, the available cost-to-benefit ratio for this proposal is unacceptably high. The currently available net monetized benefits are a staggering -$366,000,000/yr (twenty-times the estimated annualized monetized benefits!). Despite this, EPA concludes that the "benefits associated with the proposal justify its costs" (76 FR 22207).

NextEra Energy believes strongly the calculated costs and monetized benefits, while incomplete, do not support the proposed action and are inconsistent with Executive Order 13563. Important excerpts of Executive Order 13563 relevant to costs and benefits are provided here (with emphasis added):

> Section 1. (b) This order is supplemental to and reaffirms the principles, structures, and definitions governing contemporary regulatory review that were established in Executive Order 12866 of September 30, 1993. As stated in that Executive Order and to the extent permitted by law, each agency *must*, among other things: (1) *propose or adopt a regulation only upon a reasoned determination that its benefits justify its costs* (recognizing that some benefits and costs are difficult to quantify); (2) *tailor its regulations to impose the least burden on society, consistent with obtaining regulatory objectives, taking into account, among other things, and to the extent practicable, the costs of cumulative regulations*; (3) select, in choosing among alternative regulatory approaches, those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity); (4) to the extent feasible, specify performance objectives, rather than specifying the behavior or manner of compliance that regulated entities must adopt; and (5) identify and assess available alternatives to direct regulation, including providing economic incentives to encourage the desired behavior, such as user fees or marketable permits, or providing information upon which choices can be made by the public.

As importantly, the adverse cost to benefit ratio must not serve as a precedent for the site-specific cost and benefit analysis associated with evaluation of potential entrainment control measures. NextEra Energy believes that it is only reasonable that both a proposed rulemaking and a site-specific regulatory action should have a net *positive* monetized benefit (i.e., the cost-to-monetized benefit ratio should be less than 1.0).

D.21 Pending Additional Analysis of Potential Non-use Benefits is Not Currently Available Making Full Perspective on the Costs and Benefits of the Rule Inaccessible During the Comment Period.

EPA is in the process of polling the public on its willingness to pay for additional fisheries protection. These data will be collected, analyzed, and used to update the economic analysis in the next several months. This will proceed as the 316(b) Rule is being finalized. While we call on EPA to make the data available and call for public comment through a Notice of Data Availability, we believe that it is inappropriate for EPA to attempt to justify such a far-reaching proposed Rule on an undefined placeholder for the unquantified non-use benefits. Such an approach denies the public an opportunity to provide meaningful comment on the actual monetized benefits of the proposed Rule.

D.22 The Bases of the Rule's Reductions in Impingement Mortality and the Alternative Options' Impingement and Entrainment Mortality, as Described in the Environmental and Economic Benefits Analysis (EEBA)[19], Are Not Clear.

As part of the estimation of monetized benefits of the proposed Rule and the other options, EPA has estimated the current losses on facility-, regional-, and national-bases. Losses of commercial and recreational fisheries are estimated for the nationwide set of facilities and converted to Age-1 equivalents and then monetized based on certain assumptions. Similarly, benefits associated with non-use values and protection of listed species are estimated for some regions.

The reviewer is left with very little ability to understand or comment on the actual basis for the facility-specific rates of impingement or entrainment as well their regional and national aggregation. For example, the data used to estimate the impingement and entrainment losses within each region are not specified. Were these data collected during Phase II implementation? Were they stratified or sampled to account for a range of conditions within each region? What is the genesis of the impingement and entrainment rates for listed species? It appears that some are mapped to facilities based, at least in part, on geographic proximity without any direct evidence for impingement or entrainment.

These are absolutely critical inputs to the economic analysis supporting the Rule. The temporal, spatial, and technology-based variation of impingement and entrainment are very significant. We are concerned that simplifying assumptions that might have been used to generate regional rates of impingement and entrainment will overstate the rates at several facilities, particularly at those facilities that employ effective mitigation measures such as offshore velocity caps, acoustic deterrents, and periodic flow reduction. As it stands, EPA has not provided a meaningful opportunity to comment on this very important technical basis of the proposed Rule.

D.23 The Requirement to Minimize Entrapment (40 CFR 125.94(b)(1)(iv)) Further Exacerbates EPA's Underestimate of the Costs of the Rule.

EPA indicates that facilities with offshore intakes with velocity caps would incur costs for entrapment (76 FR 22275), but does not account for those costs. The approach to estimating the cost of the proposed Rule described in the TDD includes the use of a velocity cap as one path to compliance with the impingement mortality requirements of the rule. Despite this, EPA describes an intake with a

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[19] EPA. 2011. Environmental and Economic Benefits Analysis for Proposed Section 316(b) Existing Facilities Rule. EPA 821-R-11-002.

velocity cap and indicates that in this situation the facility would need to install a fish handling and return system (76 FR 22251). The only available fish handling and return systems of which we are aware are those associated with modified travelling screens. If addition of traveling screens and a fish return is necessary, the modifications necessary to install a screen house, new screens, and all the associated systems would be exorbitantly expensive and much higher than those estimated by EPA for the retrofit of existing travelling screens.

There is not available evidence in the record that indicates the very high costs associated with this type of modification are justified. This is particularly the case for intakes with offshore velocity caps. These structures are known to be effective at deterring organisms from entering the intake structure. We are not aware of evidence that the entrapment of organisms is a significant problem for this or any other type of intake structure.

In the final regulation, EPA should provide an explicit path for compliance using offshore velocity caps. Since velocity caps deter organisms from entering the intake structure, and intakes are located offshore in areas of lower biological productivity, the rule should indicate that this technology is compliant with the requirement to ensure there is a means for fish or shellfish to escape the intake (40 CFR 125.94(b)(1)(iv) and 125.94(b)(2)(vi)).

For other configurations of intakes, EPA must provide guidance and identify the types of modifications that are necessary to avoid entrapment and estimate their costs. Many facilities without travelling screens would be subjected to this requirement. The only alternatives for these facilities to comply with the entrapment requirements we can envision would be the installation of barrier nets, wedgewire screens with less than 0.5 fps intake velocity, or the installation of modified travelling screens and a fish return. The costs of these alternatives are substantial and should be justified by evidence that entrapment is a significant environmental concern. The costs of these efforts should also be considered in any estimates of the Rule's cost.

D.24 The Rule's Impingement Mortality Monitoring Requirements are Unnecessary and Excessive.

Executive order 13563 directs federal agencies to "... tailor its regulations to impose the least burden on society." The impingement mortality monitoring requirements in the rule are not consistent with this direction. The requirements will lead to burdensome efforts to collect data that are without utility. Monitoring requirements in the final rule should be limited to collecting data that has utility that justifies the cost of collecting it. The current monitoring requirements are not consistent with this principle. The following comments expand on this concern.

D.25 Monitoring Impingement Rates is Unnecessary. Section 125.96(a)(2) requires all facilities covered by the regulation to "...collect samples to monitor impingement rates (simple enumeration) for each species over a 24-hour period and no less than once per month..." This requirement is unnecessary, will impose a significant burden, and is not applicable to some intakes.

This requirement will impose a substantial burden on the regulated community. For facilities with travelling screens, this monitoring will require the collection of samples from the fish return troughs for a 24-hour period and the identification of the organisms impinged. This will require expertise in local fisheries and therefore in most cases will require hiring outside staff to conduct the monitoring. If the monitoring requirements are applied to intakes without traveling screens or with multiple intakes the costs could be much higher.

There is no apparent rationale for measuring impingement rates. The draft rule's impingement mortality limitations are unrelated to impingement rates; therefore this monitoring requirement will not provide any information on the performance of the intake relative to any of the rule's requirements. The data collected will not provide information with utility for optimizing the design and operation of the cooling water intake structure. Therefore, the collection of this information is unnecessary and should be removed. At a minimum, the requirement should not be applied to all facilities with closed-cycle cooling or intake velocities of less than 0.5 fps.

<u>D.26 The Methods for Conducting Latent Mortality Monitoring Required by the Rule are Costly, Uncertain, Controversial, and Subject to Artifacts.</u>

Achieving compliance with the rule's impingement mortality limitations requires measuring the latent mortality of organisms following 24-48 hrs of holding (40 CFR 125.94(b)(1)(i)). The draft rule suggests that such monitoring is required on a biweekly basis (40 CFR 122.21(r)(6)(iii)). Compliance with this requirement would impose a substantial expense and produce results with high uncertainty.

Monitoring latent mortality of impinged organisms is complicated, there are no accepted standardized methods, and a variety of factors can lead to artifacts. Latent mortality monitoring requires the collection, handling, and long-term holding of organisms that are impinged. Each of these activities can lead to mortality of the organisms. To minimize the mortality of these factors, the methods employed need to be very carefully designed and employed. Since there are no standard methods for conducting this monitoring, each facility will need to develop their own approach. This will lead to wide variation in methods and likely results that are not directly comparable between facilities and potentially to the performance standards.

Given the complications associated with latent impingement monitoring, the requirements to conduct latent mortality monitoring should only be applied to limited circumstances. Facilities that install the required modified travelling screens should not be required to conduct latent mortality monitoring.

When latent mortality monitoring is required, it should be limited in scope and duration. In addition, the requirements must include flexibility to account for real world conditions encountered. For example, it is not unusual for impingement sampling events to collect only 1 or 2 individuals from among Species of Concerns. In these situations, the results from latent mortality monitoring will not be meaningful and therefore the costs associated with conducting the survival studies are unwarranted. Therefore, the monitoring requirements should only require latent mortality monitoring when a meaningful number of organisms are available for conducting the studies. This is particularly the case if the results will be used to evaluate compliance with any numeric performance standards or limitation. Other conditions that may make latent mortality monitoring impracticable or lead to questionable results include extreme temperatures, unusual impingement events (e.g., mass impingement events of cold shocked forage fish), and periodic debris and ice events.

Given importance of site conditions and other factors when interpreting the results of latent mortality monitoring, they should not be reported in DMRs. As elaborated on in Comment D.30, DMRs are intended for reporting relatively simple monitoring results and are required to be certified prior to submission. Certifying results as accurate that are based on non-standard methods and highly influenced by ambient conditions is not advisable. In addition, the interpretation of latent mortality studies requires the consideration of methods employed and conditions encountered. It is also advisable to integrate the interpretation of the data across several rounds in order to calculate annual average and monthly maximum impingement mortality. Therefore, the results of any studies should be submitted in a report format on an annual basis. This would provide the Director the information necessary to interpret the findings of the monitoring effort.

D.27 The Draft Rule Requirements for Bi-weekly Monitoring of Intake Velocity are Needlessly Burdensome (125.96(a)(4)).

Conducting bi-weekly monitoring of velocity through-screen mesh of intake screens would be very challenging for a number of reasons. Ensuring that the probe of any velocity measuring device is placed accurately in the screen mesh would be very difficult; particularly when the wet area of the screen is located a substantial distance from any area that is safely accessible. Also, the velocity sensor may disturb the local flow field artificially increasing the measured flow. For screens that are rotating, it would be likely infeasible to place the probe within the screen mesh. Finally, any measurement would represent the velocity at a single point and not necessarily be representative of the velocity across the entire screen. These challenges in combination with the rule's proposed monitoring frequency would result in a significant burden. For offshore intake structures these challenges would be compounded by the difficult of accessing the intake structure, particularly during inclement weather. In many cases divers could be required; this could lead to hazardous situations.

More accurate and representative estimates of through-screen velocity can be obtained at significantly less expense and without creating safety concerns through the measurement of proxies for intake velocity and conducting calculations. For example, at many intakes the intake velocity can be estimated through a calculation based on the intake flow rate and wet area of the screen. For submerged intakes with fixed open areas, the intake velocity is simply a function of the flow rate. Measurement of the head loss through the intake structure can also be used to estimate intake velocity. Therefore, the final rule should allow measurement of proxies to estimate through-screen velocity. If any actual measurements of intake velocity are required, they should be infrequent and only intended to confirm the estimated values.

D.28 Weekly Visual or Remote Inspections are Unnecessary, Likely to be Very Costly, and Potentially Hazardous if Applied to Offshore Intakes.

Visual inspection of offshore intake structures (such as velocity caps or cylindrical wedgewire screens) on a weekly basis would potentially require the use of divers. This would be costly and, during inclement weather, hazardous. It is not clear how a remote inspection of an offshore intake structure could be conducted.

There is no apparent need for regular inspections of many technologies installed on offshore intakes. Velocity caps and cylindrical wedgewire screens are robust and not subject to failure except under extreme or unusual conditions. The only factor that would change their potential effectiveness would be occlusion of the intake opening with debris. Debris occlusion could be assessed by monitoring the head loss across the intake opening. Therefore, regular visual or remote monitoring of the intake is unnecessary.

The requirements at 40 CFR 125.96 (c) to conduct weekly visual or remote monitoring should be revised to allow the permitting authority the discretion to determine the need and frequency of visual or remote monitoring. This would allow permit writers to account for site-specific factors including the need for monitoring, the costs, the potential risks, and consider alternative approaches to monitoring (e.g. head-loss monitoring). Since all of these factors will vary widely, specifying the frequency and nature of such monitoring is not appropriate for a national rule.

<u>D.29 Verification and Monitoring of Preapproved Technologies Should be Limited to Demonstration that they are Installed and Operated Properly</u>.

Each facility should be required to demonstrate the installed BTA technology is operating consistent with best management practices. Each permit review will also require the permitting director to confirm the technology installed is BTA and operated appropriately to ensure maximum benefit.

<u>D.30 It is Inappropriate and Inefficient to Report Impingement Mortality as Part of the Monthly Discharge Monitoring Reports (DMRs)</u>

The DMRs transmit the results of common and standardized chemical and physical methods. Such data are easily put into perspective and fit into the forms that exist for DMRs. In contrast, there is no standardized approach to evaluation of impingement mortality including specification of holding time and conditions, selection of Species of Concern, evaluation of prior dead or injured, etc. The perspective on impingement mortality including the distribution across species, temporal patterns, conformance to the proposed performance criteria, methods of data reduction (i.e., calculation of weighted average impingement mortality) will likely vary across sites. Such data will not be possible to report completely within DMRs. For these reasons, NextEra Energy requests that reporting of impingement mortality, if required, be in the form of stand-alone monthly and annual reports. NextEra Energy believes strongly that such a report is necessary to provide the necessary perspective on the data.

<u>D.31 The Timing of Implementation of the Impingement Mortality Requirements Should be Staggered as it was with the Phase II Rule.</u>

EPA's proposed Rule would have all facilities with DIF > 50 MGD develop and submit their required documents on the same schedule, starting six months after promulgation of the Rule. Such a schedule will place significant burdens on the reviewing agencies, the regulated community, and the relevant engineering/consulting firms. This is particularly the case given the subsequent set of proposed deadlines. As proposed, delays in the implementation schedule seem very likely.

NextEra Energy believes that the approach used in the Phase II Rule, a schedule tied to the NPDES permit renewal date, is more appropriate. Such a schedule would spread out the set of deliverables and would allow coordination of the NPDES permit renewal with major rule-related activities.

D.32 The Rule Should Include a Robust Economic Variance Provision.

NextEra Energy believes that the cost-cost and cost-benefit tests included in the Phase II rule were critical components that should be included in the final existing facility rule. In the preamble to the draft existing facility rule EPA states that "EPA concluded that a specific cost-cost variance is not necessary because the Director already has the discretion to consider such factors" (76 FR 22273) and therefore concluded that a cost-cost variance was unnecessary. NextEra Energy disagrees with this statement for a number of reasons. First, there is no allowance in the rule for the director to provide a variance from any of impingement mortality requirements based on cost and benefits. In fact, there is no variance from the impingement mortality requirements due to any factors. If EPA intends to include this flexibility, the regulatory language must be clarified.

Second, while the rule allows the Director to make a BPJ determination of site-specific BTA for entrainment mortality controls and to take into consideration the social benefits and social costs when making such a determination it does not clearly indicate that the Director may make a decision based on the actual costs relative to the cost estimated by EPA in the rulemaking. The regulation should be clarified to explicitly allow the Director to make a finding that the costs are significantly greater than those considered when developing the rule. This would be similar to the provisions provided in the Phase I rule and in the requirements for new units at existing facilities (125.93(c)(4)(i)). There is no clear rationale for why the draft rule provides for a cost-cost variance for new units but not for existing facilities.

EPA's concern that Appendix A does not contain accurate information for all facilities may be valid. This could be addressed by basing the cost-cost test on the results obtained from the EPA cost estimating tool when applied to a specific facility. Such an approach was considered in the Draft Phase III rule and should be considered here.

Including a cost-cost variance is important in the final rule. NextEra Energy does not agree with EPA's conclusion that there is "...low variability in the costs of impingement mortality controls..." (76 FR 22186). The costs of implementing technologies to reduce both impingement mortality and entrainment mortality are highly dependent on a number of site-specific factors that are likely to be poorly captured by EPA's model facility-based cost estimates. These factors could include space constraints to installing the Ristroph screens, requirements to move or modify structures within the route of the fish return trough, requirements to retrofit the screen house and associated power supply, requirements to mitigate the impacts of any lead based paints or other substances of concern during retrofit, and many other factors.

The impacts of these factors on site-specific costs are difficult to predict even on a site-specific basis without extensive investigation. However, these factors would all increase the costs of retrofit and in many cases result in costs above those estimated by EPA. As a result, some facilities will face compliance costs that are far higher than those considered by EPA during the rulemaking. The inclusion of a cost-cost test ensures the individual facilities are not unduly burdened and ensures that the costs considered by EPA when developing the rule are reflective of the actual costs of the regulation. Without this test, the actual costs of the rule could be substantially higher than estimated by EPA during the rulemaking; therefore, any conclusions about the costs of the rule relative to the benefits are suspect without a cost-cost provision in the rule (see Comments D.18 through D.22). This cost-cost variance would only have implications where EPA's cost estimates and conclusion that costs do not vary substantially between facilities are inaccurate.

D.33 NextEra Energy Endorses the Proposed Provision of the Impingement Mortality Standards (40 CFR 125.94(e) Allowing for Site-Specific Consideration of Potential Measures at Nuclear Power Plants.

Nuclear power plants present unique operation and maintenance issues when compared to fossil fuel burning facilities. They also have a heightened level of oversight by a dedicated federal agency, the Nuclear Regulatory Commission. Nuclear power plants are also baseload facilities that require extraordinary planning and construction time when making retrofits. Given the critical importance of maintaining a consistent cooling water supply, the provisions set out in the proposed 40 CFR 125.94(e) are appropriate.

E. Evaluation of Entrainment Control Measures on Site-Specific Basis is Appropriate but Certain Requirements of the Proposed Rule are Overly Burdensome

E.1 Options 2 and 3 Considered by EPA Are Estimated to Have Extremely Negative Net Monetized Benefits

In its evaluation of rulemaking options, EPA considered requiring closed-cycle cooling at two subsets of the population of facilities (facilities with design intake flow of over 125 MGD and 50 MGD for Options 2 and 3, respectively). As noted above, NextEra Energy believes that the estimated net benefits of EPA's selected option (Option 1 in Table 6 below) are unreasonable for a national rule. Having said that, the net benefits associated with Options 2 and 3 (those associated with closed-cycle cooling) are far worse, in excess of $4,300,000,000 per year with cost-to-monetized benefit ratios of over 36.

The net benefits estimated for the closed-cycle cooling options are affected by: 1) a very substantial increase in the costs of the option; and 2) an increase in the monetized benefits that is proportionally less than the increase in costs. Given the means by which EPA calculated monetized benefits, the increase associated with closed-cycle cooling is greatly dominated by the monetized benefits associated with estimated reductions in entrainment mortality.

Table 6:
EXHIBIT X–1 (Modified) —TOTAL ANNUALIZED BENEFITS AND COSTS OF THE REGULATORY OPTIONS
[Millions; 2009 $] [a]

Option	Social Costs [b]	Benefits	Social Costs/Monetized Benefits [c]	Net Monetized Benefits [c]
1. IM Everywhere	$384	$18 + B1	21.3	-$366
2. IM Everywhere, EM for Facilities with DIF > 125 MGD	4,463	121 + B2	36.9	-$4,342
3. I&E Mortality Everywhere	4,632	126 + B3	36.8	-$4,506
4. IM for Facilities with DIF > 50 MGD	327	17 + B4	19.2	-$310

a All costs and benefits were annualized over 50 years and discounted using 3 percent rate. [Note that this footnote is replicated from the proposed Rule. Other references indicated that costs are annualized over 30 years.]

b Total Social Costs include compliance costs to facilities and government administrative costs. Costs and benefits for Options 1, 2, and 4 do not include costs or benefits associated site-specific BTA determinations. In section VI.I, EPA presents several scenarios to illustrate potential costs associated with these determinations for Options 1 and 4. EPA believes the costs and benefits of these determinations could be substantial, and could be significantly larger than the costs and benefits shown for Options 1 and 4. For Option 2, only facilities with AIF < 125 MGD would be subject to site-specific BTA and additional costs and benefits for these facilities are likely to be small relative to the costs and benefits already estimated for this option.

c The unquantified benefits purportedly associated with non-use benefits and protection of listed species are not estimated by EPA and therefore not considered.

Therefore, EPA's figures on costs and monetized benefits, as coarse as they are, provide perspective on the potential site-specific evaluation of the costs and monetized benefits of entrainment control. Based on EPA's figures, it appears unlikely that site-specific net monetized benefits will support retrofit of many facilities to closed-cycle cooling. This conclusion supports limiting the site-specific evaluation of entrainment to the smaller subset of facilities (i.e., AIF > 125 MGD) based on the less negative net benefit calculated for that subset of facilities. It also suggests that the evaluation of entrainment options should be focused and streamlined to help the NPDES Director prioritize those relatively uncommon facilities at which closed-cycle cooling is feasible and at which the benefits justify the costs.

E.2 By Separating the Timeframe for the Evaluation of BTA for Impingement Mortality and Entrainment Mortality, the Proposed Rule Increases the Potential that the Facilities will Face Redundant Costs.

Under the proposed Rule, the site-specific evaluation of measures to mitigate entrainment mortality will lag by several years the required measures to address impingement mortality. This raises the potential that measures installed to address impingement will be found insufficient or even in conflict with measures determined to be necessary to address entrainment. For example, a facility may decide to expand and refit its traveling water screens to achieve a through-screen velocity of less than 0.5 fps in order to address impingement mortality. Several years later, it may decide that installation of fine mesh wedgewire screens in the presence of a sweeping flow is the best approach to controlling entrainment. In that event, the refitted traveling screens would be irrelevant and the costs to install them essentially wasted.

The suggested changes to the proposed Rule made by NextEra Energy would greatly mitigate this risk to the regulated community in a number of ways: 1) clarifying preapproved BTA approaches; 2) eliminating closed-cycle cooling facilities from any obligation to pursue additional measures; 3) by increasing the flexibility of the rule to credit a variety of impingement measures including existing ones; and 4) providing a cost and benefit-based approach to screen impingement technologies. NextEra Energy also encourages EPA to anticipate this risk to facilities in evaluating the costs of the Rule and to streamline the evaluation of entrainment options in order to reduce the potential for redundant costs.

E.3 The Requirements for Evaluation of Potential Entrainment Mitigation Measures Should Reflect More Limited Data Availability at Some Plants.

Section 40 CFR 125.98(e) of the proposed rule indicates that "...at a minimum..." the proposed determination of site specific BTA for entrainment mortality must be based on nine factors listed in that section. As drafted, this requirement could be interpreted to apply to facilities with actual intake flows below 125 MGD. This would be problematic and could lead to unnecessary and expensive data collection when the clear intent of the proposed Rule is to hold lower flow facilities to a less formal, site-specific standard. In fact, the current language could be interpreted to require studies of similar magnitude to those required for facilities with greater than 125 MGD AIF. Therefore this language should be modified to clarify that the Director should consider those factors for facilities with actual intake flow of greater than 125 MGD. For facilities with lower flows, the Director should rely on available data to assess those factors deemed relevant based on a consideration of site-specific factors.

E.4 NextEra Energy Believes that Winter-time Protection of Manatees is a Very Positive Environmental Benefit Associated with the Maintenance of Open Cycle Cooling.

Under conditions of their NPDES permits, five of NextEra Energy's generating facilities located on coastal waters (Canaveral, Riviera, Port Everglades, Lauderdale, and Fort Myers) are required to maintain thermal refuges to protect manatees from the impacts of cold temperatures. The refuges are associated with viewing areas for public education/recreation and up to a 1,000 manatees have been observed in the thermal refuge of a single NextEra Energy plant. In contrast, approximately 77 unprotected manatees are estimated to have died associated with a cold-snap in the winter of 2010[20]. Therefore, continued use of once-through cooling provides for critical element of the conservation of a very high profile protected species while improving the public's appreciation of this unique biological resource. NextEra Energy anticipates that the monetized costs and benefits of adoption of closed-cycle cooling at these plants will include consideration of the adverse effects on manatee protection.

E.5 The Peer Review Requirements for the Entrainment Mortality Studies Called for Under 122.21(r) are Ill-defined and Onerous.

The proposed Rule calls for peer review of four critical elements of the evaluation of potential entrainment controls. NextEra Energy has several concerns about the peer-review process:

- The scope and mandate of the peer review processes are undefined. This is likely to increase the level of effort associated with peer review process and increases the potential that efforts will have to be redone. It also increases the potential that EPA will adversely review NPDES permits if it disagrees with the scope of the peer review.
- The methods associated with assessing post-entrainment survival are very controversial. It is likely to be difficult to obtain consensus regarding workable methods and the interpretation of the results.

[20] Unprecedented number of cold-related manatee deaths in Florida.

http://www.wildlifeextra.com/go/news/manatee-deaths928.html#cr

- EPA has guidance on the peer review process[21] that defines a complex, multi-step process for peer review. In NextEra Energy's exposure to this process, the costs for the peer review alone have exceeded $100,000 and the process has taken well over one year. The potential for costs and complexity to increase are increased by the invitation to the NPDES Director to bring experts from other agencies into the process. Similarly, by requiring peer review on four separate and very different deliverables, the scope of the effort is likely to be very substantial.
- Given the scale of the proposed Rule (i.e., more than 300 facilities with AIF > 125 MGD) as well as the specialized expertise involved (e.g., ichthyoplankton enumeration and ecology, relatively arcane resource economics, engineering and costing of cooling systems, etc.) implementation is very likely to be impeded by the availability of peer-reviewers. In Florida where there are several coastal power plants and a relatively unique set of biological resources, the availability of peer reviewers will be acute. This will be exacerbated by the ill-defined mandate and process particularly given that the candidate reviewers (e.g., fisheries specialists) are likely to have little experience with the issues posed by Section 316(b).
- The burden placed on the NPDES agencies to participate in and assess the peer review process will be extraordinary. NextEra Energy's discussions with NPDES staff indicate that they have no experience with peer review. As proposed, the staff in some states will be inundated with several dozen proposals and reports dealing with peer review.

NextEra Energy urges EPA to consider limiting or eliminating the peer review elements of the proposed Rule. It is excessively burdensome to the regulated community and the NPDES agencies, it will very likely drive cost and schedule issues, and its benefit to the process is not clear. If peer review is maintained, its parameters should be better defined. EPA staff has responded to our concerns about the burden associated with peer review by indicating that the process should be relatively simple. If this is EPA's intention, the agency should document that goal and provide meaningful guidance on how to limit the scope, schedule, and budget associated with the effort.

[21] EPA, 2006. Peer Review Handbook, 3rd Edition. Science Policy Council. EPA/100/B-06/002.

Response to EPA's Requests for Specific Comments in Section XI(B)

In Section XI(B) of the preamble to the proposed Rule, EPA solicits specific comments on several aspects of the proposed Rule and the rulemaking process. NextEra Energy's comments above address several of these issues. The following pages provide a paraphrased title to EPA's specific requested comment followed by either a reference to the comments provided above or a brief stand-alone comment.

1. Definition of "Design Intake Flow". As noted in Comment A.2, NextEra Energy believes that AIF represents a more sound estimate of the actual potential impacts and should be used instead of DIF.
2. National BTA Categorical Standards for Offshore Oil and Gas Extraction and Seafood Processing Facilities. NextEra Energy has no comment on this aspect of the Rule.
3. Cost-cost Alternative from Phase II Rule. As noted in Comment D.32, NextEra Energy believes that a cost-cost alternative is justified, workable, and highly useful in the context of the proposed Rule.
4. Entrainment Survival. NextEra Energy believes that entrainment survival can be an important phenomenon and agrees with EPA's findings that the survival rate through the cooling system may rival the survival rate following impingement on fine mesh panels. NextEra Energy agrees that having the ability to demonstrate rates of entrainment survival on a site-specific basis should be part of a protective and cost-effective rule. Having said that, NextEra Energy has concerns about the methods to be used to assess post-entrainment survival rates. It will be necessary to reach consensus regarding methods and their interpretation before accounting for post-entrainment survival can be done successfully.
5. Alternative Impingement Mortality Compliance Requirements. NextEra Energy believes that intake velocities of less than or equal to 0.5 fps provide an adequate measure of fisheries protection. As noted in Comment C.3, NextEra Energy believes that the literature supports that 1.0 fps provides an adequate measure of fisheries protection. In previous rulemakings, EPA has lowered that threshold to 0.5 fps to offer a higher level of protection.
6. Monthly and Annual Limits on Impingement Mortality. In Comments D.14 through D.16, NextEra Energy indicates that it has significant technical issues with the overall approach to the monthly and annual limits as well as the specifics of their calculation. Among other concerns, NextEra Energy believes that the exclusive focus on impingement mortality, as distinct from impingement, is misguided. NextEra Energy is sympathetic to the definition of goals for impingement but believes that a range of mitigation options should be considered within the context of a calculation baseline. It also believes that the rule must contain a tangible and accessible cost-cost or cost-benefit variance in the event that measures are neither feasible nor cost-effective.
7. Flow Basis for Option. NextEra Energy endorses the use of AIF over the DIF.
8. Waterbody Type as a Basis for Different Standards. NextEra Energy generally concurs that differences in the density and reproductive strategies of freshwater and seawater organisms do

not justify a different set of standards for the two types of water bodies. Having said that, NextEra Energy believes that the proportion of river flow and lake/reservoir residence times used in the Phase II Rule to trigger evaluation of entrainment were sensible.

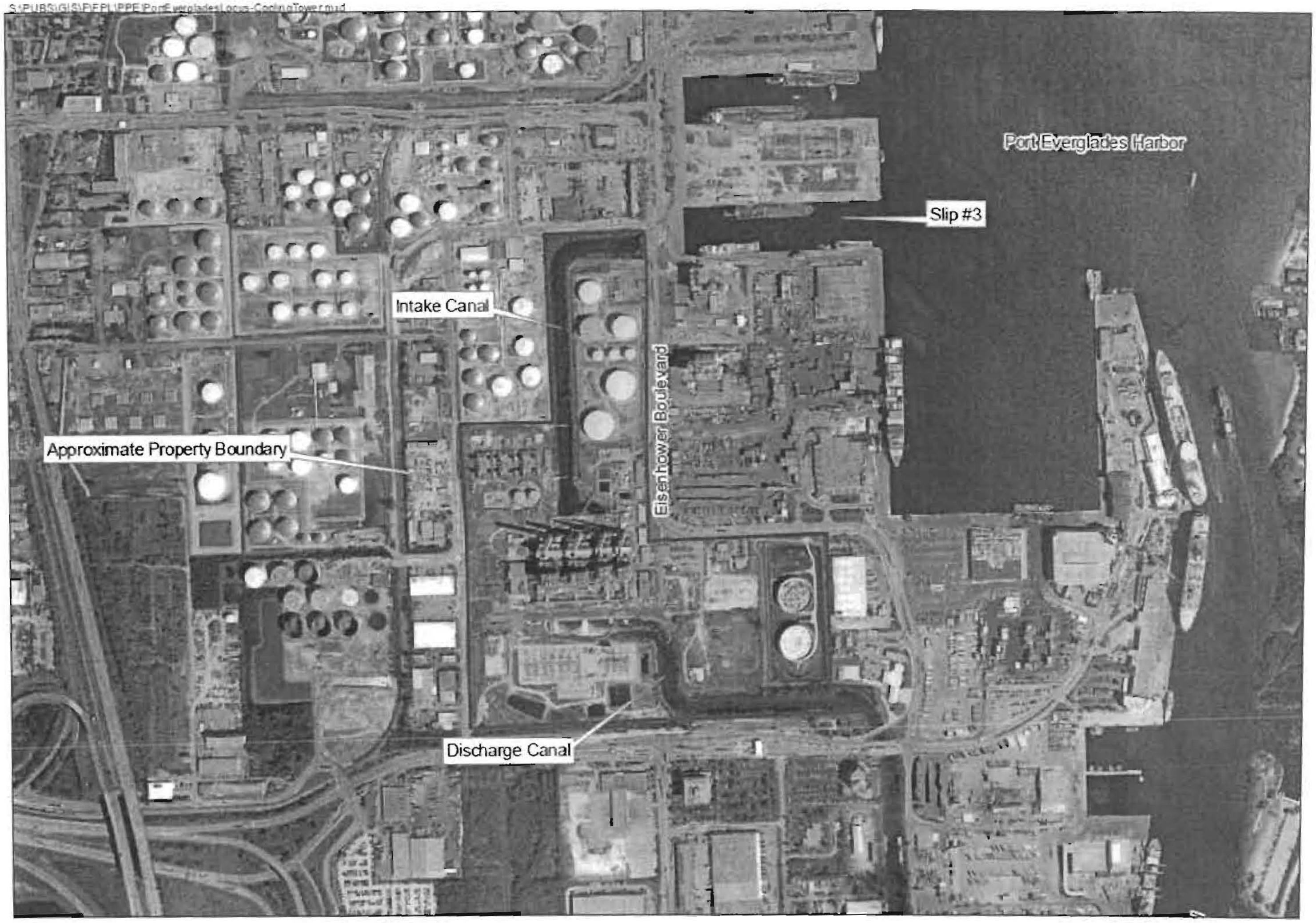
9. Capacity Utilization Rating as a Basis for Different Standards. NextEra Energy believes that is highly reasonable to consider Capacity Utilization Factor in defining different sets of performance standards. An alternative approach would be to allow Capacity Utilization Factor in the context of flow reduction and the calculation baseline to calculate reductions in impingement and entrainment.
10. Flow Commensurate with Closed-Cycle Cooling. NextEra Energy believes that targets for flow reduction associated with closed-cycle cooling are not useful. Closed-cycle cooling should be defined based on the simple and demonstrable existence of recirculating cooling water. This is discussed at Comment C.1.
11. Credits for Unit Closures. NextEra Energy believes that unit closures, unit repowering, and other measures that reduce water flow should receive credit toward reductions in impingement and entrainment consistent with the calculation baseline approach. NextEra Energy does not believe that such credit should be tied to any additional requirement to "make future progress to ensure its operations reflect best available entrainment controls".
12. Land Constraints. NextEra Energy believes that land constraints represent a very significant issue for the potential retrofit to closed-cycle cooling. It believes strongly that developing a standardized threshold (e.g., 160 acres/MW) is inappropriate as it fails to capture details relevant to cooling tower construction and placement (e.g., presence of site constraints such as existing structures and wetlands; position of the condensers relative to the cooling tower locations, etc.). NextEra Energy believes that a site-specific analysis of spatial constraints is necessary to evaluate potential land constraints to cooling tower and recirculation line placement.
13. Proposed Implementation Schedule. NextEra Energy comments on the proposed schedule in Comment D.31.
14. Methods for Evaluating Latent Mortality Effects Resulting from Impingement. NextEra Energy notes in Comment D.26 that there are not standard methods for establishing impingement mortality and that it has been done relatively rarely. NextEra Energy believes that monitoring of impingement mortality should minimized in favor of designated preapproved technologies for which only demonstrating proper installation and operation is necessary or for minimizing impingement relative to a calculation baseline. If measurement of impingement mortality is required by the final rule, NextEra Energy believes that an expert panel should be convened to develop a standard method with appropriate accommodations for site-specific and region-specific adaptations.
15. Counting Impinged Organisms with the "Hypothetical Net". NextEra Energy believes that EPA's proposal to consider only those organisms that would be impinged on a 3/8" screen is an appropriate one to avoid inflating the rates of impingement. Such an approach is consistent with the majority of impingement sampling practice. NextEra Energy notes, however, that the relatively simple act of netting the fish does introduce a new stress that is not encountered during normal operation of the Ristroph screens and fish return. The additional steps of

removing the fish from the net and holding them to measure post-impingement survival rates also introduce unusual stresses. These stresses should be considered and, when possible, minimized in the design and execution of any impingement sampling program. They also contribute to NextEra Energy's significant concern regarding the quantitative performance standards for post-impingement mortality. As stated in our comments, NextEra Energy does not believe that the standards are achievable at many facilities across the country and, for that reason and others, the performance standards should be removed from the rule.

16. Incentives for Reducing I&E by Reducing Water Withdrawals. NextEra Energy does not believe that alternative water supplies with sufficient capacity to meaningfully supplement once-through cooling flows are available at the vast majority of facilities. Having said that, application of alternative cooling water supplies should be credited to impingement and entrainment reductions proportional to flow under an approach similar to the calculation baseline.
17. Options Which Provide Closed-cycle Cooling as BTA. As noted in Comments A.3 and B.1, NextEra Energy does not believe that closed-cycle cooling represents BTA for existing facilities.
18. Costs of Controls to Eliminate Entrapment. As noted in Comment D.23, NextEra Energy does not believe that entrapment represents a significant impact to fisheries. NextEra Energy believes that minimizing entrapment in settings without a functional fish return will be extremely costly and may be infeasible (see Comment D.23).
19. Analysis of New Capacity. NextEra Energy has no comments on this aspect of the proposed Rule.
20. Monitoring Reports. In Comment D.30, NextEra Energy provides comments on the nature and frequency of monitoring reports.
21. Seasonal Operation of Cooling Towers. NextEra Energy believes strongly that the installation of cooling towers to be used on seasonal basis is a very poor idea. The great majority of the costs (i.e., capital costs, permitting costs, increased operating costs during closed-cycle operation) and all of the facility disruption and downtime associated with closed-cycle retrofit would be incurred under this scenario. Only a relatively small portion of the costs of retrofit (e.g., power hit, parasitic load, treatment chemicals when operating in open cycle mode) would be avoided under this scenario. In addition, it is NextEra Energy's experience that reliably predicting periods of peak entrainment is very difficult. Finally, NextEra Energy remains convinced that the costs of retrofit to closed-cycle cooling are far higher than the monetized benefits.
22. New Unit Provision. As noted in Comment A.3, NextEra Energy believes that the New Unit Provision of the proposed Rule should be deleted.
23. Review Criteria to Guide Evaluation of Entrainment Feasibility Factors. NextEra Energy generally agrees that the nine review criteria established by EPA are complete and appropriate. As discussed in Comment E.3, we are concerned that the nine criteria could be construed to apply to facilities with AIF below 125 MGD.
24. Alternative Procedures for Visual or Remote Inspections. NextEra Energy endorses the concept of visual and/or remote inspections to reduce labor and improve worker safety.
25. Threshold for In-Scope Facilities. As documented in Comment A.1, NextEra Energy believes that the threshold of 2 MGD is too low for inclusion in the Rule.

26. Application Requirements. NextEra Energy has provided comments on application requirements and their timing in Comments D.31, E.2, E.3, and E.5.

Attachment 1: Facility Site Maps



0 500 1,000 Feet

AECOM

Site Plan Port Everglades Florida

DATE	FIGURE NUMBER
March 2011	1

FIGURE 2
RBEC COOLING TOWER SIZE RELATIVE TO SITE LAYOUT

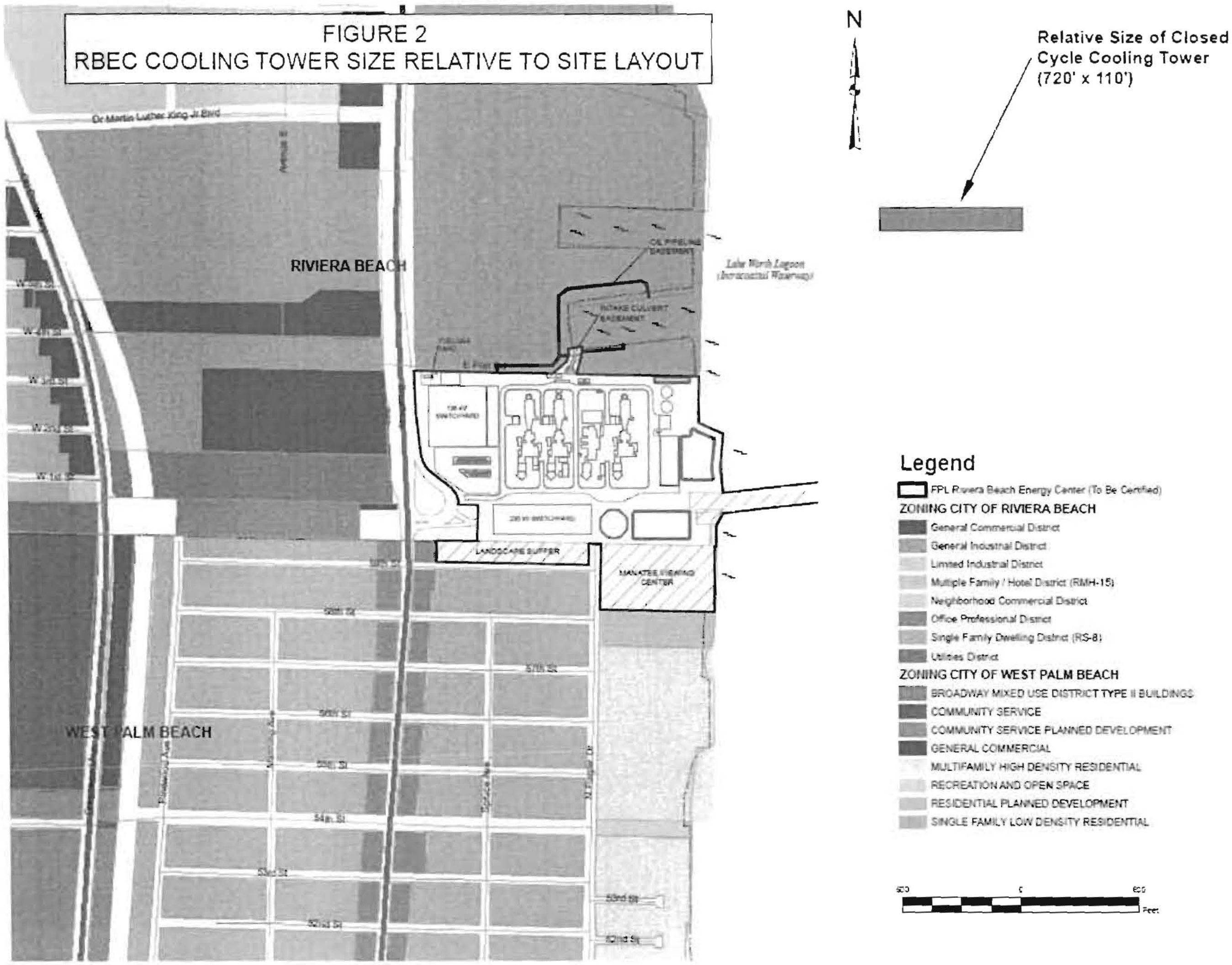
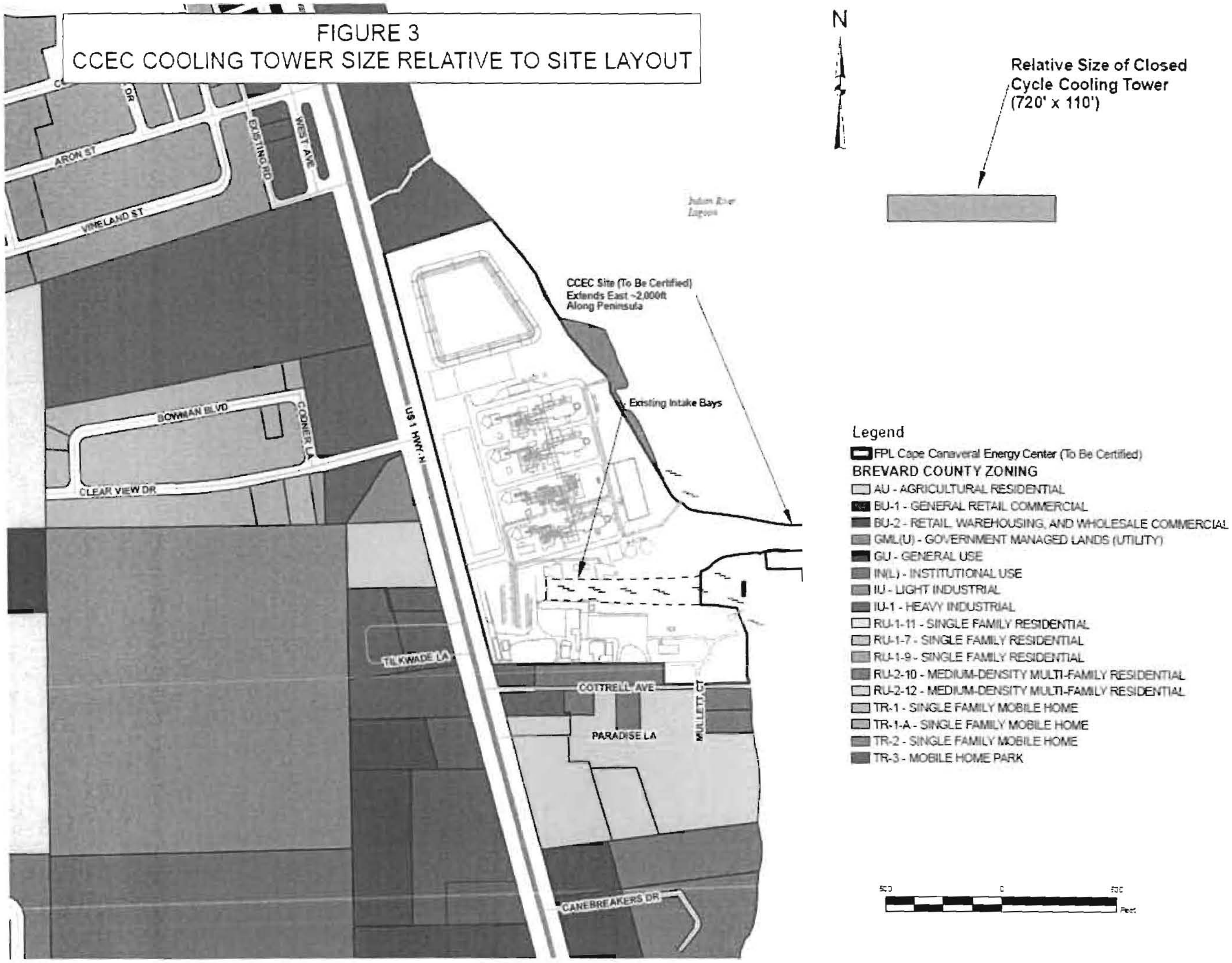
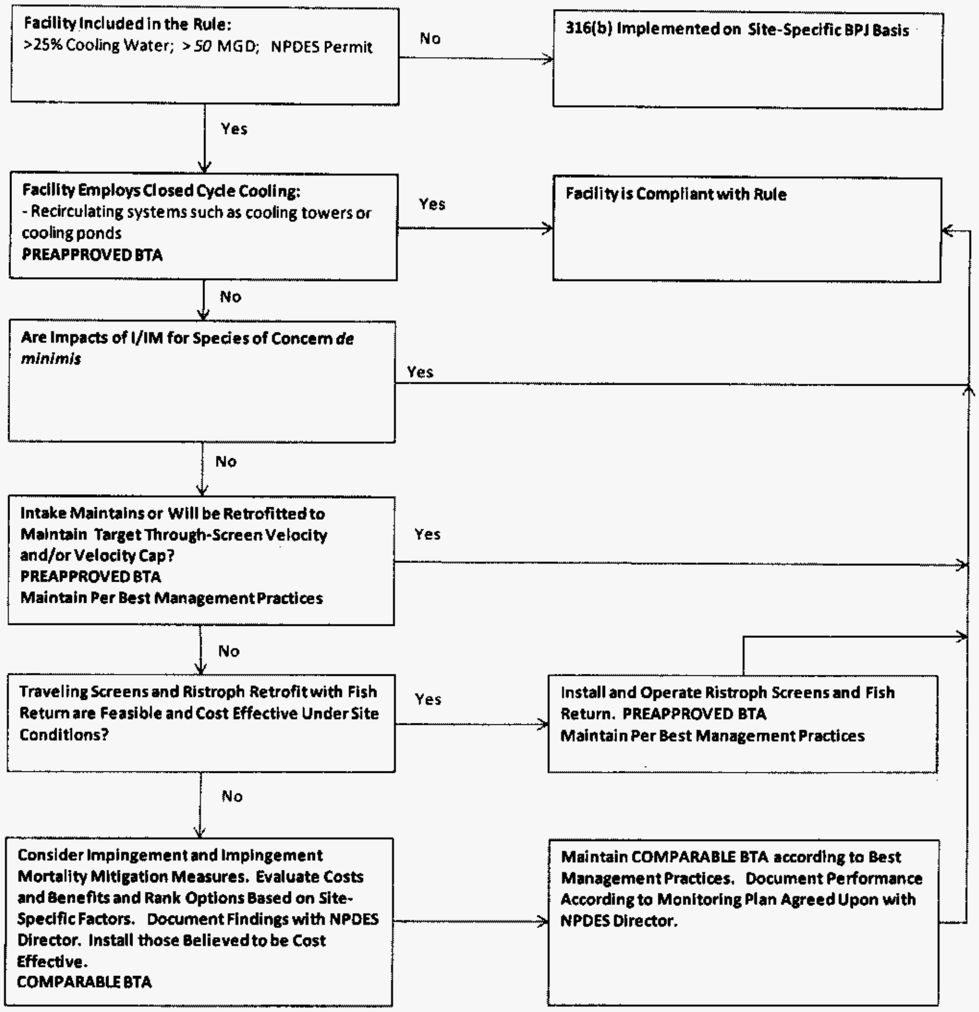


FIGURE 3
CCEC COOLING TOWER SIZE RELATIVE TO SITE LAYOUT



Attachment 2:
Proposed Compliance Sequence
Draft Section 316(b) Existing Facilities Rule

Proposed Compliance Sequence
316(b) Existing Facilities Rule



Attachment 3:

Table 2: Estimated Impingement Survival for FPL Plants – Modified Ristroph Screens - Survival Data from EPRI, 2003.

The following table has been developed using impingement data collected under the Phase II Rule Impingement Mortality and Entrainment Characterization Study at four of NextEra Energy's plants in Florida. The percentage of fish and shellfish[22] collected over the duration of the program (generally a year) represented by each species is defined in the table. The average rate of survival following impingement on Ristroph type screens is also listed along with the number of studies and the standard deviation of the survival rate. Note that a surrogate species is used in some cases as noted in the table. For each species the percentage of total impingement is multiplied by the average survival rate to estimate the numerically weighted survival rate.

The sum of the numerically weighted survival rates is then summed and divided by the total percentage of the catch represented in the evaluated taxa. This assumes that the taxa not represented in the sum survive at the same rate as those in the sum. This is presented as the estimated total impingement survival rate. To be compliant with the proposed Rule, the impingement survival rate should equal or exceed 88%.

NextEra Facility	Species Impinged	Common Name	Use Surrogate?	Percent composition[1]	Ristroph Screen[2]			% Survival on Ristroph screen[4]
	Species				Survival[3]	#[3]	Stdev[3]	
Cape Canaveral Plant	*Anchoa mitchilli*	Bay anchovy	no	77.8%	40%	24	35%	31%
	Bairdiella chrysoura	Silver perch	no	5.2%	86%	7	30%	4%
	Diapterus auratus	Irish pompano	yes	2.3%	99%	11	2%	2%
	Paguridae	Hermit crab family	yes	1.8%	97%	3	4%	2%
	Paguroidea	Hermit crab family	yes	1.6%	97%	3	4%	2%
	Lucania parva	Rainwater killifish	yes	1.4%	92%	30	16%	1%
	Limulus polyphemus	Horseshoe crab	yes	1.3%	96%	11	5%	1%
	Brevoortia tyrannus	Atlantic menhaden	no	1.3%	75%	9	29%	1%
	Xanthidae	Mud crab family	yes	1.1%	97%	3	4%	1%
	Farfantepenaeus duorarum	Pink shrimp	yes	1.0%	95%	1	-	1%
	Palaemonetes sp.	Palaemonetes shrimp	yes	1.0%	95%	1	-	1%
Total				96.8%				50%
Fort Myers Plant	*Trinectes maculatus*	Hogchoker	no	32.8%	98%	18	4%	32%
	Anchoa mitchilli	Bay anchovy	no	18.8%	40%	24	35%	8%
	Xanthidae	Mud crab family	no	13.7%	97%	3	4%	13%
	Cynoscion arenarius	Sand Weakfish	yes	11.8%	90%	10	10%	11%
	Hoplosternum littorale	#N/A	yes	5.9%	86%	1	-	5%
	Callinectes sapidus	Blue Crab	yes	4.7%	96%	11	5%	5%
	Farfantepenaeus duorarum	#N/A	yes	3.6%	95%	1	-	3%
	Diapterus auratus	#N/A	yes	1.9%	87%	8	14%	2%
	Tilapia mariae	#N/A	yes	1.6%	87%	8	14%	1%
Total				94.8%				84%
Riveria Plant	*Farfantepenaeus duorarum*	White shrimp	Yes	33%	95%	1	na	31%
	Callinectes ornatus	Blue Crab	Yes	15%	96%	11	5%	14%
	Haemulon aurolineatum	Atlantic croaker	Yes	11%	82%	12	18%	9%
	Xanthidae	Mud crab family	Yes	8%	97%	3	4%	8%
	Sphoeroides spengleri	Fourspine stickleback	Yes	4%	93%	2	9%	4%
	Portunus depressifrons	Blue Crab	Yes	4%	96%	11	5%	4%
	Callinectes sp.	Blue Crab	Yes	3%	96%	11	5%	3%
	Portunus gibbesi	Blue Crab	yes	2%	96%	11	5%	2%
	Anisotremus virginicus	Spot	Yes	2%	87%	8	14%	2%
	Stephanolepis hispida	Fourspine stickleback	Yes	2%	93%	2	9%	2%
	Portunus sayi	Blue Crab	Yes	1%	96%	11	5%	1%
	Portunus spinimanus	Blue Crab	Yes	1%	96%	11	5%	1%
	Eucinostomus gula	Spot	Yes	1%	87%	8	14%	1%
	Callinectes similis	Blue Crab	yes	1%	96%	11	5%	1%
	Sphoeroides testudineus	Fourspine stickleback	Yes	1%	93%	2	9%	1%
	Menippe mercenaria	Blue Crab	Yes	1%	96%	11	5%	1%
	Haemulon sciurus	Atlantic croaker	Yes	0%	82%	12	18%	0%
	Histrio histrio	Fourspine stickleback	Yes	0%	93%	2	9%	0%
	Hippocampus erectus	Northern Pipefish	No	0%	98%	8	4%	0%
	Rimapenaeus constrictus	White shrimp	Yes	0%	95%	1	-	0%
	Lolliguncula brevis	Atlantic brief squid	No	0%	-	0	-	-
	Selene vomer	-	No	0%	86%	1	-	0%
	Portunus spinicarpus	Blue Crab	Yes	0%	96%	11	5%	0%
	Apogon binotatus	Spot	Yes	0%	87%	8	14%	0%
	Portunus sp.	Blue Crab	Yes	0%	96%	11	5%	0%
Total				95%				93%
Everglades Plant	*Anchoa lamprotaenia*	Bid-eyed anchovy	yes	44.8%	40%	24	35%	18%
	Anchoa hepsetus	Striped anchovy	yes	9.6%	40%	24	35%	4%
	Farfantepenaeus duorarum	Pink shrimp	yes	4.1%	95%	1	-	4%
	Eucinostomus argenteus	Silver mojarra	yes	2.1%	99%	11	2%	2%
	Anchoa sp.	Anchovy	yes	1.8%	40%	24	35%	1%
	Eucinostomus harengulus	Mojarra	yes	1.7%	99%	11	2%	2%
	Haemulon aurolinealum	Tomtate	yes	1.5%	99%	11	2%	2%
	Xanthidae	Mud crab family	no	1.3%	97%	3	4%	1%
Total				67%				49%

Notes:
[1]Percent composition from Impingement studies
[2]Data are for modified Ristroph screens rotated continuously
[3]Data from EPRI 2003 Summary of Impingment Survival Studies
[4]Survival is weighted based on the proportion of the population each species represents

[22] As noted above, NextEra Energy finds that the proposed rule may have conflicting statements regarding the inclusion of shellfish in the assessment of impingement mortality. Shellfish have been included in these calculations. NextEra Energy notes that inclusion of shellfish increases the rate of post-impingement survival relative to finfish alone.

NEXTera ENERGY

August 31, 2010

BY FIRST-CLASS MAIL AND
ELECTRONIC SUBMISSION

The Honorable Lisa P. Jackson
Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Ave, NW
Washington, DC 20460

Re: Docket No. EPA-HQ-OAR-2009-0491

Dear Administrator Jackson:

On behalf of NextEra Energy, Inc., I am writing to request a 60-day extension of the comment period on the proposed "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone," published in the *Federal Register* on August 2, 2010, at 75 Fed. Reg. 45210 ("Proposal"). The Proposal is one of the most far-reaching and complicated rules ever proposed under the Clean Air Act ("CAA"). The current 60-day comment period is inadequate to allow potentially affected sources and States to review and analyze the Proposal and respond to the Agency's specific requests for comments. Accordingly, NextEra Energy requests that EPA extend the deadline for submitting comments on the Proposal from October 1, 2010 to November 30, 2010.

NextEra Energy operates electric generating units in 10 of the states covered under the Proposal and, therefore, will be directly affected by any final rule issued by EPA. The regulatory scheme finalized by EPA will have a significant impact on every aspect of NextEra Energy's business - including long-term business planning, the determination of consumer rates, and the day-to-day operation of electric generating units. It is of the utmost importance that NextEra Energy is given adequate time to analyze the Proposal and provide the Agency with meaningful feedback on the proposed regulatory schemes.

The Proposal and supporting materials are too complex and lengthy to review and analyze in 60 days. The Proposal alone consumes 250 pages of the *Federal Register*. In addition, EPA has posted over 150 supporting materials and documents in the rulemaking docket, most of which consist of highly technical data. Review of these materials constitutes a massive undertaking. Although the Agency made many of these materials available at the time the Proposal was signed, and before the Proposal was published in the Federal Register, the additional time offered for review is insufficient to thoroughly analyze the data. Already, based on an initial review, NextEra Energy has identified a number of inaccuracies in the data underlying the Proposal, including mistakes regarding operations at certain affected electric generating units. If they are not fully identified and corrected, inaccuracies such as these will undermine the foundation of any regulatory scheme promulgated by EPA and result in an ineffectual program that will impair the reliable generation and transmission of electricity throughout the country. NextEra Energy faces the daunting task of processing the available information, evaluating the feasibility of implementing each of the three regulatory schemes set forth in the Proposal, and providing EPA with constructive feedback through detailed comments.

EPA has the discretion to extend the comment period for the Proposal and doing so would benefit the Agency, States, and the regulated community. Providing adequate time for meaningful public participation in the rulemaking process will help ensure that the final rule comports with the CAA and effectively addresses concerns related to the interstate transport of air pollutants.

NextEra Energy appreciates the opportunity to submit comments on the Proposal. If you have any questions regarding the Company's request for an extension of the comment period, please contact me at Ray.Butts@fpl.com or (561) 691-7040.

Sincerely

Rayburn L. Butts
Director, Environmental Services

August 4, 2011

Docket ID No. EPA-HQ-OAR-2009-0234
EPA Docket Center (EPA/DC)
Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
(submitted via regulations.gov)

Re: National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units

To Whom It May Concern:

NextEra Energy Inc. (NextEra Energy) appreciates the opportunity to comment on the proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units ("Toxics Rule"), published in the Federal Register on May 3, 2011 (76 FR 24976)

NextEra Energy is a leading clean-energy company with 2010 revenues of more than $15 billion, nearly 43,000 megawatts of generating capacity, and approximately 15,000 employees in 28 states and Canada. Headquartered in Juno Beach, Florida, NextEra Energy's principal subsidiaries are NextEra Energy Resources, LLC, the largest generator in North America of renewable energy from the wind and the sun, and Florida Power & Light Company (FPL), which serves approximately 4.5 million customer accounts in Florida and has been recognized as having one of the most successful energy-efficiency programs in the nation. Through its subsidiaries, NextEra Energy collectively operates the third largest U.S. nuclear power generation fleet.

NextEra Energy has one of the cleanest energy profiles in the electric sector. Since 1990, while the Company's power generation has increased by 230 percent, our nitrogen oxides (NOx) emissions rate has decreased by 88 percent, our sulfur dioxide (SO_2) emissions rate has decreased by 87 percent and our carbon dioxide (CO_2) emissions rate has decreased by 31 percent. Notwithstanding the Company's clean energy profile, NextEra Energy owns and operates a significant amount of coal- and oil-fired electric generation in the U.S. that will be subject to the proposed Toxics Rule. Therefore, we have a keen interest in the final outcome of the rule.

The Toxics Rule provides the business certainty the electric sector needs to move forward with capital investment decisions, and NextEra Energy supports finalizing the rule as required by consent decree in November 2011. While we offer specific recommendations below for improving the rule, overall, we believe the proposal is reasonable and consistent with the requirements of the Clean Air Act. We also believe, as discussed below, that the electric sector is well positioned to comply with the proposed rule. Further, where individual circumstances warrant, Section 112 of the Clean Air Act provides additional flexibility to accommodate situations where additional time may be necessary to install controls. Our recommendations on specific revisions to the proposed rule address broad comments applicable to all electric generating units (EGUs), and then comments specific to coal- and oil-fired EGUs. It should also be noted that NextEra Energy supports the comments on the proposed rule being submitted by the Class of '85, the Clean Energy Group and the Edison Electric Institute, *except in instances when the comments of these industry groups may conflict with*

NextEra Energy's position as set forth in the comments below.

I. Recommendations Related to all Affected Existing EGUs (Coal and Oil)

A. Compliance Schedule and Implications with Respect to Reliability of the Electric System

EPA is under a court-imposed deadline to finalize the Toxics Rule by November 16, 2011. In general, under the Clean Air Act, Congress requires existing, affected sources to comply with standards for hazardous air pollutants "as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard[1]." As a result, affected coal-fired power plants will need to comply with the emissions limits contained in the final Toxics Rule by the beginning of 2015. This schedule concerns a number of companies in the electric sector who believe that pollution controls cannot be installed soon enough to comply with the emission limits contained in the rule and that implementation of this and other upcoming EPA regulations will lead to the closure of otherwise economically healthy power plants that could jeopardize reliability of the electric system.

NextEra Energy is sensitive to companies' concerns with the three-year timeframe required to comply with the Toxics Rule. However, there are provisions under the law which allow additional time for the installation of emission controls and, in fact, EPA emphasizes in the proposed Toxics Rule that the Agency and state regulatory authorities have the discretion to grant, on a case-by-case basis, an additional 12 months for the installation of pollution control systems where appropriate. State permitting authorities have provided additional time under this subsection of the Act for other sectors, and EPA anticipates that states will continue to provide such additional time if needed by electric generators to install controls. EPA suggests that this extension can be used to address a range of reasons that installation schedules may take more than three years including: staggering installations for reliability or constructability purposes, or other site-specific challenges that may arise related to source-specific construction issues, permitting, or local manpower or resource challenges. EPA is proposing that States consider applying this extension both to the installation of add-on controls (e.g., a fabric filter, or a dry scrubber) and the construction of on-site replacement power (e.g., a case when a coal unit is being shut down and the capacity is being replaced on-site by another cleaner unit such as a combined cycle or simple cycle gas turbine and the replacement process requires more than three years to accomplish). NextEra Energy believes that this is appropriate since replacing an existing, affected source with a new, cleaner unit such as a combined-cycle natural gas facility is bound to result in greater emission reductions than would be achieved if the existing unit were retrofitted with emissions control technology.

Beyond the one year, case-by-case compliance extension explicitly provided for under Section 112(i)(3)(B) of the Act, if a company demonstrates a need for time *beyond four years*, EPA has the authority to enter into administrative orders of consent (AOCs) or consent decrees to provide such additional time. EPA has used AOCs and consent decrees in the past to address similar situations.

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[1] *(3) COMPLIANCE SCHEDULE FOR EXISTING SOURCES.*
(A) After the effective date of any emissions standard, limitation or regulation promulgated under this section and applicable to a source, no person may operate such source in violation of such standard, limitation or regulation except, in the case of an existing source, the Administrator shall establish a compliance date or dates for each category or subcategory of existing sources, which shall provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard [...].
(B) The Administrator (or a State with a program approved under title V) may issue a permit that grants an extension permitting an existing source up to 1 additional year to comply with standards under subsection (d) if such additional period is necessary for the installation of controls.[...]
CAA Section 112(i)(3)(A)-(B)

Finally, as a last resort, there are provisions under Section 112(i)(4) of the Act for the President to grant extensions to affected sources for a period of up to two years, on a case-by-case basis, if the President determines that the technology to implement an air toxics standard is not available and it is in the national security interest of the U.S. to do so.

As numerous states have adopted regulations limiting mercury emissions from coal-fired power plants, and in anticipation of EPA's Toxics Rule, many companies, including NextEra Energy, have already begun to install emission control technologies. Also, scrubber and particulate control systems installed, or being installed, to comply with the recently promulgated Cross State Air Pollution Rule (CSAPR) and other EPA regulations will help companies to comply with the proposed Toxics Rule. EPA projects that about 14 GW of additional coal-fired generating capacity will need to be retrofit with scrubbers and less than 1 GW with selective catalytic reduction (SCR) controls by 2014 to comply with the CSAPR. Based on the results of EPA's Integrated Planning Model (IPM) analysis, the Agency projects that the proposed Toxics Rule will drive the installation of an additional 24 GW of scrubbers (almost all of which are projected to be dry scrubbers), 56 GW of dry sorbent injection (DSI), 93 GW of additional activated carbon injection (ACI), and 3 GW of SCR. Additionally, EPA is assuming for the purposes of this analysis that a subset of all covered coal-fired EGUs will require a fabric filter in order to meet the total particulate matter (PM) standard. This assumption results in an additional 49 GW of fabric filter retrofits, for a total of 165 GW by 2015. Considering that scrubbers and SCR have the longest installation schedules, this number of retrofits is similar in magnitude to what he industry has installed in past construction cycles. For example, during the peak of scrubber construction, between 2008 and 2010, approximately 60 GW of coal capacity was retrofitted with scrubber controls, highlighting the industry's ability to complete a substantial number of retrofits over a short period of time. In 2009 and 2010, the industry completed between 50 and 60 scrubber retrofits each year.

EPA indicates that its analysis of the proposed rule shows that "the expected number of [EGU] retirements is less than many have predicted and that these can be managed effectively with existing tools and processes for ensuring continued grid reliability." EPA's modeling projects that plants totaling less than 10 GW of the nation's coal-fired capacity (not generation) are expected to retire by 2015 rather than invest in control technologies, which represents about a 2 percent decrease in coal-fired generation. The plants that are expected to retire are primarily the smaller, less efficient and higher polluting units that are not used much.

The electric industry has a proven track record of adding additional generating capacity and transmission solutions when and where needed and of coordinating effectively to address reliability concerns. However, if local reliability issues arise, state and federal regulators have an array of tools available to moderate impacts on the electric system including, as indicated above, the granting of compliance extensions to companies that, despite their best efforts, are unable to complete the installation of air pollution controls within the three-year timeframe specified under Section 112(i)(3)(A) of the Act. These federal tools, combined with market rules and signals, industry reliability standards and enforcement mechanisms, and utility regulatory requirements and incentives, provide a robust portfolio of techniques to assure compliance with the proposed Toxics Rule while maintaining reliable electricity supply.

B. Low-Emitting Units

NextEra Energy supports EPA's proposal to establish alternative monitoring requirements for low-emitting EGUs (LEE) to reduce the monitoring costs for these units, but recommends a less burdensome approach for determining continuous compliance and requests that EPA clarify certain aspects of the provisions.

EPA proposes that units with low emissions should be eligible for reduced compliance testing. LEE status requires, with the exception of mercury, emissions less than 50 percent of the applicable emissions limitation. For mercury, LEE status requires emissions that are less than 10 percent of its applicable mercury emissions limit or less than 22.0 pounds per year of mercury. When qualifying for LEE status for mercury based on a unit's annual emissions (i.e., emissions less than or equal to 22.0 pounds per year), the affected unit must also demonstrate compliance with the applicable emission rate limitation specified in Table 2 to Subpart UUUUU of Part 63.

Table 5 in Subpart UUUUU of Part 63, which details the performance stack testing requirements, includes the requirements for LEE testing; however, it only includes the requirements for mercury testing. NextEra Energy requests clarification that low-emitting EGU status is available to *all* subcategories of affected EGUs and all hazardous air pollutants (HAPs), not just mercury from coal units. The discussion of LEE status in §63.10005 and in the preamble of the rule suggests that EPA intends the LEE provisions to apply to all subcategories, but monitoring requirements for other HAPs and fuels are not specified in Table 5. We request that the final rule explicitly include LEE thresholds and compliance requirements for all subcategories and HAP groups, with specific recommendations provided below.

1. <u>Low-Emitting Units: Mercury</u>

For mercury, the proposed rule states that an LEE must conduct "at least three nominally equal length" test runs over a 28 to 30-day test period, using Method 30B, to determine the mercury emissions of the unit (lb/MMBtu or lb/MWh). Table 5 in Subpart UUUUU of Part 63 requires that a company then calculate its annual mercury emissions based on the "potential maximum annual heat input" or "potential maximum electricity generated". For example, a coal unit meeting the proposed mercury emissions limit for units designed to combust coal with a heat content ≥ 8,300 Btu/lb (1.0 lb/TBtu) would emit just under 22.0 lbs per year of mercury, assuming a capacity of 250 MW, a heat rate of 10,000 Btu/KWh, and a capacity factor of 100 percent. Conversely, a larger unit could operate at 10 percent of the mercury emissions rate limit, or 0.12 lb/TBtu, and exceed 22.0 pounds per year.

To maintain LEE status and demonstrate continuous compliance a unit must: (1) conduct fuel sampling and analysis according to Table 6 and §63.10008 at least every month; (2) operate within the operating limits established during the 28- to 30-operating day performance test; and (3) repeat the performance test once every five years according to Table 5 and §63.10007. NextEra Energy's understanding of the rule is that monthly fuel tests would be compared against the inlet fuel that was burned during the mercury emissions performance testing. This fuel content value from the initial performance testing becomes the unit's maximum fuel inlet operating limit for mercury.

NextEra Energy recommends that EPA adopt an optional, alternative method for demonstrating continuous compliance for mercury when a unit qualifies for LEE status. As an alternative to conducting monthly fuel tests, we propose that owners/operators of an LEE unit have the option to conduct an annual Method 30B performance test to demonstrate that its emissions are less than 10 percent of its applicable mercury emissions limit or less than 22.0 pounds per year. If an LEE unit exceeds LEE limits, we propose that it revert back to more frequent performance tests (e.g., quarterly, as recommended below). The subsequent year, if the unit can, again, demonstrate LEE status through reduced utilization or a lower emission rate, it would return to annual stack tests under the LEE provisions. We recommend this optional, alternative approach in order to balance the need for accurate emissions data with reduced compliance costs for those units emitting only at a fraction of the proposed standards.

Also, in order to avoid having companies run units simply to conduct stack testing, we propose that LEE units have the flexibility to schedule their annual performance tests at any time during a 12-month cycle. Some of these LEEs may be smaller units with low capacity factors and may go several months without operating. Allowing flexibility in scheduling stack tests will avoid unnecessary air pollution emissions and reduce costs for these units operating well below the proposed standards. Additionally, this would allow companies to align testing under this rule with existing state testing requirements.

Finally, while NextEra Energy recommends that fuel testing be maintained as an alternate monitoring method for LEE units, it is suggested that the frequency of fuel testing be reduced to each shipment of oil received [see Section III comments related to oil-fired units for further discussion]. Mercury concentration differences should be negligible in comparison of Method 30B and fuel analyses for oil-fired units. Owners should have the option to select the most economical methodology where results are equivalent.

2. Low-Emitting Units: Other HAPs

EPA proposes that for all other HAPs, LEEs would demonstrate continuous compliance and maintain LEE status through monthly fuel analysis as well as performance (stack) testing every five years. However, in many cases, monthly fuel testing would be redundant as this requirement would result in the repetitive testing of the same fuel shipment (see further discussion below in the context of oil-fired units). Therefore, we recommend that for non-mercury HAPs as well, owners/operators of an LEE unit have the option to conduct an annual performance test to demonstrate that emissions are less than 50 percent of the relevant emissions standard.

C. Requirements During Startup, Shutdown, and Malfunction

As indicated in the preamble of the proposed Toxics Rule, in *Sierra Club v. EPA*, 551 F.3d 1019 (DC Cir. 2008), the D.C. Circuit Court vacated portions of the Section 112 regulations, commonly known as the "General Provisions Rule," which had previously exempted major sources from NESHAP during periods of startup, shutdown, and malfunction (SSM). In the proposed Toxics Rule, EPA proposes that the emissions standards for mercury and other air toxics apply at all times, including periods of SSM. According to the preamble, EPA has not proposed different standards for SSM periods because (1) the Agency has taken into account startup and shutdown periods in setting the standards; (2) the standards proposed are 30 boiler operating day averages; (3) EGUs do not normally startup and shutdown frequently; and (4) EGUs typically use cleaner fuels (e.g., natural gas or oil) during the startup period.

While EPA's assumptions regarding startup and shutdown may be correct in some cases, these assumptions are not applicable for all units under all operating conditions and do not provide a rational basis to support the imposition of numerical standards instead of work practice standards during SSM periods. Most EGUs will combust natural gas or No. 2 fuel oil (or both) at startup before switching to coal or residual fuel oil. However, in terms of shutdown, units will either reverse the sequence (switching from coal or residual oil to natural gas or No. 2 oil) or simply shutdown on whatever fuel they happen to be burning at the time. As a result, there may be EGUs that would not switch to lower emitting fuels during shutdown. Also, pollution control systems may not achieve peak performance at startup, temporarily limiting a unit's ability to limit its emission rate. These realities were not reflected in the Information Collection Request ("ICR") stack testing. Finally, EPA's assumption that EGUs can simply average their emissions over 30 boiler operating days is only relevant in the context of an EGU using a continuous emissions monitoring device. An EGU that demonstrates compliance with a monthly or quarterly performance test would not be in a position to average its emissions during periods of startup and shutdown because it would not be feasible to measure emissions during these periods.

Therefore, NextEra Energy recommends that, in the final rule, EPA follow the approach that it used in the final Industrial, Commercial and Institutional (ICI) Boiler MACT Rule; namely, that work practice standards apply during periods of startup and shutdown, while malfunctions would not be considered a distinct operating mode. In the ICI Boiler MACT Rule, EPA determined that it is not technically feasible to monitor these periods of startup and shutdown and, therefore, established separate work practice standards for periods of startup and shutdown. In the ICI Boiler MACT Rule, EPA requires affected units to follow manufacturers' specifications for minimizing periods of startup and shutdown. Specifically, 40 CFR 63.7530(h) requires that owners/operators of covered ICI boilers "minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a unit of similar design if manufacturer's recommended procedures are not available." NextEra Energy believes the same approach is appropriate for EGU boilers, recognizing that in most cases emissions will be below the applicable NESHAP standards by virtue of the lower emitting fuel being burned.

In terms of malfunctions, which are sudden, infrequent, unexpected, and not reasonably preventable, we recommend that EPA or states maintain current enforcement discretion to address situations in which a source fails to comply with a 112(d) standard as the result of a malfunction. We expect that, as current practice, EPA would determine an appropriate response based on, among other things, the good faith efforts of the source to minimize emissions during malfunction periods, including preventative and corrective actions, as well as root cause analyses to ascertain and rectify excess emissions. EPA would also consider whether the source's failure to comply with the standard was, in fact, "sudden, infrequent, not reasonably preventable" and was not "caused in part by poor maintenance or careless operation." 40 CFR 63.2 (definition of malfunction). As EPA notes in the preamble to the ICI Boiler MACT Rule, "even equipment that is properly designed and maintained can sometimes fail and that such failure can sometimes cause an exceedance of the relevant emission standard." Therefore, in the ICI Boiler MACT Rule, EPA finalized an affirmative defense to civil penalties for exceedances of numerical emission limits caused by malfunctions (40 CFR 63.7575 defining "affirmative defense").

D. Emissions Averaging

NextEra Energy supports the limited emissions averaging provisions included in the proposed rule. We agree with the Agency that emissions averaging represents an equivalent, more flexible, and less costly alternative to unit-by-unit emissions limits while still maintaining a regulation that is workable and enforceable. Additionally, we agree that the proposal is consistent with the requirements of the Clean Air Act and EPA's previous policies regarding the scope and nature of emissions averaging programs.

Most coal-fired power plants have multiple boilers and electric generating units at a single plant location. The proposed Toxics Rule would allow companies to demonstrate compliance by averaging their emissions across multiple units at an affected source. This flexible compliance option will be particularly helpful to smaller generating units that are co-located with larger generating units, but may not be economic to retrofit with pollution control systems.

Smaller boilers, which may only operate a limited number of hours each year, may comply without any major capital upgrades if co-located with a better-controlled boiler. Nearly 20 percent of existing coal capacity that currently lacks "scrubbers" is co-located at plants with existing scrubbers. These units can potentially benefit from the averaging provisions of the rule, reducing the costs and potential retirements from the Toxics Rule, as well as avoiding any related reliability issues.

II. Recommendations Related to Coal-Fired EGUs

A. Subcategorization

EPA has proposed two basic subcategories for coal-fired EGUs: (1) EGUs designed to combust coal ≥ 8,300 Btu/lb, and (2) EGUs designed to combust coal < 8,300 Btu/lb. For mercury emissions, EPA has proposed different emissions limits for the two subcategories. For all other HAPs, EPA has proposed the same emissions limits for the two subcategories. NextEra Energy supports EPA's decision to create a separate subcategory for units burning coal with less than 8,300 Btu/lb coals. Boilers designed to burn these coals (typically lignite) are significantly different than the design of plants burning coals with higher heat content. These coals are also different in composition than other coal types.

B. Emissions Standards

1. Emissions Standards for Existing Coal EGUs

Total PM vs. Filterable PM as a Surrogate for Non-mercury Metals

The proposed Toxics Rule proposes that *total* PM—filterable, *i.e.,* fine particulate emissions ($PM_{2.5}$) plus condensable—serve as a surrogate for measuring non-mercury metals from coal-fired units, with alternate surrogates of total metals or individual metals. NextEra Energy supports EPA's use of alternative surrogates for non-mercury metals, but opposes using *total* PM as a surrogate.

Specifically, we recommend a change to the proposed rule's treatment of condensable PM (CPM) for units using a PM continuous emissions monitoring system (CEMS). As proposed, sources would be required to conduct initial testing to determine emissions of total PM as well as the constituents filterable PM and CPM. These would be used to establish a facility-specific filterable PM limit as a surrogate for total PM. For instance, if the initial compliance demonstration for Facility A, an existing coal-fired power plant with heat input ≥ 8,300 Btu/lb, showed total PM emissions of 0.020 lb/MMBtu with 50 percent filterable and 50 percent CPM, a facility-specific filterable PM limit of 0.010 lb/MMBtu would be established. However, an identical Facility B with the same Total PM emissions but a higher ratio of filterable to CPM, such as 75 percent, would establish a filterable PM limit of 0.015 lb/MMBtu. This method is inherently uncertain, and could result in a facility having a variable emissions target. Additionally, this method results in unfairly "ratcheting down" the standard on some units. While NextEra Energy recognizes EPA's obligation to address CPM, which may include vapor-phase metals such as selenium, this compliance approach introduces a new set of problems.

Therefore, we propose the following options for EPA consideration:

- PM CEMS combined with occasional stack tests to ensure CPM emissions remain within limits.
- Use mercury as a surrogate for selenium and, thus, filterable PM alone may be a surrogate for other HAP metals. In the preamble, EPA states that selenium is captured by controls for mercury and acid gases. In fact, initial correlation analysis performed for NextEra Energy indicates that selenium emissions are in fact better-correlated to mercury and acid gas emissions than CPM (r=0.44 for mercury or 0.60 for HCl, versus 0.32 for CPM [r > 0.2 implies significance at 5 percent level with 60 units]).
- PM CEMS combined with a separate Se standard. In this instance, selenium emissions could be confirmed by quarterly or annual stack testing limited to selenium. Similar to the treatment of limited use units, this requirement could be scaled such that units emitting Se well below the standard were subject to less stringent monitoring requirements than those units emitting very close to the standard.

Alternatively, at a minimum, NextEra Energy recommends that EPA base the filterable PM limit on the facility-specific ratio to the total PM standard, rather than the initial numerical performance. In the above example, Facility A's emissions of 50 percent filterable PM would result in a limit of 0.015 lb/MMBtu (50 percent of the 0.030 lb/MMBtu standard), while Facility B's limit would be 0.0225 lb/MMBtu (75 percent of the 0.030 lb/MMBtu standard). We also recommend that this facility-specific limit remain constant for a longer period of time, such as annually, to provide a measure of regulatory certainty.

Emissions of Organics and Dioxins

EPA has proposed to establish work practice standards for EGUs, which would require an annual performance test program, to address any emissions of organic HAPs and dioxins. NextEra Energy agrees with and supports EPA's decision to set work practice standards for these pollutants.
Results of sampling for organics and dioxins during the ICR showed there were far more "non-detectable" observations than actual detected values. The high number of measurements at or below the detection limit makes setting a MACT limit impossible for these HAPs because, by definition, a measurement at or below the detection limit has more error associated with it than the value measured. Clean Air Act section 112(h) provides EPA discretion to set work practice standards in lieu of emissions limits if the Administrator finds it is not feasible to prescribe or enforce an emissions standard. The high percentage of non-detectable measurement for organics and dioxins shows that it is not feasible to either prescribe or enforce emission standards.

On this basis, NextEra Energy believes that EPA's decision to propose work practice standards for organic HAPs and dioxins is correct and should be maintained in the final rule.

2. <u>Compliance Requirements</u>

NextEra Energy recognizes that the integrity of an emission control program such as reflected in the proposed Toxics Rule depends in large part on the collection of accurate and reliable data to demonstrate initial as well as ongoing continuous compliance with program requirements. However, NextEra Energy believes that EPA's proposed monitoring and testing requirements governing affected coal-fired EGUs are unnecessarily burdensome and costly. We believe that the Agency can achieve an equivalent level of compliance assurance associated with the proposed Toxics Rule with a lower compliance burden by making the following adjustments to the proposal.

Stack Testing

In the proposed rule, units not measuring emissions continuously (e.g., using CEMS or sorbent traps) must conduct monthly or bi-monthly stack tests to demonstrate compliance. NextEra Energy has several concerns with the proposed compliance testing requirements. First, we believe that the proposed frequency of testing will place a significant cost burden on plant operators. Stack testing can also can be unsafe for testing personnel during harsh weather conditions, particularly the cold winter months. In addition, inflexible testing schedules may induce units to run solely for testing purposes, leading to increased emissions. Finally, beyond company costs and staff time, we assume that, like other rules requiring stack tests, state-level environmental regulators may need to be onsite to witness the tests. Given the large number of units affected by the Toxics Rule and the proposed testing frequency, staff availability could be a significant issue. This could result in delayed compliance testing, testing when the unit would not otherwise run, or not being able to run a unit when it is called.

In an effort to balance these concerns with the need for reliable compliance demonstrations, NextEra Energy recommends that all stack testing requirements governing coal-fired EGUs should be no more frequently than *quarterly* under standard operation (i.e., unless boiler operations or characteristics are substantially altered, in which case initial testing should be repeated). Quarterly stack testing in combination with parameter monitoring (discussed below) should be enough to ensure that a unit is operating within the required limits. Quarterly testing would capture seasonal variations in operation while not unnecessarily repeating testing of the same conditions.

In addition, to avoid running a unit simply to conduct a stack test, we recommend that EPA adopt the existing approach used in Part 75. Specifically, 40 CFR 72.2 defines a quarter as "a calendar quarter in which there are at least 168 unit operating hours (as defined in this section) or, for a common stack or bypass stack, a calendar quarter in which there are at least 168 stack operating hours (as defined in this section)." Unit and stack operating hours are further defined, respectively, as:

- *Unit operating hour* means a clock hour during which a unit combusts any fuel, either for part of the hour or for the entire hour. (40 CFR 72.2)
- *Stack operating hour* means a clock hour during which flue gases flow through a particular stack or duct (either for the entire hour or for part of the hour) while the associated unit(s) are combusting fuel.

This approach would ensure that no unit is run simply for the sake of testing.

Sorbent Traps for Mercury

NextEra Energy supports EPA's proposal to allow the use of sorbent traps to demonstrate compliance with the mercury emissions limits for coal-fired EGUs. While units with existing or planned CEMS anticipate using them for demonstrating compliance with the proposed rule, EPA should not assume that most coal-fired EGUs have mercury CEMS as stated in the preamble.

Operating Limits

§ 63.10011 of the proposed Toxics Rule requires coal-fired EGUs (and oil-fired EGUs) to establish "parameter operating limits" in order to demonstrate continuous compliance. The operating limits would be established during initial compliance testing. The requirements vary depending on the pollution control technology used by the unit to demonstrate compliance, as summarized in Table 1 below.

Table 1. Proposed Operating Limits

Control Device	Operating Limits
Wet Scrubber (PM)	Maintain pressure drop and liquid flow rate
Wet Scrubber (acid gases)	Maintain the pH and liquid flow rate
Fabric filter	Install and operate a bag leak detection system
ESP	Maintain secondary voltage and secondary amperage
Dry Scrubber	Maintain sorbent injection rate
Dry sorbent injection	Maintain sorbent injection rate
Carbon injection control	Maintain sorbent injection rate
Fabric filter	Install bag leak detection system and limit bag leak detection alarms

NextEra Energy has several concerns with the proposed parameter operating limits and recommends an alternative approach that we think will better ensure proper operation of pollution control systems. Our primary concerns can be summarized as follows: (1) parameter operating limits may be unnecessary, adding additional compliance costs, for an affected EGU that is already demonstrating compliance with a CEMs device; (2) parameter operating limits may be duplicative or redundant with existing, EPA-approved Compliance Assurance Monitoring (CAM) plans; and (3) a numeric operating limit, established during initial compliance testing, could set an unreasonable limit that fails to reflect the full variability of the plant's operating conditions.

For example, the proposed rule requires a plant operator to measure the voltage and current of each ESP collection field during each mercury, PM, and metals performance test. The average of the three minimum hourly values would then be used to establish a unit's site-specific minimum voltage and current operating limits for the ESP. While we agree that maximizing power input and electric field strength will generally maximize ESP collection efficiency, plant operators need a degree of flexibility to balance the power input to the ESP in order to avoid serious damage to the system and downtime. The power input to an ESP is dynamically controlled by an automated voltage control system to maximize power levels while avoiding sustained arcing or sparking between the electrodes and the collecting plates, which can damage the ESP, including the transformer-rectifier and other components in the primary circuit. Automatic voltage control varies the power to the transformer-rectifier in response to signals received from sensors in the precipitator and the transformer-rectifier itself. Power levels will vary depending on the amount of moisture in the air, accumulated ash levels, and other factors. As result, sustaining a minimum voltage and current level may not be possible or appropriate at all times, and could damage the control technology.

Rather than establishing fixed operating limits, NextEra Energy recommends that EPA require proper operation of the plant's pollution control equipment and appropriate parametric monitoring without establishing numeric operating limits. Also, units with appropriate CAM plans and units operating CEMs should not be required to have additional monitoring requirements.

III. Recommendations for Oil-Fired EGUs

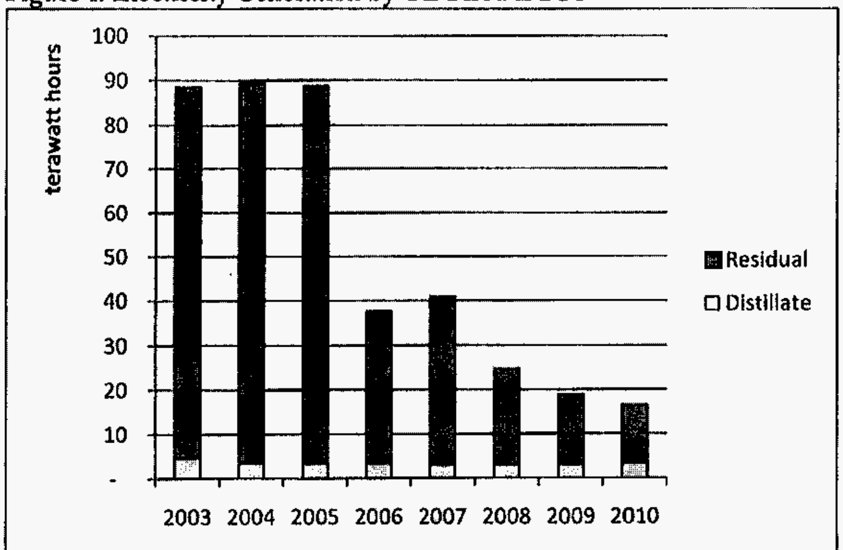
In the United States, oil-fired EGUs generally operate as peaking or load-following units, and only produce about one percent of electric power output. In 2003, oil-fired EGUs (steam) produced 88.5 terawatt hours of electricity. By 2010, this figure had declined by 80 percent, to less than 17 terawatt hours. Figure 1 shows the decline in oil use by steam EGUs based on U.S. Energy Information Administration (EIA) data. Residual (No. 6) oil is the most widely used fuel oil for generating steam and electricity because of its relatively low cost compared to lighter distillate fuel oils.

Although the use of oil for electricity production has been declining, it often serves a vital role in terms of maintaining reliable electric power supplies. For example, in the Northeast region, oil is often the only fuel available when natural gas supplies are curtailed in favor of residential and commercial natural gas customers. In addition, during high electric demand days, select units are sometimes required to fire oil even when natural gas is available, to ensure electric system reliability in the event of a gas supply interruption. Further, as a result of geographic isolation, the majority of electricity generation in Hawaii and Puerto Rico is from oil-fired power plants.

According to the proposed Toxics Rule, oil-fired EGUs produced 1,779 tons of priority HAPs in 2010. This compares to 181,287 tons produced by coal-fired EGUs.[2] HAP emissions from oil-fired EGU represent one percent of total emissions from the two subcategories, according to EPA estimates.

[2] U.S. EPA. National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units. Federal Register /Vol. 76, No. 85 /Tuesday, May 3, 2011. Page 24983.

Figure 1. Electricity Generation by Oil-Fired EGUs



Source: U.S. EIA. Form EIA-906, EIA-920, and EIA-923 Data. Prime Mover = Steam.
Note: There are only three power plants in the U.S. with steam units that rely exclusively on distillate fuel oil for electricity generation. These units account for less than one percent of the distillate oil-fired generation displayed above. Most of the distillate oil use shown in the chart above is combusted at coal-fired steam boilers.

A. Subcategorizing Between Coal- and Oil-Fired EGUs

NextEra Energy supports EPA's decision to subcategorize between coal- and oil-fired EGUs given the different operating characteristics and emissions profiles of the two subcategories. As indicated above, oil-fired EGUs generally operate as peaking or load-following units. Coal-fired power plants generally operate as baseload generating resources. According to EPA's ICR database, oil- and coal-fired EGUs report annual average capacity factors of 19 percent and 63 percent, respectively.[3]

In structuring the final rule, we would encourage EPA to better separate the compliance and monitoring requirements applicable to oil-fired EGUs from the requirements for coal-fired EGUs to ensure that the requirements for both subcategories are fully developed and clearly articulated. For example, as discussed above, the requirements for oil-fired "low emitting EGUs" are not specified in the proposal. We believe that better separation of the requirements for coal- and oil-fired EGU will reveal where these gaps may be occurring.

B. Risk Assessment of Oil-Fired EGUs

In finalizing the Toxics Rule, NextEra Energy encourages EPA to update its risk assessment supporting the regulation of oil-fired EGU under Section 112 of the Clean Air Act to reflect the latest scientific knowledge and understanding.

1. EPA Should Re-evaluate Conclusions in the Proposed Rule Regarding the Carcinogenicity of Nickel Emissions from Oil-fired EGUs

[3] U.S. EPA. ICR Database: Part I – Boiler_Information. Companies were asked to report their average annual capacity factors and hours of operation for the past three years (2007-2009).

In its original risk assessment, published in 1998, the majority of oil-fired EGUs (126 of 137) were estimated to pose inhalation cancer risks below EPA's threshold of concern (one-in-a-million or 1×10^{-6}), leaving only 11 oil-fired facilities listed as potentially presenting inhalation risks above the threshold of concern. Several of these plants have since retired or converted to natural gas, and new scientific studies have been published regarding the toxicity of HAP emissions from oil-fired EGUs. For example, the Department of Energy's final report entitled *Nickel Species Emission Inventory For Oil-Fired Boilers* (2004) found that "The presence of ... nickel oxide compound mixtures and lack of carcinogenic nickel subsulfide (Ni_3S_2) or nickel sulfide compounds (e.g., NiS, NiS_2) in [residual oil fly ash] stack-sampled from 400- and 385-MW boilers are contrary to EPA's nickel inhalation cancer risk assessment (Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, February 1998), where it is assumed that the nickel compound mixture emitted from oil-fired utilities is 50 percent as carcinogenic as Ni_3S_2 [i.e., that 50 percent of nickel emitted was in the form of Ni_3S]. Apparently, this assumption greatly overestimates the nickel inhalation cancer risk from oil-fired utilities."

A peer-reviewed study of three oil-fired utilities was recently published, further evaluating the nickel species that are emitted by residual oil-fired EGUs.[4] This paper summarizes Ni speciation in emissions from eight residual oil fired EGUs determined by nickel XAFS spectroscopy, which is the best available method for directly and non-destructively determining the speciation in such emissions. The nickel speciation of all samples investigated was found to be dominated by nickel sulfate in the form of $NiSO_4.6H_2O$, with lesser amounts of nickel oxides, either (Ni,Mg)O and/or $NiFe_2O_4$. Importantly, the highly carcinogenic nickel species, nickel subsulfide and similar nickel sulfides, were not detected in the emission samples. The data analyses of the oil used by the three companies are representative of residual oil use by EGUs in the U.S. Approximately two-thirds of the residual oil power generation in the US is supplied by Florida Power & Light, Hawaiian Electric Company and National Grid, the three utilities involved in the 2010 study.

In the proposed Toxics Rule, Section III(D), EPA concludes "that it is appropriate to regulate non-Hg HAP because emissions of these HAP from some EGUs (electric utility steam generating units) pose a cancer risk greater than one in one million to the most exposed individual." Also, under *Results* of the *EGU Case Studies of Cancer and Non-Cancer Inhalation Risks* (Section III(D)(3)(d)(iii), the proposed rule states: "The highest estimated lifetime cancer risk from any of the 16 case study facilities was 10 in 1 million (1×10^{-5}), driven by Ni emissions from the 1 case study facility with oil-fired units." EPA's conclusion references, and presumably was based on, the Memorandum to Docket EPA–HQ–OAR–2009–0234 of March 1, 2011.[5]

This comment addresses only the nickel analysis provided in Section 2.3, pp. 12-15 of the Memorandum to Docket cited above (the Memorandum). Several references are included in this comment, which were selected for the purpose of informing the points addressed. No attempt is made to present a full review of the evidence for or against nickel carcinogenicity; however, several of the cited references provide more complete reviews of the subject.

The Memorandum seems to have ignored evidence from controlled inhalation studies that nickel sulfate *alone* has shown no evidence of carcinogenicity. The most definitive of these studies, conducted by the National Toxicology Program (NTP), in which male and female F344/N rats and $B6C3F_1$ mice were exposed to nickel sulfate hexahydrate ($NiSO_4 \cdot 6H_2O$, >98% pure) over a range of exposures from 0.12 to 1.0 mg/m^3, showed

[4] Huggins, FE, KC Galbreath, KE Eylands, LL Van Loon, JA Olson, EJ Zillioux, SG Ward, PA Lynch and P Chu. 2011. Determination of nickel species in stack emissions from eight residual oil-fired utility steam-generating units. Environ. Sci. Technol. 45:6188-6195.

[5] Memorandum to Docket EPA–HQ–OAR–2009–0234. March 1, 2011. Strum, M., J. Thurman, and M. Morris, U.S. Environmental Protection Agency. Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis.

"no evidence of carcinogenic activity."[6] These results were confirmed in other well-conducted inhalation studies in rats and mice where exposures were solely to nickel sulfate hexahydrate[7]. Other papers have compared various studies including epidemiologic evidence of worker inhalation exposures to nickel refinery dust containing soluble nickel compounds. Oller (2002), for example, concluded, "Overall, the weight of evidence indicates that inhalation exposure to soluble nickel alone will not cause cancer; moreover, if exposures are kept below levels that cause chronic respiratory toxicity, any possible tumor-enhancing effects (particularly in smokers) would be avoided."[8]

In support of the Memorandum's contention that "the collection of epidemiology studies provides strong evidence of carcinogenicity specifically with respect to soluble nickel (nickel sulfate)," two agencies were cited that "have determined that nickel sulfate, specifically, and nickel compounds, in general, are carcinogenic". One of these agencies, the International Agency on Research in Cancer (IARC), concluded that "There is sufficient evidence in humans for the carcinogenicity of nickel sulfate,…encountered in the nickel refining industry"[9] (emphasis added). The second agency cited, the Danish Environmental Protection Agency, concluded that "The present evaluation of the epidemiological data demonstrated a strong relationship between lung and nasal cancer and exposure to nickel sulphate as it occurs in nickel refineries"[10] (emphasis added).

NextEra Energy believes that total reliance on exposure of workers to nickel refinery dust to conclude nickel sulfate carcinogenicity to humans is problematic. Epidemiologic studies of this type have suffered from poor quality of existing exposure data, no consistent dose response with increasing concentrations of soluble nickel, inconsistent results across cohorts, and presence of mixed exposures to water-insoluble nickel compounds and other confounders with known or suspected carcinogenic potential (e.g., soluble cobalt compounds, arsenic, acid mists, PAHs, cigarette smoke, etc.). The Danish EPA reported that the Technical Committee for Classification and Labeling (TC C&L), European Chemicals Bureau, "has agreed to classify nickel sulphate as Carc. Cat. 1; R49 (May cause cancer by inhalation), as there is no concern for carcinogenic potential with other routes of administration".

A focused assessment of the potential for carcinogenicity from inhaled nickel soluble salts was conducted by TERA (Toxicology Excellence for Risk Assessment) and others[11] under contract to the Metal Finishing Association of Southern California, Inc., the U.S. EPA, and Health Canada. Conclusions of the assessment are (1) "the role of soluble nickel *alone* in carcinogenicity to humans cannot be determined from the epidemiologic studies" (2) "the carcinogenic activity of insoluble nickel compounds should not be used to predict the carcinogenic potential of water-soluble nickel salts," and (3) "under the U.S. EPA's 1996 proposed Guidelines for Carcinogen Risk Assessment, inhaled soluble nickel compounds would be classified as '*cannot be determined*,' because the existing evidence is composed of conflicting data" (e.g., co-exposure of populations to soluble and insoluble forms of nickel and limitations in exposure measurements). The final EPA

[6] National Toxicology Program. July 1996a. NTP Technical Report on the Toxicology and Carcinogenesis Studies of Nickel Sulfate Hexahydrate (CAS No. 10101-97-0) in F344/N Rats and B6C3F1 Mice (Inhalation Studies). NTP TR 454, NIH Publication No. 96-3370, U.S. Dept. of Health and Human Services, National Institutes of Health, Washington, D.C., 376 pp.
[7] Dunnick, J.K., M.R. Elwell, A.E. Radovsky, J.M. Benson, F.F. Hahn, K.J. Nikula, E.B. Barr and C.H. Hobbs. 1995. Comparative carcinogenic effects of nickel subsulfide, nickel oxide, or nickel sulfate hexahydrate on chronic exposures in the lung. Cancer Res. 55:5251-5256.
[8] Oller, A.R. 2002. Respiratory carcinogenicity assessment of soluble nickel compounds. Environmental Health Perspectives, Vol. 1101 (Supplement 51):841-844.
[9] International Agency for Research on Cancer. 1990. IARC Monographs on the Evaluation of Carcinogenic Risks to Humans – Chromium, Nickel and Welding. Vol. 49, ISBN 92 832 1249 5, ISBN 0250-9555. World Health Organization, IARC, Lyon, France. 677 pp.
[10] Danish Environmental Protection Agency. 2008. Nickel Sulphate, CAS No. 7786-81-4, EINECS No. 232-104-9 Risk Assessment Final version. Copenhagen, Denmark. 226 pp.
[11] Haber, L.T., L Erdreich, G.L. Diamond, A.M. Maier, R. Ratney, Q. Zhao, and M.L. Dourson. 2000. Hazard identification and dose-response of inhaled nickel soluble salts. Reg. Toxicol. & Pharmacol. 31:210-230.

Guidelines for Carcinogen Risk Assessment (2005)[12] employs different descriptors than the 1996 proposed guidelines; the comparable descriptor used for conflicting evidence in the final guidelines is *'Inadequate Information to Assess Carcinogenic Potential.'*

The NTP 1996 series of inhalation studies of nickel species also included the results of 2-year studies of nickel subsulfide (Ni_3S_2) and nickel oxide (NiO). The conclusions of the studies with Ni_3S_2 were: (1) *clear evidence of carcinogenic activity of Ni_3S_2 in male and female F344/N rats* and (2) *no evidence of carcinogenic activity of Ni_3S_2 in male or female B6C3F$_1$ mice.*[13] Conclusions of studies with NiO were: (1) *some evidence of carcinogenic activity of NiO in male and female F344/N rats,* (2) *no evidence of carcinogenic activity of NiO in male B6C3F$_1$ mice,* and (3) *equivocal evidence of carcinogenic activity of NiO in female B6C3F$_1$ mice.*[14] Together with the NTP 2-year inhalation studies of nickel sulfate that showed *no evidence of carcinogenic activity* in either male or female F344/N rats, or in male or female B6C3F$_1$ mice, it is clear that differences exist in carcinogenic potential between various nickel species.

An extensive literature exists indicating that only selected compounds of nickel may be regarded as carcinogenic or potentially carcinogenic in humans, with many papers reporting on postulated mechanisms that drive the carcinogenic process among nickel species. This is the subject of an extensive review by Teaf et al. (2004)[15], which also developed RfCs for nickel sulfate and nickel oxide using the benchmark dose approach in conjunction with NTP data for nickel species. The Memorandum cites NTP (2005) which noted that "The combined results of epidemiological studies, mechanistic studies and carcinogenesis studies in rodents support the concept that nickel compounds generate nickel ions in target cells at sites critical for carcinogenesis, thus allowing consideration and evaluation of these compounds as a single group."[16] The fact that individual nickel compounds have been shown to display a wide range of efficiency with respect to the delivery of the Ni^{+2} ion to the target site has been ignored by this treatment and, thus, has not recognized the large variation in carcinogenic potential shown by the experimental evidence. For example, the Teaf et al. review cites evidence that soluble nickel does not readily enter mammalian cells, is rapidly cleared from the lung, and does not appear to be sufficiently bioavailable at nuclear target sites to induce tumors. In addition, the delivery of Ni^{+2} from high temperature NiO to the target site appears to be much less efficient than for Ni_3S_2.[17] The degree of phagocytosis between different forms of crystalline species may be a factor in carcinogenic potential (e.g., 2-3% for nickel oxide vs. >22% for nickel subsulfide), and this process may be mediated by differences in surface charges between the crystalline species and between crystalline and non-crystalline nickel species.[18,19] Such mechanistic differences help explain the range in experimental findings of carcinogenic activity from no evidence for $NiSO_4 \cdot 6H_2O$, to equivocal evidence for NiO, to clear evidence for Ni_3S_2. A recent review of mechanisms in metal carcinogenesis, including nickel,[20] included the following caveat:

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[12] Risk Assessment Forum. March 2005. Guidelines for Carcinogen Risk Assessment, EPA/630/P-03/001F. U.S. EPA, Washington, D.C. 166 pp.
[13] NTP. July 1996b. NTP Technical Report on the Toxicology and Carcinogenesis Studies of Nickel Subsulfide (CAS No. 12035-72-2) in F344/N Rats and B6C3F$_1$ Mice (Inhalation Studies). NTP TR 453, NIH Publication No. 96-3369, U.S. Dept. of Health and Human Services, National Institutes of Health, Washington, D.C., 360 pp.
[14] NTP. July 1996c. NTP Technical Report on the Toxicology and Carcinogenesis Studies of Nickel Oxide (CAS No. 1313-99-1) in F344/N Rats and B6C3F$_1$ Mice (Inhalation Studies). NTP TR 451, NIH Publication No. 96-3367, U.S. Dept. of Health and Human Services, National Institutes of Health, Washington, D.C., 375 pp.
[15] Teaf, C.M., B.J. Tuovila, E.J. Zillioux, A. Shipp, G. Lawrence, and C. Van Landingham. 2004. Nickel carcinogenicity in relation to the health risks from residual oil fly ash. HERA, 10:665-682.
[16] NTP. 2005. Report on Carcinogens, Eleventh Edition; U.S. Department of Health and Human Services, Public Health Service, Washington, D.C
[17] Sunderman, F.W. Jr, S.M. Hopfer, J.A. Knight, K.S. McCully, A.G. Cecutti, P.G. Thornhill, K. Conway, C. Miller, S.R. Patierno, and M. Costa. 1987. Physicochemical characteristics and biological effects of nickel oxides. Carcinogenesis 8:305-313
[18] Costa, M. and J.D. Heck. 1982. Specific nickel compounds as carcinogens. Trends Pharm. Sci. 3:408-410.
[19] Heck, J.D. and M. Costa. 1983. Influence of surface charge and dissolution on the selective phagocytosis of potentially carcinogenic particulate metal compounds. Cancer Res. 43:5652-5656.
[20] Salnikow, K., and A. Zhitkovich. 2008. Genetic and epigenetic mechanisms in metal carcinogenesis and cocarcinogenesis: nickel, arsenic and chromium. Chem. Res. Toxicol. 21(1):28-44.

> "The toxicity and carcinogenicity of Ni(II) depends on its intracellular dose that, in turn, is a function of physicochemical properties of particular nickel compounds, their ability to enter the cell and/or to dissolve within the cell. Because of a fast clearance from the exposed tissues, which limits cellular uptake, water-soluble Ni(II) compounds possess lower toxic and carcinogenic potential as compared to semi-soluble compounds such as nickel subsulfide."

The Memorandum also seems to have ignored evidence that no crystalline sulfidic nickel compounds, the only nickel compounds that clearly have been established as carcinogenic or potentially carcinogenic in humans, have been found in studies of residual oil fly ash samples.[e.g., 21, 22, 23, 24]

The authors of the Memorandum had available to them a report from the Energy & Environment Research Center of the University of North Dakota to the Electric Power Research Institute, which was entered into the rulemaking docket and noted in footnote #9 on p.13 of the Memorandum. The University of North Dakota report contributed to reference 20 of this comment. This was referred to in the Memorandum only as "Recent data from industry." The footnote noted that the insoluble nickel is primarily in a spinel form and that this spinel form "is not in the insoluble crystalline form." This was a mistake by the authors of the Memorandum; the spinel <u>is</u> in the insoluble crystalline form. The footnote also stated that the report "does not provide us with a better means for characterizing the risks" since there was no attempt to characterize the toxicity of the spinel form. It is generally recognized that metals in spinel forms are tightly bound in lattice structures and thus essentially lose their chemical, physical, and physiological properties. Citing studies with the spinel compounds chromite ($FeCr_2O_4$) and magnetite (Fe_3O_4), Heaney and Banfield[25] concluded "Spinels appear to be relatively inert in biological systems." In addition, there is a large and readily available literature, associated with the pigment chemical industry, on the insolubility and lack of bioavailability of heavy metal compounds absorbed by spinel lattices.

Direct speciation measurements by Galbreath et al.[24, 25, 26] indicated that >95% of the total Ni in residual oil PM was present as a mixture of $NiSO_4 \cdot xH_2O$ and a nickel oxide spinel compound, similar in composition to $NiFe_2O_4$. Each of these studies, however, looked at nickel speciation in fly ash sampled from no more than two EGUs. This has prompted the question of whether the results were applicable to oil-fired EGUs in general in the U.S. Huggins et al.[7] included emission studies of eight EGUs at three utility companies from Florida, New York, and Hawaii and is more broadly applicable. The data analyses of the oil used by these three companies are representative of residual oil use in the oil-fired electric generating industry. Approximately 2/3 of the residual oil power generation in the U.S. is supplied by the three companies involved in this testing [Florida Power and Light Company (FPL), Hawaiian Electric Company, Inc. (HECO), and National Grid]. The paper by Huggins et al.[24] was recently published in the peer-reviewed journal, Environmental Science & Technology, and has been entered into the docket of the NESHAP proposed rule. The paper summarizes Ni speciation determined by nickel XAFS spectroscopy, which is the best available method for directly and non-destructively determining the speciation in such emissions. The nickel speciation of all samples investigated was found to be dominated by nickel sulfate in the form of $NiSO_4 \cdot 6H_2O$, with lesser amounts of nickel oxides, either (Ni,Mg)O and/or $NiFe_2O_4$. Importantly, the

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[21] Galbreath, K.C., D.L. Toman, C.J. Zygarlicke, F.E. Huggins, G.P. Huffman, and J.L. Wong. 2000. Nickel speciation of residual oil fly ash and ambient particulate matter using X-ray absorption spectroscopy. J. Air & Waste Management. Assoc. 50:1876-1886.
[22] Galbreath, K.C., R.L. Schulz, D.L. Toman, C.M. Nyberg, F.E. Huggins, and G.P. Huffman. 2004. Nickel species emission inventory for oil-fired boilers, Final Report, Cooperative Agreement No. DE-FC26-98FT40321. U.S. Dept of Energy, National Energy Technology Laboratory, Pittsburgh, PA. 32 pp. Plus Appendices A-K.
[23] Galbreath, K.C., R.L. Schulz, D.L. Toman, C.M. Nyberg, F.E. Huggins, G.P. Huffman, and E.J. Zillioux. 2005. Nickel and sulfur speciation of residual oil fly ashes from two electric utility steam-generating units. J. Air & Waste Management Assoc. 55:309-318.
[24] Huggins, FE, KC Galbreath, KE Eylands, LL Van Loon, JA Olson, EJ Zillioux, SG Ward, PA Lynch and P Chu. 2011. Determination of nickel species in stack emissions from eight residual oil-fired utility steam-generating units. Environ. Sci. Technol. 45:6188-6195.
[25] Heaney, P.J., and J.A. Banfield. 1993. Structure and Chemistry of Silica, Metal Oxides, and Phosphates. In: Health Effects of Mineral Dusts, Guthrie, G.D. Jr., and B.T. Mossman, Eds., Mineralogical Society of America, Reviews in Mineralogy Series, Chapt. 5, Vol. 28, pp 185-233.

potentially carcinogenic Ni sulfide compounds are absent within the detection limits of the method (±2% of the total Ni).

In consideration of the lack of carcinogenicity of nickel sulfate *alone*, the equivocal evidence for carcinogenicity of nickel oxides along with mechanistic limitations in the delivery of the Ni^{+2} ion to the target site from nickel oxide exposures, the reported lack of bioavailability of spinel compounds, and the absence of sulfidic nickel species found in nickel speciation studies of oil-fired EGUs, all of which are documented above, NextEra Energy urges EPA to re-evaluate the conclusions in the proposed rule on the carcinogenicity of emissions from oil-fired EGUs..

2. EPA Should Re-evaluate the Appropriateness of Establishing Numerical Emission Limits Governing Acid Gas Emissions from Oil-fired EGUs

Carcinogenicity

The acid gases listed as being emitted by EGUs[26], including hydrogen chloride (HCl), hydrogen fluoride (HF), hydrogen cyanide (HCN), and chlorine (Cl_2), have not been characterized as carcinogens, due, in general, to lack of sufficient available evidence, despite tests designed to determine potential carcinogenicity having been performed with all four substances ([27, 28, 29,30,31]).

Non-cancer Toxicity

In the absence of sufficient evidence for carcinogenicity, EPA has correctly focused on application of non-cancer risk assessment guidelines. These included comparison of the maximum individual risk (MIR) associated with a HAP emission to an established health benchmark threshold for adverse effect (in this case, a hazard quotient [HQ – the estimated inhalation exposure divided by the reference dose (RfD) or reference concentration (RfC)] exceeding one for chronic non-cancer risks attributed to individual pollutants.] No HQ for any HAP emission at any case study facility selected by EPA exceeded the threshold of concern.

In addition, the HQs for all HAPs that affect a common target organ system were summed to obtain the hazard index (HI) for that Target Organ System, or TOSHI. All facilities examined had TOSHI values less than one.

Also, the maximum chronic impacts of HCl emissions were all less than 10 % of its chronic RfC (although Cl_2, HF, and HCN were not included in the assessment of non-cancer impacts due to uncertainties in their emission rates; HCl emissions represent the predominant HAP emitted by U.S. EGUs).

Thus, using EPA's risk assessment guidance, the emissions of acid gases in general from EGUs in the U.S. do not exceed established threshold levels of concern.

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[26] US Environmental Protection Agency (USEPA). 3 May 2011. National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units; Proposed Rule. 40 CFR Parts 60 and 63, Federal Register 76 (85): 24946-25147.
[27] USEPA. 28 October 2003. Hydrogen Chloride (CASRN 7647-01-0). Integrated Risk Information System (IRIS). http://www.epa.gov/iris/subst/0396.htm.
[28] USEPA. December 1988. Summary Review of Health Effects Associated with Hydrogen Fluoride and Related Compounds, Health Issue Assessment. Office of Research and Development, EPA/600/8-89/002F.
[29] Agency for Toxic Substances and Disease Registry (ATSDR). September 2003. Toxicological Profile for Fluorides, Hydrogen Fluoride and Fluorine. ATSDR, Atlanta, GA
[30] USEPA. 28 September 2010. Hydrogen Cyanide and Cyanide Salts (CASRN Various). IRIS. http://www.epa.gov/iris/subst/0060.htm
[31] USEPA. 28 October 2003. Chlorine dioxide (CASRN 10049-04-4). IRIS http://www.epa.gov/iris/subst/0496.htm.

Justification for regulation of acid gas emissions under section 112

The proposed rule notes that "EGUs remain the largest source of HCl and HF emissions in the U.S.," and "it is appropriate to regulate those HAPs which are not known to cause cancer but are known to contribute to chronic non-cancer toxicity and environmental degradation, such as the acid gases." Therefore, despite the fact that EPA "case studies did not identify significant chronic non-cancer risks from acid gas emissions…, it is appropriate to reduce emissions of this magnitude which carry the potential to aggravate acidification" of sensitive ecosystems. Further justification to regulate EGUs is given on the basis that a number of currently available control technologies to reduce acid gas emissions have been identified.

Comparison of coal- and oil-fired EGU emissions from EPA's risk analysis

EPA's Emissions Overview memorandum to the toxics rule docket[32] compared 2005 EGU acid gas emissions to 2005 total non-EGU acid gas emissions (Reference 34, Table 3), showing the percent of total national emissions attributed to EGUs for HCN, HCl, and HF to be 8%, 82%, and 62%, respectively. However, Table 3 of reference 34 also shows that the percentages of total 2010 EGU emissions attributed to oil-fired EGUs for the same acid gases are only 1.4%, 0.3%, and 0.2%, respectively. Clearly, acid gas emissions from oil-fired EGUs are not of the magnitude that triggered EPA's decision to regulate EGUs in general, raising the question of whether reduction (or even total elimination) of acid gas emissions from oil-fired EGUs could have any significant effect on EPA's goals of reducing non-cancer health risk or acidification of sensitive ecosystems in the U.S.

Nevertheless, the question remained of whether individual oil-fired units would show the same virtually *de minimis* level of acid gas emissions when compared to individual coal-fired units. Individual HCl emissions given in EPA's Non-Hg Case Study Chronic Inhalation Risk Assessment[33] were used for this comparison. EPA's case study risk analysis selected a total of 16 facilities in two groups. The first eight facilities (Group 1) were selected on criteria that emphasized higher risk facilities (highest risk in previous studies, exclude those with installed emissions controls, etc.). The second group (Group 2) of eight facilities also were selected on the basis of higher risk, although using different criteria (generating capacity >300 MW, highest throughput, minimal emission controls, etc.). However, EPA modeled HCl emissions only for facilities in Group 1, using annual emission rate, emission factor, heat input and capacity factor inputs to compute "actual" emissions in tons per year (TPY) (Reference 35, Table 2).

A comparison of HCl "actual" emissions between individual coal and oil EGUs was made based on data from Group 1 provided in EPA's case study risk analysis. However, generation capacity of the various facilities in Group 1 ranged from a low of 28 MW to a high of 760 MW. To reduce this generation capacity bias, only facilities with generation capacity >300 MW were used for this comparison. Table 2 lists all Group 1 facilities with >300 MW total generation capacity together with the HCl "actual" annual emissions copied from EPA's case study risk analysis (Reference 35, Table 2).

[32] Strum, M., Houyoux, M., U.S. Environmental Protection Agency. Emissions Overview: Hazardous Air Pollutants in Support of the Proposed Toxics Rule. Memorandum to Docket EPA-HQ-OAR-2009-0234. March 15, 2011

[33] Strum, M., Thurman, J., and Morris, M., U.S. Environmental Protection Agency. Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT "Appropriate and Necessary" Analysis. Memorandum to Docket EPA-HQ-OAR-2009-0234. March 1, 2011.

TABLE 2
HCl Emission from Individual EGUs
[source: Non-Hg Case Study Chronic Inhalation Risk Assessment (35)]

Facility	Total MW Generation	Unit Type	HCl Emissions (TPY) (actual)
SCE&G Canadys, SC	420 MW	3 coal	114
			111
			4.8
Dominion Chesapeake Energy Center Chesapeake, VA	760 MW	4 coal	113
			125
			232
			304
PSI Energy Wabash River	430 MW	Unit 4 (coal-90 MW)	43.6
		Unit 6 (coal-342 MW)	131.0
HECO Waiau, HI	500 MW	6 oil	0.2
			0.2
			0.2
			0.2
			0.3
			0.4
Dominion Yorktown, VA	580 MW	2 coal	208
			208
		1 oil	1.6

From Table 2, the mean HCl emissions from 11 coal-fired units is 145 ±82 TPY while the mean from 7 oil-fired units is 0.25 ±0.5 TPY, or only 0.17% of the average coal-fired EGU. [It should be noted that, although one of the criteria for Group 1 facility selection was to be without installed emissions controls, SCE&G unit 3 (HCl emissions of 4.8 TPY) had a baghouse installed in 1999 and a test scrubber in 2002. Without that one data point, the percent of oil over coal HCl emissions would be even less.]

Thus, individual oil-fired EGUs show essentially the same relationship to individual coal-fired EGU emissions for HCl as was seen above when the comparison was based on the total 2010 ICR database. Based on these comparisons, requiring oil-fired units to install controls for acid gases would incur substantial unnecessary cost without a demonstrable environmental benefit. Accordingly, NextEra Energy requests that numerical emission limits for acid gases from oil-fired EGUs not be adopted in the final Toxics Rule and rather, that work practice standards be adopted as discussed below in Section III. (E) 2. of our comments.

3. **EPA Should Re-Evaluate Its Decision to Include Distillate Oil-fired EGUs in the Toxics Rule.**

EPA's 1998 Report to Congress on HAP Emissions from Electric Utility Steam Generating Units[34] focused exclusively on "residual" oil-fired EGUs. There is no discussion or analysis in the report supporting the inclusion of distillate oil-fired EGUs in the December 2000 Appropriate and Necessary Finding. In fact, the only reference to distillate oil in the 1998 Report to Congress is a statement suggesting that distillate oil is more similar to natural gas than residual oil. EPA indicates that "natural gas and distillate oil" both contain relatively little fuel-bound nitrogen. For natural gas-fired EGUs, EPA found that regulation of HAP emissions is not appropriate or necessary because the impacts due to the HAP emissions from such units are negligible based on the results documented in the Report to Congress. We would also note that the Report to Congress is clear that its inhalation risk analysis—which EPA uses to justify the regulation of oil-fired EGU—is specific to No. 6 residual oil. As indicated in Table 6-25 of the Report to Congress (the basic parameters used in the inhalation risk assessment for utilities), EPA assumed an "average HAP concentration in test data of residual fuel oil No. 6".[35] Also, among the 11 oil-fired EGUs listed as potentially posing inhalation risks above the threshold of concern, none rely on distillate fuel oil. EPA lists only three power plants in the entire U.S. that rely on distillate fuel oil for the production of electricity. *As a result, NextEra Energy strongly recommends that EPA reevaluate its decision to include distillate oil-fired EGUs in the final Toxics Rule.*

C. Definition of Fossil Fuel-Fired EGU

NextEra Energy generally supports EPA's proposed definition of a "fossil fuel-fired EGU"—using the construct from the Acid Rain Program. However, we propose certain modifications to the proposal, which we ask EPA to consider.

EPA proposes that a unit must have fired a fossil fuel (other than natural gas) for more than 10.0 percent of the average annual heat input during the previous three calendar years or for more than 15.0 percent of the annual heat input during any one of those calendar years to be considered a "fossil fuel-fired" EGU subject to the proposed rule. A unit that burns natural gas exclusively or natural gas in combination with another fuel where the natural gas constitutes 90 percent or more of the average annual heat input during the previous three calendar years or 85 percent or more of the annual heat input during any one of those calendar years, is considered to be natural gas-fired and would not be subject to the proposed rule.

NextEra Energy recommends a limited exception when defining a fossil fuel-fired unit that would address natural gas curtailment situations and gas supply emergencies where a dual-fired generating unit (for example, capable of combusting both natural gas and oil) is required to combust a fossil fuel (other than natural gas), either due to a natural gas supply interruption, as in the ICI Boiler MACT, or due to requirements unique to the electric industry in which an authority, such as a state public utility commission or reliability council, requires selected units to burn a fossil fuel (other than natural gas) to ensure grid stability.

Consistent with the ICI Boiler MACT, NextEra Energy proposes excluding the fossil fuels combusted during a period of natural gas curtailment or according to a reliability directive when determining if a unit is a "fossil fuel fired" EGU subject to the proposed rule. The ICI Boiler MACT defines a "*period of natural gas curtailment or supply interruption*" as a "*period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption*"

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[34] U.S. EPA. Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units – Final Report to Congress, February 1998. Volume 1: Page 6-61.
[35] Id.

(National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. 76 FR 54 page 15685).

Specifically, NextEra Energy recommends expanding the text to define "*period of natural gas curtailment or supply interruption*" as a "*period of time during which the supply of natural gas to an affected facility is limited for reasons beyond the control of the facility,* ***including when a unit is required to run on fossil fuel (other than natural gas) by local reliability rules*** *[...]*". As an example of such a situation, units may be called upon to avoid grid instability in the State of Florida. Their operation would be to mitigate reliability issues including, but not limited to, capacity shortages and/or conditions that may exceed the capability of its power generators, and may lead to a Generating Capacity Emergency. A Generating Capacity Emergency is defined as an event where any one of the electric generating utilities in the State of Florida has inadequate generating capability, including purchased power, to supply its firm load obligations. Each region of the country faces unique emergency situations. For example, freezing, weather-related events similar to the blackouts last winter as experienced in Texas, or hurricanes that have caused extensive damage in several states in recent years may require extended periods of emergency operation.

This addition, as well as the language from the ICI Boiler MACT, would exclude fossil fuel consumed as a result of (1) an emergency situation when natural gas supplies are physically interrupted; (2) a contractual agreement that limits a unit's natural gas supply; and/or (3) mandated operating rules requiring a unit to limit the use of natural gas to ensure electric system reliability.

Also, NextEra Energy recommends allowing companies to determine whether they are "natural gas-fired" or "fossil fuel-fired" at either the individual unit level or across all electric utility steam generating units larger than 25 MW at a single plant location. For example, a power plant with multiple steam generating units may be combusting limited amounts of oil across the plant as a whole, but with an individual unit burning oil in excess of EPA's proposed thresholds. This would avoid situations where a relatively small oil unit might be designated a fossil fuel-fired EGU despite the fact that the plant as a whole is largely reliant on natural gas and its plant-average emission rates are well below the level of the proposed standards. This would seem to be consistent with EPA's proposal to allow emissions averaging across all affected units at a single plant location.

Finally, NextEra Energy seek clarification on the compliance requirements for units that may change from being "natural gas-fired" to "fossil fuel-fired". As described above, a natural gas-fired generating unit may be forced to combust oil to maintain electric system reliability, and could suddenly change from being an unregulated natural gas-fired unit to a regulated fossil fuel-fired generating unit (if EPA does not adopt the above-proposed definition for curtailment). Outside of curtailment situations, a dual-fired unit may also burn oil if prices are competitive relative to natural gas or for other reasons. The proposed rule is unclear with regard to how much time EPA would allow a newly-designated fossil fuel-fired unit to schedule and perform its initial performance tests to demonstrate compliance with the applicable standards. *NextEra Energy recommends a period of 180 days from the date that a unit newly meets the definition of an affected fossil fuel-fired unit subject to the rule.*

D. Limited Use Subcategory for Oil-Fired Units

EPA indicates in the proposed Toxics Rule that it is considering a limited-use subcategory to account for liquid oil-fired units that only operate a limited amount of time per year on oil. According to EPA, such units could have specific emission limitations or reduced monitoring requirements (for example, limited operation may preclude the ability to conduct proper stack emissions testing). *NextEra Energy strongly supports establishing a limited-use subcategory for oil-fired EGUs.*

EPA included a limited-use subcategory in the final ICI Boiler MACT rule.[36] As stated in the rule, "EPA agrees that a subcategory for limited use units is appropriate for many of the reasons stated by the commenters. The fact that the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has lead EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used and EPA is including a subcategory for these units in the final rule. The unpredictable operation of this class of units makes emission testing for the suite of pollutants being regulated impracticable. In order to test the units, they would need to be operated specifically to conduct the emissions testing because the nature and duration of their use does not allow for the required emissions testing. As commenters noted, such testing and operation of the unit when it is not needed is also economically impracticable, and would lead to increased emissions and combustion of fuel that would not otherwise be combusted. Therefore, we are regulating these units with a work practice standard that requires a biennial tune-up, which will limit HAP by ensuring that these units operate at peak efficiency during the limited hours that they do operate." (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. 76 FR 15634)

NextEra Energy recommends the following definition for a limited-use oil-fired EGU: A *limited-use oil-fired EGU* means any boiler that burns any amount of liquid oil, has a rated capacity of greater than 25 MW, and has an annual average capacity factor *based on its oil use* of 10.0 percent or less over the past three years (and not more than 20.0 percent in each of those three years).[37] This is the same general approach that EPA uses for defining "gas-fired and oil-fired peaking units" in Part 75. Borrowing from 40 CFR 72.2, we would define "capacity factor" as the ratio of the unit's actual annual oil heat input to the unit's maximum design heat input times 8,760. We believe that this is a reasonable threshold for defining limited use for oil-fired EGUs because of the existing regulatory precedent in the Clean Air Act and because, unlike a threshold based on hours of operation, it reflects the varying loads of an electric generating unit.

In defining a limited use unit, NextEra Energy requests that periods of "emergency operations" be excluded from the calculation of a unit's capacity factor on oil. Oil-fired steam units may be called upon to avoid grid instability in the State of Florida. Their operation would be to mitigate reliability issues, including, but not limited to, capacity shortages and/or conditions that may exceed the capability of its power generators and may lead to a Generating Capacity Emergency. A Generating Capacity Emergency is defined as an event where anyone of the electric generating utilities in the State of Florida has inadequate generating capability, including purchased power, to supply its firm load obligations. Emergency operation does not include non-emergency, economic operation such as peak shaving programs.

We base our recommendation for a limited use subcategory on the same logic that EPA articulated in the ICI Boiler MACT: "the nature of these units is such that they operate for unpredictable periods of time, limited hours, and at less than full load in many cases has lead EPA to determine that limited use units are a unique class of unit based on the unique way in which they are used."

Electricity generated from oil-fired units contributes a relatively small percentage of the total generation and installed capacity on a national basis and also contributes a *de minimis* amount of emissions. Consequently, creating a limited-use subcategory for oil-fired units will have a negligible impact on overall emissions. Data from EIA[38] supports this statement, indicating that:

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[36] Under the ICI Boiler MACT, a limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, and has a federally enforceable limit of no more than 876 hours per year of operation (i.e., 10 percent utilization). Limited use boilers or process heaters must conduct a biennial tune-up, but are not subject to emissions limits.

[37] Most units would not have a federally enforceable limit in place restricting their hours of operation on oil. We seek clarification from EPA in terms of whether this would be required to qualify as a limited-use oil-fired EGU.

[38] EIA, Electric Power Annual 2009, ES-1, available at: http://www.eia.gov/cneaf/electricity/epa/epa_sum.html.

- 38,937 out of 3,950,331 thousand MWH of generation came from oil, or 0.986 percent of all generation.
- There were 56,781 MW of installed oil capacity out of a total installed capacity of 1,025,400 MW, or 5.54 percent of all installed capacity.
- Calculating from the above metrics, the average capacity factor for all oil generation in 2009 was 7.83 percent.[39]

There are 4,055 oil-fired generating units in operation or on standby mode, and 89 percent of these units have nameplate capacities of 25 MW or less.[40] According to 2008 EIA data, petroleum-fired units contributed 3 percent of the total SO_2 emissions and 2.2 percent of the NO_x emissions of the power sector.[41] Such units run on distillate fuel oil, residual fuel oil or some combination.

Due to the already high levelized cost of generation for these units ($187.54/MWH, 10-percent capacity factor, on average)[42], the units operate and are dispatched primarily during times of peak load/peak demand or in emergency situations, such as hurricane recovery, curtailment of natural gas due to natural disaster disruptions, *etc.* The levelized cost of generation for these units is significantly higher than most other forms of electricity generation, such as a coal ($94.80/MWH), natural gas combined cycle ($66.10/MWH) and advanced nuclear ($103/MWH).[43] Retrofitting these units with an ESP would increase the already high levelized cost of generation another 7 percent ($200.32/MWH on average) with very little environmental benefit.[44]

The other factor that supports creation of a limited-use subcategory for oil-fired units is the fact that because these units operate so few hours during a given year, they only have a limited number of hours over which to amortize any retrofit capital expense. It is not possible to recover the capital cost of the necessary controls over the remaining life of an oil-fired unit with a capacity factor at or below the 10 percent limit proposed by EPA. Unless a separate limited-use subcategory proposed by EPA is promulgated in the final regulations, it may not be economically practical to retrofit these units with emission control technology, and their owners may be forced to shut them down. However, as already noted, these oil-fired units are critical to the generation fleet to provide electricity during times of peak load or in emergency situations, and their forced retirement could lead to near-term energy supply problems and major cost increases.

We do not support establishing an equivalent limited use subcategory for coal-fired EGU because of their higher HAP emissions rates, higher average capacity factors, and higher average capacity size (i.e., greater potential to consume larger amounts of fuel). In contrast to the vast majority of coal-fired units, oil-fired EGUs in the continental U.S. tend to be used for peaking, voltage support, or to ensure fuel diversity during winter months. According to EPA's ICR database, oil- and coal-fired EGU report annual average capacity factors of 19 percent and 63 percent, respectively.[45] Also, oil-fired EGU are smaller, on average, than coal-fired EGU. The average oil-fired EGU is less than 300 megawatts (MW).[46] The average coal-fired EGU is 440 MW.[47] According to EIA, oil steam generating units produced only about 17 terawatt hours of electricity

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[39] Calculation: (38,937,000 MWH/(56,781 MW x 8,760 hours)).
[40] Ventyx 2011.
[41] EIA, Electric Power Annual 2008, Electricity, available at: http://www.eia.gov/electricity/data.cfm. Note that the petroleum-fired category in EIA includes distillate fuel oil, residual fuel oil, petroleum coke, jet fuel, kerosene and waste oil.
[42] Edison Electric Institute comments on proposed Toxics Rule, Appendix 1. August 2011.
[43] Edison Electric Institute comments on proposed Toxics Rule, Appendix 2. August 2011.
[44] Edison Electric Institute comments on proposed Toxics Rule, Appendix 1. August 2011.
[45] U.S. EPA. ICR Database: Part I – Boiler_Information. Companies were asked to report their average annual capacity factors and hours of operation for the past three years (2007-2009). In fact, the average capacity factor for oil-fired EGU may be even lower because the reported values would also reflect natural gas consumption.
[46] *Id.*
[47] *Id.*

in 2010.[48] In contrast, coal-fired generating units produced 1,835 terawatt hours of electricity in 2010—more than 100 times greater.[49]

E. Emissions Standards

1. Metals

NextEra Energy recommends that EPA re-evaluate the proposed Total HAP Metals standard for existing oil-fired EGUs. The current proposed standard was calculated based on seven units, most of which were burning distillate fuel oil during ICR testing. EPA lists only three power plants in the entire U.S. that rely on distillate fuel oil for the production of electricity; the vast majority of oil-fired EGUs combust heavier residual oil. As a result, NextEra Energy believes that EPA has proposed a standard that is not reflective of the subcategory and not reasonably achievable. Nine units with ESPs and five units that were combusting a combination of natural gas and oil during ICR testing report emission rates well above EPA's proposed standard. In contrast, more than 70 percent of coal-fired EGU in the ICR database meet EPA's proposed standard for Total PM.

Additionally, we request that EPA reconsider its decision not to propose a PM standard for liquid oil-fired EGUs. In light of the various data corrections outlined below, we recommend that EPA consider setting an optional PM limit for liquid oil-fired EGUs to control Total HAP metals. Figure 2 below shows that units equipped with ESPs—for PM control—generally have the lowest reported Total HAP Metals emission rates. This suggests that a PM limit would be a reasonable surrogate for Total HAP Metals for oil-fired EGU. Liquid oil-fired EGU would have the option of complying with a PM limit, a Total HAP Metals limit, or individual HAP Metal limits.

Errors and Missing Data in the ICR Database

NextEra Energy has identified several data errors and missing test results in the spreadsheet summarizing EPA's MACT floor analysis for oil-fired EGUs including, notably, incorrect fuel designations:

- EPA's spreadsheet entitled "floor_analysis_oil_031611.xlsx" lists Mitchell Power Station Units 001 and 003 as combusting "No.6 Fuel Oil (residual or bunker C)". This information is incorrect based a review of the facility's test reports contained in the docket. The Mitchell units burn distillate fuel oil.
- The test reports for the Suwannee River Power Plant indicate that Units 2 and 3 were combusting "Distillate Fuel Oil (Grades 1 and 2)" during ICR testing. However, based on a call to the plant operator, we have determined that both units were combusting residual fuel oil.
- Based on discussions with industry colleagues, we would also highlight that Middletown Unit 2 and Norwalk Power Unit 2 both have ESPs installed. EPA's spreadsheet (floor_analysis_oil_031611.xlsx) only lists the NOx controls installed at the units.
- Turkey Point 2 tested for Total HAP metals as part of the ICR; however, the unit does not appear in EPA's oil floor analysis spreadsheet.
- Emissions test reports from the Puerto Rico Electric Power Authority (8 units) were not included in the MACT floor analysis because of a late submission. We recommend that EPA include these additional data points in its MACT floor analysis.
- At least two units (Eagle Valley 1 and 2) in the MACT floor for Total HAP Metals do not appear to report cobalt emissions. As a result, their Total HAP Metal emission rates appear artificially low. Additionally, six units from the Puerto Rico Electric Power Authority did not appear to report cobalt emissions. While these units would not be included in floor calculations regardless, this omission

[48] U.S. EIA. Form EIA-906, EIA-920, and EIA-923 Data.
[49] *Id.*

identifies potentially inconsistencies in the metals testing and development of the proposed standards.

- Similarly, Harding Street 9 has a zero value for one Beryllium test run, which appears to be averaged in as zero rather than dropped or substituted with the detection limit value.
- Finally, in separate comments, NRG has submitted corrected HAP Metals emissions data for Norwalk Unit 2, Montville Unit 5, and Middletown Unit 2. The errors overstated the units' HAP Metals emission rates.

The corrected data, to the extent that we have been able to identify problems in the database, is summarized in Figure 2 below. The current proposed standard (0.000030 lbs/MMBtu), also shown in Figure 2 below, was calculated based on seven units, most of which were burning distillate fuel oil during ICR testing. Apart from the two Port Everglades units (owned and operated by Florida Power & Light), all of the units that established the MACT floor for Total HAP Metals were combusting distillate fuel oil. In some cases, these units were burning low sulfur distillate fuel oil. Eagle Valley, for example, specifies low sulfur (0.05%) distillate fuel oil and most shipments received by the facility contain less than 0.03% sulfur. Also, the ESPs at the Port Everglades facility were recently installed (construction was completed in 2006). However, nine units with ESPs and five units that were combusting as much as 75 percent natural gas during ICR testing report emission rates above EPA's proposed standard (units known to be combusting natural gas during the ICR testing are shown in green in the figures below).

NextEra Energy recommends that EPA post a revised spreadsheet on the utility Toxics Rule website, reflecting the corrections above and any further corrections identified by other commenters.

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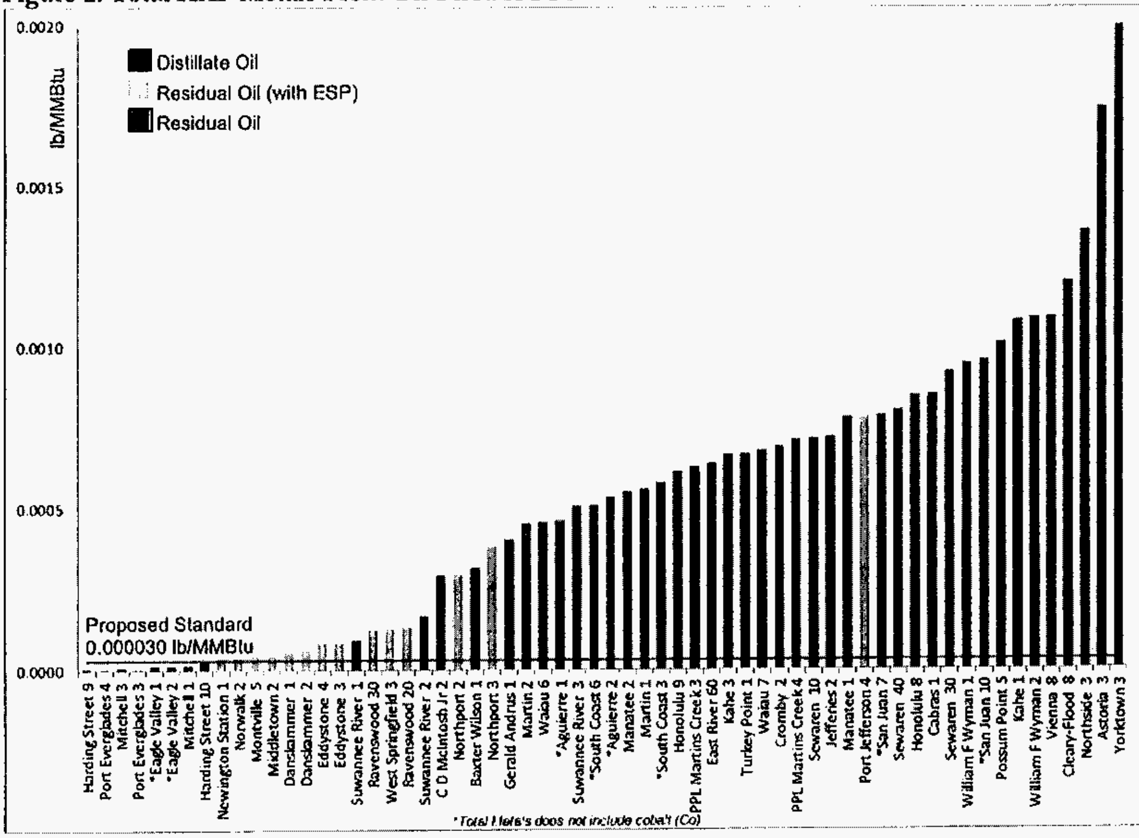
Figure 2. Total HAP Metals From Oil-Fired EGUs



Reevaluating the Proposed Standard

As discussed above, NextEra Energy recommends that EPA re-evaluate its decision to include distillate oil-fired EGUs in the final Toxics Rule. After re-evaluating the risk assessment, if EPA confirms that it is "appropriate and necessary" to regulate distillate oil-fired EGUs under Section 112, NextEra Energy recommends that EPA recalculate the Total HAP Metals standard for oil-fired generating units based on *all existing oil-fired EGUs*, not simply the sources for which the Administrator has information (i.e., with the MACT floor calculated as the average of 12 percent of 154 units, or 19 units). This is consistent with the approach that EPA used in calculating the HCl and Total PM standards for coal-fired EGUs. We recommend this approach based on the fact that the ICR dataset is biased toward very low-emitting units, burning a distinctly different fuel type (distillate fuel oil). If EPA concludes that this is not a viable option, we recommend, at a minimum, that EPA subcategorize between residual- and distillate-oil fired EGU. Each of these recommendations is discussed in turn below.

As shown in Figure 2, the ICR data upon which the proposed limit is based includes six units burning distillate oil, all but one of which set the MACT floor. As a result, despite the disproportionate reliance on residual oil among the sector as a whole, five distillate oil-fired EGU were included in the calculation of the MACT floor for Total HAP Metals. This includes one or multiple units from *all* distillate oil-fired EGU in the U.S. Therefore, despite EPA's intention of selecting a random sample of units, in fact the ICR database is biased toward very low-emitting units, burning distillate fuel oil. Distillate oil-fired EGU represent more than 70 percent of the units in the MACT floor used to calculate the proposed standard. In contrast, nationwide, distillate oil-fired EGUs represent less than five percent of oil-fired EGUs within the liquid oil subcategory. This results in a standard that is contrary to the statute, which directs the Administrator to establish standards that she "determines [are] achievable for new or existing sources in the category or subcategory to which such emission standard applies." In fact, nine units with ESPs and five units that were combusting a combination of natural gas and oil during ICR testing report emission rates above EPA's proposed standard for Total HAP Metals. Taken together with the fact that one distillate unit, Harding Street 10, tested essentially at the standard without a compliance margin, there is no clear path to compliance with the standard as proposed.

Another option that we ask EPA to consider would be to subcategorize between residual and distillate oil-fired EGU. Residual and distillate oils are distinctly different fuels with different physical characteristics, heat content, and emissions profiles. Most of the fuel oil used in the electric power sector is residual fuel oil—a general classification for the heavier oils, including Grades No. 5 and No. 6, that remain after the distillate fuel oils and lighter hydrocarbons are distilled in the refining process. The lighter distillate fuel oils (No. 1 and No. 2) are characterized by lower viscosities and lower pour points. These grades of oil are used in most domestic burners and in many medium capacity commercial-industrial burners where ease of handling and ready availability justifies the higher fuel costs.

The formal classification of fuel oil grades is specified in ASTM Standard D396 - 10 (Standard Specification for Fuel Oils), providing a clear basis for subcategorizing the two fuel types. According to the standard, Grades No. 4 to No. 6 are generally residual fuels of increasing viscosity (resistance to flow) and boiling range. ASTM Standard D396 – 10 lists the viscosity of residual No. 5 and No. 6 fuel oils in the range of 5.0 to 50.0 square millimeters per second (mm^2/s) at 100°C. In contrast, ASTM Standard D396 – 10 lists the viscosity of distillate No. 1 and No. 2 fuel oils in the range of 1.3 to 4.1 mm^2/s at 40°C. We would also emphasize that the handling and use of residual and distillate fuel oils requires a different set of equipment and technologies. Residual fuel oils must be stored, shipped, and transferred in heated tanks, vessels, and heat traced piping. Further, in order to burn residual fuel oil, it is necessary to break the fuel into small droplets using steam atomization (200 psi steam) or high pressure mechanical atomization (1,000 psi).

Switching from a steam-electric boiler currently designed and operated to burn residual fuel oil to a unit capable of burning distillate oil may also require the following modifications:

Oil Secondary Containment:
- Double-wall tank bottoms
- Double pipe fuel transfer/supply lines outside containment areas

Fuel Pumping System:
- New oil transfer/supply pumps. Screw pumps are typically used for transferring and supplying Fuel Oil #6 to the boiler. Due to the low viscosity of light oil, new pumps (e.g., centrifugal or gear pumps) would be required at the tank farm and power block.

Oil Atomization:
- New oil atomizer assemblies. Heavy oil atomizers are too big for firing light oil with much lower viscosity.

Tanks & Storage:
- Review of tank venting & lightning protection systems to handle lighter hydrocarbon products present in light oil.

Boiler Performance:

- Shift heat absorption profile by pushing more heat toward the upper furnace and backend due to changes in flame emissivity of light oil, resulting in higher attemperation (spray) demand. Shifting of the boiler heat distribution may also require boiler surface area upgrades (e.g., superheat and reheat tube metals and possible larger economizer tube banks) in order to maintain current unit generation output.
- Change flame detection system (e.g., new flame scanner) with greater infrared range to safety pick up brighter flames expected with light oil firing. Current flame scanners have wider ultraviolet range to accommodate darker heavy oil flames and purely UV natural gas flames.
- Increase in thermal NOx (due to hotter flames), which may upset the expected reduction in fuel NOx (due to lower fuel Nitrogen when firing light oil), resulting in an increase of flue gas recirculation demand and/or higher total NOx emission.
- Re-tune boiler controls to account for new fuel, air, FW, drum level, spray and emission characterizations expected with light oil firing.

EPA lists 147 EGU boilers in the ICR database (Part I) that rely on residual fuel oil. EPA lists only seven EGU boilers that rely on distillate fuel oil: Harding Street (9 and 10), Eagle Valley (1 and 2), and Mitchell Generating Station (1, 2, and 3). Three of these units (Mitchell Generating Station Units 1-3) are listed for retirement in 2013. Eagle Valley Units 1 and 2 are listed for retirement in 2017. Other EGU boilers will burn limited quantities of distillate fuel oil for boiler light-off or other purposes, with fuel handling equipment separate from the residual oil equipment, while using another fuel, like natural gas, for the production of electricity.

Given the differences between residual and distillate fuel oils, we recommend that EPA consider subcategorizing between residual- and distillate-oil fired EGUs based on the ASTM specifications or the relative viscosities of the fuels—after considering the other options discussed above. Under this option, given that the total universe of distillate oil-fired EGU would include less than 30 units, the Clean Air Act directs EPA to calculate the MACT floor based on a minimum of five units.

2. <u>Acid Gases</u>

Requiring oil-fired units to install controls for acid gases would incur substantial unnecessary cost without a demonstrable environmental benefit based on the risk comparisons addressed previously in Section III. (B) 3 of these comments. This supports NextEra Energy's position that EPA should re-evaluate its risk assessment and decision to regulate acid gas emissions from oil-fired EGUs.

While there appears to be little published data regarding inherent chloride concentrations in fuel oils, one study[50] did look at the relationship between sulfur and chloride concentrations in fuel oils, and found that, in residual oils (No. 6), the most common oil used for electricity generation, low-sulfur residual oil correlated to slightly lower chloride concentrations. In this study, chloride concentrations in low-sulfur residual oil were equivalent to those in distillate oil (0.03 percent by weight). In contrast, higher-sulfur oil contained an average of 0.05 percent chlorides by weight. Additionally, chlorides may be introduced to the fuel oil during ballasting of tanker ships with seawater[51] or during processing via the presence of chloride ions in fluidized catalytic cracker catalysts.[52] Thus, because no oil-fired units are intentionally controlling for HCl or other acid gases, HCl emissions seem dependent on both inherent Cl, which may be correlated with sulfur content, as well as on handling practices.

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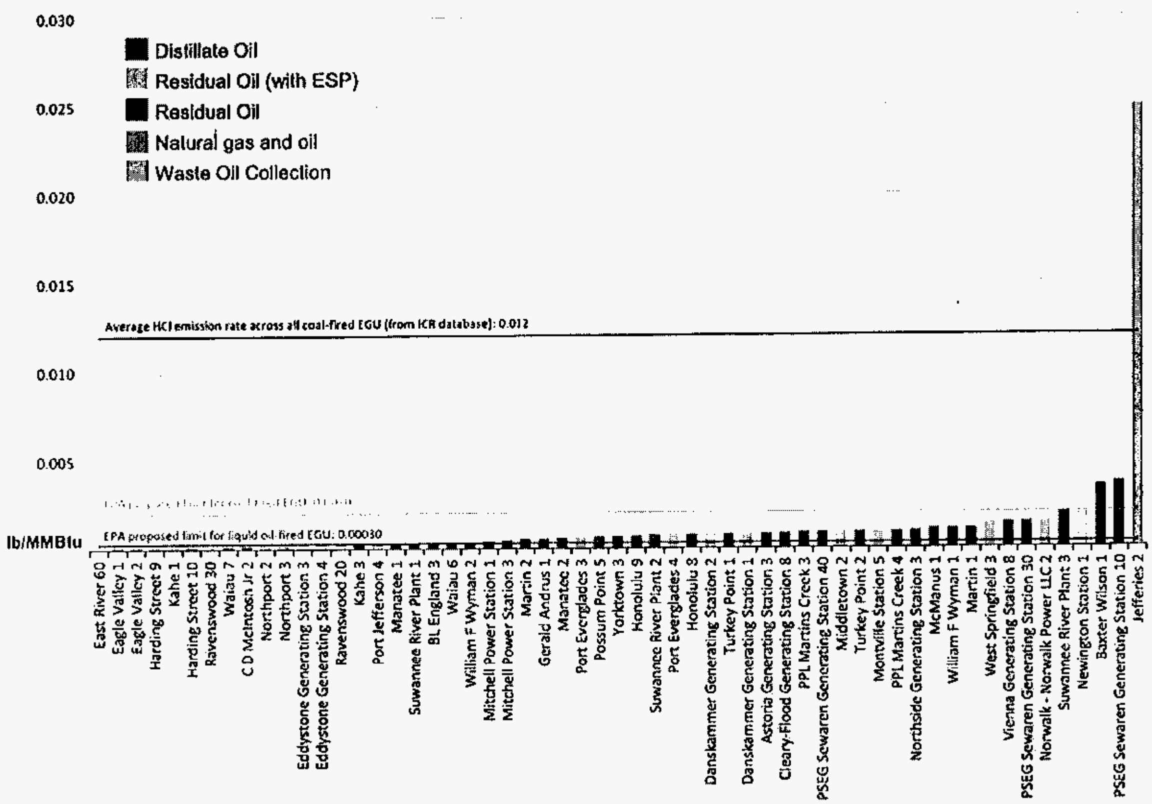
[50] Miller, C. A, J.V. Ryan and T. Lombardo. 1996. *Characterization of air toxics from an oil-fired firetube boiler.* JAWMA 46:742-748.
[51] Sloss, L. 1992. *Halogen emissions from coal combustion.* IEACR/45, IEA Coal Research, London, UK. 62 pp.
[52] Kitto, M.E., D.L. Anderson, G.E. Gordon and I. Olmez. 1992. *Rare earth distributions in catalysts and airborne particles.* Env. Sci. Tech 26:1368-1375.

The EGU MACT rule proposes emissions limits for HCl and HF for liquid oil-fired EGU. The standards for HCl and HF are proposed at 0.00030 lb/MMBtu and 0.00020 lb/MMBtu, respectively. The proposed standards for HCl and HF were calculated based on seven units.[53]

Figure 3 summarizes the HCl emissions data reported under the ICR. With the exception of Jefferies 2, which was burning waste oil during the ICR testing, all of the liquid oil-fired EGU report low concentrations of HCl emissions. (EPA's proposed standard for existing coal-fired EGU and the average HCl emission rate reported by coal-fired EGU are provided for context.) Unlike the Total HAP Metals, there is no clear pattern in terms of the units meeting the proposed standard. There are units with ESPs, units combusting residual fuel oil, units combusting distillate fuel oil, and units co-firing natural gas both above-and-below the proposed limit for HCl. Also, we would emphasize that there are no installed or demonstrated control technologies for limiting HCl and HF emissions from liquid oil-fired EGU, as there are for the other HAPs regulated under the proposed rule.

Figure 3. HCl from Oil-Fired EGUs



As further context, we calculated the potential annual emissions of HCl from the oil-fired EGUs that

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[53] The HCl standard was calculated based on East River 60, Eagle Valley 1 and 2 (distillate oil), Harding Street 9 and 10 (distillate oil), Kahe 1, and Waiau 7. The HF standard was calculated based on East River 60, Suwanee River 1 (distillate oil), CD McIntosh 2, BL England 3, Manatee 01, Northside 3, and Suwanee River 2 (distillate oil).

participated in the ICR. Virtually all units were found to emit HCl at levels below the major source threshold. Table 3 illustrates that the vast majority of the oil-fired boilers that participated in the ICR testing would emit HCl at levels well below the major source threshold of 10 tons per year for any individual HAP—particularly, when we assume low to intermediate utilization rates common among residual oil-fired boilers.

Table 3. Theoretical HCl Emissions Assuming Maximum Heat Input and a Range of Utilization Rates

Plant and Unit	Maximum heat input (mmBtu per hour)	Emissions (tons per year) assuming a range of utilization rates			
		100%	75%	50%	25%
East River 60	1,930	0.1	0.1	0.0	0.0
Eagle Valley 1	524	0.2	0.2	0.1	0.1
Eagle Valley 2	524	0.2	0.2	0.1	0.1
Harding Street 09	527	0.2	0.2	0.1	0.1
Kahe K1	903	0.4	0.3	0.2	0.1
Harding Street 10	527	0.3	0.2	0.1	0.1
Ravenswood 30	9,702	5.9	4.4	2.9	1.5
Waiau W7	922	0.6	0.4	0.3	0.1
C D Mcintosh Jr Unit 2	1,185	0.8	0.6	0.4	0.2
Northport Unit2	3,650	3.0	2.3	1.5	0.8
Northport Unit3	3,650	3.5	2.6	1.7	0.9
Eddystone Generating Station Unit 3	4,546	4.5	3.4	2.3	1.1
Eddystone Generating Station Unit 4	4,546	4.5	3.4	2.3	1.1
Ravenswood 20	3,357	3.5	2.6	1.7	0.9
Kahe K3	892	0.9	0.7	0.5	0.2
Port Jefferson Unit4	1,850	2.0	1.5	1.0	0.5
Manatee PMT01	8,650	10.2	7.7	5.1	2.6
Suwannee River Plant Suw_Cfg_1	315	0.4	0.3	0.2	0.1
BL England 3	1,720	2.5	1.9	1.2	0.6
Waiau W6	637	0.9	0.7	0.5	0.2
William F Wyman 2	630	1.0	0.8	0.5	0.3
Mitchell Power Station 001	600	1.1	0.8	0.5	0.3
Mitchell Power Station 003	600	1.2	0.9	0.6	0.3
Martin PMR02	9,040	22.1	16.6	11.1	5.5
Gerald Andrus 001	6,650	16.4	12.3	8.2	4.1
Manatee PMT02	8,650	21.7	16.3	10.8	5.4
Port Everglades PPE03	4,000	10.6	8.0	5.3	2.7
Possum Point Unit 5	8,471	24.5	18.3	12.2	6.1
Yorktown Unit 3	8,883	26.2	19.6	13.1	6.5
Honolulu H9	632	1.9	1.4	1.0	0.5
Suwannee River Plant Suw_Cfg_2	353	1.1	0.9	0.6	0.3
Port Everglades PPE04	4,000	12.9	9.7	6.5	3.2
Honolulu H8	589	2.0	1.5	1.0	0.5
Danskammer Generating Station 2	650	2.3	1.7	1.1	0.6
Turkey Point PTF01	4,000	14.4	10.8	7.2	3.6
Danskammer Generating Station 1	650	2.3	1.8	1.2	0.6
Astoria Generating Station A-50003	4,074	14.7	11.1	7.4	3.7
Cleary-Flood Generating Station 8	335	1.2	0.9	0.6	0.3
PPL Martins Creek U3	7,721	29.7	22.2	14.8	7.4
PSEG Sewaren Generating Station SEWU4E4PT4OS0	1,700	6.7	5.0	3.3	1.7
Middletown 2	1,173	4.7	3.5	2.3	1.2
Turkey Point PTF02	4,000	16.1	12.0	8.0	4.0
Montville Station 5	995	4.1	3.1	2.0	1.0
PPL Martins Creek U4	7,721	31.8	23.9	15.9	8.0
Northside Generating Station 3	4,857	20.6	15.4	10.3	5.1
McManus Unit 1	450	2.1	1.6	1.1	0.5
William F Wyman 1	630	3.0	2.2	1.5	0.7
Martin PMR01	9,040	44.3	33.3	22.2	11.1
West Springfield Unit 3	1,150	7.0	5.2	3.5	1.7
Vienna Generating Station Unit 8	2,317	14.4	10.8	7.2	3.6
PSEG Sewaren Generating Station SEWU3E3PT3OS0	1,600	10.1	7.6	5.1	2.5
Norwalk - Norwalk Power LLC 2	1,776	11.3	8.4	5.6	2.8
Suwannee River Plant Suw_Cfg_3	761	6.8	5.1	3.4	1.7
Newington Station nt1	4,350	44.4	33.3	22.2	11.1
Baxter Wilson 001	4,900	75.6	56.7	37.8	18.9
PSEG Sewaren Generating Station SEWU1E1PT1OS0	1,550	25.1	18.8	12.6	6.3

Notes:

1. Maximum heat input values and HCl emission rates are based on EPA's ICR database.
2. Values marked in green are greater than or equal to 10 tons per year. Values marked in yellow are less than 10 tons per year.

In reviewing the available literature and the ICR database, we found that chloride and fluoride concentrations in oil can vary widely. An Electric Power Research Institute analysis reported chloride values in No. 6 fuel oil ranging from 130 ppm to 715 ppm.[51] The units included in the MACT floor calculation for HCl reported significantly lower average chloride concentrations (see Table 4 below) during the test period, suggesting that the emission rates at these units could be higher with a different shipment of fuel. Baxter Wilson, for example, one of the higher emitting units in the ICR database reports chloride concentrations in fuel ranging from 62 to 239 ppm. Most of the fluoride values (from fuel testing) reported in the ICR database are below the detection level. The wide variability in the chloride concentrations in fuel oil (combined with the lack of control technologies for limiting HCl emissions) suggests that EPA's variability adjustment may not result in a standard that would be achievable by the units that were included in the calculation of the MACT floor for liquid oil-fired EGUs.

Table 4. Chloride Concentrations in Fuel Oil from ICR Testing

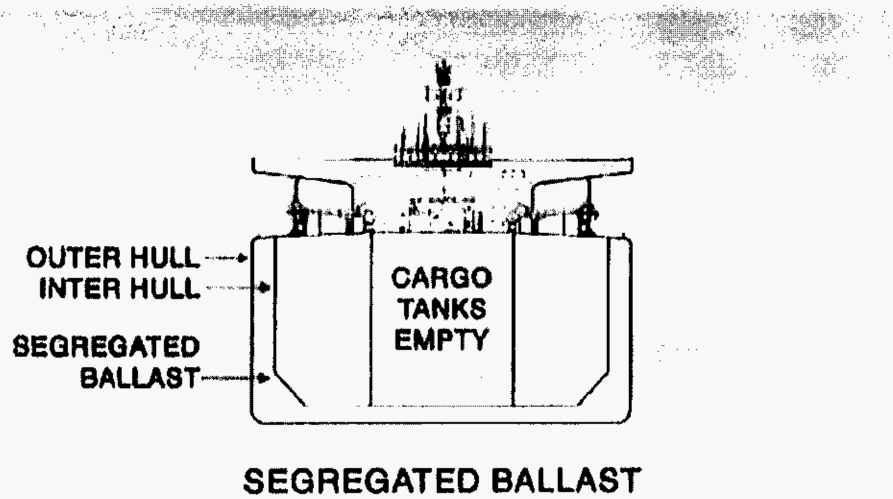
Unit	Chloride Dry
East River 60	20 ppm
Eagle Valley 1	<7.5 ppm
Eagle Valley 2	<7.5 ppm
Harding Street 9	37-38 ppm
Harding Street 10	37-38 ppm
Kahe 1	Below detection limit (less than 100 ppm)
Waiau 7	Below detection limit (less than 100 ppm)

Source: ICR Test Reports

Studies suggest that chloride in fuel oil can result from contamination during transportation and processing of crude oils.[55] For example, chloride contamination of crude oils can occur as a result of the ballasting of tanker ships with seawater.[56] Oil tankers load sea water (as ballast) for weight stabilization after a tanker has discharged its cargo. The ballast is required for safety reasons when the tanker is at sea. In older, single hull designs sea water is loaded into the same cargo tanks that store the oil, resulting in sea water contamination when the cargo tank is reloaded. However, the Oil Pollution Act of 1990 requires all new oil tankers to be double hulled (see Figure 4) and establishes a phase out schedule for existing single-hulled tankers with unsegregated ballasts. Ballast water contained in segregated ballast tanks never comes into contact with the cargo oil. Single hulled tankers are scheduled to be phased out by the middle of the decade, reducing the potential for sea water contamination. Because of the role of sea water contamination in introducing contaminants into the oil, NextEra Energy suggests that EPA set a percent water content limit for fuel oil at a level of 1.0 percent, rather than setting HCl and HF emissions limits. This would encourage handling and transport practices to limit salt water contamination. We recommend a standard of 1.0 percent water because several of the lowest HCl and HF emitting units currently require percent water (or water and sediment) specifications between 0.5 percent and 1.0 percent.

[51] Maryland Power Plant Research Program. Hydrogen Chloride (HCl) Emissions from Maryland Utility Boilers. June 1999..
[55] Ibid.
[56] Ibid.

Figure 4. Double Hulled Oil Tanker with Segregated Ballast



Source: Pacific L. A. Marine Terminal LLC

F. Compliance Requirements

1. Testing Requirements

Alternative Fuel Analysis Provisions

On Page 57 of 173 in the Federal Register version of the proposed Toxics Rule (Page 25031) it states "(6) For limited-use liquid oil combustion units, we are proposing that those units be allowed to demonstrate compliance with the Hg emission limit, the HAP metals, or the HCl and HF emissions limits separately or in combination based on fuel analysis rather than performance stack testing, upon request by you and approval by the Administrator. Such a request would require the owner/operator to follow the requirements in 40 CFR 63.8(f), which presents the procedure for submitting a request to the Administrator to use alternative monitoring, and, among other things, explain why a unit should be considered for eligibility, including, but not limited to, use over the previous 5 years and projected use over the next 5 years. Approval from the Administrator would be required before use of this alternative monitoring procedure."

This seems to imply that this provision applies only to limited use oil units and not other affected oil units. But reading the provisions of the rule itself it appears that owners/operators of *all* affected liquid oil-fired units may perform fuel analyses to demonstrate initial and continuous compliance with applicable emission limitations, as an alternative to performance stack testing.

NextEra Energy requests that the Agency clarify that the alternative to use fuel testing to demonstrate initial and continuous compliance applies to *all* affected liquid oil-fired EGUs, as opposed to just limited use units.

Continuous Compliance Demonstration Requirements

§63.10006(f) of the proposed rule states, "For liquid oil-fired EGUs with non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and §63.10007 at least every other month." §63.10006(g) states, "For liquid oil-fired EGUs without non-Hg HAP metals control devices, you must conduct all applicable performance tests for individual or total HAP metals emissions according to Table 5 and §63.10007 at least every month."

NextEra Energy does not believe that it is practical or necessary to require performance stack testing of affected oil-fired EGU emissions on a monthly or every other month basis. In NextEra Energy's view, testing of this nature and frequency would be unnecessarily restrictive and expensive to perform. Moreover, this would require units to be brought on line in many cases just for the sake of performing stack tests. This would result in an increase in emissions and be environmentally detrimental.

NextEra Energy has evaluated the potential cost of performing *monthly* stack tests for total metals, including mercury (EPA Method 29) and HCL and HF (EPA Method 26) at its affected oil-fired EGUs. Assuming two days of testing at each site (4 sites), the estimated total cost of performing the requisite stack testing is $120,000 per month. This cost, however, is dwarfed by the estimated *$215 million in incremental annual fuel costs* that would be incurred by NextEra Energy to schedule and perform monthly stack testing at the companies affected oil-fired EGUs.

Accordingly, we believe that affected liquid oil-fired EGUs should not be required to perform stack performance testing to demonstrate continuous compliance with emission limits any more frequently than on an *annual* basis.

§63.10006 (s) requires that "If you demonstrate compliance with the Hg, individual or total non-Hg HAP metals, HCl, or HF emissions limit based on fuel analysis, you must conduct a *monthly* fuel analysis according to §63.10008 for each type of fuel burned. Again, NextEra Energy believes that requiring liquid oil-fired units demonstrating compliance through fuel analysis to perform monthly analysis is unnecessarily burdensome, costly and impractical. Requiring fuel analysis to be performed *on each shipment of oil received* should be adequate to demonstrate compliance.

As discussed above, NextEra Energy recommends that EPA set a percent water content limit for oil, rather than setting HCl and HF emissions limits for liquid oil-fired EGU. ASTM test methods are available for measuring the percent water content of fuel oil (D95 and D473). Plant operators would test each shipment received to ensure compliance with the proposed limit.

2. Operating Limits

As discussed in the section above on the compliance requirements for coal-fired EGU, NextEra Energy has several concerns with the proposed parameter operating limits being applied to oil-fired units and recommends an alternative approach that we think will better ensure proper operation of pollution control systems. Rather than establishing fixed operating limits, we recommend that EPA require proper operation of the plant's pollution control equipment and appropriate parametric monitoring without establishing numeric operating limits. Also, units with appropriate CAM plans and units operating CEMs should not be required to have additional monitoring requirements.

IV. SUMMARY

The Toxics Rule provides the business certainty the electric sector needs to move forward with capital investment decisions, and NextEra Energy supports finalizing the rule as required by consent decree in November 2011. We believe the proposed rule is reasonable, consistent with the requirements of the Clean Air Act, and that the electric sector is well-positioned to comply. Moreover, where individual circumstances warrant, Section 112 of the Clean Air Act provides additional flexibility to accommodate situations where additional time may be necessary to install controls.

While NextEra Energy supports the proposed rule in general, we believe that certain revisions should be incorporated into the final rule in order minimize the compliance burden on regulated entities while fulfilling

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the requirements of Section 112 of the Clean Air Act. NextEra Energy's primary recommendations in this regard include, but are not limited to, the following:

- EPA should re-evaluate the risk assessment it undertook on the carcinogenicity of nickel emissions from oil-fired EGUs to reflect the latest scientific knowledge and understanding
- NextEra Energy strongly recommends that EPA establish a "limited use" subcategory for oil-fired units, similar to what the Agency adopted in the ICI Boiler MACT Rule.
- EPA should re-evaluate its decision to include *distillate* oil-fired EGUs in the Toxics Rule. At a minimum, EPA should establish a separate subcategory for liquid oil-fired units burning distillate fuel oil (as opposed to residual fuel oil).
- EPA should re-evaluate the appropriateness of establishing numerical emission limits governing acid gas emissions from oil-fired EGUs and consider, instead, adopting a work practice standard in the form of a 1.0 percent water content specification.
- As opposed to the monthly/bi-monthly stack testing requirements contained in the proposed Toxics Rule, liquid oil-fired EGUs should not be required to perform stack performance testing to demonstrate continuous compliance with emission limits any more frequently than on an *annual* basis.
- As opposed to the monthly fuel analysis requirements contained in the proposed rule, EPA should require fuel analysis to be performed *on each shipment of oil received* in order to demonstrate continuous compliance with applicable numerical emission limits

NextEra Energy looks forward to working with EPA on refining and implementing this important rulemaking. If you have any questions, please do not hesitate to contact me at (561) 691-7001 or Ray Butts of my staff at (561) 691-7040.

Sincerely,

Randall R. LaBauve
Vice-President, Environmental Services

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Decided December 23, 2008

No. 05-1244

STATE OF NORTH CAROLINA,
PETITIONER

v.

ENVIRONMENTAL PROTECTION AGENCY,
RESPONDENT

UTILITY AIR REGULATORY GROUP, ET AL.,
INTERVENORS

Consolidated with
05-1246, 05-1249, 05-1250, 05-1251, 05-1252, 05-1253,
05-1254, 05-1256, 05-1259, 05-1260, 05-1262, 06-1217,
06-1222, 06-1224, 06-1226, 06-1227, 06-1228, 06-1229,
06-1230, 06-1232, 06-1233, 06-1235, 06-1236, 06-1237,
06-1238, 06-1240, 06-1241, 06-1242, 06-1243, 06-1245,
07-1115

On Petitions for Rehearing

Before: SENTELLE, *Chief Judge*, and ROGERS and BROWN, *Circuit Judges*.

Opinion for the Court filed PER CURIAM.

Opinion concurring in part filed by *Circuit Judge* ROGERS.

PER CURIAM: In these consolidated cases, we considered petitions for review challenging various aspects of the Clean Air Interstate Rule ("CAIR"). On July 11, 2008, we issued an opinion, in which we found "more than several fatal flaws in the rule." *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C. Cir. 2008) (per curiam). In light of the fact that the Environmental Protection Agency ("EPA") adopted CAIR as an integral action, we vacated the rule in its entirety and remanded to EPA to promulgate a rule consistent with our opinion. *Id.* at 929-30.

On September 24, 2008, Respondent EPA filed a petition for rehearing or, in the alternative, for a remand of the case without vacatur. On October 21, 2008, we issued an order on our own motion directing the parties to file a response to EPA's petition. (Order at 1, Oct. 21, 2008.) We also required the parties to "address (1) whether any party is seeking vacatur of the Clean Air Interstate Rule, and (2) whether the court should stay its mandate until Respondent [EPA] promulgates a revised rule." *Id.* Respondent EPA was given leave to "reply to the question whether a stay of the court's mandate in lieu of immediate vacatur would suffice." *Id.*

Having considered the parties' respective positions with respect to the remedy in this case, the court hereby grants EPA's petition only to the extent that we will remand the case without vacatur for EPA to conduct further proceedings consistent with our prior opinion. This method of disposition is consistent with this court's precedent. *See Natural Res. Def. Council v. EPA*, 489 F.3d 1250, 1262 (D.C. Cir. 2007) (noting this court's prior practice of remanding without vacatur). This court has further noted that it is appropriate to remand without vacatur in particular occasions where vacatur "would at least temporarily defeat . . . the enhanced protection of the environmental values covered by [the EPA rule at issue]." *Envtl. Def. Fund, Inc. v. Adm'r of the United States EPA*, 898 F.2d 183, 190 (D.C. Cir. 1990). Here, we are convinced that, notwithstanding the relative flaws of CAIR, allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values covered by CAIR. Accordingly, a remand without vacatur is appropriate in this case.

In addition, some of the Petitioners have suggested that this court impose a definitive deadline by which EPA must correct CAIR's flaws. Notwithstanding these requests, the court will refrain from doing so. Though we do not impose a particular schedule by which EPA must alter CAIR, we remind EPA that we do not intend to grant an indefinite stay of the effectiveness of this court's decision. Our opinion revealed CAIR's fundamental flaws, which EPA must still remedy. Further, we remind the Petitioners that they may bring a mandamus petition to this court in the event that EPA fails to modify CAIR in a manner consistent with our July 11, 2008 opinion. *See Natural Res. Def. Council*, 489 F.3d at 1264 (Randolph, J., concurring).

We therefore remand these cases to EPA without vacatur of CAIR so that EPA may remedy CAIR's flaws in accordance with our July 11, 2008 opinion in this case.

ROGERS, *Circuit Judge*, concurring in granting rehearing in part: In deciding on rehearing to remand without vacating the final rule, the court has adhered to its traditional position where vacating would have serious adverse implications for public health and the environment. *NRDC v. EPA*, 489 F.3d 1250, 1264 (D.C. Cir. 2007) (Rogers, J., concurring in part and dissenting in part); *see, e.g., Envtl. Def. Fund, Inc. v. Adm'r of the United States EPA*, 898 F.2d 183, 190 (D.C. Cir. 1990). When the court has ordered vacatur despite potential adverse implications for public health and the environment, it has usually provided an explanation, *see NRDC*, 489 F.3d at 1265, and we did so here, *North Carolina v. EPA*, 531 F.3d 896, 929-30 (D.C. Cir. 2008). We explained that vacatur was appropriate because of the depth of CAIR's flaws, the integral nature of the rule, and because other statutory and regulatory measures would mitigate the disruption caused by vacating the rule. *Id.* However, on rehearing, EPA, petitioners, and amici states point to serious implications that our previous remedy analysis, including our consideration of mitigation measures, did not adequately take into account. The parties' persuasive demonstration, extending beyond short-term health benefits to impacts on planning by states and industry with respect to interference with the states' ability to meet deadlines for attaining national ambient air quality standards for PM2.5 and 8-hour ozone, shows that the rule has become so intertwined with the regulatory scheme that its vacatur would sacrifice clear benefits to public health and the environment while EPA fixes the rule.

Environmental Services, 700 Universe Blvd, Juno Beach, FL 33455
Ph: 561-691-7040

FPL GROUP

Submitted to: a-and-r Docket@epa.gov

November 28, 2008

Joe Dougherty
Air and Radiation Docket and Information Center
Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Docket ID No. EPA-HQ-OAR-2008-0318

Re: Advance Notice of Proposed Rulemaking on Regulating Greenhouse Gas Emissions under the Clean Air Act

Dear Mr. Dougherty,

FPL Group appreciates the opportunity to comment on EPA's Advance Notice of Proposed Rulemaking (ANPR) relating to regulating greenhouse gas emissions under the Clean Air Act (CAA). FPL Group is a member of and endorses the comments filed in this docket by the Clean Energy Group (CEG), the Class of 85 Regulatory Response Group, and the Edison Electric Institute.

FPL Group

FPL Group, is nationally known as a high quality, efficient, and customer-driven organization focused on energy-related products and services. With a growing presence in 27 states, it is widely recognized as one of the country's premier power companies. Its rate-regulated subsidiary, Florida Power & Light Company, serves approximately 4.5 million customer accounts in Florida. FPL Energy, LLC, an FPL Group competitive energy subsidiary is the nation's No. 1 producer of wind energy, with 58 projects in 16 states capable of producing more than 5,800 megawatts of emissions-free electricity. FPL Energy is also the nation's No. 1 producer of solar energy. We operate the largest solar-thermal plant in the world in California's Mojave Desert, the 310-megawatt Solar Electric Generating System. FPL Group has one of the lowest emissions profiles of any power company in the nation. More than 50 percent of our electricity comes from natural gas, more than a quarter from nuclear, and 7 percent from wind. Just 5 percent comes from coal, compared with an average of 50 percent nationwide. Additional information is available on the Internet at www.FPLGroup.com, www.FPL.com and www.FPLEnergy.com.

FPL Group recommends comprehensive federal legislation over Clean Air Act regulation

FPL Group has long supported the passage of comprehensive legislation that would establish a national policy for the orderly reduction of GHG emissions in the U.S. As participants in the U.S. Climate Action Partnership, the Clinton Global Climate Initiative and the World Wildlife Fund's PowerSwitch Program we have consistently called for Congress to quickly implement legislation that would begin the reduction of GHG emissions in the U.S. This reduction should be achieved through an economy-wide emissions reduction program that prices carbon in the economy in a manner that effectively reduces emissions without harming the U.S. economy. In addition to a price for carbon, GHG emissions reduction legislation should include a safety valve or cost containment mechanism that will protect the economy from dramatic increases in GHG allowance cost. The legislation should include options for the use of offsets, banking and borrowing of allowances to allow companies the opportunity to weigh the timely use of allowances against the future development of carbon reduction technologies. FPL Group also supports the development of federal and state programs to promote energy efficiency projects, research, development and deployment of renewable generation, nuclear generation and carbon capture/sequestration projects. The effective reduction of GHG emissions in the U.S. will require numerous technological, economic and policy related tools to reach the desired reductions of GHG emissions.

FPL Group does not believe that the regulation of GHGs under the current CAA provides the authority for EPA to implement all of the necessary strategies described above. Thus, FPL Group does not support unilateral action by EPA to regulate GHG emissions under the CAA. We suggest that EPA should instead continue to work with Congress to pursue comprehensive GHG reduction legislation. Several Federal agencies that have weighed-in on the ANPR have taken this same position and highlighted the futility in trying to regulate greenhouse gases through the existing Clean Air Act. Even EPA's Administrator, Stephan Johnson notes in the ANPR that the CAA is not the most effective tool for regulating greenhouse gas emissions.

The Clean Air Act does not authorize EPA to collect carbon fees or implement an auction

The current form of the CAA fails to provide EPA with ample opportunity to establish efficient methods to price carbon in the economy. FPL Group believes that greenhouse gas emissions will best be controlled under a national policy developed through comprehensive Congressional legislation. Reducing greenhouse gas emissions effectively will require changing behaviors by pricing carbon throughout the economy. The most efficient and transparent mechanism for implementing this cost for carbon is through a carbon fee, applied either at the emissions source or upstream in the economy. Increasingly, policy makers and world renowned economists such as, Al Gore, Alan Greenspan, and William Nordhaus have expressed support for a carbon fee as the best method to price carbon in the economy. A carbon fee that is properly recycled into the economy provides several benefits over a traditional cap and trade based allowance allocation method, including:

- Assignment of a predictable price on carbon economy-wide
- Provision for a progressive and measured implementation over time
- Easy and much less expensive administration
- Clear cost transparency to all parties
- Avoidance of cap & trade pitfalls, such as market manipulation, windfall profits, price volatility and regressive impacts on low income consumers
- Incentives for the capture and reduction of emissions, the development of cleaner generation, including nuclear and renewables and creates a price signal encouraging energy conservation
- Certainty for long term investments and economic benefit for early action
- Options for funding R&D for lower carbon technologies and the protection of internationally competing industries and recycles the bulk of revenue back to consumers
- Easily allows border adjustment – tariffs on imports, credits on exports

The current form of the CAA does not offer EPA the authority to implement a carbon fee or to redistribute revenues from the fee back into the economy.

In the ANPR EPA indicates that the CAA may offer the option for implementing a cap and trade program for GHG allowances. If a cap and trade program were implemented in lieu of a carbon fee approach FPL Group supports a 100% auction of allowances where the proceeds from the auction are recycled back into the economy through the development of energy efficiency projects, deployment of additional renewable technologies or offsets of detrimental impacts associated with GHG regulation affecting low income families or business. Auctions provide a pay as you go option for pricing carbon into the economy. An auction based allowance distribution system, similar to the auction program currently being implemented by the states participating in the Regional Greenhouse Gas Initiative (RGGI), does not create winners and losers, or result in windfall profits such as those seen in historical forms of cap and trade programs that include free allowance allocations. An auction-based allocation program would incentivize companies to reduce emissions or utilize lower carbon emissions technologies. As an example, in the first quarterly RGGI auction, held in September, 2008, over $38 million worth of allowances were auctioned. These auction revenues will result in significant quarterly funding to the participating states for use in the development of clean, alternative energy programs, energy efficiency programs or assistance to low income families and businesses affected by the regulations. A similar auction format applied nationally could assist in the deployment of new technologies, energy efficiency programs, renewable energy and fund the development of carbon capture and sequestration technology to reduce GHG emissions.

The current CAA neither provides authority for EPA to implement an allowance auction nor does it provide direction for the agency to distribute the proceeds that may be collected through an auction.

A GHG cap and trade program will likely face court challenges

If EPA chooses to regulate GHG emissions using the , FPL Group would recommend the implementation of a market based cap and trade system for the distribution of GHG allowances. This system should be based on carbon intensity (lbs/MWh) in order to incentivize energy efficiency and promote the development of low and non-emitting electric generation. However, in light of recent court decisions on the Clean Air Interstate Rule and the Clean Air Mercury Rule it is uncertain whether EPA will be able to successfully implement a cap and trade program to meet emissions limits. Without a market-based cap and trade system the regulation of GHGs under the CAA would force EPA to regulate GHGs through a strict command-and-control system establishing hard emissions limits and control technology requirements. Without a cap and trade program it is uncertain how regulated facilities would meet the new GHG limits since there are currently no commercially available GHG capture and sequestration technologies on the market. A command-and-control emissions reduction program without market-based trading would lead to extensive fuel switching and the likely shutdown of numerous electric generating facilities that could not meet the new emissions limits. This approach would likely have a dramatic impact to the economy and the reliability of the nation's electric generation system.

GHG regulation under the CAA will increase leakage

An additional downside to the economy-wide regulation of GHGs under the CAA is the negative impact to U.S. businesses that will be competitively disadvantaged by the cost of GHG regulation when other countries do not impose GHG reduction requirements on their businesses and products. This additional cost would likely lead some industries and businesses to relocate overseas to countries that do not impose GHG regulation. The results of this costly regulation will include additional leakage of GHGs from other countries. This phenomenon further highlights the need for Congressional legislation that could impose border taxes on imports from countries not imposing GHG regulations or legislation that could provide assistance to U.S. businesses having to compete with overseas companies. Carbon fee revenues or auction proceeds would be an efficient form of funding for this assistance. These are options not available to EPA under the current CAA.

<u>EPA's Options for Regulating GHG Under the Clean Air Act</u>

In the ANPR EPA requested comments on the possible options for regulating GHG emissions under the Clean Air Act. These regulatory options include New Source Performance Standards (NSPS), National Ambient Air Quality Standards (NAAQS), and Hazardous Air Pollutants (HAPs). EPA also requested commenter's views on the impacts of Prevention of Significant Deterioration (PSD)/New Source Review (NSR) programs as a result of GHG regulation. FPL Group addresses each of these regulatory options below:

New Source Performance Standards (NSPS)

If EPA is compelled to regulate GHG emissions from stationary sources under the CAA, FPL Group contends that the NSPS option is the only appropriate regulatory option as compared to the other sections of the CAA. Section 111 of the CAA provides opportunity for EPA to determine appropriate source categories, in addition to electric utility sources, that should be regulated. Section 111 also allows EPA to establish emissions limits for individual units or for overall facilities including output basis standards that promote efficiency and conservation. Furthermore, under Section 111(d) EPA may have the authority to establish NSPS for existing sources .

Section 111 also directs EPA to take into account the cost of achieving emissions reductions. This option allows EPA to evaluate the most cost effective emissions standards seeking the lowest economic cost. With regard to standards promulgated on electric utility sources, the ability to take into consideration the cost of emissions reduction could allow EPA to mitigate some impact to the reliability of electric generation.

In the ANPR EPA indicates that the agency may have the authority to establish a traditional cap and trade program under Section 111. The use of an allowance cap and trade program is likely to result in litigation as evidenced by the litigation surrounding the now vacated Clean Air Interstate Rule and Clean Air Mercury Rule. Furthermore, FPL Group does not believe the CAA provides EPA the authority to establish an allowance auction program or the authority to collect and distribute auction revenues. The potential limitations to establish market-based allowance trading programs represents a significant shortcoming to the use of Section 111 of the CAA to regulate GHGs.

Finally, FPL Group believes that the most limiting concern for establishing existing facility or New Source Performance Standards under Section 111 is the lack of emission control options that would allow facilities to achieve lower emissions standards. Today and for the foreseeable future there are no commercially available controls to reduce GHG emissions or sequester carbon once it is captured. This lack of control options is of particular concern given the uncertainty surrounding EPA's authority to implement a cap and trade program and the agency's lack of authority to utilize offsets to achieve GHG reduction compliance.

National Ambient Air Quality Standards (NAAQS)

The regulation of GHG emissions under Section 110 of the CAA is likely the most untenable option available to EPA. Since GHG concentrations are relatively uniform globally it is uncertain how EPA would establish attainment or non-attainment areas of the country. Even less certain is how individual State's would prepare their State Implementation Plans (SIP) without clear attainment goals that could be reached by their efforts. If the entire country were deemed to be in non-attainment it is unclear how rural states with relatively minimal contributions to GHG emissions would be able to reach attainment. In fact, it is unlikely that the nation could reach attainment status during the maximum 10 year limit for achieving the primary NAAQS given the influences of GHG emissions globally.

It is unlikely that EPA could establish NAAQS without additional legislative authority and significant revision to the CAA.

Hazardous Air Pollutants (HAPs)

If EPA determines that GHGs have "an adverse environmental effect" they could then regulate under Section 112 of the CAA. However, the thresholds established under Section 112 would require numerous stationary sources to be regulated as major sources. Regulation under Section 112 of the CAA would require EPA to designate GHGs as HAPs, thus forcing the establishment of strict emissions standards. The most likely option would include Maximum Achievable Control Technology (MACT) standards. MACT controls are generally required for all new HAP emissions sources and would be rapidly phased-in for existing emissions sources. FPL Group is unaware of a reasonable, cost effective or commercially available control technology for reducing GHG emissions that would meet the requirements of MACT. Another option would include the development of an alternative standard under Section 112 (h) that would establish an efficiency or output-based standard. Neither of these regulatory options includes the opportunity to use a cap and trade program, offsets, or cost containment. FPL Group opposes regulation under Section 112 as this option would pose the greatest risk to electric generation reliability and likely the greatest cost for compliance.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

FPL Group believes the use of the CAA in its current form will result in an unworkable regulatory program burdened with inefficiencies and costly requirements that will not necessarily be applied to the appropriate sectors for regulation. In fact, the facility-based application of the current CAA will result in tens, if not hundreds of thousands of new, smaller facilities that will be regulated under the Act as a result of extremely low regulatory thresholds. Even EPA has acknowledged that applying "major source" thresholds to GHGs would "increase the number of Prevention of Significant Deterioration (PSD) permits by an order of magnitude -- from 200-300 per year to thousands of PSD permits each year." If GHGs become subject to PSD, even the smallest changes at commercial and industrial sources may require a lengthy pre-construction permit. Thousands of otherwise insignificant projects would be subject to PSD review based solely on GHG emissions, inflicting extremely burdensome requirements on industry and permitting authorities alike.

The PSD permitting program regulates stationary sources that either emit or have the potential to emit 250 tons per year (tpy) of a regulated pollutant or, if they are included on the list of source categories, at least 100 tpy of a regulated pollutant. These thresholds are extremely low when considered with respect to GHGs. For example, carbon dioxide (CO_2) emissions from a typical 200,000 square foot commercial building may approach 1,000 tpy. The ANPR acknowledges that regulation of GHGs under the CAA could result in the regulation of "small commercial or institutional establishments and facilities with natural gas-fired furnaces." This could include large single family homes, small businesses, schools, or hospitals heated by natural gas.

Already permittees affected by the PSD program can expect a single permit to take months if not years to complete, costing hundreds of thousands or millions of dollars. As noted above regulation of GHGs under the CAA would result in significant increases in the number of PSD permits required. The costs and administrative burdens to both permittees and regulatory agencies would be significant. Moreover, permitting under the PSD program would require EPA to establish permit limits reflecting the Best Available Control Technology (BACT) or Lowest Achievable Control Technology (LAER). FPL Group is unaware how the agency could establish either BACT or LAER as no commercially available technologies for carbon capture and sequestration have yet been deployed.

The use of the CAA's current NSR program for the regulation of GHGs seems unworkable. FPL Group suggests that EPA would need to seek legislation that would either limit the applicability of NSR or limit the emissions levels that would trigger NSR. Otherwise the number of facilities that would be burdened by NSR requirements would skyrocket. Further, as noted there are no currently available carbon capture or sequestration technologies that could meet the requirements of BACT or LAER.

EPA should support expanded use of electric vehicles

Finally, in Section VI of the ANPR, EPA addressed the increased use of plug-in hybrid electric vehicles in the future. FPL Group agrees with EPA's assessment that the nationwide use of grid electricity can result in significant reductions of transportation tailpipe GHG emissions. EPA also notes that wide usage of PHEVs will increase the demand for electricity and increase GHG emissions from the electric sector.

FPL Group supports the increased use of PHEVs as an obviously more efficient method of fueling the nation's transportation needs and reducing GHG emissions. However, the increased load growth to the electric sector would have to be taken into account when developing sector caps and allowance allocations. FPL Group suggests that EPA seek legislative support from Congress to eliminate barriers to the development and deployment of PHEVs outside of the CAA GHG regulation process.

Conclusions

In summary, FPL Group does not support the use of the current CAA for the regulation of GHG emissions. The uncertainties and apparent inefficiencies of using the CAA will likely lead EPA into yet another string of protracted rule challenges that will only delay implementation of real GHG reductions. FPL Group does recognize that EPA's role in regulating GHG emissions in the future is necessary and preferred in order to achieve an effective program. As members of EPA's Climate Leaders program FPL Group is well aware of the agency's knowledge and understanding of GHG emissions issues and emissions sources. However, EPA's future role should be initiated through comprehensive legislation that establishes a streamlined national policy with clear goals and strategies for achieving successful GHG reduction. Regulation under the current form of the CAA will not achieve this goal. We are also aware that EPA is compelled by a recent court decision to make an endangerment finding that may lead the agency to regulate GHG emissions under the CAA. If this inefficient regulatory approach becomes necessary, FPL Group encourages EPA to implement a broad and transparent stakeholder process. Further, to the extent emissions modeling is necessary to establish regulatory limits, we advise a robust and timely process of sharing data and models with stakeholders.

If you have any questions or need additional information from FPL Group please contact me at 561-691-7040.

Sincerely,

Rayburn L. Butts
Director, Strategic & Regulatory Planning
Environmental Services

cc: Randall R LaBauve, V.P.
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Air and Radiation Docket and Information Center
Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Ave., NW
Washington, DC 20460
(submitted through www.regulations.gov)

Re: Proposed Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule

To Whom it May Concern:

Provided below are FPL Group's comments on the Environmental Protection Agency's (EPA's) proposed *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule* (tailoring rule), published in the Federal Register on October 27, 2009 (74 FR 55292).

FPL Group is a leading clean energy company with 2008 revenues of more than $16 billion, approximately 39,000 megawatts of generating capacity, and more than 15,000 employees in 27 states and Canada. FPL Group's principal subsidiaries are NextEra Energy Resources, the largest generator in North America of renewable energy from the wind and sun, and Florida Power & Light Company, which serves 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country.

FPL Group has long been one of the electric power sector's strongest advocates of meaningful action to address the threat of climate change. FPL Group has one of the lowest emission rates of greenhouse gases (GHGs) in the electric power sector. Nearly 50 percent of the company's approximate 39,000-megawatt generating capacity is fueled by natural gas, 15 percent by nuclear and 10 percent by wind. As part of EPA's Climate Leaders program, FPL Group has successfully achieved, and surpassed, its Climate Leaders goal of having reduced its emissions rate by 21 percent.

Despite the outstanding track record that FPL Group has with respect to addressing the climate change issue, the Company has proposed additional initiatives:

- The Company is planning to invest $20 billion in new wind energy facilities from 2007 through 2012.
- The Company plans to invest $2.4 billion in renewable energy and energy efficiency technologies in the future, including solar power, consumer renewable energy programs and an advanced metering initiative to provide more control over energy efficiency to utility customers.

- The Company is in the process of modernizing its power plants at Riviera Beach and Cape Canaveral to clean, high-efficiency natural gas units employing the latest technology, a move that will significantly improve the emissions profile of FPL Group's generation fleet.
- The Company is planning to increase the power output of its St. Lucie and Turkey Point nuclear units by a total of 414 MW. In addition, the Company has filed license and permit applications with the Nuclear Regulatory Commission and other federal and state agencies to construct and operate two new nuclear reactors at Turkey Point (Units 6 and 7)

FPL Group believes that the threat of major, long-term environmental and economic damage from climate change is real and that, although uncertainties remain, there is sufficient evidence today to warrant taking action to slow and eventually reverse the growth in GHG emissions. We believe that the most effective climate change strategy will impose a price on carbon throughout the economy and do so in a predictable fashion. By internalizing the cost of carbon into the overall cost of all goods and services throughout the economy, the proper incentives and economic signals to reduce emissions will be created, without also introducing unnecessary economic burdens or distortions. To this end, FPL Group believes an economy-wide cap-and-trade program is the most cost-effective and environmentally-certain strategy to reduce GHG emissions during the transition to a low-carbon economy. Cap-and-trade programs provide predictable and enforceable emissions reductions while directing capital investment to the lowest-cost low-carbon opportunities. Federal legislation that creates an economy-wide cap-and-trade program would provide the most effective and efficient pathway to reducing GHG emissions in the U.S. Following a legislative path will provide flexibility to address the unique characteristics of GHG emissions (e.g., global mixing, national uniformity, ubiquity of sources) in a way that following a regulatory path under the Clean Air Act will not.

However, FPL Group recognizes that with the finalization of the endangerment finding related to GHG emissions from motor vehicles, regulation of GHG emissions from stationary sources. under the PSD and Title V permit programs will be triggered 60 days after publication of the final GHG Vehicle Emissions Rule in the Federal Register. In this context, FPL Group appreciates the opportunity to submit the following comments and continue ongoing dialogue with EPA to ensure that inclusion of GHGs under these programs achieves necessary reductions in GHG emissions while maintaining the overall viability of these complex programs.

1. PSD and Title V Applicability Thresholds and Significance Levels

FPL Group strongly supports EPA's proposal in the tailoring rule to temporarily raise the applicability threshold of the PSD and Title V programs to a minimum of 25,000 tpy CO_{2e} (and preferably higher) in order to avoid exceeding the administrative capacity of permitting agencies to process permit applications, avoid delays in the issuance of permits to all sources, and avoid a situation where thousands of relatively small sources (millions in the case of Title V permits) that have never been confronted with Clean Air Act compliance obligations would incur the expense of PSD and Title V permitting requirements including, most importantly, identifying and developing BACT controls for GHGs on a source-by-source basis. For similar reasons, FPL

Group recommends setting the significance level for major modifications of existing sources at a level of at least 25,000 tpy, and preferably higher. FPL believes that initially regulating GHG emissions from the larger stationary sources, and phasing in regulation of smaller sources, is a reasonable, legally defensible approach for EPA to pursue.

A low modification significance level could impose a burden on facility owners that would discourage companies from making plant efficiency improvements. The following two examples illustrate situations where PSD permitting for GHG emissions could potentially discourage energy efficiency upgrades and investments at fossil fuel-fired power plants—completely counter to the objectives of a GHG control program.

Example 1: Efficiency Upgrade

Consider, for example, a natural gas combined cycle facility that undergoes a steam turbine upgrade to improve the operational efficiency of its operations. A modest increase in the utilization of the plant (post-modification) would trigger a threshold of 25,000 tpy for CO_2e, while falling well short of the thresholds for conventional air pollutants, such as nitrogen oxides (NO_X) and carbon monoxide (CO).

Power plants are generally dispatched based on their operating costs, with the facilities with the lowest-cost generation dispatched first. An efficiency improvement, to the extent that it reduces a plant's operating costs relative to its peers, may increase a plant's dispatch and operating hours.

Table 1 calculates the annual emission rate of a 500-megawatt (MW) natural gas combined cycle power plant before and after undertaking an upgrade that results in a five percent heat rate improvement. If the utilization of the plant increases by just *four percent* following the modification, the plant would trigger the 25,000 tpy CO_2e PSD threshold proposed by EPA. The main takeaway points from this example are:

- A four percent (4%) increase in the operating hours of the unit would increase its CO_2 emissions by 28,306 tpy. (Note that electric grid-wide emissions would be expected to decrease because the more efficient modified unit will likely displace higher emitting units, although this is difficult to quantify and not addressed here.[1])
- A four percent (4%) increase in the unit's operating hours would increase NO_X and CO emissions by less than three tons combined.

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[1] California, in particular, recognizes the positive effect of increasing utilization of more efficient and/or natural gas plants to reduce system-wide emissions. See, for example, California Energy Commission's (CEC's) recent Presiding Member's Proposed Decision (PMPD) on the Avenal Energy project, released November 10, 2009, and available at http://www.energy.ca.gov/sitingcases/avenal/documents/. The PMPD states that the 600 MW natural gas-fired combined-cycle Avenal Energy project was the first proposed power plant in the state to be evaluated in greater detail for greenhouse gas emission impacts, in line with current guidance for fulfilling California Environmental Quality Act responsibilities for power plant siting projects. The Commission found that the project, a new natural gas combined cycle power plant, will reduce overall greenhouse gas emissions within the electrical system by displacing more carbon-intensive generation sources. See also the CEC Final Staff Assessment for the 558 MW natural gas-fired Carlsbad Energy Project, which reaches the same conclusion, available at http://www.energy.ca.gov/sitingcases/carlsbad/index.html.

- Plant utilization would need to increase to more than 80% before the PSD threshold for NO_X (40 tpy) would be triggered.[2]

Table 1

Emissions Resulting from an Efficiency Upgrade

Example of PSD Threshold Calculations: Modeled 500 MW Combined Cycle Power Plant

Heat Rate (Btu/kWh)	Utilization (%)	CO_2e (tpy)	NO_X (tpy)	CO (tpy)
Baseline (pre-modification):				
8,500	50%	-	-	-
After 5% heat rate improvement:				
8,075	51%	-	-	-
	52%	-	-	-
	53%	7,621	0.5	0.3
	54%	28,306	1.8	1.1
	55%	48,991	3.1	1.9
	56%	69,676	4.4	2.7
	57%	90,361	5.7	3.5
	58%	111,046	7.0	4.3
	59%	131,731	8.3	5.1
	60%	152,416	9.6	5.8
	75%	462,692	29.2	17.8
	83%	628,172	39.6	24.1
	90%	772,967	48.7	29.7

Notes and Assumptions

PSD thresholds: NO_X = 40 tpy, CO = 100 tpy, CO_2e = 10,000-25,000 tpy (proposed).
CO_2e calculated as Heat Rate * Utilization * Annual Hours * Carbon Content of Natural Gas
Assumed NO_X emission rate: 2 ppm.
Assumed CO emission rate: 2 ppm.

[2]For simplicity, this analysis does not attempt to account for increased utilization due to product demand growth, which would be excluded from the emissions increase calculation. See 40 CFR section 52.21(b)(41)(ii)(c).

Example 2: Repowering to Combined Cycle

As a second example, the California Energy Commission is considering an application to repower a portion of an aging natural gas plant to more-efficient combined cycle generation.[3] The upgraded facility will be significantly more efficient with a reduced GHG emissions rate.

In the proposed reconfiguration, three 1950s-era natural gas steam boilers would be replaced by a 558 MW combined cycle power generating facility configured with two Siemens SCC6-5000F natural gas-fired combustion turbines. The project, the Carlsbad Energy Center Project (CECP), would be built at the existing Encina Power Station located in San Diego County, California. Table 2 summarizes the baseline and projected emissions of the project. As indicated, there would be a substantial improvement in the GHG emissions rate of the facility (approximately a 40% decrease), while NOx and CO emissions would remain below the PSD threshold. Under the reasoning established in the Avenal decision, CEC staff determined that the new facility would decrease overall system GHG emissions.[4]

Table 2

Emissions Change Resulting from Upgrades at the Encina Power Station

Example of PSD Threshold Calculations: Current Repowering Project

CO_2 Emissions (tons/MWh)	Utilization (%)	CO_2e (tpy)	NO_X (tpy)	CO (tpy)
Baseline (current simple cycle units):				
0.637	14%	243,523	32.21	268.80
Combined Cycle Configuration:				
0.404	47%	844,091	72.11	217.3
Change:				
-37%	+236%	**+600,568**	+39.9	-51.5

Notes and Assumptions

PSD thresholds: NO_X = 40 tpy, CO = 100 tpy, CO_2 = 10,000-25,000 tpy (proposed).
Emissions data for Units 1-3 is reported as an annual average (2002-2008).
Applicant limited proposed operation to 4,100 hours per year to avoid triggering PSD with NO_X emissions.
This comparison addresses only the current emissions from the units to be replaced (Units 1-3), and does not include current or projected emissions from the on-site units not affected by the proposed project (Units 4-5).

Recommendations Regarding PSD Significance Levels

It is unknown at this time what would constitute BACT for GHG emissions from a fossil fuel-fired electric generating facility. However, the fact that efficiency upgrades could potentially trigger PSD permitting for CO_2 will tend to discourage such investments as some owners/operators will likely avoid or delay projects that trigger PSD due to the significant administrative burdens and potential financial costs. FPL Group urges EPA to design the inclusion of CO_2e in the PSD program in a way that will encourage, not discourage, power plant

[3] CEC Docket Number 07-AFC-06, available at http://www.energy.ca.gov/sitingcases/carlsbad/index.html.
[4] See Footnote 2

efficiency upgrades. Part of that strategy should be establishment of an appropriate significance level for major modifications.

In addition, while the examples described above would clearly qualify as modifications, FPL Group encourages EPA to issue guidance clarifying activities that would qualify as routine maintenance, repair and replacement (RMRR), such as periodic turbine overhauls. This is a longstanding concern with the PSD program that requires renewed attention in light of the Agency's efforts to regulate GHG emissions. RMRR activities play an important role in maintaining operating efficiency and reducing fuel use and emissions. FPL Group recommends that, at a minimum, EPA issue guidance that identifies a list of activities conducted at power plants that would *presume* to be RMRR unless unique conditions exist that demonstrate otherwise.

Treatment of High-GWP Gases

The tailoring rule specifically requests comment on the treatment of GHGs with high global warming (GWP) potentials. In electricity generation, SF_6 plays a crucial role in both safety and performance. In the U.S., nearly 80 percent of all SF_6 produced is used by the electric power industry in high voltage equipment such as electrical switchgear and circuit breakers. SF_6 is preferred for use in high-voltage equipment applications and designs because of its extremely stable molecular structure, high dielectric strength, powerful arc quenching abilities, and excellent insulation properties. However, with a GWP of approximately 23,900, SF_6 is the most potent greenhouse gas known. In 1999, EPA launched the voluntary SF_6 Emission Reduction Partnership for Electric Power Systems to collaboratively develop and implement cost-effective options to reduce SF_6 emissions. Florida Power and Light, FPL Group's regulated electric utility company in Florida, was a member of EPA's SF_6 Reduction Partnership from 2000 to 2005 and achieved its goal of achieving a 6% or less leak rate compared to a 2001 baseline.

SF_6 is one of the gases noted by EPA in the preamble to the proposed tailoring rule that, at mass emission rates lower than those specified in the Act, could trigger tailoring rule thresholds on a CO_2e basis. EPA has requested comment on whether the threshold for these gases should be 25,000 tpy on a CO_2e basis <u>and</u> the 100/250 tpy stated in the Act (e.g., high-GWP gases emitted in quantities less than 100/250 tpy would not trigger PSD by themselves even if CO_2e emissions exceeded 25,000 tpy). FPL Group supports applying the dual threshold for SF_6 because we believe it is consistent with the phasing-in approach reflected in the tailoring rule and is an effective way to address the current uncertainty surrounding how to measure these high-GWP gases.

Given the methodological questions highlighted by EPA's decision not to finalize the reporting methodology for SF_6 under the Mandatory Reporting of Greenhouse Gases Rule, SF_6 and other high-GWP gases should not trigger PSD in such small quantities during the first phase because measurement is too uncertain and SF_6's high GWP will magnify potential measurement errors. Including the mass threshold ensures that the most significant sources of SF_6 emissions are addressed during this phase.

Regardless of the threshold adopted for high-GWP gases such as SF_6, FPL Group also requests clarification on (1) when fugitive emissions of SF_6 are counted in determining BACT applicability, particularly at transmission or other facilities where there is no clear emissions unit; (2) when fugitive emissions of SF_6 are subject to a BACT determination; and (3) how PTE would be calculated for fugitive emissions of SF_6 based either on leak rates or total quantity of gas on site, although the vast majority of this gas would not be emitted under normal conditions. To the extent SF_6 emissions trigger a BACT analysis, FPL Group recommends considering leak rates only, as this is more in line with the consideration of PTE for other pollutants.

2. **Alternative Option for Addressing PSD and Title V GHG Applicability Issue**

In addition to the temporary applicability threshold adjustments described above, EPA requests comment on an option to define sources subject to permitting under the PSD and title V programs *as only those sources that trigger application of the program based on non-GHG emissions.*[5]

FPL Group believes that the Clean Air Act can, and should, be interpreted to require that *increases in criteria pollutants subject to a National Ambient Air Quality Standard (NAAQS)* occur before there is an ability to require PSD review for a new source or for an existing source undergoing a modification. Clean Air Act section 161 requires that State Implementation Plans (SIPs) "shall contain" emission limitations and necessary measures "in each region (or portion thereof) designated pursuant to section 7407 of this title as attainment or unclassifiable."[6] Under this section, EPA is required to promulgate regulations "under this part" of the Clean Air Act, or Part C – Prevention of Significant Deterioration of Air Quality. In addition, CAA section 165(a)(3) further indicates that owners or operators of facilities need to demonstrate that construction and operation of facilities to which PSD applies "will not cause, or contribute to, air pollution in excess of any (A) maximum allowable increase or maximum allowable concentration for any pollutant *in any area to which this part applies* more than one time per year . . ."[7]

Accordingly, the PSD program "applies" with regard to an "area" and the PSD program is based on the location of a source (*i.e.*, in an "area") that is directly linked to the NAAQS. Therefore, PSD applicability is linked to the existence of NAAQS for particular air pollutants. *Under this interpretation, the emission of any quantity of GHGs alone would not trigger PSD applicability because there is no NAAQS for GHGs; PSD would only apply if a new stationary source were to have the potential to emit an air pollutant above applicable NAAQS thresholds established in CAA section 169, and the source was to be located in an area which was in attainment or unclassifiable for that NAAQS. The same interpretation would hold true for modifications where potential emissions exceeded significance levels for the relevant NAAQS.*

[5] 74 *Fed. Reg.* at 55327.
[6] 42 U.S.C. § 7472.
[7] *Id.* at § 7475(a)(3) (emphasis added).

This interpretation would also serve the goal of an orderly, efficient transition to regulating GHG emissions from stationary sources. Explicitly acknowledging the required link between the existence of a NAAQS for a particular air pollutant and the triggering of PSD obligations for GHG sources is an option that can be used indefinitely going forward to streamline the PSD and title V permitting processes. This interpretation also would provide greater regulatory certainty to many facilities, including smaller electric generating units that do not have the potential to emit criteria pollutants in sufficient quantities to be subject to the PSD program, but may emit more than the threshold level of GHGs. It is not clear currently whether these facilities will need PSD permits now or in the future.

3. Best Available Control Technology (BACT) and Title V Guidance\

Forthcoming BACT Guidance

FPL Group is aware that EPA's Clean Air Act Advisory Committee has convened a *Workgroup on BACT and Greenhouse Gases* with the intention to provide guidance on BACT for GHGs in coordination with the finalization of the tailoring rule. FPL Group strongly urges EPA to provide sector-specific guidance on BACT determinations for GHGs as discussed in section X.E. of the proposed rule as soon as practicable to ensure a smooth transition of GHGs into the PSD program.

In the sector-specific guidance that EPA develops on BACT for GHGs, FPL Group urges the Agency to consider creative, cost-effective options that promote energy efficiency and clean energy sources during the BACT determination process. To the extent possible under the law, sources subject to BACT should be allowed the flexibility of obtaining required emission reductions from all of the emissions-producing equipment at a particular facility as well as obtaining equivalent emission reductions beyond the fence-line of a facility (e.g., compliance on a fleetwide basis, the use of emission offsets, etc.)

In addition, EPA should finalize or otherwise clarify the status of the guidance document on BACT determinations entitled *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Permitting (Draft, October 1990).* This nearly two-decade old draft document has become the *de facto* authority for the top-down, case-by-case BACT analysis required by the Clean Air Act (40 CFR Part 51, §165(a)(1)(xl)) and is widely used by permit applicants, consultant practitioners, agency permit writers, and the courts. Its use has been upheld by the Environmental Appeals Board and the courts, but it appears to have no final status with the agency. Finalizing this important draft guidance document prior to finalizing the tailoring rule would be an important step in providing the guidance that EPA commits to in this proposed rulemaking, and would send a signal to the regulated community that EPA intends to provide the guidance that will be needed to implement the tailoring rule.

Forthcoming Title V Guidance

For sources that are not currently covered by Title V, FPL Group requests guidance from EPA on identifying and quantifying these sources, similar to the general and sector-specific applicability guidance provided with the Mandatory Reporting of Greenhouse Gases Rule. Particularly for non-combustion sources, even the higher applicability threshold proposed in the tailoring rule will apply to many sources, such as switchyards and commercial or service centers that have never been subject to Title V or equivalent state requirements.

FPL Group supports consideration of options to voluntarily limit potential to emit (PTE), which would limit the PSD and Title V programs to sources whose *actual* emissions are likely to be greater than the major source threshold for CO_2e. FPL Group requests that EPA issue specific guidance from EPA to potential sources and permitting authorities of when administrative limitations to PTE are assumed appropriate. One example that is currently used for criteria pollutants and may be useful in consideration of GHGs is an explicit and/or enforceable limitation on hours of operation. For example, EPA currently allows applicants and permitting authorities to assume that emergency generators would operate no more than 500 hours per year. While this is still well above most facilities' utilization, it more accurately reflects these sources' emissions potential than assuming continuous operation. For other sources, however, it is standard to assume a source will operate continuously year-round, which may or may not be a reasonable assumption. For situations such as emergency generators or heating, ventilation and air conditioning equipment where there are practical and/or legal limitations on hours of operation or other key factors in determining a facility's true PTE, FPL Group supports PTE limits and/or permits-by-rule for smaller and/or limited-use sources.

4. Presumptive BACT

CAA section 165(a)(4) requires that sources subject to PSD implement BACT for each pollutant subject to regulation under the Act, and CAA section 169(3) requires that BACT emissions limits be determined ''on a case-by-case basis'' that reflects the use of state-of-the-art demonstrated control technology at the time of the permit action. Thus, BACT is required to be source-specific, changes over time, and requires continual updating. The permitting authority's decision as to what control requirements constitute BACT affords flexibility to consider a range of case-specific factors, such as available control options and collateral cost, energy, and environmental impacts. However, full consideration of those factors requires significant data and analysis in order for permitting authorities to arrive at a case-by-case permitting decision that is appropriate for each individual source when it constructs or modifies.

For all these reasons, determining BACT for a particular source can often be a complicated, resource-intensive, time-consuming, and sometimes contentious process. If the number of required PSD permitting decisions increases significantly when GHGs become "regulated pollutants" under the Clean Air Act, these challenges will be magnified, and BACT determinations will be a major factor contributing to uncertainty and delay for sources seeking PSD permits. Furthermore, the increase in workload of BACT determinations will require large investments of resources by permitting authorities, affected sources, EPA, and the public interested in commenting on these decisions.

In the proposed tailoring rule, EPA indicates that the Agency is interested in whether there would be ways to move from a PSD permit system in which BACT limits are set on an individual case-by-case basis to a system in which BACT determinations could be made for common types of equipment and sources, and those determinations could be applied to individual permits with little to no additional tailoring or analysis. EPA has previously introduced this concept, known as "presumptive BACT", as an aid in streamlining permitting for desulphurization projects at refineries, in streamlining BART determinations under the Clean Air Visibility Rule as well as in other instances, and some state permitting authorities have adopted similar approaches in their air permitting programs.

Considering the types and numbers of sources that will become subject to PSD if GHG emissions are regulated at the statutory 100/250-tpy threshold, or even if EPA adopts the proposed higher threshold of 25,000 tpy, the presumptive BACT process could offer significant streamlining benefits. These benefits arise because many of the sources that would become subject to BACT will likely have very similar emissions producing equipment, and there will be little variation across sources with respect to the cost, energy, and environmental considerations in the BACT decision.

While the Clean Air Act states that PSD permits shall be issued with BACT determinations made for each pollutant on a "on case-by-case basis," the court in Alabama Power v. EPA, 636 F.2d at 358 (D.C. Cir. 1980) recognized that exceptions may be appropriate where "case-by-case determinations, would, as a practical matter, prevent the agency from carrying out the mission assigned to it by Congress." The court recognized that such streamlining measures may be needed when time or personnel constraints or other practical considerations "would make it impossible for the agency to carry out its mandate." Given the more-than-tenfold increase in new sources projected by EPA to be brought into the PSD program once GHGs are regulated, maintaining a traditional PSD permitting program with individual case-by-case BACT determinations may be impractical, warranting streamlined regulatory approaches as allowed under the Act. A presumptive BACT permitting program would allow EPA, state and local permitting authorities to carry out the PSD program in a timely and efficient manner necessary to promote (rather than hinder) control of GHG emissions from the many new, small source categories that would be required to have PSD permits based on their GHG emissions, while still preserving opportunities for public participation.

In terms of how presumptive BACT limits should be established and used, and what provisions in the Clean Air Act would set requirements or limits on their establishment and use, the Clean Air Act requires EPA to set BACT limits on a case-by-case basis after taking into account site-specific energy, economic, and environmental impacts (otherwise known as collateral impacts). EPA is required to subject proposed PSD permits, and the BACT limits contained within them, to public notice and comment before such permits become final.

One possible approach would be to develop, through notice-and-comment rulemaking, a presumptive BACT level for sources in a particular source category, but require that permitting authorities allow public comment on individual permits as to whether there are significant case-specific energy, economic, and/or environmental impacts that would require adjustment of the presumed limit for that particular source. This phase-in approach could streamline the BACT determination process to some extent. However, the fact that presumptive BACT determinations would, as a result of public comment, still have to be reviewed for numerous individual sources could well negate those streamlining benefits.

On this basis, FPL Group believes that EPA should consider adoption of a system under which presumptive BACT levels for a source category are developed through guidance that would be issued only after public notice and comment procedures *without requiring permitting authorities to individualize the BACT determination or to allow for public comment on how presumptive BACT levels would apply to an individual source.* This approach would preserve opportunities for public participation by taking comment during the determination of presumptive BACT levels for a source category.

5. Timing and Implementation

FPL Group also requests that the final tailoring rule provide clear transitional relief, clarifying at which stage ongoing projects' PSD reviews must consider GHGs. When GHGs become regulated under the Clean Air Act, many projects will be at differing points along the development spectrum. Consistent with longstanding EPA practice, a BACT analysis should be complete at the time of issuance of a final permit.

FPL Group urges EPA to confirm in the final tailoring rule that projects that have been issued a valid PSD permit are not required to seek a revised PSD permit for GHGs in the absence of an application for additional major modifications or a renewal. Similarly, EPA should also confirm that projects with a valid permit that commence construction within 18 months should also not be required to seek a revised PSD permit for GHGs.

FPL Group appreciates the opportunity to comment on EPA's proposed PSD/Title V GHG tailoring rule. If you have any questions, please do not hesitate to contact me at (561) 691-7001 or Joseph Miakisz of my staff at (561) 691-7680.

Sincerely,

Joseph A. Miakisz for Randall R. LaBauve

Randall R. LaBauve
Vice-President, Environmental Services

FPL GROUP
FPL Group, P.O. Box 14000, 700 Universe Blvd., Juno Beach, FL 33408

June 9, 2009

Docket ID No. HQ-OAR-2008-0508
Climate Change Division, Office of Atmospheric Programs
EPA Docket Center (EPA/DC), Mail code 6102T
1200 Pennsylvania Avenue, NW
Washington, DC 20460
(submitted through www.regulations.gov)

Re: Proposed Mandatory Reporting of Greenhouse Gases, Docket ID No. EPA-HQ-OAR-2008-0508

To Whom It May Concern:

FPL Group appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) proposed rule for the mandatory reporting of greenhouse gases (GHGs).

FPL Group is a leading clean energy company with 2008 revenues of more than $16 billion, approximately 39,000 megawatts of generating capacity, and more than 15,000 employees in 27 states and Canada. FPL Group's principal subsidiaries are NextEra Energy Resources, the largest generator in North America of renewable energy from the wind and sun, and Florida Power & Light Company, which serves 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country.

FPL Group has long been one of the electric power sector's strongest advocates of meaningful action to address the threat of climate change FPL Group has one of the lowest emission rates of GHGs in the electric power sector. Nearly 50 percent of the company's approximate 39,000-megawatt generating capacity is fueled by natural gas, 15 percent by nuclear and 10 percent by wind. As part of EPA's Climate Leaders program, FPL Group has successfully achieved, and surpassed, our Climate Leaders goal of having reduced our emissions rate by 21 percent. FPL Group believes that an accurate accounting of all sectors' emissions is a critical tool to reducing nationwide GHG emissions and addressing global climate change

FPL Group broadly supports EPA's proposed rule for the mandatory reporting of GHGs (proposed rule). We believe it meets EPA's legislative obligations, and provides a framework that is both administratively manageable and that is likely to result in an accurate representation of many varied sectors' GHG emissions. We also appreciate the fact that, for electric utilities, the draft GHG Reporting Rule builds off the Clean Air Act Acid Rain Program, and recognizes the reporting done to date by our sector under section 821 of the Clean Air Act Acid Rain Program.

FPL Group offers comments on several broad themes related to the proposed rule as well as source category-specific comments below.

Overarching Comments

1. Coordination between EPA and Other Programs

Under Section 114(b) of the Clean Air Act (CAA), EPA may delegate the authority to collect emissions data from stationary sources to State agencies provided the state agency can satisfy the procedural requirements. At this time, FPL Group does not take a formal position on delegation, but strongly encourages EPA to work with states that already have or are considering state-level mandatory reporting to ensure compatibility and to minimize duplication and other administrative burdens.

To the extent practicable, EPA should strive for reporting of GHG emissions data that can be shared between state and federal programs to avoid sources having to report the same or similar information to multiple levels of government or multiple agencies. Differences in reporting requirements (including emissions thresholds, scope of reporting, methodologies, reporting deadlines, etc.) not only increase the administrative burden of reporting on companies, but also obscure the data for use by the public. For example, a source could end up reporting one set of emissions data to EPA and another to individual states. If these registries utilize different thresholds or categories, an entity's reporting data, while accurate, could be markedly different, which would make it more difficult for the public to assess entities' GHG performance.

Further, FPL Group would support EPA consideration of alternatives to double-reporting at the federal and state levels, such as incentivizing states to fold state-level emissions reporting programs into the federal program to the extent possible. For example, EPA could encourage states to use the federal reporting data for the covered GHGs and operations, and supplement with reporting of additional gases at the state level if desired.

FPL Group anticipates eventual Congressional legislation addressing GHG emissions reductions. Such legislation and implementing regulations would necessarily have a monitoring and reporting program, and FPL Group strongly encourages EPA to consider whether the proposed rule would likely serve as an adequate framework for the legislative proposals to date. This would ensure that the effort thus far to craft a workable rule, as well as the upcoming compliance effort, is not wasted or repeated.

2. Reporting Start Date and Timing

FPL Group suggests that EPA's proposal to begin implementation of the mandatory GHG reporting program in January, 2010, following promulgation of a final rule in September 2009, allows inadequate time for companies to prepare for compliance. To begin reporting, companies will need to assess the final rule, and then, where appropriate, install and certify emissions monitoring equipment; develop or purchase, test and implement software programs to support electronic filing; develop internal reporting procedures and guidance; and finally train personnel in the use of the new equipment, software, and reporting procedures and guidance. Allowing what will likely be 90 days from the promulgation of the final rule to the start of the compliance period, is simply inadequate time. The forgoing is especially true where utilities are for the first time reporting emissions from categories not required by 40 CFR Part 75, such as sulfur hexafluoride (SF_6), or where new fossil-fueled combustion units that are exempt under the Acid Rain provisions of Title IV of the CAA are for the first time subject to a CO_2 emissions reporting requirement under the proposed rule.

In the preamble of the proposed rule, EPA requests comments on two options regarding the timing of initial implementation of the GHG reporting program:

- report 2011 data in 2012; or
- report 2010 data in 2011 using best available data, similar to the approach adopted by the California Air Resources Board (ARB) mandatory reporting rule.

FPL recommends that EPA adopt the first option of requiring the initial report (of 2011 data) be submitted in 2012. However, if this option is ultimately rejected by the Agency, then FPL Group recommends that EPA adopt the second option of requiring the reporting of 2010 data in 2011 using the best data available. Beginning with 2011 data or best available 2010 data and methods would provide affected sources an opportunity to evaluate the implications of the final rule on their individual lines of business; install and certify necessary emissions monitoring equipment; develop or purchase, test and implement new software programs to support electronic filing of data; develop internal reporting procedures and guidance; and train personnel in the use of new equipment, software, and reporting procedures and guidance.

Beyond our concerns with the initial implementation data of the new mandatory GHG reporting program, FPL Group does not believe a reporting deadline of March 31 allows adequate time to collect and verify data. On this basis, we suggest moving the reporting deadline to June 30 of the year following the reporting year.

Finally, FPL Group requests that EPA consider phasing in the reporting of all six GHGs over the first few years of the program, similar to how The Climate Registry initially collected data. The first several years of reporting under EPA's mandatory reporting rule should require the reporting of CO_2 emissions from combustion together with the manufacture and import of high global warming potential (GWP) gases (HFC, PFC, and SF_6). Following this initial phase, sources could then report CH_4 and N_2O emissions from combustion, as well as other process and fugitive emissions. This would allow reporting entities to begin with larger sources of GHG emissions for which there are more established reporting protocols and procedures, and phase in sources and processes for which reporting protocols are currently less widely applied.

3. Verification

Overall, FPL Group supports gathering accurate emissions data, with the minimum administrative burden, to ensure an accurate accounting of each sector's emissions, as well as to serve as the foundation for any sector-based allowance allocation under a future national cap-and-trade system.

FPL Group strongly supports EPA's decision *not* to require third-party verification of the electric generating sector's GHG emissions reporting. Since the Clean Air Act Amendments of 1990, the electric generating sector has reported high quality quarterly SO_2, NOx and CO_2 emissions data to EPA. The majority of the emissions data is captured using continuous emissions monitoring systems (CEMS) that are highly accurate and utilized for compliance with existing cap and trade programs. In addition, for electric generating facilities that are not required to have CEMS, fuel use data is accurately metered and heat content is routinely measured, producing high quality data and emissions calculations. As EPA has been collecting, verifying, and utilizing this data for nearly two decades, FPL Group does not believe these data require third-party verification.

4. Facility Definition and Emissions Reporting Requirements

FPL Group supports the facility-level reporting approach EPA has proposed for most source categories. Facility-level reporting by owners or operators is consistent with other Clean Air Act and state-level regulatory programs and coordination will facilitate compliance and minimize the administrative burden of the proposed rule.

However, the proposed rule states that the owner or operator of a "facility" would be required to report GHG emissions from all source categories at the facility for which there are methods developed and listed in the proposed rule.[1] This provision raises certain interpretive questions that FPL Group requests clarification on from EPA. Specifically, the proposed rule defines a facility as "under common ownership or common control." Since deregulation, co-located substations and other supporting infrastructure at electric generation facilities may be under the same ownership/control as the electric generating facility *or* they may be owned and operated by a separate entity (i.e., *not* the owner/operator of the electric generating facility). In these situations, it is unclear who would be obligated under the proposed rule to report any SF_6 emissions from co-located substations and other infrastructure.

If co-located substations and other supporting infrastructure included SF_6-containing equipment owned by the same electric generating facility owner, then it appears that the proposed rule would require any SF_6 emissions to be included in the reporting by the generating facility owner. However, if the substation and other supporting infrastructure is owned by another entity (i.e., *not* the owner of the generating facility), it is unclear who would be responsible for reporting any SF_6 emissions emanating from the co-located substations and other supporting structure, the owner of the generating facility or the owner of the SF6-containing equipment. This issue is further addressed in the Electric Power Systems section of FPL Group's comments (see Page 6)

[1] Any facility that exceeds the emissions threshold is required to report emissions for all source categories that are located at the facility, including SF_6 emissions from electric power systems. *See* proposed § 98.2(a)(2), 74 *Fed. Reg.* 16612.

5. Determining Facility Level Applicability

§ 98.2(g) of the proposed rule requires that "[o]nce a facility or supplier is subject to the requirements of this part, the owners and operators of the facility or supply operation must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit GHG emission reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year." FPL Group believes that this once-in-always-in provision should be amended to allow facilities to avoid reporting in future years if they have reduced their GHG emissions to a level below the applicability requirements.

The once-in-always-in requirement of proposed § 98.2 fails to provide any incentive for facilities to reduce their GHG emissions. However, the opportunity to escape the monitoring and reporting burdens would offer facilities a meaningful incentive to reduce their GHG emissions. Creation of an exit mechanism that would allow proactive facilities to lessen their regulatory burden by reducing their emissions below the proposed rule's established reporting thresholds would offer facilities a meaningful incentive to reduce their GHG emissions. Accordingly, FPL Group supports the alternative option provided by EPA, which is similar to the approach adopted by the California Air Resources Board (CARB). Under CARB's mandatory GHG reporting program, a facility that has emissions under the threshold for three consecutive years has the opportunity to exempt itself from the reporting program. FPL Group requests that EPA include an exit mechanism similar to that utilized by CARB when developing its final GHG reporting requirements.

6. Vehicle Fleets

Under the proposed rule, EPA is proposing that manufacturers of mobile sources and engines would be required to report emissions from the vehicles and engines they produce in terms of a general emissions rate, as opposed to requiring fleet operators to report their GHG emissions. However, the Agency is soliciting comment on whether fleet operators should be required to report GHG emissions under the proposed rule. FPL Group supports EPA's proposal to place the GHG reporting obligation on the manufacturers of mobile sources and engines and to exclude the reporting of mobile source fleet emissions.

Source Category-Specific Comments

1. Electricity Generation Sources

FPL Group agrees with the approach that EPA proposes for the electric generation sector and commends the Agency for building off of the existing quarterly emissions reporting requirements of the Acid Rain Program and following the existing requirements under 40 CFR Part 75 and Appendices.

FPL Group encourages EPA to harmonize emissions monitoring requirements across EPA air programs to the extent possible. Particularly in instances where the proposed rule would require upgrading the existing CEMS, FPL Group urges EPA to consider other existing or planned CEMS requirements for the electric sector, such as under a replacement Clean Air Interstate Rule (CAIR) program or under upcoming utility Maximum Achievable Control Technology (MACT) standards (e.g., MACT standards to replace the Clean Air Mercury Rule [CAMR] and its CEMS requirements).

Proposed §§ 98.30 and 98.40 would exempt portable equipment and emergency generators from GHG emission reporting requirements. Due to the minimal GHG emissions expected from such equipment, FPL Group supports the equipment's exemption from the proposed reporting requirements. However, we believe that EPA has crafted the proposed exemption too narrowly. Under proposed §§ 98.30 and 98.40, only portable equipment and emergency generators *that are designated as emergency generators in a permit issued by a state or local air pollution control agency* would be exempt from the reporting requirements of the regulation. FPL Group believes that the permit designation restriction is unnecessary. Because GHG emissions from such equipment are generally minimal, and because exempt emergency generators would already be required to meet the specifications listed in the definition of "emergency generators" under proposed § 98.6, there is no reason to add a further restriction that the equipment be listed in a permit.

Some states exempt emergency generators from construction or operating permits if certain operating criteria are met. For example, in Wisconsin an emergency electric generator means "an electric generator whose purpose is to provide electricity to a facility if normal electrical service is interrupted and which is operated no more than 200 hours per year." WIS. ADMIN. CODE NR § 400.02(56). An emergency electrical generator fitting this definition is exempt from construction or operating permit requirements provided it is "powered by internal combustion engines which are fueled by gaseous fuels, gasoline or distillate fuel oil with an electric output of less than 3,000 kilowatts." WIS. ADMIN. CODE NR §§ 406.04(1)(w) and 407.03(1)(u)). As a result of such state exemptions, emergency generators may be designated as emergency generators by the state, but not included in the state or local air pollution control agency permit.

For these reasons, FPL Group believes that proposed §§ 98.30 and 98.40 should be revised to simply state that portable equipment and emergency generators that meet the definition of "emergency generators" under § 98.6 are excluded from the proposed reporting requirements of applicable source categories. At a minimum, EPA should expand the exemption to apply not only to emergency generators that are exempted by permit but also to emergency generators that are exempted from permitting.

2. Electric Power Systems

In subpart DD of the proposed rule, EPA provides for the reporting of SF_6 (or perfluorocarbons (PFCs)) from the "electric power system source category," which includes "transmission and distribution systems that operate gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers" containing SF_6 or PFCs. Proposed § 98.300, 74 *Fed. Reg.* 16694. EPA proposes to require emissions reporting if the total nameplate capacity of equipment containing SF_6 exceeds 17,820 lbs. *See id.*, proposed § 98.301. EPA states that this threshold is equivalent to that used for other source categories and was based on emissions reported by members (including FPL Group) of EPA's voluntary SF_6 Emission Reduction Partnership for Electric Power Systems (Partnership). To calculate SF_6 emissions, EPA proposes that owners of electric power systems use the mass balance approach (*see id.*, proposed § 98.303) that is similar to the one currently used by the Partnership. *See id.* 16549/3.

SF_6 Emissions Should Be Reported at the Corporate Level

EPA's formulation of the source category and the proposed reporting threshold for electric power systems and the use of the mass balance approach for calculating emissions imply that, unlike other source categories, reporting of SF_6 from electric power systems will be done at the system or *corporate* level instead of facility level. As indicated above, however, it appears that EPA is also proposing to require electric generating units – "facilities," in the parlance of the proposed rule – that exceed the 25,000 metric tons of CO_2e per year threshold include in their annual reports SF_6 emissions data. It is very important for EPA to confirm that SF_6 reporting is to be done at the corporate level, and to clarify in the final rule that such emissions data are *not* required to be included in annual reports for other facilities.

In the case of SF_6 emissions from electric power systems, reporting at the corporate level serves two important purposes recognized by EPA. First, it ensures that the largest potential emitters of SF_6 will be covered by the rule, consistent with EPA's goals when selecting thresholds for this reporting rule. Second, it will ensure more accurate emissions reporting while minimizing the burden on owners and operators of electric power systems.

As an initial matter, it is not clear how the definition of "facility" would function if transmission and distribution (T&D) equipment were included. EPA would need to propose a methodology for determining whether equipment, particularly transmission and distribution lines, were part of a facility, based on extent, voltage, ownership or some other rubric. Such complexity is not consistent with EPA's rational for selecting the 17,820 lbs threshold for SF_6 reporting. In the preamble of the proposed rule, EPA states that this capacity-based threshold allows "utilities to quickly determine whether they are covered." *See id.* 16550/1. There would be nothing quick about having to rely on regulatory interpretations to determine which SF_6-containing T&D equipment would have to be included in the facility's annual report. Allowing companies to report corporate SF_6 emissions based on nameplate capacity is much simpler, as EPA noted.

Moreover, the corporate reporting approach is likely to provide more accurate data. For example, including T&D SF_6 emissions in electric generating unit facility reports could lead to double counting of SF_6 emissions, especially if it is not clear which equipment is considered to be part of the electric generating unit facility. In a worst case scenario, this could lead to underreporting of SF_6 emissions. Treating the electric power system as a *system* mitigates this potential problem.

Finally, expanding the "facility" concept to include T&D equipment that might necessarily be co-located with electric generating units also is not workable from a logistical standpoint. There are a variety of corporate structures and relationships in the electric power industry such that it is not always (and not often) the case that the owner of the electric generating unit is also the owner of the T&D equipment. Therefore, including SF_6 data in an electric generating unit facility emissions report could possibly require the sharing of emissions and nameplate capacity data across not only intra-company lines, but also across inter-company lines. Companies should not have to rely on outside sources to ensure that they meet their own reporting obligations. In addition, potentially sensitive business information should not have to be shared to meet reporting obligations.

Even if the EGU and the T&D equipment are commonly owned, companies purchase and store SF_6, which is expensive, for use across the entire T&D system, not for specific substations or lines. Consequently, EPA's mass balance approach makes sense from a corporate perspective, but not from an individual facility standpoint. In order to use the mass balance approach at the facility level, T&D owners would have to separately store, or at least very closely track, SF_6 designated for specific equipment. Such an approach is unnecessarily burdensome, not cost-effective and potentially inefficient as it may require a company to purchase more SF_6 than necessary to ensure sufficient SF_6 supplies are available. Companies should be encouraged to keep stores of SF_6, a GHG with a high radiative forcing, to a minimum.

Small, Sealed Equipment Should be Exempted from Reporting Requirements

FPL Group requests clarification with regard to reporting requirements and any de minimis exemption for small SF_6 equipment that is sealed, similar to the exemption that exists for partners in the EPA Voluntary SF_6 Partnership Program. Sealed equipment (e.g., transformers) is not designed for refill and is instead replaced when no longer functioning. FPL Group suggests that small sources (containing less than 15 lbs of SF_6) should not be included in the capacity total.

Monitoring Requirements Are Unnecessarily Burdensome and Should be Revised

Proposed § 98.304(b)(2) would require the reporter to "[e]nsure that procedures are in place and followed to track and weigh all cylinders as they are leaving and entering storage. Cylinders shall be weighed on a scale that is certified to be accurate to within 1 percent of the true weight; . . ." FPL Group understands that this would require electric power system operators to purchase and maintain numerous high-accuracy scales, which would have to be placed at each site where SF_6 cylinders are stored. This requirement would cause electric power system operators to incur significant costs to monitor relatively de minimis amounts of GHG emissions.

FPL Group believes that SF_6 cylinders could be monitored by affected electric power systems using less costly monitoring techniques. For example, proposed § 98.306 would already require reporting of SF_6 stored in containers at the beginning of the year, SF_6 sales and purchases, SF_6 sent off site for destruction, and SF_6 sent for and returned from recycling. FPL Group believes that the initial measurement of SF_6 stored in containers, combined with the submission of records tracking subsequent SF_6 transactions, would provide a sufficient means for monitoring SF_6 emissions without requiring the weighing of all SF_6 cylinders as they leave and enter storage.

Finally, EPA is also proposing that a facility meeting the SF_6 threshold to report GHG emissions would also be required to report on all sources in any source category for which calculation methodologies are provided in proposed 40 CFR part 98, subparts B through JJ. FPL Group requests clarification on the specific emission reporting requirements for electric power systems that are in addition to the fugitive SF_6 and PFC emissions. For example, would the facility be required to report smaller combustion sources on site if under the same ownership control? Would there be any emissions or heat input size threshold for determining applicability? Finally, FPL Group recommends that portable equipment or generating units designated as emergency generators should be exempted from this category as well.

FPL Group appreciates the opportunity to comment on EPA's proposed mandatory GHG reporting rule. If you have any questions, please do not hesitate to contact me at (561) 691-7001 or Joseph Miakisz of my staff at (561) 691-7680.

Sincerely,

Randall R. LaBauve
Vice President
Environmental Services

Florida Power & Light Company, P.O. Box 14000, Juno Beach, FL 33408-0420

FPL.
POWERING TODAY.
EMPOWERING TOMORROW.

August 31, 2009

Air and Radiation Docket and
Environnemental Protection Agency, Mail code: 6102T,
1200 Pennsylvania Ave., NW.,
Washington, DC 20460.

ATTENTION: Docket ID No. EPA–HQ–OAR–2009–0234.

Reason: FPL Group comments on the Agency Information Collection Activities: Proposed Collection; Comment Request; Information Request for National Emission Standards for Coal- and Oil-fired Electric Utility Steam Generating Units; EPA ICR No. 2362.01

Submitted by: E-mail: a-and-r-docket@epa.gov

FPL Group would like to thank EPA for the requesting of comments on the proposed collection request.

FPL Group, Inc. (NYSE: FPL) is a leading clean energy company with approximately 39,000 megawatts of generating capacity and more than 15,000 employees in 27 states and Canada. Headquartered in Juno Beach, Fla., FPL Group's principal subsidiaries are NextEra Energy Resources, LLC, the largest generator in North America of renewable energy from the wind and sun, and Florida Power & Light Company, which serves 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country. Through its subsidiaries, FPL Group collectively operates the third largest U.S. nuclear power generation fleet.

Over all FPL Group finds this proposed collection to be monetarily significant for impacted units thus adding a burden to our customers. Our comments focus on burden reduction, collection data improvements, and clarifications.

FPL Group concurs except as may be noted in this letter with the August 31, 2009, letters from the Clean Energy Group and the Class of 85 comments that recommend revisions to the proposed collection.

COMMENTS:

1. **FPL Group requests the removal from the test portion of the collection for two NextEra Energy Resources facilities.**

The William F. Wyman facility located in Yarmouth, Maine requests to be removed from the obligation to stack test due to the burden involved for this facility. The Wyman facility is on the stack test list for required testing of two units. We request that W.F. Wyman Plant be removed because the capacity factors are not projected to increase. The annual capacity factors are addressed in Attachment 1 along with the cost of testing the facility.

The Stockton Cogen [POSDEF] facility is on the stack test list for two required tests: non-Dioxin & Furan HAPs. The Stockton facility is currently shutdown and no plans to startup are predicted. The staff has been reduced to a minimal crew of 4-employees. The facility located in Stockton, Ca., requests to be removed from the obligation to stack test due to the burden involved for this facility to bring in staff and fuel to power up from long term shutdown. Please see Attachment 2 for additional detail on this facility.

2. **FPL Group requests the removal from the test portion of the collection for the following FPL Company units.**

The Sanford Power Plant Unit 3 is on long term cold standby. The current annual capacity factor is zero as the unit is nitrogen capped. The unit has a low capacity factor and the facility has a "not to exceed" emissions cap that is a concern for long periods of oil firing. This unit is limited on specific pollutants where the higher emissions of these pollutants come from fuel oil.
Detailed return to service costs can be provided upon request.

FPL requests that the Cape Canaveral Power Plant units be excluded from the stack test portion of the collection request. The demolition of the FPL Cape Canaveral Power Plant units 1 & 2 will begin taking place next year [2010]. Detailed delay of demolition costs can be provided upon request.

3. **FPL Group requests the extension of the stack test period and response time from 6-months to 12-months.**

FPL Group supports a revision to allow stack tests to be done during periods of planned operation. Due to breakdowns and competition for qualified stack testers additional time will be needed beyond the six months listed in the draft ICR. This revision would also help limit emissions produced just for the purposes of testing.

FPL Company has 10-units identified for testing and it will be very difficult to complete the testing, analyses, QA/QC and submittal in a 6-month period especially if all 10 units must be tested within the same 6-month period.

4. **FPL Group requests the speciation of Nickel for Oil-Fired Units**

EPA has recognized the importance of speciation of Chrome in the draft ICR. Equally as important is the need to speciate nickel and mercury for oil fired units.

FPL Group requests that the final ICR include language that all oil-fired units are required to analyze residual oil fly ash (ROFA) samples for Ni concentrations and to speciate for compounds of nickel including, at a minimum, nickel sulfate ($NiSO_4$), nickel oxide (NiO), nickel subsulfide (Ni_3S_2) and other nickel sulfide compounds (e.g., NiS, NiS_2). It has long been recognized that nickel and nickel compounds vary greatly in their toxicity and carcinogenicity potential (e.g., Costa and Heck, 1982; Costa and Mollenhauer, 1980; National Toxicology Program a, b, c, 1996; Oller et al. 1996). More recently, a series of papers from studies led by the Energy & Environment Research Center, University of North Dakota, have analyzed speciated combustion ash and ROFA samples from laboratory-scale (7 kW) and utility-scale (400 MW) combustion systems (Galbreath et al., 1998; Galbreath et al. 2000; Galbreath et al. 2005). The final paper demonstrated that speciated analyses of ROFA samples obtained from 400- and 385-MW utility boilers did not detect any nickel sulfide compounds, including all those compounds of nickel determined to be carcinogenetic. Thus speciation of nickel compounds is essential to develop a risk-based evaluation of oil-fired utility emissions on human health. Please see references in Attachment 3.

5. **FPL Group requests the speciation of Mercury**

FPL Group requests that EPA amend the Draft ICR so that it requires oil-fired units to identify the species of mercury emitted by a unit, in addition to submitting general data on mercury emissions. Section 112(n)(1)(a) of the Act allows EPA to set NESHAPs for coal- and oil-fired EUSGUS to protect human health from hazards reasonably anticipated to occur as a result of emissions by EUSGUs of pollutants listed under CAA § 112(b). The Draft ICR would require Fossil Fuel-Fired units to test for total mercury because "mercury compounds" are listed as a HAP under Section 112(b). However, not all mercury compounds present equal risk. Speciation data would demonstrate that the species of mercury emitted by EUSGUs do not present equal risk to human health. Different Species of mercury have widely variable atmospheric residence time. The value of mercury speiation data, therefore, is in estimating the residence time and resulting dispersion before desposition is likely to occur. This directly affects the "HOT SPOT" issue of near-source deposition. In some cases, exposure pathways of mercury to human populations may derive more from Asian combustion sources tha from US based utilities.

Accordingly, information on the species of mercury emitted by Fossil Fuel-fired EUSGUs would be extremely helpful to EPA in identifying potentially harmful emissions effects relevant to U.S. populations pursuant to the mandate in CAA § 112.

References can also be supplied for mercury speciation as provided for the preceding comment on nickel.

6. **FPL Group requests removal of NOx from the required stack test for oil-fired units.**

Chemicals such as NOx that have been tested in previous stack tests are in many cases continuously monitored have been requested as a part of the stack test chemicals. FPL Group requests these routinely tested chemicals be removed as a requirement for the new stack testing to reduce the costs and need for additional resources. Accurate NOx values can be provided from the continuous emissions monitors for the stack test periods.

7. **FPL Group requests exemption from the requirement to collect an additional nine fuel oil samples over a 30-day period for units with low capacity factors that may not run for an extended period after the required stack test is performed.**

For units required to perform stack testing an additional 9 fuel oil samples spread evenly across a 30 day testing period is unfeasible for some units due to reasons of not running or running very sporadically. If testing is required and performed, the initial set of samples should be valid and no further testing required for these low capacity units.

8. **Volatile organic compounds as a surrogate instead of formaldehyde**

FPL Group recommends a comparison of formaldehyde testing versus VOC testing. The use of VOC testing over formaldehyde is recommended for the setting of a MACT standard, as the VOC testing has a history where results indicate the methodology to be more accurate and consistent than that of formaldehyde testing methodology. The test procedures for VOCs are also more cost-effective.

9. **FPL Group requests alternate methods be allowed in the final ICR such as a modified Method 17 for Nickel sampling. Other methods may need similar enhancements to adjust methods to be utilized with oil-fired units.**

As an example FPL Group plans to utilize the nickel speciation sampling and analytical methods described in Galbreath, K.C.; Schulz, R.L.; Toman, D.L.; Nyberg, C.M.; Huggins, F.E.; Huffman, G.P.; Zillioux, E.J. Nickel and sulfur speciation of residual oil fly ashes from two electric utility steam-generating units, *Journal of the Air & Waste Management Association* 2005, *55*, 309-318. Residual oil fly ash (ROFA) will be sampled isokinetically using a modified EPA Method 17 sampling train assembly with the nozzle, probe, and quartz thimble filter maintained at greater than 290 degrees Celsius, well above the sulfuric acid dew point temperature. The sampled ROFA will be analyzed for nickel speciation using nickel K-edge x-ray absorption fine structure spectroscopy (XAFS), soluble nickel extraction, and x-ray diffraction (XRD).

10. **How many oil-fired units does EPA plan to test in the ICR request?**

The draft ICR supporting document "INFORMATION COLLECTION REQUEST FOR NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPS) FOR COAL AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS" Part B of the Supporting Statement page 7 identifies 189 oil fired units for testing. This number conflicts with the Attachment 2 of the burden statement and estimated cost which lists 116 units with testing costs estimated.

11. **FPL Group requests the removal of the requirement to perform duel trains collection for PM during stack testing and address the option of duplicate testing and extended PM collection periods.**

Dual trains for PM collection are very difficult to perform and would be better served to extend collection periods for better sample collection.

FPL preliminary estimates exceed the EPA estimate of ~$302K per unit in Attachment 2 of the ICR. Assumption is that this covers all stack testing & associated lab analyses, plus fuel oil sampling and analyses.

Duplicate stack tests, speciation of nickel and mercury, and extended sampling periods to collect adequate PM for metals analyses are anticipated and reflected in our preliminary estimate for stack testing. Preliminary estimates are in the $350k range for duplicate testing.

12. **FPL Group recommends the division of Coal units into four categories for testing be condensed into one test category for development of one MACT with one group of best performing units. A new set of Categories is recommended.**

FPL Group recommends that the coal units be categorized to: **Category 1** all fuel types, **Category 2** IGCC units, and **Category 3** CFB units. All units that are not IGCC or CFB would fall under the fuel type category.

FPL Group supports the Class of 85 "Comments on EPA's Method for Selecting Units to Conduct Testing": FPL Group recommends EPA set a single MACT standard for coal-fired units based on the three categories suggested and any unit tested will complete the draft ICR four chemical categories EPA set up in the ICR to allow for the formation of one MACT standard.

The division of coal units into the four ICR categories for testing can create a requirement of multiple additions of control devices to reach the floor for each of the separate categories. This stacking of controls will be cost intensive and may give unanticipated results.

In closing FPL Group urges EPA to consider the following requests to ease the burden of providing the necessary information for EPA to create a viable standard. Primary requests include a.) Allow exemption for selected units from the requirement to perform tests; b.) Extend the period to test and report to one-year; c.) Include the speciation of nickel and mercury in the collection request.

FPL Group appreciates the opportunity to provide these comments to EPA. If you have any questions concerning this information, please contact me at 561-691-7040; or Mary Archer at 561-691-7057; mary.archer@fpl.com

Sincerely,

Rayburn Butts
Director, Environmental Services
Florida Power and Light Company

FPL GROUP **ATTACHMENT 1**

William F. Wyman – 2 units [unit with ESP and 1 of the units without ESP]
Estimated Wyman EPA Stack Testing Costs for proposed ICR

Based on 48 hours of testing, actual testing may exceed 48 hours.

	Cold Start	Hot Start		
Unit #3	$24,400	$8,700		$59,200
Unit #4	$71,000	$27,500		$181,000
Assume 1 Cold Start and 4 Hot Starts per unit.			Start total	$240,200

Fuel Cost MwHr * 1.5 bbl oil @ $70.00 per bbl assuming Unit 3 is at 90 MW and Unit 4 is at 300 MW.

Unit #3	90 MwHr * 1.5 * 70 * 48 =	$453,600
Unit #4	300MwHr * 1.5 * 70 * 48 =	$1,512,000
EPA Estimated Stack Team Cost		$302,000
Fuel Oil Testing 48 samples * 500 =		$48,000
Additional labor costs, 3 men * 48 * $40 =		$5,800
Total Estimated Cost		**$2,561,600.00**

Annual Capacity Factors

	Unit #3	Unit #4
2006	1.18	0.96
2007	6.03	5.81
2008	2.66	2.41
2009 Jan - July	5.27	5.52

POSDEF Power Company
Cost to Test A & B Boiler
Updated: 8/27/2009

ATTACHMENT 2

Cost Items	Qty	Rate, $/unit	Amt	Total	Comments
1					
Personnel Cost to Mobilize and Operate the units for testing (No longer at Site)					
# of Personnel	12				Two shifts of five plus 2 coaches
# of Weeks	5				Assume 2 weeks prior to SU, 2 weeks to run and do test and one week to shutdown (Burn-up remaining fuel).
Ave Hours per Week per Person	84				
Ave Cost per Person	$94,640	$45.50	$229,320		Annual/hourly Rate, All In
Fleet Team Support	200	$100.00	$20,000		Augie de la Vega, John Mulligan
Travel & Temp Living Expenses		$9,275.00	$111,300		
Total				$340,620	
2 *Testing Contractor Cost (both units)*	2	$35,000	$70,000		$30k per Unit
				$70,000	
3 *VOM*					
Coal, tons	8,400	$83.00	$697,200		Approximately 2 weeks of full load burn
Limestone, tons	924	$35.00	$32,340		Approximately 2 weeks of full load burn
Ammonia, lbs	20,000	$11.60	$232,000		Approximately 2 weeks of full load burn
Water, ccf	25,000	$2.00	$50,000		Approximately 2 weeks of full load burn
Sand, tons	360	$37.00	$13,320		Assume 2 Startups
Ash Disposal, tons	1,932	$65.00	$125,580		Approximately 2 weeks of full load burn
Purchased Power, MWH	710	$120.00	$85,200		Assume 3 Startups + 25 MW per Day
SU Fuel (NG), mmbtu	9,000	$8.61	$77,490		Assume 3 Cold Startups + 2 Hot Starts
Water Treatment System, Trailers	2.8	$5,000.00	$13,975		Approximately 2 weeks of full load burn
Boiler Water Treatment Chemicals	1	$6,000.00	$6,000		
Cooling Tower Treatment Chemicals	1	$2,000.00	$2,000		
				$1,335,105	
3 *Required Maintenance Projects to Run Plant*					
Boiler A	1	$200,000.00	$200,000		
Boiler B	1	$400,000.00	$400,000		
Turbine Generator	1	$50,000.00	$50,000		
BOP	1	$100,000.00	$100,000		
				$750,000	
4					
Cost to Return Site to Caretaker Mode					
Vacuum & Clean Around Boilers, Towers, etc	2	$60,000.00	$120,000		CIS, Temp Labor, etc
Boiler Layup Chemicals	2	$1,200.00	$2,400		
Empty Fuel & Ash Silos	2	$5,000.00	$10,000		CIS & Temp Labor
Clean Coal Storage Area	1	$5,000.00	$5,000		A +
				$137,400	
5 *Total Cost*				$2,633,125	

FPL Group Comments ATTACHMENT 3

References

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b. Costa, M and H.H. Mollenhauer. 1980. Carcinogenic activity of particulate nickel compounds is proportional to their cellular uptake. Science, 209:515-517.
c. National Toxicology Program (a) 1996. Toxicology and Carcinogenesis Studies of Nickel Oxide (CAS No. 1313-99-1) in F344/N Rats and B6C3F Mice (Inhalation Studies). Technical Report Series No. 451, NTP, Research Triangle Park, NC.
d. National Toxicology Program (b) 1996. Toxicology and Carcinogenesis Studies of Nickel Subsulfide (CAS No. 12035-72-2) in F344/N Rats and B6C3F Mice (Inhalation Studies). Technical Report Series No. 453, NTP, Research Triangle Park, NC.
e. National Toxicology Program (c) 1996. Toxicology and Carcinogenesis Studies of Nickel Sulfate Hexahydrate (CAS No. 10101-97-0) in F344/N Rats and B6C3F Mice (Inhalation Studies). Technical Report Series No. 454, NTP, Research Triangle Park, NC.
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NEXTera ENERGY

March 18, 2011

EPA-HQ-OAR-2011-0090
Air and Radiation Docket and Information Center
Environmental Protection Agency, Mail Code: 6102T
1200 Pennsylvania Ave., NW
Washington, DC 20460
(submitted through www.regulations.gov)

Re: NextEra Energy, Inc. Preliminary Recommendations Regarding New Source Performance Standards Governing Greenhouse Gas Emissions from the Power Sector

To Whom it May Concern:

Introduction

In December 2010, the Environmental Protection Agency (EPA) announced a settlement agreement that requires the Agency to set greenhouse gas (GHG) new source performance standards (NSPS) for fossil fuel-based power plants under the Clean Air Act (CAA). Under the terms of the agreement, EPA will propose GHG standards for new and modified electric generating units (EGUs) under CAA subsection 111(b) by July 26, 2011, and will promulgate final standards by May 26, 2012.

On the same schedule, EPA also will propose and promulgate guidelines for states to address GHG standards for existing EGUs under CAA subsection 111(d). Under the expected schedule, states will need to submit plans to EPA within nine months of issuance of the final rule and guidelines.

EPA is accepting pre-proposal comments on GHG NSPS for EGUs until March 18, 2011. NextEra Energy Inc. appreciates the opportunity to provide our preliminary views on GHG NSPS for EGUs. We will also be submitting comments on the proposed rule when it is issued

As an initial matter, it is important to recognize that GHGs are unlike traditional air pollutants. GHGs are ubiquitous, well mixed globally and do not create local or regional hot spots Consequently, GHGs do not readily fit into the regulatory scheme for addressing local and regional air pollution established by the CAA.

Moreover, there currently are no commercially available technologies for significantly reducing GHG emissions from fossil fuel-based EGUs. Significant technology, economic and regulatory issues must be overcome before large-scale carbon dioxide (CO_2) capture systems and end-use CO_2 options (geologic storage, beneficial reuse, *etc.*) become commercially feasible for the power sector. Carbon capture and storage (CCS) technologies for EGUs will not be available commercially before 2020-2025 at the earliest, and this timing assumes that key legal and regulatory issues are resolved and that CCS has been demonstrated at scale and integrated with power generation.

With these initial thoughts in mind, provided below are NextEra Energy's preliminary recommendations as to how EPA should proceed to develop and implement GHG NSPS governing the electric power sector.

NextEra Energy Preliminary Recommendations

A Framework of Environmental Regulatory Principles

As EPA considers how best to develop and promulgate GHG NSPS for EGUs, it should work to achieve *flexible* regulations that help facilitate the transformation to a cleaner, more efficient and modernized generation fleet and electric grid in a meaningful and predictable manner. To that end, EPA should strive to:

- develop reasonable, achievable compliance limits and deadlines, attainable with commercially available and adequately demonstrated technologies, equipment and other resources;
- allow for compliance in the most cost-effective manner and reflect applicable cost-benefit and market-based principles to minimize impacts on customers, especially low-income consumers, the economy and jobs;
- support and encourage maximum harmonization across state boundaries while allowing states flexibility in how they achieve required reductions from existing power plants, as long as they can demonstrate equivalency with EPA guidelines.
- allow a coordinated and orderly transition of the generation fleet, consistent with technical and economic capabilities;
- allow a range of approaches to reduce average fleet emissions, including generation efficiency improvements, retirements of current units, repowerings, retrofits, increased use of clean energy technologies, increased end-use efficiency and use of offsets and emissions averaging;
- provide greater certainty for business planning;
- reward, not penalize, companies that have taken early action to invest in clean energy technologies and to improve the efficiency of their fleet.

NSPS for New, Modified and Reconstructed Units

For listed source categories such as steam electric generating units, Section 111(b) of the CAA requires that EPA establish "standards of performance" that apply to sources that are constructed, modified or reconstructed after EPA proposes the NSPS for the relevant source category. However, EPA has significant discretion to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered, and set the level of the standards.

NextEra Energy believes that GHG NSPS for new EGUs should be based on the most efficient boiler designs commercially available for the type of unit being proposed (e.g., coal-fired, natural gas-fired) and its intended function (e.g., baseload, peaking), without redefining the source. For new and reconstructed coal-fired units, standards should be based on supercritical or ultra-supercritical boiler design. For new and reconstructed natural gas-fired units, NSPS should be based on the efficiencies achievable from state-of-the-art turbines available for the type of unit being proposed, whether it be a single-cycle combustion turbine intended for peaking purposes or a combined-cycle facility intended for meeting baseload requirements.

With respect to major modifications of existing EGUs that trigger NSPS requirements, NextEra Energy believes that GHG NSPS should be based on the original design heat rate of the unit and a variability factor that takes into account cyclical degradation of heat rate between scheduled outages.

NSPS for Existing Un-modified Sources

Section 111(d) of the Clean Air Act requires regulation of existing sources in specific circumstances. Specifically, where EPA establishes an NSPS for a pollutant, a section 111(d) standard is required for existing sources in the regulated source category except in two circumstances. First, section 111(d) prohibits regulation of a NAAQS pollutant under that section. Second, "where a source category is being regulated under section 112, a section 111(d) standard of performance cannot be established to address any hazardous air pollutant listed under 112(b) that may be emitted from that particular source category."

Section 111(d) also uses a different regulatory mechanism to regulate existing sources than section 111(b) uses for new and modified sources in a source category. Instead of giving EPA direct authority to set national standards applicable to existing sources in the source category, section 111(d) provides that EPA shall establish a procedure for states to issue performance standards for existing sources in that source category. Under the 111(d) mechanism, EPA first develops regulations known as "emission guidelines." Section 111(d) guidelines, like NSPS standards, must reflect the emission reduction achievable through the application of Best Demonstrated Technology. However, both the statute and EPA's regulations implementing section 111(d) recognize that existing sources may not always have the capability to achieve the same levels of control at reasonable cost as new sources. The statute and EPA's regulations in 40 CFR 60.24 permit states and EPA to set less stringent standards or longer compliance schedules for existing sources where warranted considering cost of control; useful life of the facilities; location or process design at a particular facility; physical impossibility of installing necessary control equipment; or other factors making less stringent limits or longer compliance schedules appropriate. In addition, EPA has indicated in the past that it believes that the NSPS program is flexible enough to allow the use of certain market-oriented mechanisms to regulate emissions.[1]

NextEra's recommended approach for establishing GHG Emission Guidelines under Section 111(d) of the Act governing existing EGUs is to adopt a Generation Performance Standard (GPS). Under this approach, EPA would set a uniform GHG emissions standard for the power sector based on emissions intensity, expressed in terms of tons of CO_2 emitted per MWh of electricity generated. To the extent that a covered source has an emission rate below the regulatory intensity standard, the source would generate credits (measured in a fixed unit of emissions, e.g., a ton of CO_2) that it could average with or transfer to sources with emission rates higher than the regulatory intensity standard.

The rate-based GHG emissions standard should be set at a level that reflects opportunities EGUs have to improve the efficiency of their units. Over time, as technologies for capturing and sequestering CO_2 become commercially available, the standard could be ratcheted down.

Under NextEra's vision of how a GHG GPS program governing the power sector would be implemented, once a rate-based emissions standard was established by EPA, covered sources would have flexibility in complying with the standard:

- The GPS could be applied through a national program administered by EPA; or
- Compliance with the standard could be demonstrated on a fleetwide average basis; or
- States would have the option, through the SIP process, to either require affected units in their jurisdiction to comply with the national GPS for CO_2 or to substitute "equivalent" emission reductions from their own CO_2 control program.

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[1] *Advance Notice of Proposed Rulemaking: Regulating Greenhouse Gas Emissions Under the Clean Air Act*. EPA-HQ-OAR-2008-0318, July 11 2008

- Under any of the above compliance options, verifiable emission offsets (e.g., from renewables, energy efficiency initiatives, etc.) could be generated and allowed as a compliance option.

As an alternative to a rate-based GHG emissions credit program, EPA may want to consider adopting a *heat rate* performance standard for power plants. The heat rate of a plant is the amount of fuel energy input needed (Btus) to produce 1 kWh of net electrical energy output. It is the metric most often used in the electric power generation industry to track and report the performance of thermal power plants. Lower heat rates are associated with more efficient power generating plants and lower CO_2 emissions.

Similar to the rate-based GHG GPS approach outlined above, a power plant heat rate performance standard could be implemented in a manner wherein EGUs with heat rates below the heat rate standard established by EPA would generate credits that they could average with or transfer to sources with heat rates higher than the standard. In addition, compliance with the standard could be achieved through a national heat rate performance standard program administered by EPA, through fleet averaging, through the use of offsets or through participation in a state program that has demonstrated equivalency with the federal emission guidelines.

NextEra Energy appreciates the opportunity to share its views with EPA on how GHG NSPS for the power sector should be established. If you have any questions regarding our comments, please do not hesitate to contact me at (561) 691-7001 or Ray Butts of my staff at (561) 691-7040.

Sincerely,

Randall R. LaBauve
Vice-President, Environmental Services

NextEra Energy, Inc.
700 Universe Boulevard, Juno Beach, FL 33408

NEXTera ENERGY

June 11, 2010

Docket ID No. EPA-HQ-OAR-2009-0927
EPA Docket Center, Attention Docket OAR-2009-0927
Mail code 2822T
1200 Pennsylvania Avenue, NW.
Washington, DC 20460
(submitted through www.regulations.gov)

Re: Mandatory Reporting of Greenhouse Gases: Additional Sources of Fluorinated GHGs

To Whom It May Concern:

NextEra Energy, Inc (NYSE: NEE), formerly FPL Group, would like to thank EPA for the opportunity to comment on the Agency's proposed rule for the Mandatory Reporting of Greenhouse Gases: Additional Sources of Fluorinated GHGs.

NextEra Energy is a leading clean energy company with approximately 39,000 megawatts of generating capacity and more than 15,000 employees in 27 states and Canada. Headquartered in Juno Beach, Fla., NextEra Energy, Inc's principal subsidiaries are NextEra Energy Resources, LLC, the largest generator in North America of renewable energy from the wind and sun, and Florida Power & Light Company, which serves 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country. Through its subsidiaries, NextEra Energy, Inc collectively operates the third largest U.S. nuclear power generation fleet.

Overall, NextEra Energy finds that the burden of this proposed rule would be reduced if the guidelines of the EPA SF_6 Partners Voluntary Reporting Program were integrated into the rule.

NextEra Energy concurs with the June 10, 2010 letter from the Clean Energy Group, providing comments supporting revisions to the proposed rule, except as may be noted in the enclosed comments. Included in this letter are both additional and a number of the concurring comments brought to the attention of EPA by the addressed comment letter.

COMMENTS:

EPA's Proposed Mandatory Reporting of Greenhouse Gases Rule

NextEra Energy's comments focus on the Use of Electric Transmission and Distribution Equipment (Subpart DD). NextEra Energy is generally supportive of the proposed Subpart DD.

Facility Definition

EPA proposes to define the facility as follows:

> *For purposes of this subpart, "facility" means an electric power system. Electric power system means the collection of SF_6- and PFC-insulated equipment linked through electric power transmission or distribution lines and operated as an integrated unit by one electric power entity or several entities that have a single owner. SF_6- and PFC-insulated equipment includes gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, and power transformers containing SF_6 or PFCs. Equipment also includes gas containers such as pressurized cylinders, gas carts, new equipment owned but not yet installed, or other containers.*

NextEra Energy supports the Clean Energy Group belief that it is appropriate to approach reporting of SF_6 emissions on a transmission and distribution utility-wide basis rather than a facility-specific basis. NextEra Energy also recommends that EPA distinguish one electric power system from the next on the basis of ownership of the T&D assets and delete "or several entities that have a single owner" from the above definition.

While this definition is an improvement to the originally proposed definition in 2009, it still leaves uncertainty regarding the reporting of SF_6-containing equipment at switchyards located at electric generation facilities. As EPA is well aware, electric generation facility ownership structures in the electric power industry tend to be very complex. In some cases, the electric generating facility entity owns some or all of the SF_6 equipment in the switchyard. In other cases, a cogeneration host facility owns some or all of the equipment and in other cases the transmission entity does. In addition, in some cases, the electric generation facility and T&D entity are owned by the same parent company but are operated as distinct companies. In other cases, the electric generation facility is an independent power producer and does not have an associated T&D business. Across these ownership arrangements, SF_6 equipment maintenance is sometimes handled in an integrated fashion and other times it is not which presents additional challenges for emissions reporting.

NextEra Energy supports the Clean Energy Group recommendation that EPA clarify reporting of SF_6 from electric generation facility switchyards within the facility definition. Requiring entities to report SF_6 equipment that they do not own/control at electric generating facility switchyards would be overly complex and unreasonable. Please see Footnote 1 addressing the intent of "own" as addressed in this comment. Therefore, NextEra Energy recommends the following:

1. Require transmission/distribution and electric generating entities to separately report SF_6 emissions for the equipment that they own[1] within the switchyard, and

[1] Equipment in utilities with both generating and transmission/distribution services utilize FERC regulations and guidance [Property Retirement Unit Catalog] to assign ownership responsibility to the appropriate operations portion of the business. Some breakers such as the startup breaker are assigned to power generation per these guidelines. The power generation business unit would then have the control and knowledge necessary to certify the emissions for that piece of SF_6 equipment. Other pieces of equipment would be assigned to transmission per the same FERC Property Retirement Unit Catalog. Reference: Code of

2. Allow electric generation facility entities to report SF_6 emissions for the equipment that it owns within the switchyard/contiguous power block with utilization of alternative calculation methodologies (such as engineering calculations) to estimate the emissions of SF_6.containing equipment rather than the mass balance methodology. EPA should identify SF_6 emissions as de minimis compared to stationary combustion greenhouse gas emissions on-site. (Also, keep the 17,820 pound minimum by reporting entity.) Reporters should be allowed the option to report per mass balance where the incoming inventory and the returning bottles are weight certified by the suppliers/recyclers. Suppliers of equipment or bottles must supply certified gas weight to the purchaser.
3. Electric generation facilities and T&D entities that are owned by the same parent company but operated as distinct companies should be allowed to report at the distinct company level.

Best Available Data

Subpart DD will require the development of new operating procedures and staff training in order to collect the data in the manner that EPA is proposing. EPA is proposing that facilities returning cylinders to storage or to the supplier would either weigh the cylinders themselves or have the supplier weigh the cylinders, obtaining a detailed monthly account (within 1 percent) from the supplier. NextEra Energy agrees with the Clean Energy Group that the potential administrative burden and health and safety issues associated with frequent cylinder weighing by substation personnel is a concern, and prefers employing a standardized approach that would require vendors' weighing of the delivered cylinders' residual gas upon return of the cylinder, and recycler's weighing of cylinders, as an effective means to ensure that SF_6 return weights are accurate, consistent, and uniform across the industry. SF_6 vendors and recyclers are better prepared to report this information, as they already employ procedures to weigh cylinders using scales that are routinely maintained and calibrated.

EPA should permit the use of best available estimation methodologies in the first reporting year to limit the administrative burden on industry to weigh each SF_6 cylinder. In the first year, companies should have flexibility to report SF_6 emission estimates using a combination of internal engineering calculations and/or purchase records (or delay the reporting start period to 12 months after the final rulemaking when undue hardship can be demonstrated).

Installation and Commissioning of Equipment Performed by OEMs

EPA requested comment on two issues related to equipment installation and commissioning that is performed by equipment manufacturers at electric power systems. Where the manufacturer filled the equipment before transferring custody to the equipment user, EPA is assuming that the manufacturer would be responsible for the associated emissions. This would also apply to equipment that was filled at the factory but whose charge leaked out before being delivered to the customer. NextEra Energy believes that the manufacturer should certify the weight of gas

Federal Regulation 18, Part 101 at the link: http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=5b2033a9494a622f2fa2666c5f2911b7&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

received in the equipment and should certify the nameplate SF_6 weight. There is a field on the mass balance spreadsheet to record this "pre charge" weight and to record the added nameplate capacity of the breaker.

In addition, NextEra Energy supports the Clean Energy Group recommendation that manufacturers also be responsible for the associated emissions for any overcharge of SF_6 when OEMs install and commission equipment on the utility system. .

Exemptions for Small Distribution Equipment

The vast majority of SF_6 is used in transmission equipment greater than 66kV. The SF_6 used in distribution equipment tends to be very small, enclosed, very hard to track, and has no more than a few pounds of SF_6 capacity. An example of the difficulty of providing this equipment for inclusion in the starting nameplate is addressed by Florida Power & Light Company in the following description.

> *Florida Power & Light Company ("FPL") has switches in distribution transformers in vaults that contain small amounts of SF_6 gas. FPL has approximately 27,000 distribution transformers in vault locations containing between 2,000 – 3,000 switches in these vaults that contain $SF_{6\,gas}$ in quantities that range from 1 to 14 pounds per containment within individualized compartments. Each switch has between 1 to 3 containments, which are individual SF_6 containment structures for each phase or as many as two for three phases. Each of these containments are individual SF_6 components that can be replaced or fail without impact on the other components.*
>
> *Inspection and assessment of the 2,000 – 3,000 distribution switches to determine the serial number and manufacturer to determine the nameplate amount of SF_6 in this legacy equipment is a difficult task given that the equipment is energized and operational. It is also difficult given our vast distribution infrastructure that serves 4.5 million customers within a 28,000 square-mile service territory.*
>
> *The rule proposal implies a degree of accuracy (+/- 1%) in reporting the SF_6 amounts that is not possible with this small equipment in the field. The process and procedures moving forward could potentially capture the amount of SF_6 gas that is being placed into service by its nameplate when this equipment is inventoried and deployed into the field, however, give the small volumes represented, it is not clear that this is the type of equipment that should be targeted. It is our experience that the nameplate amount of SF_6 in the smaller pieces of equipment should be viewed as a range rather than as a specific number. It is our experience that the manufacturer representation of the amount of the SF_6 gas in the switches may not be accurate, and it is impossible to get a confirmation of initial SF_6 amounts for the smaller distribution equipment after it is deployed in the field. It is unreasonable to believe that an estimate of the current volume of $_{SF6}$ gas for the legacy operational equipment would meet an accuracy of +/- 1%.*

As such, NextEra Energy recommends that EPA permit a *de minimis* exemption for small distribution SF_6 equipment that is sealed. This sealed equipment has been exempt from inventory in the voluntary program and a method of tracking has not been established for reporting purposes. Sealed equipment (e.g., switches) is not designed for refill and is instead replaced when no longer functioning. NextEra Energy also supports the CEG recommendation that small sources (containing less than 35 lbs of SF_6) should not be included in the capacity total. This is an instance where upstream regulation of SF_6 is more effective, specifically at the original equipment manufacturer.

Conclusion

NextEra Energy looks forward to working with EPA as this final rule is developed and urges EPA to reconsider the *de minimis* allowance for small equipment addressed in the distribution area to exclude it from the nameplate accounting.

NextEra Energy appreciates the opportunity to provide these comments to EPA. If you have any questions concerning our comments, please contact me at 561-691-7040; or Joseph Miakisz at 561-691-7680; joseph.miakisz@fpl.com, or Mary Archer at 561-691-7057; mary.archer@fpl.com

Sincerely,

Rayburn L. Butts
Director of Environmental Services
Florida Power and Light Company

cc:
Carole Cook
U.S. EPA Office of Atmospheric Programs
Climate Change Division, Mail Code 6207-J
Washington, DC 20460
GHGReportingRule@epa.gov

NEXTera ENERGY

November 19, 2010

VIA ELECTRONIC DELIVERY

Hazardous Waste Management System
Identification and Listing of Special Waste
Disposal of Coal Combustion Residuals From Electric Utilities
Environmental Protection Agency
Mail Code 5305T
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001
Attn: Docket ID No. EPA-HQ-RCRA-2009-0640

Re: **Comments on Proposed Rule; Hazardous Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities (75 Fed. Reg. 35128 (June 21, 2010)), Docket ID No. EPA-HQ-RCRA-2009-00640**

To whom it may concern:

NextEra Energy, Inc. ("NextEra Energy") submits these comments on EPA's Proposed Rule relating to the listing and management of coal combustion residuals (CCR) by electric utilities.[1] NextEra Energy is a leading clean energy company with 2009 revenues[2] of more than $15 billion, approximately 43,000 megawatts of generating capacity, and more than 15,000 employees in 28 states and Canada. Nextera Energy's available generation is comprised of 59% natural gas, 18.9 % renewable (wind, hydro, solar), 12.9% nuclear, 7.0 % oil and 2.2 % coal.

[1] 75 Fed. Reg. 35128 (June 21, 2010).
[2] NextEra Energy 2009 Annual Report

NextEra Energy's principal subsidiaries are NextEra Energy Resources, the largest generator in North America of renewable energy from the wind and sun, and Florida Power & Light Company, ("FPL") which serves 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country.

NextEra Energy is a member of the Utility Solid Waste Activities Group ("USWAG"). For the reasons set forth below, NextEra Energy supports and incorporates herein the comments submitted by USWAG on the proposed rule for the identification, listing and disposal of CCR.

NextEra Energy understands EPA's desire to insure that appropriate standards and controls are in place for the safe management of CCR generated by electric utilities. In the proposed rule USEPA offered and requested comment on two options (Subtitle C and Subtitle D) and a modification of the Subtitle D option referred to as "D Prime". The question for Nextera Energy is not should federal standards be established, but rather what form such standards should take. Nextera Energy therefore supports USEPA's subtitle D Prime option with appropriate adjustments. An effective Subtitle D program would provide for minimum standards, a mechanism for approval of effective state programs, state specific flexibility for alternatives to the minimum criteria, and continued use of existing ash management facilities (both wet and dry) to end of life as long as they do not endanger public health or the environment. A rigid prescriptive approach that has no flexibility to consider other factors such as local geology and available materials can be inefficient and add unnecessary costs.

For the many reasons elaborated upon in the comments submitted by USWAG including questions of legality, damage to the beneficial use markets, and increased electric costs, NextEra Energy holds that a reversal of the 2000 Bevill determination and regulation of CCR as a hazardous waste under the proposed rule is not appropriate.

If USEPA chooses to pursue the Subtitle C hazardous waste option with a reversal of the 2000 Bevill determination, NextEra Energy encourages the Agency to at least follow the Bevill process prior to issuing a final rule to allow for a full disclosure of the decision review process. The Bevill amendment included clear instructions to USEPA regarding how a determination was to be made including a formal report to Congress, input from other agencies, hearings, consideration of impacts to the continued use of coal and beneficial use of CCR. The process was put in place to assure that there was not a rush to judgment and the information relied on for the determination was fully vetted.

As part of a subtitle D approach, USEPA should provide for recognition of effective state management programs. NextEra Energy's Florida Power and Light subsidiary does not operate but does have co-ownership interest in two coal fired power plants, one in Florida and one in Georgia. Both Florida and Georgia have established programs to regulate the disposal of CCR and beneficial use. CCR in Florida is regulated through site certification orders, the solid waste and industrial wastewater rules. Florida regulation of industrial solid waste is found at 62-701 Florida Administrative Code establishing standards for the permitting, construction and performance of solid waste management facilities. Florida does allow for exemption petitions with case-by-case review for industrial waste management. Groundwater monitoring is typically required to insure that groundwater is not contaminated beyond the immediate zone of discharge. If an imminent hazard to public heath or the environment is identified immediate action is required to address the condition. While Florida does not have a specific CCR rule it does effectively regulate the management and disposal through the existing rules. In Georgia CCR is identified as an industrial solid waste and regulated under the solid waste management regulations. Georgia's regulations were designed to handle municipal solid waste (MSW). These regulations include criteria for professional design, liners, and groundwater monitoring similar to the Subtitle D and D Prime approaches. Since, CCR is less variable and not as potentially harmful as MSW these regulations provide acceptable control and protection. Facilities designed and currently performing as designed should be allowed to continue in operation for the remaining useful life.

Another reason for adopting Subtitle D or D Prime is to avoid unintended consequences related to the beneficial use market. As noted by EPA in the preamble for the proposed rule there are a variety of opinions as to the actual effect of a Subtitle C determination on the beneficial use market. NextEra Energy would like the EPA to recognize that the possible exposure to future liability risks caused by a determination that CCR is hazardous waste would negatively impact the beneficial use market. In Florida, a Subtitle C determination, even with an exclusion for beneficially used CCR, would likely curtail the beneficial use of CCR due to the structure of Florida law. The criteria for industrial byproducts in the Florida statutes states:

Chapter 403, Part IV, Section 7045,

> (1) The following wastes or activities shall not be regulated pursuant to this act: (...)
>
> (e) Recovered materials or recovered materials processing facilities, except as provided in s. 403.7046, if:
> (...)
> 3. The recovered materials handled by the facility are not hazardous wastes as defined under s. 403.703, and rules promulgated pursuant thereto.
> (2) Except as provided in s. 403.704(9), the following wastes shall not be regulated as a hazardous waste pursuant to this act, **except when determined by the United States Environmental Protection Agency to be a hazardous waste**: [emphasis added]
> (a) Ashes and scrubber sludges generated from the burning of boiler fuel for generation of electricity or steam.

A conservative reading of the above statute would subject any CCR to full regulation and deem it to be ineligible for use as an industrial byproduct. Other states are likely to have similar conflicts in existing regulations related to the previous determination that CCR did not warrant regulation as a hazardous waste.

As stated earlier NextEra energy supports the development of Subtitle D regulation under the D Prime option with some modification. The USWAG comments provide extended detail of the modifications recommended. (See Section XI and XII of the comments submitted by USWAG) To protect the established CCR beneficial use markets and avoid unnecessary customer rate increases NextEra Energy encourages EPA to pursue the Subtitle D proposal with modifications to allow for acceptance of qualified state programs, use to end of life for existing landfills and impoundments that are performing according to design and allowing for alternative liner systems. A flexible nonhazardous industrial waste standard will provide for protection of public health and the environment as well as avoiding an excessive financial burden for the utility industry and its customers that would result form either a Subtitle C hazardous waste determination or restrictive Subtitle D regimen.

We appreciate the opportunity to comment on this important process. If you have any questions regarding these comments, please contact Tomey Tuttle, Environmental Services Project Manager at 561-691-7050.

Sincerely,

Tomey E. Tuttle

Tomey Tuttle, CPEA, CHMM

NextEra Energy, Inc.

700 Universe Blvd.

Juno Beach, Florida 33408

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February 7, 2011

Docket ID No. EPA-HQ-OAR-2009-0491
U.S. Environmental Protection Agency, Mailcode: 2822T
1200 Pennsylvania Avenue, NW, Washington, DC 20460
(submitted via regulations.gov)

Re: Notice of Data Availability for Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone: Request for Comment on Alternative Allocations, Calculation of Assurance Provision Allowance Surrender Requirements, New-Unit Allocations in Indian Country, and Allocations by States

To Whom It May Concern:

NextEra Energy, Inc. (formerly FPL Group) appreciates the opportunity to comment on the Notice of Data Availability (NODA) EPA published on January 7, 2011 for the proposed Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Transport Rule). NextEra Energy is a leading clean-energy company with 2009 revenues of more than $15 billion, nearly 43,000 megawatts of generating capacity, and more than 15,000 employees in 28 states and Canada. Headquartered in Juno Beach, Florida, NextEra Energy's principal subsidiaries are NextEra Energy Resources, LLC, the largest generator in North America of renewable energy from the wind and the sun, and Florida Power & Light Company (FPL), which serves approximately 4.5 million customer accounts in Florida and is one of the largest rate-regulated electric utilities in the country. FPL has been recognized as having one of the most successful energy-efficiency programs in the nation. Through its subsidiaries, NextEra Energy collectively operates the third largest U.S. nuclear power generation fleet.

NextEra Energy has one of the cleanest energy profiles in the electric sector. Since 1990, while the Company's power generation has increased by 230 percent, our nitrogen oxides (NOx) emissions rate has decreased by 88 percent, our sulfur dioxide (SO_2) emissions rate has decreased by 87 percent and our carbon dioxide (CO_2) emissions rate has decreased by 31 percent. Notwithstanding the Company's clean energy profile, NextEra Energy owns and operates a substantial amount of fossil fuel-fired electric generation in the Eastern U.S. that will be subject to the proposed Transport Rule. Therefore, the Company has a keen interest in the final outcome of the rule.

As stated in our October 1, 2010 comments, NextEra Energy generally supports the proposed Transport Rule. The proposed rule will achieve important air quality, health, and economic benefits utilizing EPA's current authority. It is critical that EPA implement the rule as expeditiously as practicable to ensure realization of these benefits. We are committed to working with EPA to ensure the Agency can implement the Transport Rule by January 1, 2012, and to that end, we offer these comments on the January 7th NODA.

I. Optional methods for allocating allowances to affected sources under the Transport Rule

EPA is taking comment on the appropriateness of two alternative allowance allocation methodologies and their implications for implementation of the Transport Rule. The two alternative methods both rely primarily on historic heat input data, in contrast to the allocation method in the August 2, 2010 proposed Transport Rule, which used a combination of adjusted historic and projected emissions data. The first of the two alternative methods, Option 1, allocates allowances based on an existing unit's proportion of heat input for the state. The second method, Option 2, is similar to the first, but imposes an additional constraint based on historic emission levels.

While NextEra Energy has long supported allowance allocation methodologies based on energy output (megawatt hours), the Company supports allocating allowances under the Transport Rule for SO_2 and NOx to units based on historic heat input, as contemplated under Options 1 and 2 in the January 7th NODA. While both options address most of NextEra Energy's concerns with EPA's preferred approach, as reflected in the August 2, 2010 proposed rule, Option 1 is the more straightforward of the two options and our preference. We are concerned that Option 2 introduces too many potential adjustment factors to be cleanly implemented without legal challenge in the short time EPA has to finalize the rule.

As we noted in our comments on the proposed Transport Rule, the language of the Clean Air Act provides EPA with broad authority to implement allowance allocation methodologies, and there is no strong policy or legal reason that the methodology for determining state budgets and the methodology for distributing allowances to units need to be the same. By maintaining the proposed methodology for determining the state budgets, EPA is consistent with the D.C. Circuit's decision requiring that state budgets be based on each state's significant contribution.

A historic heat input-based allocation has a number of advantages over EPA's preferred approach. Most significantly, it is not based on *modeled* future emissions with its known inaccuracies for units that may dispatch for non-economic purposes and would be based on verified data EPA already holds. Additionally, NextEra Energy agrees with the advantages of allocating allowances on a heat input basis cited by EPA and other commenters:

- Historic heat input data are more likely to be accurate at a unit level than projected unit-level emissions and are generally based on quality-assured data reported by sources from continuous monitoring systems.
- Historic heat input data are fuel-neutral.
- Historic heat input data are emissions-control-neutral and thus do not yield reduced allocations for units that installed or are projected to install pollution control technology.

As we explained in our comments on the proposed rule, the Integrated Planning Model (IPM) used to project emissions under the originally proposed allocation approach does not consider a range of non-economic factors that may influence a company's decision to operate particular types of units or for the respective Independent System Operator (ISO) to call upon specific units. As a result, the modeling can create unrealistic scenarios for some individual units, such as ignoring dispatch requirements of EGUs subject to power purchase agreements, running natural gas combined-cycle units at higher utilization than can be accommodated by the local natural gas pipeline network and not running oil-fired units that are required to operate to meet load requirements. While these distortions of the electricity market are masked when data are aggregated at the state level for setting state budgets, the modeling results in unrealistic or infeasible outcomes when used at the unit level to allocate allowances. By contrast, a historic basis for allocating the state budgets avoids these problems and strengthens the legal basis for the rule.

Using a historic heat input basis for allowance allocation corrects the originally proposed methodology's disadvantage for early actors that EPA acknowledged in the proposed rule and creates the right incentives to drive additional reductions. Thus, NextEra Energy agrees with EPA that an historic heat input-based allocation meets the goals of the section 110 of the Clean Air Act – to encourage the most cost-effective emissions reductions and drive investment in the technologies necessary to address transport and non-attainment on a long-term basis.

Conversely, an initial allocation of allowances based on units' historic heat input would put a relatively greater burden on units with higher emissions rates to reduce their emissions or purchase allowances. This is because a unit with a higher emissions rate would receive the same number of allowances as a lower emitting unit with the same heat input, yet be required to cover more emissions with those allowances. NextEra Energy shares EPA's belief that because higher-emissions-rate units are generally responsible for a larger share of a state's emissions – and thus that state's significant contribution and interference with maintenance – this distribution of burden is consistent with the goals of CAA section 110(a)(2)(D)(i)(I).

II. Optional method for calculating allowance surrender requirements under the compliance assurance provisions of the proposed rule.

EPA is also requesting comment in the NODA on a proposed alternative method for calculating the allowance surrender requirements under the compliance assurance provisions of the proposed rule. Under the compliance assurance provisions contained in the August 2, 2010 proposed Transport Rule, if the emissions from affected units in a covered state in any year exceed the state's "assurance level" (i.e., the state budget plus the state's variability level), certain owners of affected units would be required to surrender allowances. The surrender requirement would be imposed on the *owners and operators* of units whose share of the state's total covered-unit emissions was greater than their share of the state's assurance level – i.e., the units that can be considered partially responsible for the exceedance. The allowances the owners would be required to surrender would also be proportionate to their responsibility for the state's exceedance.

In the January 7 NODA, EPA is requesting comment on changing the way the allowance surrender requirement is calculated. Under this alternative approach each source, along with having an owner and operator, would have a "Designated Representative" (DR) authorized to represent the source in any Transport Rule related trading programs. EPA would calculate the allowance surrender requirements on a *DR-by-DR basis* instead of an owner-by-owner basis. Under this approach, all covered units in the same state with the same DR would be treated as a group, and the applicability of the allowance surrender requirement as well as the number of allowances required would be calculated for the group as a whole. The owners and operators in the group would be both collectively and individually liable for the allowance surrender, and could decide amongst themselves how to divide up the surrender. EPA believes that this method would simplify the implementation of the surrender requirements, because it relies on information EPA already collects rather than requiring EPA to collect new ownership data, and it would avoid the complication of having partial owners of the same unit divide up the emissions and allocations for the unit. Owners and operators could also designate a common DR for all the sources at which their units were located, giving them increased flexibility.

First of all, NextEra Energy agrees with EPA's conclusion that changing the allowance allocation methodology does not require a change in the proposed compliance assurance provisions. As explained in the proposed Transport Rule, in the event that a state's total emissions exceeds the state budget plus variability, those groups of units (whether grouped by owner as in the proposal or by common DR as discussed in the NODA) with an analogous exceedance (*i.e.*, those groups of units with total emissions exceeding their total allowance allocations plus their shares of state variability) would reasonably be viewed as accounting for the state's exceedance and, thus, should be subject to proportionate shares of the allowance surrender penalty. Even under a different allowance allocation methodology than the allocation methodology proposed in the Transport Rule, it would continue to be the case that groups of units with greater emissions than their allocations plus share of state variability would reasonably be held responsible for the state's excess of emissions over the state assurance level. EPA believes that any state that would exceed its state assurance level would likely do so because not all units would have made the reductions necessary to eliminate the state's contribution to nonattainment or interference with maintenance. Moreover, the groups of units with emissions exceeding their allocations plus share of variability would be the units that were most likely to have contributed to the state's exceedance of its state assurance level and, thus, to the state's triggering of the assurance provisions. Consequently, it would be reasonable to penalize those groups of units (whether grouped by owner or by common DR)—through application of the assurance provision allowance surrender requirement—for the state's exceedance.

With respect to the issue of how the allowance surrender requirement should be calculated, NextEra Energy does not support the alternative approach to calculate the assurance provision allowance surrender requirements at the DR level. Rather, we support EPA's original proposal to determine assurance provisions' surrender requirements at the owner level. NextEra Energy has concerns about using the DR level because it could complicate a (non-DR) joint owner's ability to hedge against the two-for-one penalty associated with the assurance provision. For example, if the combined sources under one DR exceed that DR's allocation plus the variability limit, non-DR co-owners who otherwise would not have triggered the assurance provision (because their sources were below the assurance level) would potentially have to pay a portion of the two-for-one penalty. Alternately, if a source is long on allowances, a non-DR owner would not be able to use those additional allowances as a way to balance under-allocated sources. Thus, while the DR-based calculation may provide additional flexibility to some owners and operators (particularly majority owners of co-owned units), it may provide less flexibility to other owners and operators (particularly minority owners of co-owned units).

As an example, assume that Unit A is owned by two companies, Company 1 and Company 2. Company 1 owns 75% of Unit A and Company 2 owns 25% of Unit A. A representative from Company 1 is assigned as the DR of Unit A. If, during a particular control period, Unit A's emissions are less than its allowance allocation, Company 2 would not be able to use the surplus allowances from Unit A to offset allowance shortages at Units B and C, also owned by Company 2 that, without the surplus from Units A, would trigger assurance provisions and 2:1 compliance at Units B and C. Conversely, if facility A's emissions exceed its allocation but does not exceed its share of the state variability limit, it could still trigger assurance provisions for Owner 2 if total emissions from all of Company 1's facilities exceed their share of the state variability limit.

While the risks to a minority owner outlined above could be addressed and mitigated to a certain degree by contractual provisions in an owner's agreement, this is not as straightforward as it may sound. Co-owners agreements are complicated documents that are carefully crafted to protected each co-owners' interests. For this reason, the parties to these agreements are often reluctant to re-open these agreements unless absolutely necessary.

For the reasons above, NextEra Energy opposes the alternate DR-level approach to calculate the assurance provision allowance surrender requirements that EPA requests comment on in the NODA and urges EPA to retain the owner-level approach reflected in the August 2, 2010 proposed Transport Rule.

III. Definition of an "existing unit" under the Transport Rule

For purposes of the NODA, EPA indicates that a potential existing unit is assumed to be a unit that would potentially meet the proposed applicability criteria (i.e., the criteria in proposed §§ 97.404, 97.504, 97.604, and 97.704 in the proposed Transport Rule) for covered units *and that commenced commercial operation prior to January 1, 2009.* According to EPA, this cutoff date was chosen for existing units because it assured that at least 1 full year of historic data would be available to determine each existing unit's allocation. NextEra Energy recommends that the cutoff date for existing units be revised to January 1, 2010, or possibly even January 1, 2011, since data for 2009 and 2010 are now available to the Agency. This will allow emissions from clean and efficient units that commenced operation in 2009 or 2010 to be covered under the Transport Rule SO_2 and NOx caps and not have to rely on allowances from the new unit set-aside to cover their emissions.

NextEra Energy looks forward to working with EPA on developing and implementing this important program. If you have any questions regarding our comments, please do not hesitate to contact me at (561) 691-7001 or Joseph Miakisz of my staff at (561) 691-7680.

Sincerely,

Randall R. LaBauve
Vice-President
Environmental Services
NextEra Energy, Inc.

Q.

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?

A.

FPL's strategy for compliance with the Cross-State Air Pollution Rule's (CSAPR) cap-and-trade program was primarily based on the implementation and use of those projects identified for compliance with the predecessor Clean Air Interstate Rule, and Scherer Unit 4 compliance with the Georgia Multi-pollutant Rule. FPL petitioned EPA to reconsider applicability of the rule to Florida and, in the alternative, to reconsider its model assumptions which led to a lower allocation of allowances to the State of Florida. With the stay of CSAPR the Court instructed EPA to reinstitute the compliance requirements under CAIR until either the stay is lifted or EPA promulgates a CSAPR replacement rule. As a result of FPL's CAIR projects, and the addition of the West County and modernization projects at Cape Canaveral and Riviera, there are sufficient allocated allowances for compliance with the either the CSAPR and CAIR allowance programs. The Court's decision to stay the CSAPR does not impact FPL's compliance plan for either program. FPL anticipates that, if remanded to EPA by the Court, its compliance plans for CAIR will be sufficient to meet a revised CSAPR rule. However, FPL does not yet know whether EPA would make significant changes to the CSAPR replacement rule beyond those that would be required to meet the air quality goals required by the rule that would adversely impact current compliance plans.

Q.

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?

A.

FPL plans to continue its participation in environmental allowance trading markets as it has done under the Title IV Acid Rain Program and CAIR Allowance Programs. Allowance prices are included in the production cost modeling to adequately plan for allowance purchases and recovery during ECRC projections. On a periodic basis FPL evaluates whether actual emissions would exceed allowances held on a system basis including an excess compliance margin. Allowances are purchased, or liabilities recorded, when emissions exceed allowances held for compliance. When FPL projects that allowances held are in excess of facility compliance and regulatory compliance margins it offers excess allowances for sale. Allowance costs and revenue from sale of allowances are recovered and credited through the ECRC. FPL expects to have sufficient allocated allowances to comply with the CAIR and the current CSAPR programs. In its review of the 8-hour Ozone Standard, EPA noted that it would likely review the transport of ozone precursors from electric generating units to downwind nonattainment areas and adjust NOx ozone season budgets for those states which demonstrate adverse impacts to downwind areas. Further reduction in state budgets under CSAPR would likely result in additional emission reductions from sources or use of additional allowances. Given the uncertainty in the ozone season portion of CSAPR, FPL anticipates that it would be prudent to bank excess emission allowances until EPA completes its review of the ozone standard and provides notice whether future additional reductions from Florida facilities would be needed resulting in fewer allocated allowances.

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

A.
Florida Power and Light Company (FPL) is a co-owner of units at two generating stations, Georgia Power - Plant Scherer and JEA - St Johns River Power Park. FPL does not operate either plant. While FPL has a membership vote in decisions regarding operation of these generating units, decisions regarding coal residual disposal practices are decided by the managing boards for those plants. By contractual arrangement FPL does require that all management activities be conducted in full compliance with existing regulations and prudent industry practices. For SJRPP the solid fuel combustion byproducts that have not been transported off-site for sale have been placed in the on-site dry byproduct storage areas (BSAs). Bottom ash and pyrites are loaded by conveyor belts from the dewatering bins to a load-out area to either be transported off-site for beneficial use or transported, via rear dump truck, to the on-site BSA. Fly ash is transported to the on-site BSA or off-site for beneficial use. The solid waste handling system is also designed to load the material into rail cars for transport off-site for beneficial use. A major goal and objective of the SJRPP CCR program is to develop markets for the solid waste by-products to reduce and/or curtail the placement into the on-site byproduct storage area. For the Scherer Unit 4, byproducts are both disposed and sold for beneficial reuse depending on market conditions and product quality. Plant Scherer Unit 4 disposes coal combustion residuals in one landfill and one ash pond, which each serves all four units at the plant. Coal combustion residuals that are not beneficially reused are sluiced wet to the ash pond for storage. Powdered Activated Carbon and Gypsum are stored in the on-site landfill.

Q.

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?

A.

As discussed in FPL's response to Staff's 1st DR No. 55, FPL co-owns but does not operate its coal fired generating units. Efforts to facilitate the recycling of coal waste are conducted by the operators of each facility as agent for the owners.

SJRPP has had an aggressive by-product marketing program in place since it began operations in the late 1980s. SJRPP has pursued the following markets for its by-products: use of synthetic gypsum in wallboard and agronomic applications, use of fly ash as cement plant feed or fuel, and use of fly and bottom ash in concrete batch plants and other aggregate markets. Since 2004, overall by-product utilization rates have approached 75%, but recent declines in construction activity in Florida and the Southeast have adversely impacted markets. Utilization rates for the last several years have declined to approximately 50%.

The operator of Plant Scherer, Georgia Power, has contracted with a leading ash marketer that sells Plant Scherer's fly ash for multiple beneficial uses such as concrete, mineral filler, and exterior trim. The Georgia Power ash marketer has an active research facility that continually develops new and better uses of fly ash to improve products and to benefit the environment through increased recycling. Additionally, Georgia Power continuously seeks additional opportunities to beneficially reuse CCBs.

Q.

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.

A.

FPL anticipates that any modifications that may be required to comply with either Subtitle D or Subtitle C regulations would not impact the generating capability of either Scherer Unit 4 or the SJRPP coal units. The generating units themselves are not expected to be subject to requirements that would result in modifications. The ancillary waste management equipment and processes are expected to be subject to modifications. As discussed in the response to prior questions, FPL co-owns but does not operate its coal fired generating units. Efforts to facilitate the recycling of coal waste are conducted by the operators of each facility as agent for the owners. JEA has not conducted a detailed compliance strategy for SJRPP. JEA will do so when the regulatory approach to be undertaken by EPA becomes clarified and its direction more certain.

JEA did provide input to the comment letter submitted to EPA by the American Public Power Association (APPA). This comment letter did contain rudimentary estimates of the compliance costs associated with both alternatives. The APPA comment letter can be viewed at the following site: http://publicpower.org/files/PDFs/APPAcommentsEPA HQRCRA20090640.pdf.

For Plant Scherer compliance with Subtitle D Prime would require installation of groundwater monitoring wells and periodic monitoring. Should the site be regulated under Subtitle D compliance would require the D Prime requirements, dry ash handling conversion, and installation of new landfills. Under Subtitle C regulation all the costs of Subtitle D plus health and safety requirements for workers, additional permitting costs for on-site hazardous waste landfill, and likely closure and removal of ash from existing ash pond. An estimate of the timing of implementation for each alternative has not been developed by the facility operator and will depend on the final rule. Cost estimates for implementation have been provided in FPL's response to Staff's 1st DR No. 44.

Q.

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

A.

In its Resource Planning Process, FPL assumes future costs for CO2 emissions. The projection of these CO2 costs is based on forecasts provided by ICF International. FPL includes these projected CO2 costs when comparing the economics of alternate resource plans.

Q.

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

A.

See Attachment No. 1.

Florida Power & Light Company
2012 Ten Year Site Plan - Staff's Data Request No. 1
Request No. 59
Attachment No. 1
Tab 1 of 1

Year		Uranium		Coal		Natural Gas		Residual Oil		Distillate Oil	
		GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU	GWh	$/MMBTU
Actual	2002	25,295	0.257	5,977	1.714	34,546	4.064	18,708	3.522	188	6.373
	2003	23,524	0.255	6,625	1.830	37,707	6.237	20,304	4.460	248	7.135
	2004	23,013	0.277	6,315	1.686	40,970	6.370	19,709	4.429	199	7.959
	2005	21,406	0.321	5,765	1.724	47,114	8.533	19,069	6.164	186	12.093
	2006	23,533	0.376	6,168	2.031	56,985	8.806	9,586	8.154	26	13.876
	2007	21,899	0.380	6,856	2.122	59,300	9.703	9,651	9.306	27	14.472
	2008	24,024	0.427	6,423	2.238	58,820	10.245	5,702	10.298	17	15.834
	2009	22,893	0.512	6,363	2.443	62,728	8.188	4,560	10.645	21	14.063
	2010	22,850	0.549	5,721	2.587	66,765	6.356	4,081	11.486	278	13.841
	2011	22,942	0.608	5,634	2.844	74,388	5.832	630	12.926	123	19.465
Projected	2012	19,162	0.704	5,064	2.725	78,888	3.896	971	16.233	1	23.875
	2013	26,493	0.745	6,029	2.689	73,106	4.494	422	15.393	21	23.523
	2014	28,076	0.785	5,683	2.792	77,223	4.939	314	16.803	0	25.639
	2015	26,465	0.793	6,825	2.908	78,824	5.253	430	17.104	0	26.691
	2016	28,458	0.815	6,743	3.043	79,608	5.851	491	20.894	7	29.927
	2017	28,463	0.834	7,395	2.909	82,436	6.366	468	21.475	3	29.827
	2018	27,286	0.855	6,791	2.914	86,264	6.899	407	22.045	5	30.829
	2019	28,376	0.876	7,391	3.424	85,886	7.332	441	22.621	14	31.699
	2020	28,545	0.898	6,884	3.504	88,106	7.909	490	22.978	27	32.562
	2021	27,288	0.920	7,417	3.558	90,976	8.503	666	23.312	36	33.932

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

A.
FPL's medium fossil fuel price forecast methodology utilizes projections from The PIRA Energy Group (PIRA), rates of escalation from the Department of Energy's (DOE) Energy Information Administration (EIA), forward commodity price curves for oil and natural gas, as well as projections from JD Energy, Inc. PIRA, a world-recognized consulting firm with expertise in all aspects of the oil and natural gas industry, supplies FPL with an extensive database to support its short and long-term projections for future prices of oil and natural gas. FPL utilizes forward commodity price curves for oil and natural gas to project the first few years of the forecast (short-term) and applies escalation rates provided by the EIA for the long-term oil and natural gas projections. JD Energy, a consulting firm retained by many utilities and coal suppliers with expertise in all aspects of the coal and petroleum coke industry, supplies FPL with an extensive database to support its short and long-term projections for future prices of coal and petroleum coke. Because FPL's forecasts reflect these authoritative and independent sources, FPL believes that the projections are reasonable and comparisons to other forecasts are not necessary.

For nuclear fuel price projections, FPL subscribes to a number of publications such as reports published by Ux Consulting, Energy Resources International and Trade Tech. These firms represent a broad spectrum of companies and serves as indicators for spot and long term market behaviors. FPL long term price projections are reasonably consistent with the best estimates/projections of these recognized independent companies. FPL expects that there will be times when uranium market prices will fluctuate about these projections, but the price used for uranium provides a better representation of long term trends.

Q.

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.

A.

The current situation in the coal industry may be a harbinger of major challenges that will confront US consumers of coal including FPL through 2021. Less predictable prices and intermittent supply shortages could develop. Domestic coal production has dropped dramatically YTD 2012 in response to high stockpiles and spot pricing that reportedly has fallen below the cost of production in key producing regions including the Powder River Basin and Central & Northern Appalachia. The root cause of the demand erosion is the loss of coal dispatch to historically low natural gas prices. If natural gas prices remain low for an extended period, some existing mines, in particular Eastern underground mines, will be closed and the production capacity permanently lost. A continuation of strong coal export markets as in 2011 would tend to mitigate the erosion of production capacity and support higher commodity prices in the near to mid term. Long term, coal demand growth is doubtful unless carbon capture & control (CCS) required by the EPA's New Source Performance Standards governing carbon dioxide becomes a commercially viable technology.

The demand for natural gas in the United States as well as in the Florida market is expected to continue to grow through the 2012 through 2021 period, primarily in the power generation sector. The supply of natural gas to the United States as well as to the Florida markets is expected to grow and match the growth in demand as declines in production from the mature conventional gas regions of the Gulf Coast onshore, Gulf Coast offshore, and Permian Basin are replaced with rapid growth in unconventional gas mainly from the Mid-Continent and Central Appalachian regions. This will result in natural gas prices increasing moderately over the 2012 through 2021 period.

Similarly, oil prices will increase moderately over the 2012 through 2021 period. The worldwide demand for oil will grow over the forecast horizon primarily in the emerging market countries in the Pacific Rim and in the transportation end-use sector. Non-OPEC supply is projected to grow moderately over this period and OPEC production will grow to fill the supply shortfall.

There continues to be some volatility in the current uranium market. Demand is rather stable and supply exceeds current demand. Uranium price has been volatile recently, first increasing at news of significant increase in future demand to feed a recently announced increase in the Chinese nuclear power program, but then countered by recent events in Japan and the decision from the Department of Energy to sell some of its excess uranium inventories to fund some of the decontamination and decommissioning activities of old uranium enrichment plants. Although the market went up on the news of a more aggressive Chinese build up of nuclear plants, we expect uranium prices to return to our long term predictions, when the impact of the events in Japan are fully factored into the market. FPL expects less volatility in uranium prices within the next few years, with price behavior to be more consistent with market fundamentals.

As for the other steps of the fabrication of nuclear fuel (conversion, enrichment and fabrication services), we expect prices will remain rather stable and additional productions would be added as needed to meet new reactor requirements.

Q.

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

A.

With the incremental 400,000 mmBtu/day of Florida Gas Transmission (FGT) capacity added in April 2011, FPL has enough capacity for the next several years. FPL continues to evaluate strategies that will increase the reliability and supply diversity of its gas transportation portfolio to ensure adequate gas availability for future generation growth. The current gas transportation portfolio provides FPL access to a diverse range of gas supply alternatives, which helps mitigate FPL's exposure to supply disruptions. FPL has secured natural gas transportation on a number of upstream pipelines with access to on-shore natural gas supplies which has significantly reduced our dependence on Gulf of Mexico supplies, thereby decreasing the exposure to tropical events. In addition, FPL has contracted for natural gas storage to provide access to natural gas in the event of a loss of supply. Currently, FPL is working to encourage the development of additional natural gas transportation infrastructure within the state of Florida to further enhance the reliability of FPL's and the state's natural gas delivery system and supplies.

Q.

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.

A.

With regard to the Florida Gas Transmission (FGT) and Gulfstream Natural Gas System (Gulfstream) pipelines, there are currently no announced pipeline expansions. On April 1, 2011 Florida Gas Transmission (FGT) placed its Phase VIII expansion into commercial operation. Inclusive of Phase VIII, FPL has secured a total of 1.274 billion cubic feet (BCF) per day of firm summer transport with FGT. FPL's commitment on Gulfstream is 0.695 BCF per day.

FPL has announced the addition of a pipeline lateral from the Martin facility to the Riviera Beach Next Generation Clean Energy Center (RBEC) which will provide the primary gas delivery to RBEC. In addition, FPL is in the process of preparing a Request for Proposals (RFP) for additional pipeline infrastructure to serve the future natural gas requirements of the FPL system. There is not a firm timeline at this time for the release of the RFP, but FPL is committed, per the Final Order on the Florida EnergySecure Line, to submit the RFP to FPSC staff for review before its release.

Q.

Please discuss in detail any existing or planned natural gas pipeline expansion project, including new pipelines and off-shore projects, outside the State of Florida that will affect the Company over the period 2012 through 2021.

A.

Both Transcontinental Gas Pipe Line (Transco) and the Southeast Supply Header (SESH) pipeline continue to consider potential expansions into Florida Gas Transmission (FGT) and Gulfstream Natural Gas System (Gulfstream) which would provide additional capacity to transport unconventional shale gas into Florida. Several pipelines, such as Tennessee Gas Pipeline and Transco have announced projects which will allow their existing pipeline facilities to deliver gas from the prolific Marcellus and Utica shale regions of Pennsylvania and Ohio to the Southeast. FPL continues to explore opportunities to access this growing supply source.

From an off-shore perspective, the Gulf Clean Energy LNG Terminal in Pascagoula, Mississippi was placed in service in 2011 and can deliver gas into both FGT and Gulfstream.

Q.

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.

A.

Domestic unconventional natural gas production (shale, tight sands, and Coal Bed Methane) is expected to increase from about 26.6 billion cubic feet per day (Bcf/d) in 2012 to about 44.7 Bcf/d by 2021, primarily in the Mid-Continent (20.3 Bcf/d to 23.7 Bcf/d) and Central Appalachian (4.2 Bcf/d to 12.5 Bcf/d) regions. This projected growth in unconventional production will be more than sufficient to ensure ample natural gas supply to meet the anticipated growth in the U. S., Florida, and FPL demand well into the next decade.

Q.

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.

A.

Net Liquified Natural Gas (LNG) imports to the United States are expected to remain relatively stable over the 2012 through 2021 period, increasing and decreasing within a very narrow range of 0.65 billion cubic feet per day (Bcf/d) to 0.73 Bcf/d over the period. As domestic production grows moderately over this period, primarily from unconventional production, and Canadian imports increase slowly over the period, net LNG imports are primarily assumed to balance U.S. natural gas supply and demand. This relatively stable level in net LNG imports are expected to have minimal impact on FPL's projected natural gas supply and price to customers, as LNG imports represent less than 1% of the total U.S. supply over the 2012 through 2021 period.

Q.

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.

A.

Because of the amount of time it takes to receive a Federal Government export license, and the cost and time associated with converting Liquified Natural Gas (LNG) import terminals to export terminals, LNG exports from the U.S. are not expected to begin until 2016, assuming the U.S. price of natural gas continues to be lower than European and Asian prices, which creates an economic incentive to export. If U.S. prices remain lower than European and Asian prices, exports are expected to grow from about 0.5 billion cubic feet per day (Bdf/day) in 2016 to about 2.0 Bcf/day in 2021. This level of LNG exports represents less than 3% of the total U.S. supply over the 2016 through 2021 period, and is likely to have minimal impact on FPL's projected natural gas supply and price to customers.

Q.

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.

A.

Please refer to the explanation provided in FPL's response to Staff's 1st DR No. 67.

Q.

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

A.

Bay Gas Storage:

FPL is under contract for 2 billion cubic feet (Bcf) of firm natural gas storage capacity in the Bay Gas storage facility located in Alabama. The Bay Gas storage facility is interconnected with the Florida Gas Transmission (FGT) pipeline.

FPL typically maintains nearly full natural gas inventory at the Bay Gas storage facility during normal operations from June through November. When severe weather is forecasted to impact the Gulf of Mexico, FPL will attempt to increase its inventory to full capacity (if not already full) prior to the severe weather event. Maintaining slightly less than full inventory at certain times allows FPL the flexibility to inject gas, if necessary, due to the unexpected loss of generation and/or lower than forecasted load resulting in a natural gas oversupply situation.

When severe weather is forecasted to impact Florida, FPL's target inventory will depend on the projected location and severity of weather. Generally, storage levels will be reduced prior to severe weather to allow injection due to a natural gas oversupply situation caused by loss of load after the severe weather.

During the winter months, December through March, FPL typically maintains lower levels of natural gas inventory as compared to peak months. Inventory levels can vary between a minimum of four to five days maximum withdrawal capability to a maximum of 100% of capacity, if necessary. The appropriate level is determined by the projected duration and severity of cold weather.

Future Natural Gas Storage

The Bay Gas storage contract terminates March 31, 2013. FPL is currently evaluating our future natural gas storage needs and is anticipating increasing our access to storage by April of 2013.

Q.

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

A.

FPL is a co-owner of two coal-fired power plants, the St. Johns River Power Park (SJRPP) in Jacksonville, Florida, and Plant Scherer, which is located near Macon, Georgia. JEA, formerly known as the Jacksonville Electric Authority, is FPL's partner at SJRPP. Plant Scherer has six owners in addition to FPL.

One of the factors in the site selection process for SJRPP was the value of having alternative forms of coal transportation. FPL and JEA designed and equipped SJRPP to receive the annual coal supply by rail delivery, water delivery, or by a combination of rail and water.

Unit train rail service to SJRPP is provided by CSX Transportation (CSXT). SJRPP has a fleet of railcars to facilitate rail delivery. SJRPP is in the process of trading-in 350 railcars and leasing new, higher capacity railcars so as to take advantage of rate incentives offered by CSXT.

Vessels and ocean-going barges unload fuel at the St. Johns River Coal Terminal (SJRCT). A 3.5-mile conveyor system connects the deep water port to the plant site.

Plant Scherer receives coal only by rail via the Norfolk Southern Railroad (NS). FPL supported the conversion of Scherer from eastern to western coal in part because of transportation considerations. Many of the coal mines in Wyoming's Powder River Basin (PRB) are served by two railroads, the Union Pacific (UP) and the Burlington Northern Santa Fe (BNSF). As both the UP and BNSF can connect with NS for final delivery of PRB coal to the plant, a level of competition among the carriers is facilitated.

FPL currently owns 621 railcars which are assigned to the Scherer train pool that is utilized to transport PRB coal to the plant.

Q.

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.

A.

FPL does not anticipate being impacted to a significant extent by evolving rail industry trends and factors in the period 2012 through 2021. Neither SJRPP or Plant Scherer will be in the market for rail transportation services until late in the period.

The Staggers Act deregulated the railroad industry in 1980. In recent years, the Surface Transportation Board (STB) has had increased concern about rates imposed by the railroads, particularly on shippers without transportation alternatives, rail service, and industry oversight. Trade groups such as Consumers United for Rail Equity (CURE) and the National Industrial Transportation League (NIT) have aggressively advocated legislative reform. The ongoing debate with the American Association of Railroads (AAR) has put the industry in the political limelight where the outcome remains very much uncertain.

Emerging technology could alter railroad operations and the underlying cost structure. A plan by the Plant Scherer co-owners, including FPL, to evaluate electronic brakes by placing a test train provided by the NS in service, is currently on hold. If the Scherer test and other industry tests of electronic braking systems are ultimately successful, the Federal Rail Administration could mandate the technology and the retrofitting of existing railcar fleets.

The Burlington Northern Santa Fe (BNSF) railroad has sought to regulate coal dust released from open top rail cars in transit from Wyoming's Powder River Basin (PRB). Shippers have challenged the BNSF coal dust tariffs in proceedings before the STB. The STB ruled that the first coal dust tariff constituted an unreasonable practice. BNSF endeavored to remedy that deficiency in the drafting of a second coal dust tariff. On November 11, 2011 the STB denied a shipper petition, related to the second coal dust tariff, that sought to reopen the initial proceeding and provide for mediation. Instead, the denial set a new proceeding to consider the reasonableness of a safe harbor provision. The final ruling could ultimately have transportation implications for the Plant Scherer co-owners, including FPL.

The need to update the Uniform Rail Cost System (URCS) utilized by the STB in rail rate cases continues to be discussed. The impact a revision to the current, long-running, methodology might have on future rates is unknown.

Q.

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.

A.

There are no water transportation implications for inland Plant Scherer.

Recurring issues for St. John's River Power Park (SJRPP) include dredging and constraints imposed by the Jones Act. SJRPP is responsible for maintenance dredging at the St. Johns River Coal Terminal (SJRCT). Disposal of dredge material, while always a concern, has not been and is not currently an issue. However, circumstances could change during the period. Dredging of the main channel is the responsibility of the U.S. Army Corps of Engineers (ACOE). Should proper funding not be available to the ACOE on a timely basis, when and if conditions warrant future dredging, vessel access to SJRCT could be constrained, thereby impacting rates.

There are a limited number of Jones Act vessels and ocean-going barges. If demand for the shipment of domestic coal or petroleum coke between U.S. ports should exceed supply at any time between 2012 and 2021, alternative fuel supply chains would have to be considered and shipping costs could be impacted. The rapidly expanding demand for coal in China, India and other developing countries could indicate that factors impacting vessel/ocean barge transportation to SJRPP might change more frequently and rapidly between 2012 and 2021. Existing agreements would mitigate the impact to contract purchases, although, spot transactions would be immediately affected.

Q.

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.

A.

FPL does not expect any significant changes at SJRPP or Plant Scherer related to coal handling, blending, unloading or storage during the period from 2012 through 2021.

Q.

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.

A.

All FPL nuclear units have constructed dry cask storage facilities at their sites, which will allow for the safe, long-term on site storage of spent nuclear fuel (SNF) until a final repository is built.

On March 3, 2010, the U.S. Department of Energy (DOE) filed a motion with the Nuclear Regulatory Commission (NRC) to withdraw the license application for a high-level nuclear waste repository at Yucca Mountain with prejudice. In light of the decision not to proceed with the Yucca Mountain nuclear waste repository, the President directed the Secretary of Energy to establish a Blue Ribbon Commission on America's Nuclear Future to conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle and to provide recommendations for developing a safe, long-term solution to managing SNF and nuclear waste. DOE's withdrawal motion was denied by the NRC's Atomic Safety and Licensing Board. On appeal, the Commission split evenly on the question of whether DOE was allowed to withdraw the application, but allowed the termination of the licensing proceeding due to budgetary restraints.

On March 31, 2009, NextEra Energy Inc. reached a settlement with the U.S. Government that reimbursed certain costs incurred by NextEra Energy Inc. for on-site storage of SNF due to DOE's failures to dispose of SNF. The settlement allowed FPL to recover past SNF management costs incurred up to December 31, 2007. The settlement also permits an annual filing to recover spent fuel storage costs incurred by FPL, payable by the Government on an annual basis.

Q.

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.

A.

See FPL's response to Staff's 1st DR No. 61.

Q.

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.

A.

Heavy Fuel Oil

The general consensus is that 2012 should remain flat on Panamax freight worldwide. One year time charter rates for first class Panamax ships have fallen from a high of $27,000 per day in the spring of 2011 to the current market price of $22,000 per day. These rates are expected to remain flat through the balance of 2012 and then recover somewhat next year. Market recovery is predicted to occur in 2013/2014 when many older ships have been phased out pursuant to regulation 13G of Marpol Annex I. The new build order book offsets the phase out schedule to some extent, indicating a flat market in 2012, but the new build order book is expected to be weaker than predicted due to financial issues with the ship yards and ship owners.

Below please find the expected escalation schedule for the 2012 to 2021 period:

Panamax/ Ocean Going Barge 12 month time charter
2012: $22,000
2013: $24,500
2014: $27,000
2015: $29,500
2016: $29,500
2017: $31,000
2018: $31,000
2019: $32,000
2020: $32,000

Historically, the rates for U.S. flag ocean going fuel oil barges, which deliver the majority of the fuel oil into the FPL system, follow the same increases and decreases as Panamax charters. The rates listed above for a time charter differ from those for a spot move, but the same relative change is expected for both modes of transportation. For example, in 2011 a 150,000 barrel ocean going charter was $22,000 a day. In 2012, the same unit rate is $20,500 per day. The same percentage increase is expected to continue through 2021.

Distillate Fuel Oil

FPL's distillate fuel oil deliveries to the power plants are made by truck. These deliveries are sporadic during the year, but the freight rates for trucks are fairly stable. The freight rates typically follow the U. S. rate of inflation. During the period from 2012 through 2021 FPL does not project this pricing relationship will change.

Q.

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

A.

See Attachment No. 1.

Florida Power & Light Company
2012 Ten Year Site Plan - Staff's Data Request No. 1
Request No. 77
Attachment No. 1
Tab 1 of 1

Transmission Line	Line Length (Miles)	Nominal Voltage (kV)	Date Need Approved	Date TLSA Certified	In-Service Date
Manatee – Bobwhite	30	230		November 6, 2008	December 1, 2014
St Johns – Pringle	25	230		April 21, 2006	December 1, 2016