1

FPL Responses to Staff's First Set of Interrogatories (Nos. 1-36)

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below. Please complete the table below describing each solar project.

A.

See attached table.

CONFIDENTIAL

	Desoto Solar Center	Space Coast Solar Center	Martin Solar Center	Total (If Applicable)
General Information:				
Construction Commencement Date	11/3/2008	6/1/2009	12/2/2008	N/A
Date of Starting to Provide Electricity	8/18/2009	3/16/2010	9/13/2010	N/A
Commercial In-Service date	10/27/2009	4/16/2010	12/10/2010	N/A
Number of Positions for Operating the facility	3	2	7	12
Permanent Jobs Created	3	2	7	12
Temporary Jobs Created (including construction)	~ 400	~ 100	~ 1,000	~ 1,500
Cost Data:				
Total Capital Costs	~ $153M (1)	~ $71M	~ $397M (1)	~ $621M (1)
Total Installed Costs	~ $153M (1)	~ $71M	~ $397M (1)	~ $621M (1)
Federal ITC Received	$44 M	$18.4M	$123M	$186M
Average Annual Fixed O&M Costs (2)	$1.7 M	$.96 M	$3.8M	$6.5M
Range of the Average Annual Variable O&M Costs	No variable, all included in the avg annual fixed value provided above	No variable, all included in the avg annual fixed value provided above	No variable, all included in the avg annual fixed value provided above	N/A
Major Contractors for the Project:				
Design	SunPower	SunPower	Lauren Engineering & Construction	N/A
Engineering	SunPower	SunPower	Lauren Engineering & Construction	N/A
Procurement	SunPower	SunPower	Florida Power & Light	N/A
Solar Panels/Mirrors:				
Manufacturer(s)	SunPower	SunPower	RioGlass	N/A
Location of Manufacturer(s)	Philippines	Philippines	Spain	N/A

(1) Due to completion of remaining punchlist and other items, minor work orders remain open and therefore final project costs are not complete at this time. Figures provided are estimated.
(2) 30 year average of escalated annual costs.

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please provide the levelized cost (in $/kwh) for various capacity factors for each solar project (Desoto, Space Coast, Martin) and for a typical combustion turbine. Please provide the raw data and a chart depicting this information. Please include assumptions used to develop values.

A.
FPL does not believe that the information requested by Staff in this question provides a meaningful comparison between a solar photovoltaic facility and a combustion turbine, FPL is nevertheless providing the requested information in the attached chart and tables (Chart Int-2, Table 2-2, Table 2-3a and Table 2-3b).

The comparison of two very dissimilar resource options as a solar (PV) option and a combustion turbine using a levelized cost of electricity approach as requested cannot provide meaningful information about the relative economics of these two resource options if either were to be added to FPL's system. A levelized cost of electricity approach is useful as a preliminary economic screening tool only if the resource options in question are identical, or virtually identical, in regard to at least the following four attributes: (i) size (MW), (ii) firmness of capacity, (iii) capacity factor, and (iv) operating life. If the resource options in question differ in even one of these attributes, then a levelized cost of electricity approach cannot provide meaningful results even for preliminary analyses. This is because two dissimilar resource options will impact the FPL system in very different ways. These significant system impacts are simply not captured in a levelized cost of electricity approach. PV and combustion turbines are typically dissimilar in regard to all four of these attributes.

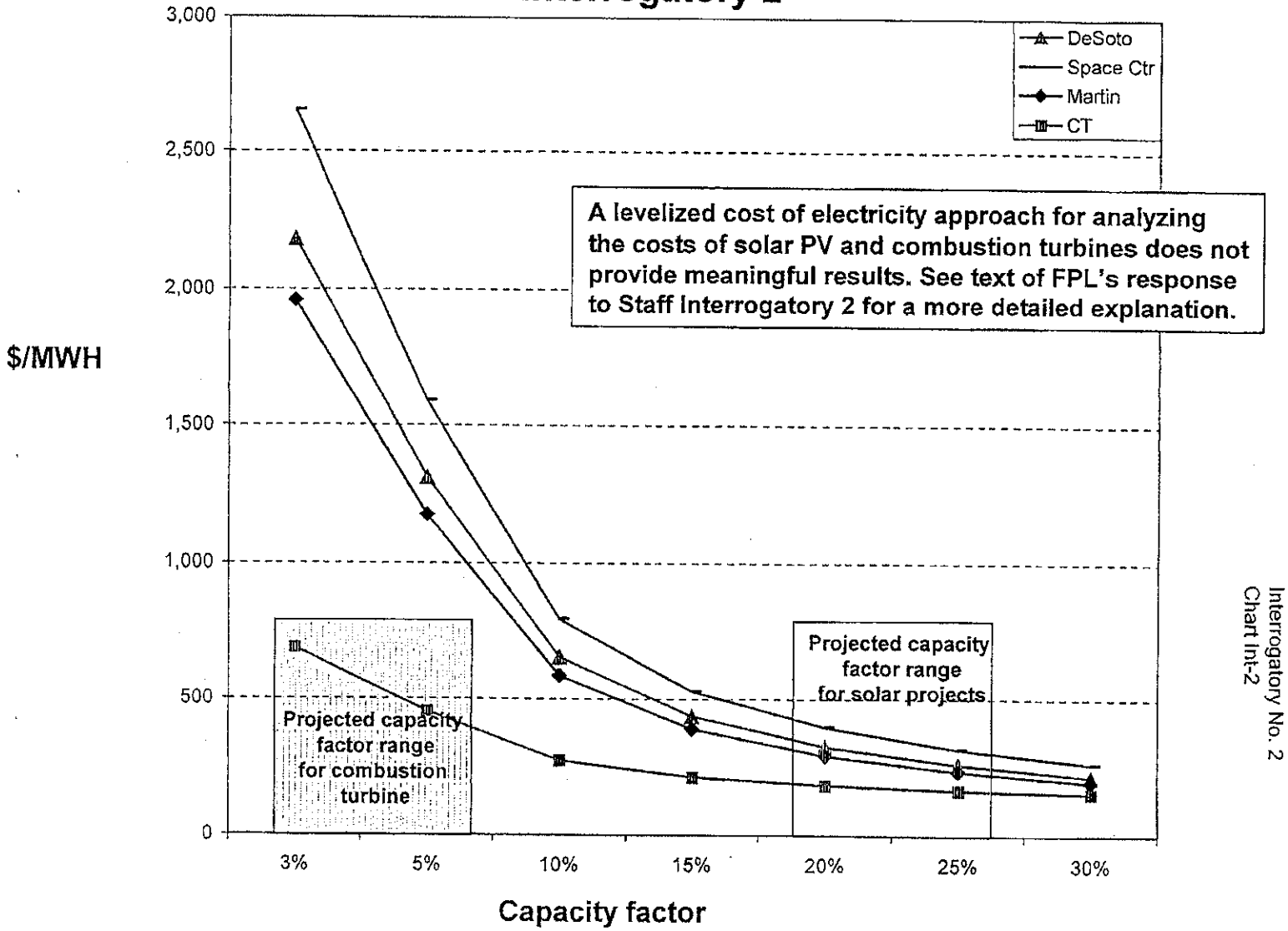
For example, solar facilities and combustion turbine are completely different in regard to the firmness of their capacity. Solar installations would be a non-firm energy (MWH) source which results in reduction of system fossil fuel use and air emissions. On the other hand, combustion turbine options would represent a firm capacity (MW) source that relies upon fossil fuel. There are also typically differences in regard to size (MW), capacity factor, and operating life as well between these two dissimilar resource options.

Consequently, the levelized cost of electricity approach for analyzing solar versus combustion turbine options, prescribed in this interrogatory, <u>does not, and cannot</u>, provide meaningful results. If a comparison of the cost of electricity associated with adding these different resource alternatives to FPL's system is to provide meaningful information, the comparison must reflect all system impacts caused by the addition of each alternative, such as effects to system fuel costs and system environmental costs, as well as capacity deferral

effects from resource options that provide firm capacity. In addition, the analysis of the FPL resource portfolio with each of the alternatives must be based on a system simulation that provides a reasonable projection of the generation to be provided by each of the alternative resources, not a pre-determined, unsupported range of assumed capacity factors.

Graph Int-2

Levelized Cost of Electricity- Solar Projects and Combustion Turbine Interrogatory 2



Florida Power & Light Company
Docket No. 110007-EI
Staff's 1st Set of Interrogatories
Interrogatory No. 2
Chart Int-2

Florida Power & Light Company
Docket No. 110007-EI
Staff's 1st Set of Interrogatories
Interrogatory No. 2
Table 2-2

	Levelized Cost of Electricity $/MWH			
Capacity Factor	DeSoto Solar	Space Center Solar	Martin Solar	CT
3%	2,185	2,650	1,959	690
5%	1,311	1,590	1,175	453
10%	656	795	588	275
15%	437	530	392	216
20%	328	398	294	186
25%	262	318	235	168
30%	219	265	196	156

Notes:

This table is provided at the request of Staff; however, a levelized cost of electricity approach for analyzing these two options does not, and cannot, provide meaningful results. See text of FPL response to Interrogatory #6 for a more detailed explanation.

These levelized costs of electricity include only the costs associated with each of the two facilities as stand alone units. They do not include the costs associated with operating these units as part of the FPL system (i.e. system impacts), which need to be considered in a proper economic analysis.

The capacity factor of the combustion turbine over the life of the project is projected to be approximately 3%.

The capacity factor of the solar facilities is expected to be between 19% and 23%.

Assumptions for levelized cost of electricity

	DeSoto Solar			Space Center Solar			Martin Solar		
	Annual Costs, $millions			Annual Costs, $millions			Annual Costs, $millions		
	Capital	FOM+capital replacement	total	Capital	FOM+capital replacement	total	Capital	FOM+capital replacement	total
2011	18	1	19	9	1	9	48	3	51
2012	17	1	18	8	1	9	47	3	50
2013	17	1	18	8	1	9	46	3	49
2014	16	1	18	8	1	8	44	3	47
2015	16	1	17	8	1	8	43	4	46
2016	15	1	17	7	1	8	41	3	45
2017	15	1	16	7	1	8	40	4	44
2018	14	1	16	7	1	8	39	3	42
2019	14	1	15	7	1	7	37	4	41
2020	13	1	15	6	1	7	36	3	39
2021	13	1	14	6	1	7	34	4	38
2022	12	2	14	6	1	7	33	4	36
2023	12	2	13	6	1	6	31	4	36
2024	11	2	13	5	1	6	30	4	34
2025	11	2	12	5	1	6	29	5	33
2026	10	2	12	5	1	6	27	4	31
2027	10	2	11	5	1	6	26	5	30
2028	9	2	11	4	1	5	24	4	29
2029	9	2	10	4	1	5	23	5	28
2030	8	2	10	4	1	5	21	4	26
2031	7	2	9	4	1	5	20	5	25
2032	7	2	9	3	1	4	19	5	23
2033	6	2	8	3	1	4	17	6	23
2034	6	2	8	3	1	4	16	5	21
2035	5	2	8	3	1	4	14	6	20
2036	5	2	7	2	1	4	13	5	18
2037	4	3	7	2	1	3	11	6	18
2038	4	3	6	2	1	3	10	5	15
2039	3	3	6	2	1	3	9	6	15
2040	0	2	2	0	1	1	-2	6	4

Notes:

This table is provided at the request of Staff; however, a levelized cost of electricity approach for analyzing these two options does not, and cannot, provide meaningful results. See text of FPL response to Interrogatory #6 for a more detailed explanation.

These levelized costs of electricity include only the costs associated with each of the two facilities as stand alone units. They do not include the costs associated with operating these units as part of the FPL system (i.e. system impacts), which need to be considered in a proper economic analysis.

Florida Power & Light Company
Docket No. 110007-EI
Staff's 1st Set of Interrogatories
Interrogatory No. 2
Table 2-3b

Assumptions for levelized cost of electricity
Combustion turbine

	Annual costs $millions				Fuel cost at various capacity factors ($millions)					
	Capital revenue requirements	FOM + capital replacement	gas transportation cost	total (not incld. fuel)	5%	10%	15%	20%	25%	30%
2011	0	0	0	0	-	-	-	-	-	-
2012	15	1	3	24	2	5	7	10	12	14
2013	25	1	6	39	4	9	13	17	21	26
2014	24	1	6	38	4	9	13	17	22	26
2015	23	1	6	37	5	9	14	19	23	28
2016	22	14	6	49	5	10	15	20	26	31
2017	21	1	6	37	6	11	17	22	28	33
2018	21	1	6	36	6	12	18	24	30	36
2019	20	1	6	36	6	13	19	25	32	38
2020	19	1	6	35	7	13	20	27	33	40
2021	18	1	6	35	7	14	21	28	35	42
2022	17	9	6	42	8	15	23	30	38	45
2023	16	1	6	34	8	16	24	32	41	49
2024	15	1	6	34	9	17	26	35	43	52
2025	14	1	6	34	9	18	28	37	46	55
2026	14	2	6	33	9	19	28	38	47	56
2027	13	2	6	32	10	19	29	38	48	57
2028	12	9	6	40	10	20	29	39	49	59
2029	12	2	6	32	10	20	30	40	50	60
2030	11	2	6	32	10	20	30	41	51	61
2031	11	2	6	31	10	21	31	41	52	62
2032	10	2	6	31	11	21	32	42	53	63
2033	10	2	6	31	11	21	32	43	54	64
2034	9	7	6	36	11	22	33	44	55	66
2035	9	3	6	32	11	22	33	45	56	67
2036	9	2	6	30	11	23	34	45	57	68
2037	8	2	6	30	12	23	35	46	58	69
2038	8	7	6	35	12	24	35	47	59	71
2039	7	4	6	32	12	24	36	48	60	72
2040	7	2	6	30	12	24	37	49	61	73
2041	7	2	6	30	12	25	37	50	62	75
2042	3	3	2	14	5	11	16	21	26	32

Notes:

This table is provided at the request of Staff; however, a levelized cost of electricity approach for analyzing these two options does not, and cannot, provide meaningful results. See text of FPL response to Interrogatory #6 for a more detailed explanation.

These levelized costs of electricity include only the costs associated with each of the two facilities as stand alone units. They do not include the costs associated with operating these units as part of the FPL system (i.e. system impacts), which need to be considered in a proper economic analysis.

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please describe any trends in the cost to construct the three next generation solar energy centers FPL has experienced. Please include data to support the response.

A.

The actual capital cost to construct the three Next Generation Solar Energy Centers was approximately $100 MM or 15% below estimated capital cost. While there are many factors which contributed to this success, economies of scale gained by constructing large utility scale solar plants, labor efficiency gains and enhancements to the engineering and design processes were significant in achieving lower final costs. Lessons learned from Desoto, the first solar PV plant to be constructed, were applied to Space Coast.

Please note that data supporting this response will be provided by COB Friday, March 18, 2011.

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below. Please complete the table below describing the avoided emissions and avoided fossil fuel usage for each solar project (Desoto, Space Coast, Martin).

A.

Please see attached tables, pages 1, 2 and 3.

Next Generation DeSoto Solar Project

Year	Natural Gas Avoided by Solar Project MMBTU	Oil Avoided by Solar Project Barrels	CO2 emissions avoided by solar project tons	SO2 emissions avoided by solar project tons	NOx emissions avoided by solar project tons
2011	386,000	10,000	26,000	29	24
2012	392,000	1,000	26,000	8	23
2013	398,000	1,000	21,000	1	9
2014	363,000	7,000	27,000	25	19
2015	307,000	9,000	24,000	27	5
2016	367,000	1,000	29,000	10	9
2017	349,000	4,000	27,000	16	12
2018	452,000	4,000	20,000	2	13
2019	386,000	3,000	27,000	9	18
2020	378,000	4,000	23,000	10	15
2021	316,000	4,000	19,000	8	11
2022	377,000	2,000	25,000	8	11
2023	372,000	0	25,000	5	8
2024	189,000	0	37,000	38	18
2025	394,000	3,000	17,000	7	12
2026	396,000	2,000	25,000	6	19
2027	350,000	2,000	21,000	3	12
2028	345,000	2,000	25,000	9	11
2029	400,000	1,000	23,000	1	12
2030	373,000	1,000	23,000	5	12
2031	396,000	2,000	19,000	6	5
2032	367,000	1,000	22,000	2	13
2033	330,000	0	17,000	2	2
2034	272,000	0	27,000	3	11
2035	319,000	1,000	23,000	5	7
2036	325,000	0	16,000	3	0
2037	371,000	0	19,000	3	7
2038	254,000	0	21,000	12	5
2039	342,000	0	19,000	1	3
2040	312,000	0	17,000	4	2

Note:

This table shows the emissions (CO2, SO2, and NOx) avoided as well as the fuel use (gas and oil) avoided by the 25 MW Solar PV facility. These values represent the difference in emissions and fuel use between two system simulations: one which represents the base case, and a second one that adds the 25 MW solar PV facility.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Next Generation Space Coast Solar Project

Year	Natural Gas Avoided by Solar Project MMBTU	Oil Avoided by Solar Project Barrels	CO2 emissions avoided by solar project tons	SO2 emissions avoided by solar project tons	NOx emissions avoided by solar project tons
2011	140,000	4,000	10,000	12	14
2012	141,000	-2,000	8,000	-5	8
2013	112,000	0	5,000	-1	-1
2014	133,000	1,000	8,000	2	4
2015	108,000	2,000	9,000	9	2
2016	95,000	1,000	9,000	6	3
2017	136,000	2,000	9,000	5	9
2018	185,000	1,000	8,000	-4	5
2019	132,000	1,000	8,000	2	6
2020	143,000	3,000	9,000	8	7
2021	102,000	2,000	6,000	4	11
2022	129,000	1,000	9,000	4	4
2023	66,000	0	17,000	5	8
2024	72,000	0	13,000	14	5
2025	116,000	1,000	10,000	5	8
2026	119,000	0	8,000	3	5
2027	100,000	1,000	10,000	7	7
2028	135,000	1,000	9,000	1	4
2029	119,000	1,000	8,000	1	3
2030	129,000	1,000	9,000	3	5
2031	105,000	2,000	10,000	6	4
2032	122,000	0	7,000	1	5
2033	118,000	0	8,000	1	3
2034	42,000	0	14,000	2	5
2035	124,000	0	8,000	0	3
2036	138,000	0	5,000	-4	1
2037	100,000	0	8,000	4	2
2038	85,000	0	5,000	0	-2
2039	129,000	0	6,000	-2	1
2040	108,000	0	8,000	0	1

Note:

This table shows the emissions (CO2, SO2, and NOx) avoided as well as the fuel use (gas and oil) avoided by the 10 MW Solar PV facility. These values represent the difference in emissions and fuel use between two system simulations: one which represents the base case, and a second one that adds the 10 MW solar PV facility.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

New Generation Martin Solar Project

Year	Natural Gas Avoided by Solar Project MMBTU	Oil Avoided by Solar Project Barrels	CO2 emissions avoided by solar project tons	SO2 emissions avoided by solar project tons	NOx emissions avoided by solar project tons
2011	1,050,000	27,000	74,000	79	51
2012	1,063,000	1,000	68,000	11	49
2013	1,089,000	3,000	69,000	17	37
2014	1,125,000	12,000	66,000	32	42
2015	1,085,000	21,000	65,000	45	26
2016	1,174,000	1,000	79,000	15	30
2017	1,146,000	7,000	80,000	27	47
2018	1,317,000	8,000	66,000	10	42
2019	1,111,000	7,000	76,000	27	45
2020	1,165,000	8,000	76,000	30	49
2021	1,198,000	10,000	64,000	30	32
2022	1,305,000	2,000	56,000	6	21
2023	1,321,000	1,000	47,000	-9	16
2024	1,512,000	2,000	39,000	-9	19
2025	1,182,000	7,000	62,000	26	35
2026	1,319,000	6,000	66,000	9	44
2027	1,062,000	5,000	67,000	12	30
2028	1,122,000	5,000	68,000	8	27
2029	1,258,000	1,000	62,000	9	29
2030	1,107,000	3,000	74,000	7	28
2031	1,151,000	3,000	68,000	3	24
2032	1,181,000	1,000	64,000	-5	28
2033	1,110,000	2,000	66,000	5	17
2034	973,000	1,000	77,000	15	25
2035	1,050,000	2,000	65,000	21	22
2036	1,061,000	1,000	60,000	1	14
2037	1,208,000	3,000	57,000	12	20
2038	948,000	1,000	80,000	26	27
2039	1,072,000	0	68,000	7	15
2040	1,132,000	0	62,000	8	9

Note:

This table shows the emissions (CO2, SO2, and NOx) avoided as well as the fuel use (gas and oil) avoided by the 75 MW Solar PV facility. These values represent the difference in emissions and fuel use between two system simulations: one which represents the base case, and a second one that adds the 75 MW solar PV facility.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

A.

Please see attached tables, pages 1, 2, and 3.

DeSoto

System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

Year	[1] Annual System Total Revenue Requirements with Solar Project $ Millions	[2] Annual System Total Revenue Requirements without Solar Project $ Millions	[3] Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	[4] Differential in Customer Bill $/ 1000 kWH	[5] Differential in Customer Bill $/ 1200 kWH
2011	15	0	15	0.147	0.176
2012	3,452	3,436	16	0.161	0.193
2013	3,469	3,453	16	0.153	0.183
2014	3,725	3,710	15	0.136	0.163
2015	4,057	4,043	14	0.130	0.155
2016	4,958	4,945	14	0.123	0.147
2017	5,544	5,533	11	0.099	0.119
2018	7,237	7,227	10	0.089	0.107
2019	7,827	7,817	10	0.091	0.109
2020	8,489	8,479	10	0.086	0.103
2021	9,355	9,346	10	0.080	0.097
2022	9,898	9,889	9	0.073	0.087
2023	9,912	9,904	8	0.066	0.080
2024	10,572	10,565	7	0.056	0.068
2025	11,593	11,586	7	0.050	0.060
2026	12,357	12,353	5	0.034	0.041
2027	13,406	13,400	5	0.038	0.046
2028	14,267	14,263	4	0.032	0.038
2029	15,288	15,284	4	0.028	0.034
2030	16,545	16,541	3	0.024	0.028
2031	17,250	17,248	2	0.014	0.017
2032	18,848	18,847	1	0.009	0.011
2033	20,986	20,983	3	0.022	0.026
2034	22,110	22,108	2	0.013	0.016
2035	23,187	23,186	1	0.005	0.007
2036	25,500	25,499	1	0.006	0.007
2037	26,614	26,614	-1	-0.005	-0.006
2038	27,573	27,572	1	0.004	0.005
2039	28,931	28,933	-2	-0.011	-0.013
2040	30,063	30,069	-5	-0.031	-0.038

Notes:

Negative indicates a reduction in the customer bill for the 25 MW solar project.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Space Coast
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]
Year	Annual System Total Revenue Requirements with Solar Project $ Millions	Annual System Total Revenue Requirements without Solar Project $ Millions	Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	Differential in Customer Bill $/ 1000 kWH	Differential in Customer Bill $/ 1200 kWH
2011	7	0	7	0.069	0.083
2012	3,444	3,436	9	0.086	0.104
2013	3,461	3,453	9	0.083	0.099
2014	3,718	3,710	7	0.070	0.083
2015	4,051	4,043	7	0.067	0.080
2016	4,952	4,945	7	0.063	0.076
2017	5,538	5,533	6	0.052	0.062
2018	7,233	7,227	6	0.056	0.067
2019	7,823	7,817	6	0.054	0.064
2020	8,484	8,479	5	0.042	0.050
2021	9,351	9,346	6	0.048	0.057
2022	9,893	9,889	4	0.036	0.043
2023	9,909	9,904	5	0.038	0.046
2024	10,568	10,565	4	0.029	0.035
2025	11,590	11,586	4	0.028	0.033
2026	12,356	12,353	3	0.025	0.030
2027	13,403	13,400	3	0.022	0.027
2028	14,265	14,263	3	0.020	0.024
2029	15,286	15,284	3	0.019	0.023
2030	16,544	16,541	2	0.016	0.020
2031	17,250	17,248	2	0.014	0.016
2032	18,850	18,847	3	0.020	0.024
2033	20,985	20,983	3	0.018	0.022
2034	22,110	22,108	2	0.013	0.016
2035	23,188	23,186	2	0.015	0.018
2036	25,500	25,499	1	0.008	0.010
2037	26,615	26,614	1	0.005	0.006
2038	27,574	27,572	2	0.011	0.014
2039	28,933	28,933	1	0.004	0.004
2040	30,067	30,069	-1	-0.009	-0.011

Notes:

Negative indicates a reduction in the customer bill for the 10 MW solar project.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Space Coast
System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

Year	[1] Annual System Total Revenue Requirements with Solar Project $ Millions	[2] Annual System Total Revenue Requirements without Solar Project $ Millions	[3] Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	[4] Differential in Customer Bill $/ 1000 kWH	[5] Differential in Customer Bill $/ 1200 kWH
2011	7	0	7	0.069	0.083
2012	3,444	3,436	9	0.086	0.104
2013	3,461	3,453	9	0.083	0.099
2014	3,718	3,710	7	0.070	0.083
2015	4,051	4,043	7	0.067	0.080
2016	4,952	4,945	7	0.063	0.076
2017	5,538	5,533	6	0.052	0.062
2018	7,233	7,227	6	0.056	0.067
2019	7,823	7,817	6	0.054	0.064
2020	8,484	8,479	5	0.042	0.050
2021	9,351	9,346	6	0.048	0.057
2022	9,893	9,889	4	0.036	0.043
2023	9,909	9,904	5	0.038	0.046
2024	10,568	10,565	4	0.029	0.035
2025	11,590	11,586	4	0.028	0.033
2026	12,356	12,353	3	0.025	0.030
2027	13,403	13,400	3	0.022	0.027
2028	14,265	14,263	3	0.020	0.024
2029	15,286	15,284	3	0.019	0.023
2030	16,544	16,541	2	0.016	0.020
2031	17,250	17,248	2	0.014	0.016
2032	18,850	18,847	3	0.020	0.024
2033	20,985	20,983	3	0.018	0.022
2034	22,110	22,108	2	0.013	0.016
2035	23,188	23,186	2	0.015	0.018
2036	25,500	25,499	1	0.008	0.010
2037	26,615	26,614	1	0.005	0.006
2038	27,574	27,572	2	0.011	0.014
2039	28,933	28,933	1	0.004	0.004
2040	30,067	30,069	-1	-0.009	-0.011

Notes:

Negative indicates a reduction in the customer bill for the 10 MW solar project.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Martin Solar

System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]
Year	Annual System Total Revenue Requirements with Solar Project $ Millions	Annual System Total Revenue Requirements without Solar Project $ Millions	Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	Differential in Customer Bill $/ 1000 kWH	Differential in Customer Bill $/ 1200 kWH
2011	43	0	43	0.424	0.509
2012	3,479	3,436	44	0.429	0.514
2013	3,496	3,453	43	0.413	0.496
2014	3,751	3,710	40	0.377	0.452
2015	4,081	4,043	37	0.345	0.414
2016	4,980	4,945	36	0.323	0.388
2017	5,565	5,533	33	0.294	0.353
2018	7,255	7,227	28	0.250	0.300
2019	7,846	7,817	29	0.253	0.304
2020	8,504	8,479	25	0.213	0.256
2021	9,370	9,346	24	0.204	0.245
2022	9,910	9,889	21	0.177	0.212
2023	9,925	9,904	21	0.168	0.202
2024	10,580	10,565	15	0.119	0.143
2025	11,600	11,586	14	0.109	0.131
2026	12,363	12,353	10	0.074	0.089
2027	13,412	13,400	12	0.087	0.105
2028	14,272	14,263	9	0.069	0.083
2029	15,292	15,284	8	0.057	0.068
2030	16,546	16,541	5	0.034	0.041
2031	17,252	17,248	4	0.031	0.037
2032	18,849	18,847	2	0.011	0.014
2033	20,985	20,983	2	0.012	0.015
2034	22,108	22,108	0	-0.001	-0.001
2035	23,185	23,186	-1	-0.006	-0.007
2036	25,496	25,499	-3	-0.017	-0.021
2037	26,608	26,614	-6	-0.039	-0.046
2038	27,566	27,572	-6	-0.039	-0.047
2039	28,924	28,933	-9	-0.054	-0.065
2040	30,049	30,069	-20	-0.119	-0.142

Notes:

Negative indicates a reduction in the customer bill for the 75 MW solar project.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below describing the CPVRR of all three solar projects (Desoto, Space Coast, Martin).

A. Please see attached table.

Solar Portfolio

System Annual Revenue Requirements - with and without Solar Project
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]
Year	Annual System Total Revenue Requirements with Solar Project $ Millions	Annual System Total Revenue Requirements without Solar Project $ Millions	Differential in Annual System Total Revenue Requirements [1] - [2] $ Millions	Differential in Customer Bill $/ 1000 kWH	Differential in Customer Bill $/ 1200 kWH
2011	67	0	67	0.660	0.792
2012	3,504	3,436	68	0.666	0.799
2013	3,519	3,453	67	0.639	0.767
2014	3,773	3,710	62	0.582	0.699
2015	4,102	4,043	59	0.541	0.649
2016	5,001	4,945	56	0.510	0.611
2017	5,585	5,533	52	0.472	0.566
2018	7,272	7,227	45	0.402	0.483
2019	7,860	7,817	43	0.380	0.455
2020	8,520	8,479	41	0.350	0.420
2021	9,385	9,346	39	0.329	0.395
2022	9,924	9,889	35	0.292	0.351
2023	9,935	9,904	31	0.254	0.305
2024	10,591	10,565	27	0.210	0.252
2025	11,610	11,586	24	0.185	0.222
2026	12,371	12,353	19	0.142	0.170
2027	13,422	13,400	22	0.163	0.196
2028	14,280	14,263	18	0.128	0.154
2029	15,297	15,284	13	0.096	0.115
2030	16,552	16,541	10	0.073	0.088
2031	17,257	17,248	10	0.068	0.082
2032	18,854	18,847	7	0.049	0.059
2033	20,988	20,983	5	0.037	0.044
2034	22,109	22,108	1	0.007	0.008
2035	23,188	23,186	1	0.010	0.012
2036	25,498	25,499	-1	-0.007	-0.008
2037	26,608	26,614	-6	-0.039	-0.046
2038	27,566	27,572	-6	-0.039	-0.046
2039	28,923	28,933	-10	-0.060	-0.072
2040	30,041	30,069	-27	-0.165	-0.198

Notes:

Negative indicates a reduction in the customer bill for the 110 MW portfolio of solar projects.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.
Please complete the table below for each solar project (Desoto, Space Coast, Martin).

A. Please see attached tables.

DeSoto
Annual Emission Costs - with and without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project				[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)			
2011	0.000	0.000	-4.099	-4.099	0.000	0.000	-4.088	-4.088	-0.011	0.000	0.000
2012	0.000	-13.192	-6.179	-19.372	0.000	-13.192	-6.168	-19.360	-0.012	0.000	0.000
2013	0.000	-14.397	-8.789	-23.186	0.000	-14.397	-8.785	-23.182	-0.005	0.000	0.000
2014	0.000	-7.180	-9.269	-16.449	0.000	-7.179	-9.259	-16.438	-0.011	0.000	0.000
2015	0.000	-7.303	-7.241	-14.543	0.000	-7.301	-7.238	-14.539	-0.004	0.000	0.000
2016	0.000	-7.765	-8.385	-16.150	0.000	-7.765	-8.380	-16.145	-0.005	0.000	0.000
2017	0.000	-7.929	-8.628	-16.557	0.000	-7.928	-8.622	-16.550	-0.008	0.000	0.000
2018	1,265.603	-8.147	-9.159	1,248.297	1,266.143	-8.147	-9.152	1,248.843	-0.547	-0.005	-0.006
2019	1,406.459	-8.331	-9.450	1,388.678	1,407.248	-8.330	-9.440	1,389.479	-0.800	-0.007	-0.008
2020	1,534.112	-8.539	-9.993	1,515.580	1,534.841	-8.538	-9.984	1,516.319	-0.738	-0.006	-0.008
2021	1,705.534	-8.747	-10.739	1,687.048	1,707.186	-8.746	-10.732	1,687.708	-0.660	-0.006	-0.007
2022	1,811.027	-8.992	-13.416	1,788.620	1,811.957	-8.991	-13.409	1,789.557	-0.938	-0.008	-0.009
2023	1,829.938	-9.235	-14.382	1,806.321	1,830.946	-9.235	-14.377	1,807.335	-1.014	-0.008	-0.010
2024	1,998.822	-9.447	-14.634	1,974.741	2,000.440	-9.444	-14.622	1,976.373	-1.632	-0.013	-0.015
2025	2,202.345	-9.768	-12.707	2,179.870	2,203.150	-9.767	-12.699	2,180.684	-0.814	-0.006	-0.008
2026	2,383.888	-10.411	-12.873	2,360.604	2,385.163	-10.411	-12.860	2,361.892	-1.288	-0.010	-0.012
2027	2,640.723	-10.679	-13.685	2,616.359	2,641.876	-10.679	-13.677	2,617.520	-1.161	-0.009	-0.010
2028	2,888.258	-10.941	-13.091	2,864.226	2,889.734	-10.941	-13.083	2,865.711	-1.485	-0.011	-0.013
2029	3,156.851	-11.225	-13.848	3,131.780	3,158.313	-11.225	-13.837	3,133.251	-1.471	-0.011	-0.013
2030	3,498.378	-11.498	-14.326	3,472.554	3,499.951	-11.497	-14.317	3,474.137	-1.583	-0.011	-0.013
2031	3,641.294	-11.784	-15.549	3,613.960	3,642.626	-11.785	-15.545	3,615.295	-1.335	-0.009	-0.011
2032	3,876.695	-12.073	-16.291	3,848.331	3,878.276	-12.073	-16.281	3,849.922	-1.591	-0.011	-0.013
2033	4,332.252	-12.351	-16.532	4,303.369	4,333.504	-12.351	-16.530	4,304.623	-1.254	-0.008	-0.010
2034	4,560.156	-12.312	-18.036	4,549.808	4,582.194	-12.312	-18.027	4,551.856	-2.048	-0.014	-0.016
2035	4,760.516	-12.617	-18.628	4,729.271	4,762.296	-12.617	-18.622	4,731.057	-1.786	-0.012	-0.014
2036	5,202.684	-12.914	-18.851	5,170.919	5,203.953	-12.915	-18.851	5,172.188	-1.269	-0.008	-0.010
2037	5,447.065	-13.232	-19.485	5,414.347	5,448.610	-13.232	-19.479	5,415.898	-1.551	-0.010	-0.012
2038	5,662.078	-13.560	-20.310	5,628.208	5,663.828	-13.559	-20.305	5,629.964	-1.756	-0.011	-0.013
2039	5,933.982	-13.893	-20.931	5,899.158	5,935.605	-13.893	-20.928	5,900.784	-1.626	-0.010	-0.012
2040	6,153.952	-14.237	-22.079	6,117.636	6,155.440	-14.237	-22.081	6,119.122	-1.486	-0.009	-0.011

Notes:

Negative indicates a reduction in the customer bil for the 25 MW DeSoto solar project.

The annual costs include only the system emission costs.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Space Coast
Annual Emission Costs - with and without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project				[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)			
2011	0.000	0.000	-4.094	-4.094	0.000	0.000	-4.088	-4.088	-0.007	0.000	0.000
2012	0.000	-13.191	-6.172	-19.363	0.000	-13.192	-6.168	-19.360	-0.003	0.000	0.000
2013	0.000	-14.397	-8.784	-23.181	0.000	-14.397	-8.785	-23.182	0.001	0.000	0.000
2014	0.000	-7.179	-9.261	-16.440	0.000	-7.179	-9.259	-16.438	-0.002	0.000	0.000
2015	0.000	-7.301	-7.239	-14.541	0.000	-7.301	-7.238	-14.539	-0.002	0.000	0.000
2016	0.000	-7.765	-8.382	-16.147	0.000	-7.765	-8.380	-16.145	-0.002	0.000	0.000
2017	0.000	-7.929	-8.627	-16.555	0.000	-7.928	-8.622	-16.550	-0.005	0.000	0.000
2018	1,265.927	-8.147	-9.155	1,248.625	1,266.143	-8.147	-9.152	1,248.843	-0.218	-0.002	-0.002
2019	1,407.015	-8.330	-9.443	1,389.241	1,407.248	-8.330	-9.440	1,389.479	-0.238	-0.002	-0.003
2020	1,534.556	-8.539	-9.988	1,516.029	1,534.841	-8.538	-9.984	1,516.319	-0.290	-0.003	-0.003
2021	1,706.980	-8.747	-10.739	1,687.495	1,707.188	-8.746	-10.732	1,687.708	-0.213	-0.002	-0.002
2022	1,811.622	-8.991	-13.411	1,789.220	1,811.957	-8.991	-13.409	1,789.557	-0.338	-0.003	-0.003
2023	1,830.260	-9.235	-14.382	1,806.644	1,830.946	-9.235	-14.377	1,807.335	-0.691	-0.006	-0.007
2024	1,999.871	-9.445	-14.626	1,975.801	2,000.440	-9.444	-14.622	1,976.373	-0.573	-0.005	-0.005
2025	2,202.677	-9.768	-12.704	2,180.204	2,203.150	-9.767	-12.699	2,180.684	-0.479	-0.004	-0.004
2026	2,384.755	-10.411	-12.863	2,361.481	2,385.163	-10.411	-12.860	2,361.892	-0.412	-0.003	-0.004
2027	2,641.327	-10.679	-13.682	2,616.966	2,641.876	-10.679	-13.677	2,617.520	-0.554	-0.004	-0.005
2028	2,889.203	-10.941	-13.086	2,865.176	2,889.734	-10.941	-13.083	2,865.711	-0.534	-0.004	-0.005
2029	3,157.804	-11.225	-13.840	3,132.740	3,158.313	-11.225	-13.837	3,133.251	-0.511	-0.004	-0.004
2030	3,499.336	-11.498	-14.321	3,473.517	3,499.951	-11.497	-14.317	3,474.137	-0.620	-0.004	-0.005
2031	3,641.925	-11.785	-15.549	3,614.591	3,642.626	-11.785	-15.545	3,615.295	-0.705	-0.005	-0.006
2032	3,877.773	-12.073	-16.285	3,849.415	3,878.276	-12.073	-16.281	3,849.922	-0.507	-0.003	-0.004
2033	4,332.915	-12.351	-16.532	4,304.031	4,333.504	-12.351	-16.530	4,304.623	-0.592	-0.004	-0.005
2034	4,581.137	-12.312	-18.031	4,550.794	4,582.194	-12.312	-18.027	4,551.856	-1.061	-0.007	-0.008
2035	4,761.677	-12.617	-18.624	4,730.436	4,762.296	-12.617	-18.622	4,731.057	-0.622	-0.004	-0.005
2036	5,203.556	-12.914	-18.852	5,171.790	5,203.953	-12.915	-18.851	5,172.188	-0.397	-0.003	-0.003
2037	5,447.959	-13.233	-19.481	5,415.246	5,448.610	-13.232	-19.479	5,415.898	-0.653	-0.004	-0.005
2038	5,663.411	-13.559	-20.303	5,629.549	5,663.828	-13.559	-20.305	5,629.964	-0.415	-0.003	-0.003
2039	5,935.092	-13.893	-20.929	5,900.270	5,935.605	-13.893	-20.928	5,900.784	-0.513	-0.003	-0.004
2040	6,154.740	-14.237	-22.082	6,118.421	6,155.440	-14.237	-22.081	6,119.122	-0.701	-0.004	-0.005

Notes:

Negative indicates a reduction in the customer bil for the 10 MW solar project.

The annual costs include only the system emission costs.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Martin Solar

Annual Emission Costs - with and without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project				[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)			
2011	0.000	0.000	-4.112	-4.112	0.000	0.000	-4.088	-4.088	-0.024	0.000	0.000
2012	0.000	-13.193	-6.192	-19.385	0.000	-13.192	-6.168	-19.360	-0.025	0.000	0.000
2013	0.000	-14.399	-8.803	-23.202	0.000	-14.397	-8.785	-23.182	-0.020	0.000	0.000
2014	0.000	-7.180	-9.280	-16.461	0.000	-7.179	-9.259	-16.438	-0.023	0.000	0.000
2015	0.000	-7.304	-7.252	-14.555	0.000	-7.301	-7.238	-14.539	-0.016	0.000	0.000
2016	0.000	-7.766	-8.396	-16.162	0.000	-7.765	-8.380	-16.145	-0.017	0.000	0.000
2017	0.000	-7.930	-8.647	-16.577	0.000	-7.928	-8.622	-16.550	-0.027	0.000	0.000
2018	1,264.362	-8.148	-9.176	1,247.038	1,266.143	-8.147	-9.152	1,248.843	-1.805	-0.016	-0.019
2019	1,405.026	-8.332	-9.465	1,387.229	1,407.248	-8.330	-9.440	1,389.479	-2.250	-0.020	-0.024
2020	1,532.433	-8.540	-10.013	1,513.879	1,534.841	-8.538	-9.984	1,516.319	-2.439	-0.021	-0.025
2021	1,704.988	-8.748	-10.751	1,685.489	1,707.186	-8.746	-10.732	1,687.708	-2.219	-0.019	-0.023
2022	1,809.873	-8.991	-13.422	1,787.460	1,811.957	-8.991	-13.409	1,789.557	-2.098	-0.017	-0.021
2023	1,829.050	-9.234	-14.387	1,805.430	1,830.946	-9.235	-14.377	1,807.335	-1.905	-0.015	-0.018
2024	1,998.735	-9.443	-14.635	1,974.657	2,000.440	-9.444	-14.522	1,976.373	-1.717	-0.014	-0.016
2025	2,200.213	-9.769	-12.722	2,177.721	2,203.150	-9.767	-12.699	2,180.684	-2.962	-0.023	-0.027
2026	2,361.798	-10.412	-12.890	2,358.497	2,385.163	-10.411	-12.860	2,361.892	-3.396	-0.026	-0.031
2027	2,638.199	-10.680	-13.698	2,613.821	2,641.876	-10.679	-13.677	2,617.520	-3.698	-0.027	-0.033
2028	2,885.718	-10.941	-13.102	2,861.675	2,889.734	-10.941	-13.083	2,865.711	-4.036	-0.029	-0.035
2029	3,154.372	-11.225	-13.859	3,129.288	3,158.313	-11.225	-13.837	3,133.251	-3.962	-0.028	-0.034
2030	3,494.890	-11.498	-14.338	3,469.054	3,499.951	-11.497	-14.317	3,474.137	-5.083	-0.036	-0.043
2031	3,637.858	-11.785	-15.564	3,610.509	3,642.626	-11.785	-15.545	3,615.295	-4.786	-0.033	-0.040
2032	3,873.677	-12.072	-15.303	3,845.301	3,878.278	-12.073	-16.281	3,849.922	-4.621	-0.032	-0.038
2033	4,328.643	-12.352	-16.544	4,299.747	4,333.504	-12.351	-16.530	4,304.623	-4.876	-0.033	-0.039
2034	4,576.381	-12.314	-18.048	4,546.020	4,582.194	-12.312	-18.027	4,551.856	-5.836	-0.039	-0.046
2035	4,757.266	-12.619	-18.641	4,726.006	4,762.296	-12.617	-18.622	4,731.057	-5.051	-0.033	-0.040
2036	5,199.194	-12.915	-18.863	5,167.416	5,203.953	-12.915	-18.851	5,172.188	-4.772	-0.031	-0.037
2037	5,443.975	-13.234	-19.497	5,411.245	5,448.610	-13.232	-19.479	5,415.898	-4.654	-0.029	-0.035
2038	5,657.161	-13.561	-20.330	5,623.270	5,663.828	-13.559	-20.305	5,629.964	-6.694	-0.042	-0.050
2039	5,929.796	-13.894	-20.942	5,894.960	5,935.605	-13.893	-20.928	5,900.784	-5.823	-0.036	-0.043
2040	6,150.012	-14.238	-22.089	6,113.684	6,155.440	-14.237	-22.081	6,119.122	-5.438	-0.033	-0.040

Notes:

Negative indicates a reduction in the customer bil for the 75 MW Martin solar project.

The annual costs include only the system emission costs.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

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Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below for each solar project (Desoto, Space Coast, Martin).

A. Please see attached tables.

Capital and O&M Costs for the DeSoto Solar Project
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2011	18.0	1.0	18.9	0.186	0.223
2012	17.5	1.0	18.5	0.180	0.217
2013	16.9	1.0	17.9	0.172	0.207
2014	16.4	1.1	17.5	0.164	0.197
2015	15.9	1.1	17.0	0.157	0.189
2016	15.4	1.1	16.5	0.150	0.180
2017	14.8	1.2	16.0	0.144	0.173
2018	14.3	1.3	15.6	0.139	0.166
2019	13.8	1.4	15.1	0.133	0.160
2020	13.3	1.4	14.7	0.126	0.152
2021	12.7	1.4	14.2	0.120	0.144
2022	12.2	1.5	13.7	0.113	0.136
2023	11.7	1.6	13.2	0.107	0.128
2024	11.1	1.6	12.8	0.101	0.121
2025	10.6	1.7	12.3	0.095	0.114
2026	10.1	1.7	11.8	0.089	0.107
2027	9.6	1.8	11.3	0.084	0.101
2028	9.0	1.8	10.8	0.079	0.095
2029	8.5	1.9	10.4	0.075	0.090
2030	8.0	1.9	9.9	0.070	0.084
2031	7.4	1.9	9.4	0.065	0.078
2032	6.9	2.0	8.9	0.061	0.073
2033	6.4	2.1	8.5	0.057	0.068
2034	5.9	2.2	8.1	0.054	0.064
2035	5.3	2.3	7.6	0.050	0.060
2036	4.8	2.4	7.2	0.046	0.056
2037	4.3	2.5	6.8	0.043	0.052
2038	3.7	2.6	6.4	0.040	0.048
2039	3.1	2.8	5.9	0.036	0.043
2040	-0.1	2.4	2.3	0.014	0.017

Notes:

Negative indicates a reduction in the customer bill for the 25 MW DeSoto solar project.

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

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Capital and O&M Costs for the Space Cost Solar Project
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2011	8.5	0.6	9.1	0.089	0.107
2012	8.3	0.6	8.9	0.087	0.104
2013	8.0	0.6	8.6	0.083	0.099
2014	7.8	0.6	8.4	0.079	0.095
2015	7.5	0.7	8.2	0.076	0.091
2016	7.3	0.7	8.0	0.072	0.087
2017	7.0	0.7	7.7	0.070	0.084
2018	6.8	0.7	7.5	0.067	0.080
2019	6.6	0.8	7.3	0.064	0.077
2020	6.3	0.8	7.1	0.062	0.074
2021	6.1	0.8	6.9	0.058	0.070
2022	5.8	0.8	6.6	0.055	0.066
2023	5.6	0.9	6.4	0.052	0.062
2024	5.3	0.9	6.2	0.049	0.059
2025	5.1	1.0	6.0	0.047	0.056
2026	4.8	0.9	5.8	0.044	0.052
2027	4.6	1.0	5.6	0.041	0.049
2028	4.3	1.0	5.3	0.039	0.047
2029	4.1	1.0	5.1	0.037	0.044
2030	3.9	1.1	5.0	0.035	0.042
2031	3.6	1.1	4.7	0.032	0.039
2032	3.4	1.1	4.5	0.030	0.037
2033	3.1	1.1	4.3	0.029	0.034
2034	2.9	1.2	4.1	0.027	0.032
2035	2.6	1.3	3.9	0.026	0.031
2036	2.4	1.3	3.6	0.023	0.028
2037	2.1	1.3	3.5	0.022	0.026
2038	1.9	1.4	3.2	0.020	0.024
2039	1.6	1.4	3.1	0.019	0.023
2040	-0.1	1.3	1.2	0.007	0.009

Notes:

Negative indicates a reduction in the customer bill for the 10 MW Space Cost solar project.

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

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Capital and O&M Costs for the Martin Solar Project
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2011	48.4	2.9	51.3	0.503	0.603
2012	47.1	2.9	49.9	0.488	0.585
2013	45.7	3.4	49.0	0.471	0.565
2014	44.2	3.0	47.2	0.443	0.531
2015	42.8	3.5	46.4	0.428	0.513
2016	41.4	3.2	44.5	0.405	0.487
2017	40.0	3.7	43.7	0.393	0.472
2018	38.5	3.3	41.9	0.372	0.447
2019	37.1	3.9	41.0	0.361	0.433
2020	35.7	3.5	39.2	0.338	0.406
2021	34.3	4.1	38.4	0.325	0.390
2022	32.8	3.7	36.5	0.302	0.362
2023	31.4	4.3	35.7	0.289	0.346
2024	30.0	3.9	33.8	0.267	0.321
2025	28.6	4.5	33.1	0.265	0.306
2026	27.1	4.0	31.2	0.236	0.283
2027	25.7	4.8	30.5	0.226	0.271
2028	24.3	4.3	28.5	0.208	0.250
2029	22.9	5.0	27.9	0.200	0.240
2030	21.4	4.5	25.9	0.183	0.219
2031	20.0	5.3	25.3	0.176	0.211
2032	18.6	4.7	23.3	0.159	0.191
2033	17.2	5.5	22.7	0.153	0.183
2034	15.7	4.9	20.7	0.137	0.164
2035	14.3	5.8	20.1	0.131	0.158
2036	12.9	5.2	18.1	0.116	0.139
2037	11.5	6.1	17.6	0.111	0.134
2038	10.0	5.4	15.5	0.097	0.116
2039	8.6	6.4	15.0	0.092	0.111
2040	-1.9	5.7	3.9	0.023	0.028

Notes:

Negative indicates a reduction in the customer bill for the 75 MW Martin solar project.

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

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Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below for each solar project (Desoto, Space Coast, Martin).

A. See attached tables.

DeSoto
System Variable O&M and System Fuel Costs - With and Without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[8]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1,000 KWH	Impact on Customer Bill of 1,200 KWH
2011	119	3,188	3,307	32.441	38.9	120	3,191	3,311	32.480	39.0	-1.000	-3.000	-4.000	-0.039	-0.047
2012	121	3,341	3,462	33.769	40.5	121	3,343	3,464	33.809	40.6	0.000	-2.000	-2.000	-0.020	-0.023
2013	127	3,356	3,483	33.432	40.1	127	3,358	3,485	33.451	40.1	0.000	-2.000	-2.000	-0.019	-0.023
2014	140	3,595	3,735	34.990	42.0	140	3,598	3,738	35.018	42.0	0.000	-3.000	-3.000	-0.028	-0.034
2015	149	3,919	4,068	37.547	45.1	149	3,922	4,071	37.575	45.1	0.000	-3.000	-3.000	-0.028	-0.033
2016	152	4,409	4,561	41.511	49.8	152	4,412	4,564	41.538	49.8	0.000	-3.000	-3.000	-0.027	-0.033
2017	156	4,904	5,060	45.534	54.6	157	4,908	5,065	45.579	54.7	-1.000	-4.000	-5.000	-0.045	-0.054
2018	157	5,354	5,511	49.037	58.8	158	5,358	5,516	49.081	58.9	-1.000	-4.000	-5.000	-0.044	-0.053
2019	163	5,754	5,917	52.018	62.4	163	5,758	5,921	52.053	62.5	0.000	-4.000	-4.000	-0.035	-0.042
2020	176	6,178	6,354	54.836	65.8	176	6,182	6,358	54.870	65.8	0.000	-4.000	-4.000	-0.035	-0.041
2021	178	6,653	6,831	57.788	69.3	178	6,657	6,835	57.822	69.4	0.000	-4.000	-4.000	-0.034	-0.041
2022	182	6,985	7,167	59.256	71.1	182	6,989	7,171	59.289	71.1	0.000	-4.000	-4.000	-0.033	-0.040
2023	191	6,962	7,153	57.803	69.4	191	6,966	7,157	57.835	69.4	0.000	-4.000	-4.000	-0.032	-0.039
2024	203	7,466	7,669	60.559	72.7	203	7,470	7,673	60.591	72.7	0.000	-4.000	-4.000	-0.032	-0.038
2025	216	8,291	8,507	65.567	78.7	215	8,296	8,511	65.618	78.7	1.000	-5.000	-4.000	-0.031	-0.037
2026	232	8,738	8,970	67.808	81.4	232	8,744	8,976	67.854	81.4	0.000	-6.000	-6.000	-0.045	-0.054
2027	256	9,153	9,409	69.837	83.8	255	9,158	9,413	69.866	83.8	1.000	-5.000	-4.000	-0.030	-0.036
2028	280	9,485	9,765	71.244	85.5	280	9,490	9,770	71.280	85.5	0.000	-5.000	-5.000	-0.036	-0.044
2029	309	9,844	10,153	72.889	87.5	308	9,849	10,158	72.925	87.5	0.000	-5.000	-5.000	-0.036	-0.043
2030	336	10,400	10,736	75.747	90.9	336	10,405	10,741	75.782	90.9	0.000	-5.000	-5.000	-0.035	-0.042
2031	361	10,839	11,200	77.804	93.4	361	10,845	11,206	77.846	93.4	0.000	-6.000	-6.000	-0.042	-0.050
2032	392	11,454	11,846	81.040	97.2	393	11,459	11,852	81.081	97.3	-1.000	-5.000	-6.000	-0.041	-0.049
2033	424	12,661	13,085	88.150	105.8	424	12,665	13,089	88.177	105.8	0.000	-4.000	-4.000	-0.027	-0.032
2034	452	13,324	13,776	91.392	109.7	452	13,328	13,780	91.419	109.7	0.000	-4.000	-4.000	-0.027	-0.032
2035	481	13,833	14,314	93.517	112.2	481	13,838	14,319	93.550	112.3	0.000	-5.000	-5.000	-0.033	-0.039
2036	521	14,966	15,487	99.643	119.6	520	14,971	15,491	99.669	119.6	1.000	-5.000	-4.000	-0.026	-0.031
2037	554	15,608	16,162	102.412	122.9	554	15,614	16,168	102.450	122.9	0.000	-6.000	-6.000	-0.038	-0.046
2038	585	16,154	16,739	104.463	125.4	585	16,158	16,743	104.488	125.4	0.000	-4.000	-4.000	-0.025	-0.030
2039	612	16,851	17,463	107.335	128.8	612	16,857	17,469	107.372	128.8	0.000	-6.000	-6.000	-0.037	-0.044
2040	655	17,395	18,050	109.271	131.1	655	17,401	18,056	109.307	131.2	0.000	-6.000	-6.000	-0.036	-0.044

Notes:

Negative indicates a reduction in the customer bill for the 25 MW DeSoto solar project.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

New Generation Space Cost Solar Project
System Variable O&M and System Fuel Costs - With and Without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[8]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1000 KWH	Impact on Customer Bill of 1,200 KWH
2011	119	3,190	3,309	32.460	39.0	120	3,191	3,311	32.480	39.0	-1.000	-1.000	-2.000	-0.020	-0.024
2012	121	3,343	3,464	33.809	40.6	121	3,343	3,464	33.809	40.6	0.000	0.000	0.000	0.000	0.000
2013	127	3,358	3,485	33.451	40.1	127	3,358	3,485	33.451	40.1	0.000	0.000	0.000	0.000	0.000
2014	140	3,597	3,737	35.006	42.0	140	3,598	3,738	35.018	42.0	0.000	-1.000	-1.000	-0.009	-0.011
2015	149	3,921	4,070	37.565	45.1	149	3,922	4,071	37.575	45.1	0.000	-1.000	-1.000	-0.009	-0.011
2016	152	4,411	4,563	41.529	49.8	152	4,412	4,564	41.538	49.8	0.000	-1.000	-1.000	-0.009	-0.011
2017	157	4,906	5,063	45.561	54.7	157	4,908	5,065	45.579	54.7	0.000	-2.000	-2.000	-0.018	-0.022
2018	158	5,357	5,515	49.072	58.9	158	5,358	5,516	49.081	58.9	0.000	-1.000	-1.000	-0.009	-0.011
2019	163	5,757	5,920	52.044	62.5	163	5,758	5,921	52.053	62.5	0.000	-1.000	-1.000	-0.009	-0.011
2020	176	6,180	6,356	54.853	65.8	176	6,182	6,358	54.870	65.8	0.000	-2.000	-2.000	-0.017	-0.021
2021	178	6,656	6,834	57.814	69.4	178	6,657	6,835	57.822	69.4	0.000	-1.000	-1.000	-0.008	-0.010
2022	182	6,987	7,169	59.273	71.1	182	6,989	7,171	59.289	71.1	0.000	-2.000	-2.000	-0.017	-0.020
2023	191	6,965	7,156	57.827	69.4	191	6,966	7,157	57.835	69.4	0.000	-1.000	-1.000	-0.008	-0.010
2024	203	7,468	7,671	60.575	72.7	203	7,470	7,673	60.591	72.7	0.000	-2.000	-2.000	-0.016	-0.019
2025	215	8,294	8,509	65.602	78.7	215	8,296	8,511	65.618	78.7	0.000	-2.000	-2.000	-0.015	-0.019
2026	232	8,742	8,974	67.838	81.4	232	8,744	8,976	67.854	81.4	0.000	-2.000	-2.000	-0.015	-0.018
2027	255	9,156	9,411	69.851	83.8	255	9,158	9,413	69.866	83.8	0.000	-2.000	-2.000	-0.015	-0.018
2028	280	9,488	9,768	71.266	85.5	280	9,490	9,770	71.280	85.5	0.000	-2.000	-2.000	-0.015	-0.018
2029	309	9,847	10,156	72.910	87.5	309	9,849	10,158	72.925	87.5	0.000	-2.000	-2.000	-0.014	-0.017
2030	336	10,403	10,739	75.768	90.9	336	10,405	10,741	75.782	90.9	0.000	-2.000	-2.000	-0.014	-0.017
2031	361	10,843	11,204	77.832	93.4	361	10,845	11,206	77.846	93.4	0.000	-2.000	-2.000	-0.014	-0.017
2032	393	11,458	11,851	81.074	97.3	393	11,459	11,852	81.081	97.3	0.000	-1.000	-1.000	-0.007	-0.008
2033	424	12,664	13,088	88.170	105.8	424	12,665	13,089	88.177	105.8	0.000	-1.000	-1.000	-0.007	-0.008
2034	452	13,327	13,779	91.412	109.7	452	13,328	13,780	91.419	109.7	0.000	-1.000	-1.000	-0.007	-0.008
2035	481	13,837	14,318	93.543	112.3	481	13,838	14,319	93.550	112.3	0.000	-1.000	-1.000	-0.007	-0.008
2036	520	14,969	15,489	99.656	119.6	520	14,971	15,491	99.669	119.6	0.000	-2.000	-2.000	-0.013	-0.015
2037	554	15,612	16,166	102.438	122.9	554	15,614	16,168	102.450	122.9	0.000	-2.000	-2.000	-0.013	-0.015
2038	565	16,157	16,742	104.482	125.4	565	16,158	16,743	104.488	125.4	0.000	-1.000	-1.000	-0.006	-0.007
2039	612	16,855	17,467	107.359	128.8	612	16,857	17,469	107.372	128.8	0.000	-2.000	-2.000	-0.012	-0.015
2040	655	17,399	18,054	109.295	131.2	655	17,401	18,056	109.307	131.2	0.000	-2.000	-2.000	-0.012	-0.015

Notes:

Negative indicates a reduction in the customer bill for the 10 MW Space Cost solar project.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Martin Solar Project
System Variable O&M and System Fuel Costs - With and Without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[8]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1,000 KWH	Impact on Customer Bill of 1,200 KWH
2011	119	3,184	3,303	32.491	38.9	120	3,191	3,311	32.480	39.0	-1.000	-7.000	-8.000	-0.078	-0.094
2012	121	3,337	3,458	33.750	40.5	121	3,343	3,464	33.809	40.6	0.000	-6.000	-6.000	-0.059	-0.070
2013	127	3,352	3,479	33.394	40.1	127	3,358	3,485	33.451	40.1	0.000	-6.000	-6.000	-0.058	-0.069
2014	149	3,591	3,731	34.952	41.9	140	3,598	3,738	35.018	42.0	0.000	-7.000	-7.000	-0.066	-0.079
2015	149	3,913	4,062	37.482	45.0	149	3,922	4,071	37.575	45.1	0.000	-9.000	-9.000	-0.083	-0.100
2016	152	4,403	4,555	41.456	49.7	152	4,412	4,564	41.538	49.8	0.000	-9.000	-9.000	-0.082	-0.098
2017	156	4,898	5,054	45.480	54.6	157	4,908	5,065	45.579	54.7	-1.000	-10.000	-11.000	-0.099	-0.119
2018	157	5,347	5,504	48.975	58.8	158	5,358	5,516	49.081	58.9	-1.000	-11.000	-12.000	-0.107	-0.128
2019	163	5,748	5,911	51.965	62.4	163	5,758	5,921	52.053	62.5	0.000	-10.000	-10.000	-0.088	-0.105
2020	176	6,170	6,346	54.767	65.7	176	6,182	6,358	54.870	65.8	0.000	-12.000	-12.000	-0.104	-0.124
2021	178	6,645	6,823	57.721	69.3	178	6,657	6,835	57.822	69.4	0.000	-12.000	-12.000	-0.102	-0.122
2022	182	6,978	7,156	59.182	71.0	182	6,989	7,171	59.289	71.1	0.000	-13.000	-13.000	-0.107	-0.129
2023	191	6,953	7,144	57.730	69.3	191	6,966	7,157	57.835	69.4	0.000	-13.000	-13.000	-0.105	-0.126
2024	203	7,453	7,656	60.456	72.5	203	7,470	7,673	60.591	72.7	0.000	-17.000	-17.000	-0.134	-0.161
2025	215	8,280	8,495	65.494	78.6	215	8,296	8,511	65.618	78.7	0.000	-16.000	-16.000	-0.123	-0.148
2026	231	8,727	8,958	67.718	81.3	232	8,744	8,976	67.854	81.4	-1.000	-17.000	-18.000	-0.136	-0.163
2027	255	9,143	9,398	69.755	83.7	255	9,158	9,413	69.866	83.8	0.000	-15.000	-15.000	-0.111	-0.134
2028	281	9,474	9,755	71.171	85.4	280	9,490	9,770	71.280	85.5	1.000	-16.000	-15.000	-0.109	-0.131
2029	309	9,833	10,142	72.810	87.4	309	9,849	10,158	72.925	87.5	0.000	-16.000	-16.000	-0.115	-0.138
2030	336	10,389	10,725	75.669	90.8	336	10,405	10,741	75.782	90.9	0.000	-16.000	-16.000	-0.113	-0.135
2031	361	10,829	11,190	77.734	93.3	361	10,845	11,206	77.846	93.4	0.000	-16.000	-16.000	-0.111	-0.133
2032	392	11,443	11,835	80.955	97.2	393	11,459	11,852	81.081	97.3	-1.000	-16.000	-17.000	-0.116	-0.140
2033	424	12,649	13,073	88.069	105.7	424	12,665	13,089	88.177	105.8	0.000	-16.000	-16.000	-0.108	-0.129
2034	452	13,313	13,765	91.319	109.6	452	13,328	13,780	91.419	109.7	0.000	-15.000	-15.000	-0.100	-0.119
2035	480	13,823	14,303	93.445	112.1	481	13,838	14,319	93.550	112.3	-1.000	-15.000	-16.000	-0.105	-0.125
2036	520	14,955	15,475	99.566	119.5	520	14,971	15,491	99.669	119.6	0.000	-16.000	-16.000	-0.103	-0.124
2037	554	15,595	16,149	102.330	122.8	554	15,614	16,168	102.450	122.9	0.000	-19.000	-19.000	-0.120	-0.144
2038	585	16,143	16,728	104.394	125.3	585	16,158	16,743	104.488	125.4	0.000	-15.000	-15.000	-0.094	-0.112
2039	612	16,839	17,451	107.261	128.7	612	16,857	17,469	107.372	128.8	0.000	-18.000	-18.000	-0.111	-0.133
2040	655	17,383	18,038	109.198	131.0	655	17,401	18,056	109.307	131.2	0.000	-18.000	-18.000	-0.109	-0.131

Notes:

Negative indicates a reduction in the customer bill for the 25 MW DeSoto solar project.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below for all three solar projects (Desoto, Space Coast, Martin).

A. See attached table.

Existing Generation Solar Portfolio
Annual Emission Costs - with and without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
	Emission Related Revenue Requirements Costs with Solar Project				Emission Related Revenue Requirements Costs without Solar Project				[4]- [8] Differential in Revenue Requirements ($ millions)	Differential in Customer Bill $/1,000 kwh	Differential in Customer Bill $/1,200 kwh
	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)	CO2 ($ millions)	SO2 ($ millions)	NOx ($ millions)	Total ($ millions)			
2011	0.000	0.000	-4.126	-4.126	0.000	0.000	-4.126	-4.126	0.000	0.000	0.000
2012	0.000	-13.194	-6.208	-19.402	0.000	-13.194	-6.208	-19.402	0.000	0.000	0.000
2013	0.000	-14.399	-8.811	-23.210	0.000	-14.399	-8.811	-23.210	0.000	0.000	0.000
2014	0.000	-7.182	-9.290	-16.472	0.000	-7.182	-9.290	-16.472	0.000	0.000	0.000
2015	0.000	-7.306	-7.263	-14.569	0.000	-7.306	-7.263	-14.569	0.000	0.000	0.000
2016	0.000	-7.765	-8.405	-16.171	0.000	-7.765	-8.405	-16.171	0.000	0.000	0.000
2017	0.000	-7.930	-8.655	-16.585	0.000	-7.930	-8.655	-16.585	0.000	0.000	0.000
2018	1,263.472	-8.148	-9.187	1,248.136	1,266.143	-8.148	-9.187	1,248.808	-2.671	-0.024	-0.029
2019	1,403.974	-8.333	-9.479	1,386.162	1,407.248	-8.333	-9.479	1,389.437	-3.275	-0.029	-0.035
2020	1,531.450	-8.541	-10.021	1,512.889	1,534.841	-8.541	-10.021	1,516.279	-3.391	-0.029	-0.035
2021	1,703.718	-8.750	-10.762	1,684.205	1,707.186	-8.750	-10.762	1,687.674	-3.469	-0.029	-0.035
2022	1,808.459	-8.992	-13.429	1,786.037	1,811.957	-8.992	-13.429	1,789.536	-3.498	-0.029	-0.035
2023	1,828.002	-9.235	-14.393	1,804.374	1,830.946	-9.235	-14.393	1,807.318	-2.944	-0.024	-0.029
2024	1,997.161	-9.443	-14.846	1,973.072	2,000.440	-9.443	-14.846	1,976.350	-3.278	-0.026	-0.031
2025	2,198.697	-9.769	-12.737	2,176.191	2,203.150	-9.769	-12.737	2,180.644	-4.453	-0.034	-0.041
2026	2,380.217	-10.412	-12.899	2,356.906	2,385.163	-10.412	-12.899	2,361.851	-4.945	-0.037	-0.045
2027	2,636.553	-10.681	-13.712	2,612.161	2,641.876	-10.681	-13.712	2,617.483	-5.322	-0.040	-0.047
2028	2,883.652	-10.942	-13.113	2,859.597	2,889.734	-10.942	-13.113	2,865.679	-6.082	-0.044	-0.053
2029	3,152.275	-11.225	-13.872	3,127.178	3,158.313	-11.225	-13.872	3,133.216	-6.038	-0.043	-0.052
2030	3,492.633	-11.498	-14.350	3,466.784	3,499.951	-11.498	-14.350	3,474.103	-7.319	-0.052	-0.062
2031	3,636.106	-11.784	-15.573	3,608.749	3,642.626	-11.784	-15.573	3,615.269	-6.520	-0.045	-0.054
2032	3,871.880	-12.072	-16.308	3,843.500	3,878.276	-12.072	-16.308	3,849.896	-6.396	-0.044	-0.053
2033	4,326.580	-12.352	-16.553	4,297.674	4,333.504	-12.352	-16.553	4,304.598	-6.924	-0.047	-0.056
2034	4,574.418	-12.314	-18.055	4,544.049	4,582.194	-12.314	-18.055	4,551.825	-7.776	-0.052	-0.062
2035	4,755.176	-12.619	-18.647	4,723.910	4,762.296	-12.619	-18.647	4,731.030	-7.120	-0.047	-0.056
2036	5,196.973	-12.915	-18.868	5,165.189	5,203.953	-12.915	-18.868	5,172.169	-6.980	-0.045	-0.054
2037	5,441.699	-13.234	-19.504	5,408.961	5,448.610	-13.234	-19.504	5,415.872	-6.911	-0.044	-0.053
2038	5,854.578	-13.561	-20.337	5,820.680	5,863.828	-13.561	-20.337	5,829.930	-9.250	-0.058	-0.069
2039	5,926.892	-13.894	-20.953	5,892.045	5,935.605	-13.894	-20.953	5,900.757	-8.713	-0.054	-0.064
2040	6,146.860	-14.239	-22.103	6,110.518	6,155.440	-14.239	-22.103	6,119.098	-8.580	-0.052	-0.062

Notes:

Negative indicates a reduction in the customer bill .

The annual costs include only the system emission costs.

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Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below for all three solar projects (Desoto, Space Coast, Martin).

A. See attached table.

Capital and O&M Costs of the 110 MW Solar Project Portfolio
(do not include system benefits)

	Capital Revenue Requirements ($ millions)	Fixed O&M and Capital Replacement Costs ($ millions)	Total ($ millions)	Impact on Customer Bill of 1,000 kwh ($)	Impact on Customer Bill of 1,200 kwh ($)
2011	74.886	4.411	79.297	0.778	0.933
2012	72.836	4.464	77.300	0.754	0.905
2013	70.637	4.952	75.589	0.726	0.871
2014	68.438	4.757	73.195	0.686	0.823
2015	66.239	5.377	71.616	0.661	0.793
2016	64.041	4.968	69.009	0.628	0.754
2017	61.842	5.640	67.481	0.607	0.729
2018	59.643	5.291	64.934	0.578	0.693
2019	57.444	6.041	63.485	0.558	0.670
2020	55.245	5.709	60.954	0.526	0.631
2021	53.046	6.363	59.409	0.503	0.603
2022	50.848	6.002	56.850	0.470	0.564
2023	48.649	6.741	55.390	0.448	0.537
2024	46.450	6.396	52.846	0.417	0.501
2025	44.251	7.227	51.478	0.397	0.476
2026	42.052	6.698	48.750	0.369	0.442
2027	39.853	7.498	47.352	0.351	0.422
2028	37.655	7.030	44.685	0.326	0.391
2029	35.456	7.948	43.404	0.312	0.374
2030	33.257	7.511	40.767	0.288	0.345
2031	31.058	8.273	39.331	0.273	0.328
2032	28.859	7.779	36.639	0.251	0.301
2033	26.660	8.759	35.419	0.239	0.286
2034	24.461	8.335	32.797	0.218	0.261
2035	22.263	9.384	31.647	0.207	0.248
2036	20.064	8.836	28.899	0.186	0.223
2037	17.865	9.960	27.825	0.176	0.212
2038	15.666	9.410	25.076	0.156	0.188
2039	13.337	10.623	23.960	0.147	0.177
2040	-2.086	9.468	7.382	0.045	0.054

Notes:

Negative indicates a reduction in the customer bill for the 110 MW portfolio of solar projects.

As requested, the capital revenue requirements and the O&M requirements shown in this table only include the costs of the solar project. System impacts are not included.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below for all three solar projects (Desoto, Space Coast, Martin).

A. See attached table.

Existing Solar Generation Portfolio
System Variable O&M and System Fuel Costs - With and Without Solar Project

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	System Costs w/Solar Project					System Costs w/o Solar Project					Differential in annual costs [3]-[8]				
	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [1] + [2] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total costs [6] + [7] ($ millions)	Impact on Customer Bill $/1000 KWH	Impact on Customer Bill $/1200 KWH	Variable O&M ($ millions)	Fuel ($ millions)	Total Revenue Requirements ($ millions)	Impact on Customer Bill of 1,000 kwh $/1000 KWH	Impact on Customer Bill of 1,200 kwh $/1200 KWH
2011	119	3,180	3,299	32.4	38.8	120	3,191	3,311	32.5	39.0	-1	-11	-12	-0.118	-0.141
2012	121	3,334	3,455	33.7	40.5	121	3,343	3,464	33.6	40.6	0	-9	-9	-0.088	-0.105
2013	127	3,349	3,476	33.4	40.0	127	3,358	3,485	33.5	40.1	0	-9	-9	-0.086	-0.104
2014	140	3,587	3,727	34.9	41.9	140	3,598	3,738	35.0	42.0	0	-11	-11	-0.103	-0.124
2015	149	3,909	4,058	37.5	44.9	149	3,922	4,071	37.6	45.1	0	-13	-13	-0.120	-0.144
2016	152	4,399	4,551	41.4	49.7	152	4,412	4,564	41.5	49.8	0	-13	-13	-0.118	-0.142
2017	156	4,894	5,050	45.4	54.5	157	4,908	5,065	45.6	54.7	-1	-14	-15	-0.135	-0.162
2018	157	5,242	5,499	48.9	58.7	158	5,358	5,516	49.1	58.9	-1	-16	-17	-0.151	-0.182
2019	162	5,742	5,904	51.9	62.3	163	5,758	5,921	52.1	62.5	-1	-16	-17	-0.149	-0.179
2020	175	6,166	6,341	54.7	65.7	178	6,182	6,358	54.9	65.8	-1	-16	-17	-0.147	-0.176
2021	178	6,640	6,818	57.7	69.2	178	6,657	6,835	57.8	69.4	0	-17	-17	-0.144	-0.173
2022	182	6,971	7,153	59.1	71.0	182	6,989	7,171	59.3	71.1	0	-18	-18	-0.149	-0.179
2023	190	6,946	7,136	57.7	69.2	191	6,966	7,157	57.8	69.4	-1	-20	-21	-0.170	-0.204
2024	203	7,447	7,650	60.4	72.5	203	7,470	7,673	60.6	72.7	0	-23	-23	-0.182	-0.218
2025	215	8,273	8,488	65.4	78.5	215	8,296	8,511	65.6	78.7	0	-23	-23	-0.177	-0.213
2026	231	8,720	8,951	67.7	81.2	232	8,744	8,976	67.9	81.4	-1	-24	-25	-0.189	-0.227
2027	255	9,138	9,393	69.7	83.7	255	9,158	9,413	69.9	83.8	0	-20	-20	-0.148	-0.178
2028	281	9,468	9,749	71.1	85.4	280	9,490	9,770	71.3	85.5	1	-22	-21	-0.153	-0.184
2029	309	9,825	10,134	72.8	87.3	308	9,849	10,158	72.9	87.5	0	-24	-24	-0.172	-0.207
2030	338	10,382	10,718	75.6	90.7	336	10,405	10,741	75.8	90.9	0	-23	-23	-0.162	-0.195
2031	361	10,822	11,183	77.7	93.2	361	10,845	11,206	77.8	93.4	0	-23	-23	-0.160	-0.192
2032	392	11,437	11,829	80.9	97.1	393	11,459	11,852	81.1	97.3	-1	-22	-23	-0.157	-0.189
2033	423	12,643	13,066	88.0	105.6	424	12,665	13,089	88.2	105.8	-1	-22	-23	-0.155	-0.186
2034	451	13,305	13,756	91.3	109.5	452	13,328	13,780	91.4	109.7	-1	-23	-24	-0.159	-0.191
2035	480	13,816	14,296	93.4	112.1	481	13,838	14,319	93.5	112.3	-1	-22	-23	-0.150	-0.180
2036	520	14,948	15,468	99.5	119.4	520	14,971	15,491	99.7	119.6	0	-23	-23	-0.148	-0.178
2037	554	15,587	16,141	102.3	122.7	554	15,614	16,168	102.5	122.9	0	-27	-27	-0.171	-0.205
2038	585	16,136	16,721	104.4	125.2	585	16,158	16,743	104.5	125.4	0	-22	-22	-0.137	-0.165
2039	612	16,832	17,444	107.2	128.7	612	16,857	17,469	107.4	128.8	0	-25	-25	-0.154	-0.184
2040	654	17,376	18,030	109.1	131.0	655	17,401	18,055	109.3	131.2	-1	-25	-26	-0.157	-0.189

Notes:

Negative indicates a reduction in the customer bill for the 110 MW solar project portfolio.
The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. For responding to this interrogatory, however, FPL is not reporting historical data, but rather is only including projected system benefits, starting January 2011. These projected benefits were developed using FPL's production costing model PMAREA.

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please Complete the table below for the Peak Demand Day in 2010. Please identify the date of the peak day.

A.

Peak Day: 01/11/2010. Space Coast did not go commercial until April 16, 2010.

		Net Output (MW)	
Time of Day	System Firm Demand (MW)	DESOTO	SPACE COAST
12:00:00-12:59:59 AM	19792	0	N/A
1:00:00-1:59:59 AM	19766	0	N/A
2:00:00-2:59:59 AM	19920	0	N/A
3:00:00-3:59:59 AM	20228	0	N/A
4:00:00-4:59:59 AM	20829	0	N/A
5:00:00-5:59:59 AM	21783	0	N/A
6:00:00-6:59:59 AM	23614	0	N/A
7:00:00-7:59:59 AM	24346	0.9	N/A
8:00:00-8:59:59 AM	23292	12.6	N/A
9:00:00-9:59:59 AM	22279	18.2	N/A
10:00:00-10:59:59 AM	20989	18.3	N/A
11:00:00-11:59:59 AM	19372	17.4	N/A
12:00:00-12:59:59 PM	17730	16.9	N/A
1:00:00-1:59:59 PM	16327	17.1	N/A
2:00:00-2:59:59 PM	15118	17.8	N/A
3:00:00-3:59:59 PM	14411	17.8	N/A
4:00:00-4:59:59 PM	14695	14.3	N/A
5:00:00-5:59:59 PM	16445	2.2	N/A
6:00:00-6:59:59 PM	19273	0	N/A
7:00:00-7:59:59 PM	19931	0	N/A
8:00:00-8:59:59 PM	19925	0	N/A
9:00:00-9:59:59 PM	19433	0	N/A
10:00:00-10:59:59 PM	18310	0	N/A
11:00:00-11:59:59 PM	17328	0	N/A

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please Complete the table below for the Peak Demand Day in January 2010. Please identify the date of the peak day.

A.

Peak Day: 01/11/2010 in January, 2010. Space Coast did not go commercial until April 16, 2010.

		Net Output (MW)	
Time of Day	System Firm Demand (MW)	DESOTO	SPACE COAST
12:00:00-12:59:59 AM	19792	0	N/A
1:00:00-1:59:59 AM	19766	0	N/A
2:00:00-2:59:59 AM	19920	0	N/A
3:00:00-3:59:59 AM	20228	0	N/A
4:00:00-4:59:59 AM	20829	0	N/A
5:00:00-5:59:59 AM	21783	0	N/A
6:00:00-6:59:59 AM	23614	0	N/A
7:00:00-7:59:59 AM	24346	0.9	N/A
8:00:00-8:59:59 AM	23292	12.6	N/A
9:00:00-9:59:59 AM	22279	18.2	N/A
10:00:00-10:59:59 AM	20989	18.3	N/A
11:00:00-11:59:59 AM	19372	17.4	N/A
12:00:00-12:59:59 PM	17730	16.9	N/A
1:00:00-1:59:59 PM	16327	17.1	N/A
2:00:00-2:59:59 PM	15118	17.8	N/A
3:00:00-3:59:59 PM	14411	17.8	N/A
4:00:00-4:59:59 PM	14695	14.3	N/A
5:00:00-5:59:59 PM	16445	2.2	N/A
6:00:00-6:59:59 PM	19273	0	N/A
7:00:00-7:59:59 PM	19931	0	N/A
8:00:00-8:59:59 PM	19925	0	N/A
9:00:00-9:59:59 PM	19433	0	N/A
10:00:00-10:59:59 PM	18310	0	N/A
11:00:00-11:59:59 PM	17328	0	N/A

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please Complete the table below for the Peak Demand Day in August 2010. Please identify the date of the peak day.

A.

Peak Day: in August, 2010 was 08/19/2010.

		Net Output (MW)	
Time of Day	System Firm Demand (MW)	DESOTO	SPACE COAST
12:00:00-12:59:59 AM	14436	0	0
1:00:00-1:59:59 AM	13493	0	0
2:00:00-2:59:59 AM	12769	0	0
3:00:00-3:59:59 AM	12338	0	0
4:00:00-4:59:59 AM	12162	0	0
5:00:00-5:59:59 AM	12445	0	0
6:00:00-6:59:59 AM	13221	0	0
7:00:00-7:59:59 AM	13725	2.7	0.3
8:00:00-8:59:59 AM	15013	15	2.1
9:00:00-9:59:59 AM	16713	19.2	4.5
10:00:00-10:59:59 AM	18369	20.7	6.4
11:00:00-11:59:59 AM	19778	21.1	7.8
12:00:00-12:59:59 PM	20828	18.7	7.9
1:00:00-1:59:59 PM	21556	19.1	5.2
2:00:00-2:59:59 PM	21959	19.4	6.1
3:00:00-3:59:59 PM	22256	18.4	6.1
4:00:00-4:59:59 PM	22277	20.9	6.2
5:00:00-5:59:59 PM	21925	16.3	4.2
6:00:00-6:59:59 PM	21165	5.5	1.7
7:00:00-7:59:59 PM	20163	1.4	0.1
8:00:00-8:59:59 PM	19521	0	0
9:00:00-9:59:59 PM	18279	0	0
10:00:00-10:59:59 PM	16664	0	0
11:00:00-11:59:59 PM	14967	0	0

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please Complete the table below describing the lowest output day for the Desoto Energy Center. Please identify the date of the day described. Please explain why output was low.

A.
The lowest output day for the Desoto Solar site was 3/12/10. The low output was due to inclement weather causing very low solar irradiance. There were no forced outages, planned or unplanned maintenance activities.

Time of Day	System Firm Demand (MW)	Net Output (MW) DESOTO
12:00:00-12:59:59 AM	8601	0
1:00:00-1:59:59 AM	7956	0
2:00:00-2:59:59 AM	7598	0
3:00:00-3:59:59 AM	7434	0
4:00:00-4:59:59 AM	7518	0
5:00:00-5:59:59 AM	8157	0
6:00:00-6:59:59 AM	9512	0
7:00:00-7:59:59 AM	10538	0
8:00:00-8:59:59 AM	11163	0.4
9:00:00-9:59:59 AM	11799	0.4
10:00:00-10:59:59 AM	12291	0.3
11:00:00-11:59:59 AM	12413	0.1
12:00:00-12:59:59 PM	12292	2.7
1:00:00-1:59:59 PM	12080	2.7
2:00:00-2:59:59 PM	11852	3.4
3:00:00-3:59:59 PM	11590	0.4
4:00:00-4:59:59 PM	11521	0.3
5:00:00-5:59:59 PM	11700	0.2
6:00:00-6:59:59 PM	12101	0.1
7:00:00-7:59:59 PM	12106	0
8:00:00-8:59:59 PM	11658	0
9:00:00-9:59:59 PM	10994	0
10:00:00-10:59:59 PM	10150	0
11:00:00-11:59:59 PM	9237	0

Q.
Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please Complete the table below describing the lowest output day for the Space Coast Energy Center. Please identify the date of the day described. Please explain why output was low.

A.
The lowest output day for the Space Coast Solar site was 12/18/10. The low output was due to inclement weather causing very low solar irradiance. There were no forced outages, planned or unplanned maintenance activities.

Time of Day	System Firm Demand (MW)	Net Output (MW) Space Coast
12:00:00-12:59:59 AM	8286	0
1:00:00-1:59:59 AM	7808	0
2:00:00-2:59:59 AM	7581	0
3:00:00-3:59:59 AM	7527	0
4:00:00-4:59:59 AM	7631	0
5:00:00-5:59:59 AM	7918	0
6:00:00-6:59:59 AM	8430	0
7:00:00-7:59:59 AM	9058	0.1
8:00:00-8:59:59 AM	10150	0.2
9:00:00-9:59:59 AM	10972	0.1
10:00:00-10:59:59 AM	11488	0.4
11:00:00-11:59:59 AM	11534	0.8
12:00:00-12:59:59 PM	11383	0.9
1:00:00-1:59:59 PM	11146	0.6
2:00:00-2:59:59 PM	10845	0.6
3:00:00-3:59:59 PM	10648	1.3
4:00:00-4:59:59 PM	10481	0.5
5:00:00-5:59:59 PM	11152	0
6:00:00-6:59:59 PM	11786	0
7:00:00-7:59:59 PM	11508	0
8:00:00-8:59:59 PM	11086	0
9:00:00-9:59:59 PM	10564	0
10:00:00-10:59:59 PM	9876	0
11:00:00-11:59:59 PM	8978	0

Q.

Please refer to FPL's three Next Generation Solar Energy Centers for questions 1 - 18 below.

Please complete the table below describing the rate impact of the solar projects with and without Federal ITCs.

A.

Please see attached table

Rate impact- with and without ITC
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	With ITC				Without ITC			
Year	DeSoto Solar $/ 1200 kWH	Space Center Solar $/ 1200 kWH	Martin Solar $/ 1200 kWH	All three projects $/ 1200 KWH	DeSoto Solar $/ 1200 kWH	Space Center Solar $/ 1200 kWH	Martin Solar $/ 1200 kWH	All three projects $/ 1200 KWH
2009	0.117	0.012	0.078	0.207	0.130	0.012	0.078	0.219
2010	0.175	0.078	0.331	0.585	0.188	0.081	0.332	0.601
2011	0.176	0.083	0.509	0.792	0.187	0.086	0.539	0.838
2012	0.193	0.104	0.514	0.799	0.205	0.109	0.546	0.847
2013	0.183	0.099	0.496	0.767	0.195	0.104	0.527	0.815
2014	0.163	0.083	0.452	0.699	0.175	0.088	0.484	0.748
2015	0.155	0.080	0.414	0.649	0.168	0.085	0.446	0.699
2016	0.147	0.076	0.388	0.611	0.160	0.081	0.421	0.662
2017	0.119	0.062	0.353	0.566	0.132	0.067	0.387	0.618
2018	0.107	0.067	0.300	0.483	0.120	0.072	0.334	0.536
2019	0.109	0.064	0.304	0.455	0.122	0.070	0.339	0.509
2020	0.103	0.050	0.256	0.420	0.116	0.056	0.292	0.474
2021	0.097	0.057	0.245	0.395	0.110	0.063	0.281	0.450
2022	0.087	0.043	0.212	0.351	0.100	0.048	0.248	0.405
2023	0.080	0.046	0.202	0.305	0.093	0.051	0.238	0.360
2024	0.068	0.035	0.143	0.252	0.081	0.040	0.180	0.307
2025	0.060	0.033	0.131	0.222	0.074	0.039	0.167	0.277
2026	0.041	0.030	0.089	0.170	0.054	0.036	0.125	0.226
2027	0.046	0.027	0.105	0.196	0.059	0.032	0.142	0.252
2028	0.038	0.024	0.083	0.154	0.051	0.030	0.120	0.210
2029	0.034	0.023	0.068	0.115	0.047	0.028	0.105	0.171
2030	0.028	0.020	0.041	0.088	0.042	0.025	0.078	0.145
2031	0.017	0.016	0.037	0.082	0.031	0.022	0.075	0.138
2032	0.011	0.024	0.014	0.059	0.025	0.030	0.051	0.116
2033	0.026	0.022	0.015	0.044	0.040	0.027	0.063	0.102
2034	0.016	0.016	-0.001	0.008	0.030	0.022	0.037	0.066
2035	0.007	0.018	-0.007	0.012	0.021	0.024	0.031	0.070
2036	0.007	0.010	-0.021	-0.008	0.021	0.015	0.018	0.050
2037	-0.006	0.006	-0.046	-0.046	0.008	0.012	-0.008	0.012
2038	0.005	0.014	-0.047	-0.046	0.019	0.020	-0.008	0.012
2039	-0.013	0.004	-0.065	-0.072	-0.001	0.010	-0.026	-0.016
2040	-0.038	-0.011	-0.142	-0.198	-0.038	-0.009	-0.106	-0.159

Notes:
Negative indicates a reduction in the customer bill for the 25 MW solar project.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Please note that the combined rate impact for the portfolio of the three solar projects together is different than the sum of the rate impacts of the three individual projects.

Until recently, FPL has not had a system in place capable of capturing historical data on the fuel-displacement or environmental benefits of the three Next Generation Solar Energy Center facilities. In response to Staff's request for monthly reporting on historical fuel-displacement and environmental benefits of the existing solar facilities, FPL has developed a system to capture those benefits starting in January 2011. Initially, the system is capturing data on the benefits manually, but FPL expects to have an automated system in service by April 2011. FPL will file schedules showing the monthly historical fuel-displacement and environmental benefits for the existing solar facilities along with each month's A-Schedule filing, starting with the filing that will be made in mid-March 2011. Because this system was not in place during 2009 or 2010, FPL has estimated the system savings for the 2009 and 2010 results reported above by using average system fossil generation costs. For 2011 and later years, FPL used projected benefits developed from FPL's production costing model PMAREA.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

Referring to page 3 of the Notice, is the $78,400 categorized as capital or O&M cost?

A.

The $78,400 represents capital costs.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

Referring to page 3, second paragraph of the notice, if FPL decides that the 800-horsepower Supplemental Heating System is the solution for providing warm water to the manatee embayment area for 2011-2013, will FPL lease the heater for the entire 2011-2013 period, or will it lease the heater only during each heating season and incur annual installation, mobilization and demobilization costs?

A.

FPL's current lease ends in March 2011. FPL is currently evaluating whether the 800 horsepower heater will be utilized between 2011 and 2013 and examining the cost effectiveness of various options including those mentioned and an "on property off rent" scenario for non manatee season periods.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

Referring to page 4 of the notice, what will be the estimated monthly cost for light oil consumed by the 800 horsepower heater?

A.

The monthly fuel cost for the 800 horsepower heater varies with hours of operation. In December 2010 the 800 horsepower heater operated for 469 hours and the estimated cost of the fuel used $233,521. In January 2011 the 800 horsepower heater operated for 123 hours and its estimated fuel cost was $50,449. The expected monthly average cost for the four month period is $70,993.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

What will be the respective dismantlement and demobilization costs for the 800-horsepower heater when it is removed from the site?

A.

The cost to dismantle the 800 horsepower heater is expected to be $23,100. The cost to demobilize the 800 horsepower heater is expected to be $13,750. The combined dismantle and demobilize cost is expected to be $36,850.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

What will be the demobilization cost for the 200-horspower heater?

A.

The demobilization cost for the 200 horsepower heater is expected to be approximately $13,525.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

What will be the respective dismantlement and demobilization costs for FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral?

A.

FPL has not yet estimated dismantlement and demobilization costs for its electric temporary manatee heating systems. Consistent with the testimony of FPL witness Randall R. Labauve in Docket No 090007-EI (page 12), FPL continues to assume that the removal costs and salvage value will net to zero.

Q.

Please refer to FPL's Manatee Temporary Heating Systems at Plant Riviera and Plant Canaveral, and FPL's Notice of Additional Activities filed on January 4, 2011, for questions 19 – 25 below.

Please fill out Table 1 below.

A.

Please see attached tables.

Table 1: FPL's Manatee Protection Costs									
	Incurred / To be Incurred Costs ($)								
	Capital	**O&M**	**Mobilization & Installation**	**Dismantle & Demob**	**Leasing Payment / month**	**Nos of Month to Lease**	**Light Oil Consumption per month**	**Total**	**Corresponding Period mm/yy-mm/yy**
Plant Canaveral									
FPL's heating system	$4,532,542	$98,163						$4,630,705	06/10-10/10
Discharge pipe mod	$78,400							$176,563	12/10
200 HP heater lease	$0	$59,136	$8,125	$13,525	$19,712	3	$18,707	$136,908	12/10-3/11
800 HP heater lease	$0	$233,932	$13,750	$36,850	$58,483	4	$70,993	$568,502	12/10-3/11
Total	**$4,610,942**	**$391,231**	**$21,875**	**$50,375**	**$78,195**		**$89,700**	**$5,512,679**	
Plant Riviera									
Original heating system	$2,967,000	$0						$2,967,000	04/09-11/09
Modification	$0	$30,281						$30,281	10/10
Total	**$2,967,000**	**$30,281**	**$0**	**$0**	**$0**		**$0**	**$2,997,281**	
Grand Total	**$7,577,942**	**$421,512**	**$21,875**	**$50,375**	**$78,195**		**$89,700**	**$8,509,960**	

FPL Notes:

1. The O&M and other recurring costs above are estimated amounts for the 2010-2011 heating season which ends Mar 31 2011. FPL will be evaluating in 2011 the most cost-effective way to continue providing supplemental heating in subsequent heating seasons.
2. Only 3 monthly lease payments are anticipated for the 200 HP heater since it was temporarily unavailable due to maintenance issues.

Q.
Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.
Please provide updated information regarding the date of commencing commercial operation of the repowered St. Lucie nuclear Unit 1 &
Unit 2.

A.
FPL can not commence commercial operation of St. Lucie Units 1 and 2 in the uprated condition until the NRC has approved each unit's Extended Power Uprate (EPU) License Amendment Request (LAR). NRC guidelines specify a typical 14 month review for an EPU LAR. The St. Lucie Unit 1 EPU LAR was resubmitted to the NRC in November 2010; therefore, NRC approval is expected in February 2012. The St. Lucie Unit 2 LAR was submitted in February 2011; therefore, NRC approval is expected in April 2012.

Based on the EPU LAR schedule and FPL's current approved operating schedule, St. Lucie Unit 1 is currently planned to commence commercial operation in the uprated condition in February 2012 and St. Lucie Unit 2 is currently planned to commence commercial operation in the uprated condition in July 2012. FPL will continue to evaluate the EPU project schedule and may adjust these dates as necessary to ensure successful completion of the EPU project.

Q.
Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

Referring to page 3, line 17, through page 4, line 18, of the testimony and pages 2 through 4 of Exhibit RRL-2, please explain whether FPL will use internal resources, or will it retain or has it retained contractor(s), to perform the activities listed below:

- **(i) prepare the Ambient Monitoring Report**
- **(ii) install, calibrate and certify new remote thermometer(s)**
- **(iii) prepare the Heated Water Plan of Study (HWPOS) and schedule**
- **(iv) implement the HWPOS**
- **(v) perform the mathematical modeling**
- **(vi) evaluate more than 24 months of data to be collected against the modeling results**
- **(vii) prepare the Heated Water Report**
- **(viii) prepare the Biological Plan of Study (BPOS) and schedule**
- **(ix) implement the BPOS**
- **(x) prepare the Biological Report**

A.
(i) FPL has retained a contractor to prepare the Ambient Monitoring Report.
(ii) FPL will retain a contractor to install, calibrate and certify new remote thermometers.
(iii) FPL has retained a contractor to prepare the Heated Water Plan of Study and schedule.
(iv) FPL will retain a contractor to implement the HWPOS.
(v) The mathematical modeling was completed previously. This activity is not included in FPL's petition for recovery.
(vi) FPL will retain a contractor to evaluate the data to be collected against the modeling results during the HWPOS.
(vii) FPL will retain a contractor to prepare the Heated Water Report.
(viii) FPL has retained a contractor to prepare the Biological Plan of Study (BPOS) and schedule. It should be noted that the costs for preparation of the BPOS are not included in FPL's petition for recovery.
(ix) FPL will retain a contractor to implement the BPOS.
(x) FPL will retain a contractor to prepare the Biological Report.

It should be noted that FPL and the State of Florida Department of Environmental Protection (FDEP) are in continued discussions regarding the requirements for the Cooling Water Monitoring Discharge Project which may result in changes monitoring and studies discussed above.

Q.

Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below. Regarding FPL's responses to Interrogatory No. 27:

a. **For any contractor to be retained, will FPL be soliciting bids? If so, when will an RFP be issued?**

b. **For any contractor that has been retained, please identify its name and the services it provides.**

A.

(i) prepare the Ambient Monitoring Report
FPL solicited bids and an RFP was issued to Golder and Associates, Inc. to prepare the Ambient Monitoring Report (AMR) on December 2, 2010.

(ii) install, calibrate and certify new remote thermometer(s)
FPL will solicit bills following FDEP approval of the AMR.

(iii) prepare the Heated Water Plan of Study (HWPOS) and schedule
FPL solicited bids and an RFP was issued to Golder and Associates, Inc. to prepare the HWPOS on December 2, 2010.

(iv) implement the HWPOS
FPL will solicit bills following FDEP approval of the HWPOS.

(v) perform the mathematical modeling
FPL will not solicit bids or issue an RFP as this work was done previously and FPL is not included in the petition for recovery.

(vi) evaluate more than 24 months of data to be collected against the modeling results
FPL will solicit bills following FDEP approval of the HWPOS.

(vii) prepare the Heated Water Report
FPL will solicit bills following FDEP approval of the HWPOS.

(viii) prepare the Biological Plan of Study (BPOS) and schedule
Ecological Associates, Inc. has been awarded a contract to prepare the Biological Plan of Study (BPOS). It should be noted that the costs for preparation of the BPOS are not included in FPL's petition for recovery.

(ix) implement the BPOS
FPL will solicit bills following FDEP approval of the BPOS.

(x) prepare the Biological Report
FPL will solicit bills following FDEP approval of the BPOS.

It should be noted that FPL and the State of Florida Department of Environmental Protection (FDEP) are in continued discussions regarding the requirements for the Cooling Water Monitoring Discharge Project which may result in changes monitoring and studies discussed above.

Q.
Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

Please refer to page 4, line 9, of the testimony and page 2, item 7, of Exhibit RRL-2.

a. **Has FPL purchased or developed the software of thermodynamic models for the mathematical modeling?**
b. **If the response to (a) is affirmative, who is the provider of the software?**
c. **If the response to (a) is negative, will FPL be soliciting bids? If so, when will an RFP be issued?**
d. **If the response to (a) is negative, has the cost of purchasing the software been included in the estimated costs of this petition?**
e. **Who performed the mathematical modeling described in Exhibit RRL-2?**
f. **Have the costs associated with the mathematical modeling been included in the estimated costs of this petition?**

A.

a. The software used to model the St. Lucie thermal discharge was developed by the Environmental Protection Agency (EPA) and therefore was in the public domain so there was no cost and FPL is fully licensed to use it. However, FPL contracted with Ebasco to customize the model for the St. Lucie Plant thermal discharges during the original construction and operational permitting during the 1970's and 1980's using the EPA developed software.
b. EPA.
c. No.
d. No.
e. Golder and Associates, Inc.
f. No.

Q.
Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

Referring to page 5, lines 18 through 20 of the testimony, please provide a detailed breakdown of the component activities that comprise the estimated $2,567,000 of O&M costs. Please also specify the time frame over which each cost component will be incurred.

A.
The breakdown of activities associated with the estimated O&M costs of $2,567,000 provided on page 5, lines 18 through 20 of the testimony is as follows:

Ambient Monitoring Report Phase I (AMR):	
2011:	$ 78,177
Implement AMR (Ambient Monitoring Program) PII	
2011:	$ 4,752
2012:	$ 19,008
2013:	$ 19,008
2014:	$ 14,256
(19 years O&M for permanent thermometers):	$ 380,000
Sub-Total	$ 515,201
Heated Water Plan of Study (HWPOS) Phase I:	
2011:	$ 77,601
Implement HWPOS-Thermal Monitoring Program PII	
2012:	$ 12,705
2013:	$ 50,822
2014:	$ 38,118
Sub-Total	$ 179,246
Implement BPOS (Biological Monitoring Program) PII	
2011:	$ 388,164
2012:	$ 564,996
2013:	$ 564,996
2014:	$ 354,581
Sub-Total	$1,872,737
Total:	$2,567,184

It should be noted that FPL and the State of Florida Department of Environmental Protection (FDEP) are in continued discussions regarding the requirements for the Cooling Water Monitoring Discharge Project which may result in changes monitoring and studies discussed above.

Q.

Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

Referring to page 6, line 1 of the testimony, please provide a detailed breakdown of the component items that comprise the estimated $467,000 of capital costs. Please also specify when each of the cost items will be incurred.

A.

The breakdown of activities associated with the estimated capital expenditures of $467,000 provided on page 6, line 1 of the testimony is as follows:

Implement AMR (Ambient Monitoring Program) PII 2011:		$ 123,780
	Sub-Total	$ 123,780
Implement HWPOS-Thermal Monitoring Program PII 2012:		$ 233,324
	Sub-Total	$ 233,324
Implement BPOS (Biological Monitoring Program) PII 2011:		$ 110,000
	Sub-Total	$ 110,000
	Total:	$ 467,104

It should be noted that FPL and the State of Florida Department of Environmental Protection (FDEP) are in continued discussions regarding the requirements for the Cooling Water Monitoring Discharge Project which may result in changes monitoring and studies discussed above.

Q.

Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

Please refer to page 6, line 2 of the testimony.

a. **Has FPL identified the supplier(s) of the temperature monitoring equipment?**
b. **If the response to (a) is affirmative, please identify the name of the supplier.**
c. **If the response to (a) is negative, will FPL be soliciting bids? If so, when will an RFP be issued?**
d. **Has FPL identified the supplier(s) of the SONAR equipment?**
e. **If the response to (d) is affirmative, please identify the name of the supplier.**
f. **If the response to (d) is negative, will FPL be soliciting bids? If so, when will an RFP be issued?**

A.

a. No.
b. Not applicable

c. No. This activity will be within the scope of the contractor who is awarded the implementation contract for the pertinent feasibility study which would include the purchase of any necessary equipment to meet requirements. However, the implementation phase for each of the feasibility studies will be bid.

d. No.

e. Not applicable.

f. No. This activity will be within the scope of the contractor who is awarded the implementation contract for the pertinent feasibility study which would include the purchase of any necessary equipment to meet requirements. However, the implementation phase for each of the feasibility studies will be bid.

Q.

Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.
Referring to page 6, line 11 of the testimony, please provide a detailed breakdown of the component items that comprise the estimated $234,000 of capital costs.

A.

The breakdown of activities associated with the estimated capital expenditures of $234,000 provided on page 6, line 11 of the testimony is as follows:

Implement AMR (Ambient Monitoring Program) PII 2011:		$ 123,780
	Sub-Total	$ 123,780
Implement BPOS (Biological Monitoring Program) PII 2011:		$ 110,000
	Sub-Total	$ 110,000
	Total:	$ 233,780
	Rounded:	$ 234,000

It should be noted that FPL and the State of Florida Department of Environmental Protection (FDEP) are in continued discussions regarding the requirements for the Cooling Water Monitoring Discharge Project which may result in changes monitoring and studies discussed above.

Q.

Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.
Referring to page 6, line 14 of the testimony, please provide a detailed breakdown of the component activities that comprise the estimated $549,000 of O&M costs.

A.

The breakdown of activities associated with the estimated O&M costs of $549,000 provided on page 6, line 14 of the testimony is as follows:

Ambient Monitoring Report Phase I (AMR):		
2011:		$ 78,177
Implement AMR (Ambient Monitoring Program) PII		
2011:		$ 4,752
	Sub-Total	$ 82,929
Heated Water Plan of Study (HWPOS) Phase I:		
2011:		$ 77,601
	Sub-Total	$ 77,601
Implement BPOS (Biological Monitoring Program) PII		
2011:		$ 388,164
	Sub-Total	$ 388,164
	Total:	$ 548,694

Q.

Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

When will the petitioned project, not including the additional activities, be completed?

A.

Under Administrative Order AO022TL, FPL is required to continue to monitor the thermal biological (BPOS) environment off-shore from the St. Lucie Plant for a minimum of 24 months following completion of the uprates. Monitoring of the thermal environment must also be performed for not less than 24 months following its commencement after the uprates.

Under Administrative Order AO022TL, FPL will be required to permanently monitor the ambient temperature near the St. Lucie ocean intake.

It should be noted that FPL and the State of Florida Department of Environmental Protection (FDEP) are in continued discussions regarding the requirements for the Cooling Water Monitoring Discharge Project which may result in changes monitoring and studies discussed above.

Q.
Please refer to FPL's Petition for Approval of St. Lucie Plant Cooling Water Discharge Monitoring Project and the Testimony & Exhibits of witness Labauve, filed on January 12, 2011, for questions 26 – 36 below.

The EPA is in a rule making process for revising the CWA 316(b) Phase II Rule, with a draft due in June 2011 and a final rule by the end of 2011, which may require the retrofitting of the nuclear plant cooling facilities with cooling towers. Has FPL evaluated the option of using cooling towers to replace the current once-through cooling water system for the St. Lucie nuclear units, so that the expenses associated with the activities listed in this petition, and potentially much more significant costs associated with the additional activities triggered by the Heat Water Report and/or the Biological Report due in 2 to 3 years, could be avoided?

A.
By court order, the draft 316 (b) rule will be issued on March 14, 2011 (however this deadline could be delayed if the Office of Management and Budget requires additional time to review the draft rule which was submitted to them by EPA on January 21, 2011), with the final rule due to be published on June 27, 2012. By that date, FPL will have just begun, if necessary, the Ambient Monitoring Report, but will have not yet begun to implement the two-year Heated Water Plan of Study or the two-year Biological Plan of Study (although the pre-EPU portion of the BPOS will have already completed).

In 2007, a study conducted for FPL by ENSR International Corp. (ENSR) and later verified by Electric Power Research Institute (EPRI), indicated that the capital cost of cooling towers for the St. Lucie Plant was estimated at $550 MM, with an annual estimated O&M cost of $29 MM (mainly for the operation of fans and motors). In addition, St. Lucie would experience a 1.1% decrease in efficiency from this installation. Studies have shown throughout the years that the St. Lucie Plant intake configuration (off-shore, mid-depth intake with velocity caps) is very effective for minimizing impingement mortality and entrainment. For that reason, coupled with the increase of green house gases associated with use of fossil power that will replace the "nuclear megawatts", FPL is providing information to EPA and FDEP in an effort to demonstrate the cost (financial and environmental) of retrofitting St. Lucie with cooling towers is wholly disproportionate to the benefit derived from installing them and therefore retrofitting the plant with cooling towers is not justified.

Due to the uncertainty associated with the final form of the rule, coupled with the unknown impact the final rule will have on St. Lucie, FPL will work with FDEP on the Ambient Monitoring Plan, the Heated Water Plan of Study and the Biological Plan of Study. These actions will ensure the plant can continue to operate in the future, under all possible regulatory scenarios at the full uprated capacity for each unit.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 11 day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared J. L. Martinez, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 1 and 3 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

J. L. Martinez

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11 day of March, 2011.

Valerie A. Hnasko

Notary Public
State of Florida, at Large

VALERIE A. HNASKO
MY COMMISSION # DD 793305
EXPIRES: May 29, 2012
Bonded Thru Notary Public Underwriters

My Commission Expires:
5/29/2012

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 11th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Dave Santilli, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 19 through 25 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

Dave Santilli

Dave Santilli

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of March, 2011.

Laura N Chase

Notary Public
State of Florida, at Large

My Commission Expires:
August 3, 2014

LAURA N. CHASE
Notary Public - State of Florida
My Comm. Expires Aug 3, 2014
Commission # EE 12393
Bonded Through National Notary Assn.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 4th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Rosemary Morley, who is personally known to me, and she acknowledged before me that she cosponsored interrogatory numbers 13 through 17 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on her personal knowledge.

Rosemary Morley

Rosemary Morley

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4 day of March, 2011.

NOTARY PUBLIC - STATE OF FLORIDA
Janet L. Ervin
Commission #DD651458
Expires: APR. 25, 2011
BONDED THRU ATLANTIC BONDING CO., INC.

Janet L. Ervin
Notary Public
State of Florida, at Large

My Commission Expires:
April 25, 2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 8th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she cosponsored interrogatory numbers 13 through 17 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of March, 2011.

JENNIFER GJONBALAJ
Notary Public - State of Florida
My Commission Expires Aug 7, 2011
Commission # DD 702895

Notary Public
State of Florida, at Large

My Commission Expires:
August 7, 2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 8th day of MARCH, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Solomon L. Stamm, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 26 through 35 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

Solomon L. Stamm

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of March, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 8, 2014
Commission # DD 948300

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 9th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan Enjamio, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 2, 4 through 7, 9 through 10, and 12, and he is cosponsoring answers to interrogatory numbers 8, 11 and 18 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

Juan Enjamio

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of March, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 10TH day of MARCH, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ronald H. Hix , who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 36 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

Ronald H. Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 10TH day of MARCH, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 9th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gloria Lopez, who is personally known to me, and she acknowledged before me that she cosponsored the answers to interrogatory numbers 8, 11 and 18 from STAFF'S FIRST SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 1-36) in Docket No. 110007-EI, and that the responses are true and correct based on her personal knowledge.

Gloria Lopez

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 9th day of March, 2011.

Iwanda S. Jenkins
Notary Public
State of Florida, at Large

My Commission Expires:

NOTARY PUBLIC-STATE OF FLORIDA
Iwanda S. Jenkins
Commission # DD827829
Expires: NOV. 19, 2012
BONDED THRU ATLANTIC BONDING CO., INC.

2

FPL Responses to Staff's Second Set of Interrogatories (Nos. 37-38)

Referring to form 42-5P, page 56 of 61:

(a) Has the St. Lucie Plant (PSL) Low Level Radioactive Waste (LLW) project been completed? If not, when will it be completed and in service?

(b) When will the Turkey Point Plant (PTN) LLW project begin? When will it be completed and in service?

(c) The "Project Description" on this page indicates that the LLW facilities at PSL and PTN will be used to store all LLW B and C class waste generated at each plant site over a 5 year period. Please explain how FPL does or will store all LLW A and GTCC class waste generated at each plant site, and how the company does or will recover the associated costs.

(d) How long will the LLW facility be operational?

(e) What will be the service life, for purposes of depreciation, of the LLW facility?

A.

(a) No. The PSL project is expected to be completed and in service in April 2011.

(b) The PTN project commenced in February 2011 and is expected to be completed and in service in December 2011.

(c) FPL has a long term contract with Energy Solutions, LLC and pursuant to that contract ships Class A waste to their facility in Utah. The Low-Level Radioactive Waste Amendment Act of 1985 assigned the federal government the responsibility for the disposal of the GTCC waste. However, to date, the federal government has not identified a schedule for acceptance. Currently all GTCC waste is stored on site at each plant. The decommissioning cost study filed in Docket No. 100458-EI, assumes that onsite storage will continue until the federal government commences pick up. The disposal costs for class A and GTCC waste are recovered through base rates.

(d) The LLW facilities will be operational as needed until the end of the plant licensed life.

(e) As the result of Order No. PSC-10-0153-FOF-EI (Docket Nos. 080677-EI and 090130-EI) issued March 17, 2010, the Florida Public Service Commission set the average service lives for Account 321 at 56-yr (32-yr ARL) for St. Lucie Common facilities and 56-yr (23-yr ARL) for Turkey Point Common facilities.

Referring to Forms 42-2P and 42-3P:

(a) Please provide a detailed breakdown of the component items that will comprise the O&M activities for which the associated costs will be reported on Form 42-2P, Line No. 1.36 Low-Level Radioactive Waste Storage.

(b) Please provide a list of all the O&M activities and capital cost components for which the associated costs have been reported in Docket No. 100458-EI, Petition for approval of 2010 nuclear decommissioning study, by Florida Power & Light Company, filed on December 12, 2010.

(c) Please identify all the O&M and capital cost items, if any, which are reported or otherwise included in both Docket Nos. 110007-EI and 1000458-EI.

A.

(a) No O&M expenses for the Low-Level Radioactive Waste (LLW) Storage Project were reported on Form 42-2P that was filed in Docket No. 100007-EI on August 27, 2010. FPL will request recovery for O&M expenses associated with operating the facility after it is placed in service, which is expected in April 2011. None of the expenses for operating the facility are included in the decontamination and dismantling activities reflected in the decommissioning study filed in Docket No. 100458-EI.

(b) The activities and related costs reported in Docket No. 100458-EI reflect the costs incurred to decontaminate and dismantle plant structures and components after shut down of both units at the Turkey Point and St Lucie sites. Additionally, the cost for Class B and C waste disposal in FPL's 2010 nuclear decommissioning study includes only those costs associated with the controlled disposition of LLW generated from decontamination and dismantling activities.

(c) None.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 24th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Gloria Lopez who is personally known to me, and she acknowledged before me that she provided the answer to interrogatory number 38 subpart b from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 37 - 38) in Docket No. 110007-EI, and that the response is true and correct based on her personal knowledge.

Gloria Lopez

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24th day of March, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 23rd day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Solomon L. Stamm who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 37 subparts a through d and 38 subparts a and c from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 37 - 38) in Docket No(s). 110007-EI, and that the responses are true and correct based on his personal knowledge.

Solomon L. Stamm

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 23rd day of March, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 8, 2014
Commission # DD 948300

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 28th day of March, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Anthony E. Biacci who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 37 subpart e from STAFF'S SECOND SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 37 - 38) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

Anthony E. Biacci

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 28th day of March, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

3

FPL Responses to Staff's Third Set of Interrogatories (Nos. 39-46)

Q.

Please refer to FPL's response to Staff's First Set of Interrogatories, No. 18.

(a) For the Rate Impact Table you have provided, please extend the data in each column back to the period of 2009 through 2010.

(b) Please provide another table, similar to the Rate Impact Table you have provided, except that it is for $/1,000 kWH bill impact and covers the period of 2009 through 2040.

A.

Please see Attachments I and II.

Rate Impact- with and without ITC
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	With ITC				Without ITC			
Year	DeSoto Solar $/ 1200 kWH	Space Center Solar $/ 1200 kWH	Martin Solar $/ 1200 kWH	All three projects $/ 1200 KWH	DeSoto Solar $/ 1200 kWH	Space Center Solar $/ 1200 kWH	Martin Solar $/ 1200 kWH	All three projects $/ 1200 KWH
2009	0.117	0.012	0.078	0.207	0.130	0.012	0.078	0.219
2010	0.176	0.078	0.331	0.585	0.188	0.081	0.332	0.601
2011	0.176	0.083	0.509	0.792	0.187	0.088	0.539	0.838
2012	0.193	0.104	0.514	0.799	0.205	0.109	0.546	0.847
2013	0.183	0.099	0.496	0.767	0.195	0.104	0.527	0.815
2014	0.183	0.083	0.452	0.699	0.175	0.088	0.484	0.748
2015	0.155	0.080	0.414	0.649	0.168	0.085	0.446	0.699
2016	0.147	0.076	0.388	0.611	0.160	0.081	0.421	0.662
2017	0.119	0.062	0.353	0.568	0.132	0.067	0.387	0.618
2018	0.107	0.067	0.300	0.483	0.120	0.072	0.334	0.536
2019	0.109	0.064	0.304	0.455	0.122	0.070	0.339	0.509
2020	0.103	0.050	0.268	0.420	0.116	0.056	0.292	0.474
2021	0.097	0.057	0.245	0.395	0.110	0.063	0.281	0.450
2022	0.087	0.043	0.212	0.351	0.100	0.048	0.248	0.405
2023	0.080	0.046	0.202	0.305	0.093	0.051	0.238	0.360
2024	0.068	0.035	0.143	0.252	0.081	0.040	0.180	0.307
2025	0.060	0.033	0.131	0.222	0.074	0.039	0.167	0.277
2026	0.041	0.030	0.089	0.170	0.054	0.036	0.125	0.226
2027	0.048	0.027	0.105	0.196	0.059	0.032	0.142	0.252
2028	0.038	0.024	0.083	0.154	0.051	0.030	0.120	0.210
2029	0.034	0.023	0.068	0.115	0.047	0.028	0.105	0.171
2030	0.028	0.020	0.041	0.088	0.042	0.025	0.078	0.145
2031	0.017	0.016	0.037	0.082	0.031	0.022	0.075	0.138
2032	0.011	0.024	0.014	0.059	0.025	0.030	0.051	0.116
2033	0.026	0.022	0.015	0.044	0.040	0.027	0.053	0.102
2034	0.016	0.016	-0.001	0.008	0.030	0.022	0.037	0.066
2035	0.007	0.018	-0.007	0.012	0.021	0.024	0.031	0.070
2036	0.007	0.010	-0.021	-0.008	0.021	0.015	0.018	0.050
2037	-0.006	0.006	-0.046	-0.046	0.008	0.012	-0.008	0.012
2038	0.005	0.014	-0.047	-0.046	0.019	0.020	-0.008	0.012
2039	-0.013	0.004	-0.065	-0.072	-0.001	0.010	-0.026	-0.018
2040	-0.038	-0.011	-0.142	-0.198	-0.038	-0.009	-0.106	-0.159

Notes:

Negative indicates a reduction in the customer bill.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Please note that the combined rate impact for the portfolio of the three solar projects together is different than the sum of the rate impacts of the three individual projects

Rate Impact- with and without ITC
(Includes all Projects Costs and System Impacts)

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
	With ITC				Without ITC			
Year	DeSoto Solar $/ 1000 kWH	Space Center Solar $/ 1000 kWH	Martin Solar $/ 1000 kWH	All three projects $/ 1000 KWH	DeSoto Solar $/ 1000 kWH	Space Center Solar $/ 1000 kWH	Martin Solar $/ 1000 kWH	All three projects $/ 1000 KWH
2009	0.098	0.010	0.065	0.143	0.108	0.010	0.065	0.183
2010	0.146	0.065	0.276	0.487	0.156	0.068	0.277	0.501
2011	0.147	0.069	0.424	0.660	0.156	0.073	0.449	0.698
2012	0.161	0.086	0.429	0.668	0.170	0.090	0.455	0.706
2013	0.153	0.083	0.413	0.639	0.163	0.087	0.440	0.679
2014	0.136	0.070	0.377	0.582	0.146	0.074	0.404	0.623
2015	0.130	0.067	0.345	0.541	0.140	0.071	0.372	0.582
2016	0.123	0.063	0.323	0.510	0.133	0.068	0.351	0.552
2017	0.099	0.052	0.294	0.472	0.110	0.056	0.322	0.515
2018	0.089	0.050	0.250	0.402	0.100	0.060	0.279	0.446
2019	0.091	0.054	0.253	0.380	0.102	0.058	0.282	0.424
2020	0.086	0.042	0.213	0.350	0.096	0.046	0.243	0.395
2021	0.080	0.048	0.204	0.329	0.091	0.052	0.234	0.376
2022	0.073	0.036	0.177	0.292	0.083	0.040	0.207	0.338
2023	0.066	0.038	0.168	0.254	0.077	0.043	0.198	0.300
2024	0.056	0.029	0.119	0.210	0.068	0.033	0.150	0.255
2025	0.050	0.028	0.109	0.185	0.061	0.032	0.139	0.231
2026	0.034	0.025	0.074	0.142	0.045	0.030	0.104	0.188
2027	0.038	0.022	0.087	0.163	0.049	0.027	0.118	0.210
2028	0.032	0.020	0.069	0.128	0.043	0.025	0.100	0.175
2029	0.028	0.019	0.057	0.096	0.039	0.024	0.088	0.143
2030	0.024	0.016	0.034	0.073	0.035	0.021	0.065	0.121
2031	0.014	0.014	0.031	0.066	0.026	0.018	0.062	0.115
2032	0.009	0.020	0.011	0.049	0.020	0.025	0.043	0.097
2033	0.022	0.018	0.012	0.037	0.033	0.023	0.044	0.085
2034	0.013	0.013	-0.001	0.007	0.025	0.016	0.031	0.055
2035	0.005	0.015	-0.006	0.010	0.017	0.020	0.028	0.058
2036	0.006	0.008	-0.017	-0.007	0.018	0.013	0.015	0.042
2037	-0.005	0.005	-0.039	-0.039	0.007	0.010	-0.006	0.010
2038	0.004	0.011	-0.039	-0.039	0.015	0.016	-0.006	0.010
2039	-0.011	0.004	-0.054	-0.060	-0.001	0.008	-0.022	-0.013
2040	-0.031	-0.009	-0.119	-0.185	-0.031	-0.008	-0.088	-0.133

Notes:
Negative indicates a reduction in the customer bill.

The annual revenue requirements include system capital costs, O&M costs, emission costs and fuel costs as well as the solar project costs in the "with solar" case.

The bill impact computation is based on dividing the differential in revenue requirements between the two cases and dividing by the system retail sales. As such it represents a system average rate impact, not specific to any one rate class.

Please note that the combined rate impact for the portfolio of the three solar projects together is different than the sum of the rate impacts of the three individual projects

Q.
Please refer to FPL's 800 MW Unit ESPs project regarding which a stipulation has been approved by the Commission in Order No. PSC-11-0083-FOF-EI, and the EPA's proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units (Proposed Standards), issued March 16, 2011 (40 CFR Parts 60 and 63), for the following questions.

(a) On page 290 of the Proposed Standards the EPA has provided Emission Limitations for existing solid oil units: 0.0020 lb/GWh of mercury, 0.080 lb/MWh of hydrogen chloride and 2.0 lb/MWh of total particulate matter. Can each of the 800 MW units meet these emission standards without an ESP retrofit?

(b) In Section 6a, Availability of Hg Emission Control Options, pages 213 through 215 of the Proposed Standards, EPA commented "Activated carbon injection (ACI) is the most successful demonstrated Hg-specific control technology." On page 215 EPA also stated that ESPs and fabric filters (FF) are the most commonly applied PM control technologies, and FFs usually provide better performance than ESPs. On page 215 it also mentioned that a wet ESP (WESP) can be used for control of condensable PM. In light of this, does FPL still believe that ESPs are the best option to control the Hg and PM at the 800 MW units? Please provide the rationale for your response.

A.
(a) The text on page 290 of the Proposed Standards refers to "solid, oil-derived fuels" (comma added for clarity). An example of such a fuel is petroleum coke. FPL's Martin and Manatee plants burn liquid fuel and are not capable of combusting solid oil. EPA's proposed standards for liquid oil-fired EGU's are found on page 854 of the proposed rule under Subpart UUUUU of Part 63 — Emission Limits for Existing EGUs. FPL's 800 MW units cannot achieve the proposed emission limits without the retrofit of additional emission control equipment. FPL has identified that ESPs are the least cost option for meeting the limits on total metals. As evidence refer to Table 40 (a), attached, which summarizes HAP metals emissions data from FPL's oil fired plants. These data were collected in 2010 and provided to EPA in response to EPA's information collection request (ICR) to assist EPA in the development of the NESHAP rule. As the ICR data show, the only FPL oil-fired units which meet the proposed rule are the Port Everglades units which already have ESPs installed. FPL believes that EPA has incorrectly included limits for emission of acid gasses for oil-fired plants and will request that EPA reconsider applicability to oil-fired units or, in

the alternative, that the agency will use water content limits for oil in lieu of numerical acid emission limits. Should EPA adopt a final rule substantially similar to the proposed rule for acid gasses, however, FPL's least cost option would be the addition of a sorbent injection system in combination with the ESP.

(b) EPA's comments on pages 213 through 215 regarding ACI (activated carbon injection) refer to EGUs that burn coal. This can be seen by the reference to the form of Hg from the type of coal combusted on Page 211 and to the level of chlorine in the coal on page 213. For oil-fired EGUs, the draft NESHAP does not require an individual mercury emission limit. Mercury can be included in the total metals emissions and, using this approach ESPs will achieve total HAP metals emissions compliance, including mercury. On page 215 EPA states "that ESPs and fabric filters (FF) are the most commonly applied PM control technologies". Fabric filters are not applicable technology for liquid oil fired units because, unlike coal ash, oil ash can be flammable. Application of FF technology with oil firing would significantly increase fire hazard from oil ash collected on filter bags. In addition, fabric filters have higher pressure drop, which translates to higher operating costs than ESPs. Therefore, oil-fired EGUs use ESPs for particulate removal. On page 215 EPA states that Wet ESP (WESP) downstream of FGD can be used for control of condensable PM. The combination of FGD and WESP technology is most applicable to coal fired EGUs. For oil-fired EGUs, which produce significantly lower emissions of both particulates and acid gases than coal-fired units, a dry ESP is a much lower cost approach to achieve compliance.

TABLE 40(a)

FPL PLANT SUMMARY DATA

		Port Everglades Unit 3	Port Everglades Unit 4	Turkey Point Unit 1	Turkey Point Unit 2	Manatee Unit 1	Manatee Unit 2	Martin Unit 1	Martin Unit 2	EPA Proposed Rule Compliance Level
Mercury (Hg)	lb/TBtu	0.0717	0.0594	0.508	no data	0.0755	0.0585	0.133	0.157	0.05
Hydrogen Chloride (HCl)	lb/MMBtu	0.00061	0.00074	0.00082	0.00092	0.00027	0.00057	0.001120	0.00056	0.0003
Hydrogen Fluoride (HF)	lb/MMBtu	0.00015	0.00016	0.00021	0.00015	0.000081	0.0004	0.00013	0.000096	0.0002
Antimony (Sb)	lb/TBtu	0.34	0.099	43.60	38.10	27.50	18.80	45.56	38.06	0.20
Arsenic (As)	lb/TBtu	0.164	0.207	2.826	2.090	2.409	1.642	2.718	2.518	0.60
Beryllium (Be)	lb/TBtu	0.029	0.131	0.167	0.113	0.0554	0.0425	0.275	0.216	0.06
Cadmium (Cd)	lb/TBtu	0.0143	0.1198	0.0847	0.0795	0.0598	0.0478	0.0794	0.0784	0.10
Chromium (Cr)	lb/TBtu	0.869	0.431	4.707	4.235	5.098	3.928	2.699	5.191	2.0
Cobalt (C0)	lb/TBtu	No data	No data	No data	No data	No data	No data	No data	No data	3.0
Lead (Pb)	lb/TBtu	0.236	0.137	5.896	5.670	6.835	4.673	8.980	8.225	2.0
Manganese (Mn)	lb/TBtu	0.833	0.527	30.300	20.419	13.971	9.360	44.170	36.951	5.0
Nickel (Ni)	lb/TBtu	4.861	3.262	551.921	427.562	687.883	488.659	414.528	333.026	8.0
Selenium (Se)	lb/TBtu	3.248	2.161	3.655	1.949	2.904	0.302	4.351	1.953	2.0
TOTAL HAP METALS	lb/TBtu	10.7	7.1	643.7	500.2	746.7	527.5	523.4	426.2	30.0
(includes Hg, exclude HCL & HF)	lb/MMBtu	0.000011	0.000007	0.000644	0.000500	0.0007467	0.000527	0.000523	0.000426	0.000030

Q.
Please refer to FPL's Revised Table 18 filed on April 6, 2011.

a. Please explain why "... the combined rate impact for the portfolio of the three solar projects together is different than the sum of the rate impacts of the three individual projects" as indicated in the Notes of Table 18.

b. Please provide another table, which will have the same columns and row heading as the revised Table 18, except that it should be for $/1000 kWH bill impacts.

A.
a. Both capital and O&M cost for the three individual projects are additive and equal to the total capital and O&M cost of the three project portfolio. However the individual project's system fuel and emission savings are not additive and will not equal to the portfolio savings.

The individual project system savings (fuel and other variable costs) were determined by adding each project, one at a time, to the FPL system and comparing each of the individual project cases to a base case without any of the solar projects. The savings of the combined portfolio were determined from a case which modeled all three solar projects in the same production costing model case. The system dispatch for the case with all the solar projects is different from the dispatch for the individual projects which leads to small differences in total system savings.

b. See response to Staff Interrogatory 39.

Q.
Please refer to witness T.J. Keith's testimony filed on April 1, 2011, for the following questions.

Referring to page 5, lines 18 - 21, what is the actual dollar amount of the expenses which "were inadvertently omitted from the 2010 Actual/Estimated true-up filing?"

A.
The actual dollar amount of the expenses that were inadvertently omitted from the 2010 Actual/Estimated true-up filing is $36,500.

Q.
Please refer to witness T.J. Keith's testimony filed on April 1, 2011, for the following questions.

Referring to line 8 on page 8, please elaborate on the "oil diversionary repairs" that were required at certain FPL substations.

A.
Oil diversionary structures (i.e., concrete perimeter curbing) are installed at most substations in accordance with the SPCC regulations at 40 CFR 112.7(c) to prevent any unexpected oil discharges from oil-filled equipment from escaping off the site and impacting nearby navigable waters. Some concrete curbing at certain substations was in need of repair due to cracks, broken sections, and washouts.

The curbing repair work consisted of removing all loose and broken curbing, excavating a 2" trench at the curbing location, installing forms for a 6" high concrete curb, installing appropriate rebar, applying bonding agent on existing exposed curbing joints, mixing and pouring concrete, chamfering or rounding exposed edges, and site cleanup.

Q.
Please refer to witness T.J. Keith's testimony filed on April 1, 2011, for the following questions.

Referring to page 8, lines 20 - 23:

a. What is the function of the ESP Hopper Vibrators?

b. What are the ESP hopper plugging issues?

c. Are these issues common for ESP operation? If so, does FPL intend to install the ESP Hopper Vibrators on all existing and planned-to-be-built ESPs of FPL's generating units?

A.
a. ESP hopper vibrators apply mechanical vibration to the hopper walls to assist ash removal from the ESP. The vibrations loosen ash from the hopper walls and the ash falls to the ash collection hoppers located below the collection plates.

b. Hopper plugging can cause mechanical damage to the ESP and significantly affect ESP performance. Hopper plugging can be caused by a variety of conditions such as low ash temperatures which can form clumping ash. Mechanical damage can include collection plate warping. Performance issues can include tripping off-line if plugging is severe.

c. ESP plugging is not uncommon. Ash particle sizing, temperature, and flue gas velocity can contribute to conditions which can cause hopper plugging. The original design of the ESPs for the Port Everglades units did not include hopper vibrators. As a result of FPL's experience, Port Everglades ESPs were retrofitted with vibrators. For Manatee and Martin Plants ESPs FPL plans include hopper vibrators.

Q.

Please refer to witness T.J. Keith's testimony filed on April 1, 2011, for the following questions.

Referring to page 9, lines 3 - 9:

a.What is the actual dollar amount of the costs that were inadvertently charged to a non-ECRC account?

b. FPL indicated "this will be corrected in March 2011." Does this mean that the actual dollar amount will be included in the Actual/Estimated True-up filing?

A.

a. The actual dollar amount of the costs that were inadvertently charged to a non-ECRC account is $7,499.26.

b. Yes.

Q.

Please refer to witness T.J. Keith's testimony filed on April 1, 2011, for the following questions.

Referring to page 12:

a. What is the purpose of the installation of booms at the intake canal (lines 1 - 3)?

b. Please specify who the agencies (line 15) are.

A.

a.Refer to: FPL's Notice of Additional Activities for Manatee Heating System filed on Jan 4, 2011 - Additional Activities Required for Manatee Temporary Heating System - Cape Canaveral Plant Project - "It became apparent that, as configured, the electric heating system would not have enough thermal capacity to maintain the Cape Canaveral manatee embayment area at the necessary temperature. FPL made modifications to the discharge pipes of the primary heating system and installed booms to direct and control the flow of warm water in the manatee embayment area, in order to maximize the effectiveness of the heating system."

The purpose of these booms was to reduce the overall size of the manatee warm water refuge. This enabled us to better control and raise the water temperature within the refuge.

b. Florida Fish and Wildlife Conservation Commission, Florida Department of Environmental Protection, United States Fish and Wildlife Service.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 16th day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Juan Enjamio, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 39 and 41 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS 39-46) in Docket No(s). 110007-EI, and that the responses are true and correct based on his personal knowledge.

Juan Enjamio

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of May, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 42, 44 and 46a from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS 39-46) in Docket No(s). 110007-EI, and that the responses are true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of May, 2011.

INGRID NICKOLAUS
MY COMMISSION # DD736310
EXPIRES November 20, 2011
(407) 398-0153 FloridaNotaryService.com

Ingrid Nickolaus
Notary Public
State of Florida, at Large

My Commission Expires:
November 20, 2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12 day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 40 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS 39-46) in Docket No(s). 110007-EI, and that the response is true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of May, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Frank Nesbihal, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 43 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS 39-46) in Docket No(s). 110007-EI, and that the response is true and correct based on his personal knowledge.

Frank Nesbihal

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of May, 2011.

Elizabeth Carrero

Notary Public
State of Florida, at Large

Notary Public State of Florida
Elizabeth Carrero
My Commission DD853827
Expires 02/18/2013

My Commission Expires:

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 12th day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Solomon L. Stamm, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 45 from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS 39-46) in Docket No(s). 110007-EI, and that the response is true and correct based on his personal knowledge.

Solomon L. Stamm

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 12th day of May, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

JO RETHA FORBES
Notary Public - State of Florida
My Comm. Expires Mar 6, 2014
Commission # DD 948300

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 17th day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Richard Merrill, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 46b from STAFF'S THIRD SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS 39-46) in Docket No(s). 110007-EI, and that the response is true and correct based on his personal knowledge.

Richard Merrill

Richard Merrill

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 17th day of May, 2011.

Jacqueline S. Bussey

Notary Public
State of Florida, at Large

My Commission Expires:

JACQUELINE S. BUSSEY
MY COMMISSION # DD 972668
EXPIRES: July 18, 2014
Bonded Thru Notary Public Underwriters

4

FPL Responses to Staff's Fourth Set of Interrogatories (No. 47)

Q.
Referring to Forms 42-5A and 42-7A of Exhibit TJK-1, please provide a detailed explanation why FPL, in its calculation of the 2010 Final True-up schedules, used the Jurisdictional Factors that the Commission approved for the period January 2011 through December 2011, on page 2 of order No. PSC-11-0083-FOF-EI, issued on January 31, 2010, in Docket No. 100007-EI, instead of using the Jurisdictional Factors that the Commission approved for the period January 2010 through December 2010, on page 4 of order No. PSC-10-0759-FOF-EI, issued on November 18, 2009, in Docket No. 100007-EI, as what the Company did previously (e.g. 2008 and 2009 Final True-up calculations).

A.
The jurisdictional separation factors approved in Order No. PSC-09-0759-FOF-EI issued in Docket No. 090007-EI on November 18, 2009 did not reflect FPL's contract with Lee County Electric Cooperative (LCEC) which became effective on January 1, 2010 and caused the retail jurisdictional separation factor to be lower by approximately 1%. FPL used the 2010 jurisdictional separation factor for energy of 98.02710%, for CP demand of 98.03105% and for GCP demand of 100.00000% approved by the Commission in Order No. PSC-10-0153-FOF-EI, issued on March 17, 2010 in Docket Nos. 080677-EI and 090130-EI which recognized the impact of the LCEC contract. FPL therefore revised the jurisdictional separation factors used in the calculation of the 2010 Actual/Estimated True-up amount and subsequently the 2010 Final True-up amount to account for the additional load required to serve the LCEC contract. This adjustment is further explained in the August 2, 2010 testimony of Terry J Keith beginning at page 3.

5

FPL Responses to Staff's Fifth Set of Interrogatories (Nos. 48-50)

Q.

Please refer to Appendix I, Exhibit TJK-1, of witness Keith's testimony filed on April 1, 2011, for the following questions.

48. Referring to the Return on Deferred Gain on Sales of Emission Allowances reported on pages 47-48 of Form 42-8A, please provide the amounts of the Allowance Auction Proceeds for each month for the period January 2010 through December 2010.

A.

Note that allowances auction proceeds are amortized depending on their vintage year. Therefore, what shows on pages 47-48 of Form 42-8a line 6a - 411.800 Gains from Dispositions of Allowances represents revenue recognized for 2010.

The table below represents the 2010 EPA auction proceeds which included $75.7K (revenues recognized in 2010) and $4.2K for vintage year 2017 for which revenues will be recognized in 2017.

Date	Reason	Vintage Year	Total Revenue Recog	Total Auction Proceeds
Jan-10	Revenue Recognition	2010	$14,460.86	
Feb-10	Revenue Recognition	2010	$14,460.86	
Mar-10	Revenue Recognition	2010	$14,460.86	
Apr-10	Proceeds - FPL	2010		($64,378.96)
Apr-10	Proceeds - FPL	2017		($3,536.68)
Apr-10	Proceeds - SJRPP	2010		($2,504.25)
Apr-10	Proceeds - SJRPP	2017		($137.57)
Apr-10	Revenue Recognition	2010	$36,755.27	
May-10	Revenue Recognition	2010	$20,034.47	
Jun-10	Revenue Recognition	2010	$24,705.54	
Jun-10	Proceeds - Scherer	2010		($8,855.67)
Jun-10	Proceeds - Scherer	2017		($486.49)
Jul-10	Revenue Recognition	2010	$20,529.15	
Aug-10	Revenue Recognition	2010	$20,772.44	
Sep-10	Revenue Recognition	2010	$20,772.44	
Oct-10	Revenue Recognition	2010	$20,772.44	
Nov-10	Revenue Recognition	2010	$20,772.44	
Dec-10	Revenue Recognition	2010	$20,772.44	
	Totals 2010		$249,269.21	
			$249,269.21	**($79,899.62)**

Q.

Please refer to Appendix I, Exhibit TJK-1, of witness Keith's testimony filed on April 1, 2011, for the following questions.
Please refer to project No. 38 Space Coast Next Generation Energy Center, on pages 39-40 of Form 42-8A. Please also refer to FPL's response to Staff's 9th Set of Interrogatories, No. 83, in Docket No. 090007-EI, which stated "[t]he lease agreement between FPL and NASA provides for FPL building an in-kind 900 kW PV facility for NASA and for providing O&M on the facility for 30 years. Therefore the liability is comprised of two parts: (1) $6,359,027 representing the installed capital cost of the NASA PV system which is being treated as an intangible asset representing prepaid rental expense and (2) $400,000 representing the NPV of the $1.2 million, 30-year O&M portion of the liability."

a. Has FPL received the federal ITC for NASA PV facility? If so, what was the amount? If not, please explain why not.

b. If the response to (a) is affirmative, has the amount of the ITC been included on Row 86 of the Excel Worksheets named Solar-NASA_P1 and Solar-NASA-P2 in FPL's Excel Workbook Form 42-8A Pgs 1-48 Final.xls?

c. If the response to (b) is negative, please specify who the beneficiary of this amount of ITC is and why, as well as in what way such ITC amount is being amortized.

d. What is the estimate of the total dismantlement costs associated with the 900 kW NASA PV facility (NASA facility)?

e. Does the aforementioned $6,359,027 installed capital cost or $1.2 million O&M cost include the NASA facility dismantlement costs?

f. If the response to (e) is negative, who will bear the NASA facility dismantlement cost, NASA, FPL, or FPL's ratepayers? Please provide explanation of your response.

g. Do the costs reported on pages 39-40 of Form 42-8A, line 8c Dismantlement, include the dismantlement costs associated with the NASA facility?

A.

A. No. FPL built the NASA PV facility for NASA and in trade received a 30 year lease for land upon which it could build the Space Coast Solar Center. Since the title to the assets was transferred to NASA, the company was not eligible to obtain any investment tax credits related to the NASA PV facility.

B. N/A

C. N/A

D. No dismantlement estimate exists. FPL has no obligation to dismantle the NASA PV facility

E. No

F. FPL has no obligation to dismantle the NASA PV facility, NASA owns the NASA PV facility. Our obligation was to construct and maintain the facility for the term of the lease (30 years).

G. The dismantlement costs showing in pages 39-40 are only for the Space Coast Center, they do not include costs for the NASA PV facility.

Q.

Please refer to Appendix I, Exhibit TJK-1, of witness Keith's testimony filed on April 1, 2011, for the following questions.

Please provide an estimate of the total dismantlement costs associated with each of FPL's three Next Generation Solar Energy Centers.

A.

Refer to Order No PSC-10-0153-FOF-EI page 89, table 9 - Docket Nos 080677-EI & 090130-EI.
DeSoto - $1,365,069
Space Coast - $724,875
Martin Solar - $7,058,465

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	)))	Docket No: 110007-EI Date: June 6, 2011

FLORIDA POWER & LIGHT COMPANY'S NOTICE OF SERVICE OF OBJECTIONS AND RESPONSES TO STAFF'S FIFTH SET OF INTERROGATORIES (NOS. 48-50)

Florida Power & Light Company hereby gives notice of service of its objections and responses to Staff's Fifth Set of Interrogatories (Nos. 48-50) to Martha Brown, counsel for Staff, on June 6, 2011.

R. Wade Litchfield, Esq.
Vice President and General Counsel
John T. Butler, Esq.
Managing Attorney
Scott A. Goorland, Esq
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5633
Facsimile: (561) 691-7135

BY: */s/ Scott A. Goorland*
Scott A. Goorland
Fla. Bar No. 0066834

RECEIVED
JUN - 8 2011
FLORIDA PUBLIC SERVICE COMMISSION
OFFICE OF THE GENERAL COUNSEL

CERTIFICATE OF SERVICE
Docket No. 110007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail and United States mail on June 6, 2011 to the following:

Martha Brown, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

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Patricia Christensen, Esq.
Charles Rehwinkle, Esq.
Office of Public Counsel
c/o The Florida Legislature
111 W Madison St. Room 812
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Ausley & McMullen
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P.O Box 6526
Tallahassee, FL 32314
Attorneys for Progress Energy Florida

BY: */s/ Scott A. Goorland*
Scott A. Goorland
Fla. Bar No. 0066834

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost Recovery Clause	)))	Docket No: 110007-EI Date: June 6, 2011

FLORIDA POWER & LIGHT COMPANY'S OBJECTIONS AND RESPONSES TO THE STAFF OF THE FLORIDA PUBLIC SERVICE COMMISSION'S FIFTH SET OF INTERROGATORIES (NOS. 48-50)

Florida Power & Light Company ("FPL"), pursuant to Rule 1.340, Florida Rules of Civil Procedure, Rule 28-106.206, Florida Administrative Code, and Order No. PSC-11-0150-PCO-EI, submits the following Objections and Responses to the Staff of the Florida Public Service Commission's ("Staff") Fifth Set of Interrogatories (Nos. 48-50).

I. General Objections

FPL objects to each and every discovery request that calls for information protected by the attorney-client privilege, the work product doctrine, the accountant-client privilege, the trade secret privilege, or any other applicable privilege or protection afforded by law, whether such privilege or protection appears at the time response is first made or is later determined to be applicable for any reason. FPL in no way intends to waive any such privilege or protection. The nature of the document(s), if any, will be described in a privilege log prepared and provided by FPL.

FPL is a large corporation with employees located in many different locations. In the course of its business, FPL creates numerous documents that are not subject to Florida Public Service Commission or other governmental record retention requirements. These documents are kept in numerous locations and frequently are moved from site to site as employees change jobs or as business is reorganized. Therefore, it is possible that not every relevant document may have been consulted in developing FPL's responses to the discovery requests. Rather, these responses provide all the information that FPL obtained after a reasonable and diligent search

conducted in connection with these discovery requests. To the extent that the discovery requests propose to require more, FPL objects on the grounds that compliance would impose an undue burden or expense on FPL.

FPL objects to each discovery request to the extent that it seeks information that is not relevant to the subject matter of this docket and is not reasonably calculated to lead to the discovery of admissible evidence.

FPL objects to each and every discovery request to the extent it is vague, ambiguous, overly broad, imprecise, or utilizes terms that are subject to multiple interpretations but are not properly defined or explained for purposes of such discovery requests. Any responses provided by FPL will be provided subject to, and without waiver of, the foregoing objection.

FPL also objects to each and every discovery request to the extent it calls for FPL to prepare information in a particular format or perform calculations or analyses not previously prepared or performed as purporting to expand FPL's obligations under applicable law.

FPL objects to providing information to the extent that such information is already in the public record before the Florida Public Service Commission and available to the requesting Party through normal procedures.

FPL objects to each and every discovery request that calls for the production of documents and/or disclosure of information from NextEra Energy, Inc. and any subsidiaries and/or affiliates of NextEra Energy, Inc. that do not deal with transactions or cost allocations between FPL and either NextEra Energy, Inc. or any subsidiaries and/or affiliates. Such documents and/or information do not affect FPL's rates or cost of service to FPL's customers. Therefore, those documents and/or information are irrelevant and not reasonably calculated to lead to the discovery of admissible evidence. Furthermore, FPL is the party appearing before the Florida Public Service Commission in this docket. To require any non-regulated entities to

participate in irrelevant discovery is by its very nature unduly burdensome and overbroad. Subject to, and without waiving, any other objections, FPL will respond to the extent the request pertains to FPL and FPL's rates or cost of service charged to FPL's customers. To the extent any responsive documents contain irrelevant affiliate information as well as information related to FPL and FPL's rates or cost of service charged to its customers, FPL may redact the irrelevant affiliate information from the responsive document(s).

Where any discovery request calls for production of documents, FPL objects to any production location other than the location established by FPL, at FPL's Tallahassee Office located at 215 South Monroe Street, Suite 810, Tallahassee, Florida.

FPL objects to each and every discovery request and any instructions that purport to expand FPL's obligations under applicable law.

In addition, FPL reserves its right to count discovery requests and their sub-parts, as permitted under the applicable rules of procedure, in determining whether it is obligated to respond to additional requests served by any party.

FPL expressly reserves and does not waive any and all objections it may have to the admissibility, authenticity or relevancy of the information provided in its responses.

Notwithstanding any of the foregoing general objections and without waiving these objections, FPL intends in good faith to respond to Staff's discovery requests.

II. Responses

Attached hereto are FPL's answers to Interrogatory Nos. 48-50 of Staff's Fifth Set of Interrogatories consistent with its objections, together with the affidavits of the persons providing said answers.

R. Wade Litchfield, Esq.
Vice President and General Counsel
John T. Butler, Esq.
Managing Attorney
Scott A. Goorland, Esq.
Principal Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408
Telephone: (561) 304-5633
Facsimile: (561) 691-7135

BY: _____
Scott A. Goorland
Fla. Bar No. 0066834

CERTIFICATE OF SERVICE
Docket No. 110007-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail and United States mail on June 6, 2011 to the following:

Martha Brown, Esq.
Division of Legal Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

J. R Kelly, Esq
Patricia Christensen, Esq.
Charles Rehwinkle, Esq.
Office of Public Counsel
c/o The Florida Legislature
111 W Madison St. Room 812
Tallahassee, FL 32399-1400

James D. Beasley, Esq.
J. Jeffrey Wahlen, Esq.
Ausley & McMullen
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Tallahassee, Florida 32302

John T. Burnett, Esq.
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501 Commendencia Street
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Jon C. Moyle, Esq.
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Co-Counsel for FIPUG
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Karen S. White, Esq.
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Attorney for the Federal Executive Agencies

Gary V. Perko, Esq.
Hopping Green & Sams
P.O Box 6526
Tallahassee, FL 32314
Attorneys for Progress Energy Florida

By: _____
Scott A. Goorland
Fla. Bar No. 0066834

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 2nd day of June, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared H. Antonio Cuba, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 48, 49 subpart g and 50 from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 48-50) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

H. Antonio Cuba

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of June, 2011.

Carolyn J Smith
Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 2nd day of June, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Dave Huss, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 49 subparts a, b and c from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 48-50) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

Dave Huss

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 2nd day of June, 2011.

Carolyn J Smith
Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 24 day of May, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Walter E. Gwinn, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 49 subparts d, e and f from STAFF'S FIFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 48-50) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

Walter E. Gwinn

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 24 day of May, 2011.

Notary Public
State of Florida, at Large

VALERIE A. HNASKO
MY COMMISSION # DD 793305
EXPIRES: May 29, 2012
Bonded Thru Notary Public Underwriters

My Commission Expires:
May 29, 2012

6

FPL Responses to Staff's Sixth Set of Interrogatories (No. 51)

Q.

Please refer to the "Actual Data for Next Generation Solar Centers for the period of April 2011" filed on May 19, 2011, for the following questions.

a. Referring to page 2, please explain how the net energy production of 2,975 MWh from Martin Solar (Unit 8) was determined. It appears that in the A-Schedules filed in Docket No. 110001-EI, on page 1 of Schedule A4, there is no solar generated net MWh from Martin Unit 8 being reported. Please explain and reconcile this apparent discrepancy.

b. The energy production values for DeSoto Solar and Space Coast Solar provided in Docket No. 110007-EI for April 2011 differ from the energy production values for the same period provided in FPL's A-Schedules. Please explain and reconcile this apparent discrepancy.

A.

a. Electric energy production from the Martin Solar Generating Site (SGS) is provided from the Martin Unit 8 steam turbine-generator. The Martin Unit 8 steam turbine-generator receives steam from the Heat Recovery Steam Generators (HRSGs) associated with the Unit 8A, 8B, 8C, & 8D combustion turbines (CTs). Steam in each HRSG is produced primarily from the exhaust of the CT and secondarily from supplemental duct firing located downstream of the CT. In FPL's hybrid design of Unit 8, steam produced by the Martin SGS can replace the steam added through duct firing of natural gas in each HRSG, with steam that is produced from heat that is transferred from the solar field to each HRSG. There are several segments to the Martin solar field that collectively act as one common energy collection device. Heat collected from the solar field by the Heat Transfer Fluid (HTF) is converted into steam through heat exchangers located adjacent to Unit 8. This steam is then routed through four independent circuits ("trains") to the High Pressure (HP) or Cold Re-Heat (CRH) section of the Unit 8 steam turbine, independently of the steam generated by the HRSGs. To the extent that steam is available from one or more of the SGS heat exchangers, duct firing is not used in the corresponding HRSG(s); in other words, the steam from the SGS heat exchangers is a substitute for steam generated by duct firing.

The calculation of energy production from the SGS involves 5 basic steps: 1) Calculation of the thermal energy transferred from the HTF to the feedwater/steam by each heat exchanger train; 2) Steam produced from each train is multiplied by the cycle efficiency

of each train's usage (HP or CRH) to calculate the gross thermal contribution to the Unit 8 Steam Turbine-Generator; 3) Thermal energy of all trains is totaled; 4) Gross Thermal energy is converted to electrical energy as Gross MWe; and 5) Net Electrical Generation is calculated from Gross Generation minus the SGS Auxiliary power consumption, including pumps and motors used to rotate array mirrors. Real-Time data collected by the Martin Distributed Control System (DCS) is used to calculate the auxiliary usage, gross solar generation and net solar generation.

Data reported on Schedule A4 for FPL's Photovoltaic (PV) solar sites is obtained from the company's regulatory reporting database, the FPL 1192/GADS system. That system has been modified to include the PV solar sites, but FPL has not yet completed the modifications necessary to implement reporting for the SGS output. While the reporting of the PV sites' generation and auxiliary usage is relatively simple, the Martin SGS generation reporting, as discussed above, is significantly more complicated and involves the calculation of the solar contribution to the steam production used for the Martin Unit 8 steam turbine. The generation data provided on the solar reporting forms is based on a calendar month and solar data provided on schedule A4 is based on a fiscal month. FPL intends to provide solar generation for the Martin site on Schedule A4 once modifications to the 1192 data system have been completed.

b. The energy production values for DeSoto Solar and Space Coast Solar provided in FPL's monthly solar reports are on a calendar month basis (as noted in footnote number (1) on the solar reports). In contrast, the energy production values included in FPL's monthly A-Schedules for these solar sites are compiled on a fiscal month basis. Footnote number 1 on schedule A4 provides a more detailed explanation about which information is provided on a fiscal month basis versus a calendar month basis. The majority of the differences identified between these separate reports can be attributed to this variation in time periods. The fiscal period runs from the 29th of a month to the 28th of the following month, resulting in up to 2 to 3 days difference at both the beginning and end of the period.

In July 2011, FPL will be implementing corporate software upgrades that will allow a wide range of business information, including the data presented on the A-Schedules, to be generated on a calendar month basis. At that time, A-Schedule data currently being compiled on a fiscal month basis will change to being compiled on a calendar month basis. This change will make the solar reports and the A-Schedule data comparable, and the resulting production values will be the same in both documents.

Additionally, auxiliary electric usage at the photovoltaic (PV) solar sites has been excluded from the generation values being reported on the monthly solar reports, whereas it is not excluded on the A-Schedules. Although this consumption is extremely small, FPL has revised the net generation data previously reported on the solar reports to include these amounts and will re-file the affected solar reports to reflect the changes. All future reports will be prepared using these net generation values.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 14th day of June, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number 51 from STAFF'S SIXTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 51) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 14th day of June, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

7

FPL Responses to Staff's Seventh Set of Interrogatories (No. 52)

Q.
Please refer to FPL's response to Staff's 5th Set of Interrogatories, No. 48 for the following questions.

A)Please explain how each of the six auction proceed amounts recorded in column Total Auction Proceeds was derived. Please provide supporting documents for your response.

B)FPL indicated that two of the auction proceed amounts recorded are for the SJRPP plant and two of the auction proceed amounts are for the Scherer Plant. Please clarify whether these recorded amounts are only FPL's portions of the entire proceeds for the corresponding plants

C)FPL indicated that three of the auction proceed amounts -- the April 10 FPL's Proceeds amount of (64,378.96), the April 10 SJRPP's Proceeds amount of (137.57), and the June 10 Scherer's Proceeds amount of (486.49) -- are for the vintage year 2017. However, it appears that these 2017 vintage proceeds have been included in FPL's 2010 final true-up calculation for April and June of 2010 as appearing on line 1d of Deferred Gain on Sales of Emission Allowances, pages 47-48 of Form 42-8A of Appendix I, Exhibit TJK-1, of witness Keith's testimony filed on April 1, 2011. Please explain the rationale of FPL's calculation.

A.
A) As a general statement, proceeds received from the sale of allowances depend on the percentage of ownership of each site. The six items consist of two separate amounts (2010 vintage and 2017 vintage) for FPL, SJRPP and Scherer. Each of the attached documents shows how the amounts that were recorded in FPL's books were derived.

Attachment I "$9,342.16 Scherer" includes three pages. The first page is the Customer Accounts Receivables (CARMS), which is an internal document produced by FPL when allowances are sold. The CARMS document is provided to FPL's Payment Processing Center with the check received for deposit. The second document which consists of two pages is produced by the EPA at the time of the sale. It outlines the plant or unit (the owner of the allowances), vintage and proceeds. This is provided to FPL to show the breakdown of the allowances sold. FPL owns 76.36% Scherer Unit 4, therefore the total proceeds of Scherer Unit 4 is $9,342.16 ($12,234.36 x 76.36% = $9,342.16).

Attachment II "$2,641.83 SJRPP" includes two pages. The first page is the CARMS. The second document is produced by the EPA at the time of the sale. It outlines the plant or unit (the owner of the allowances), vintage and proceeds. FPL owns 20% of SJRPP, therefore the total proceeds of SJRPP is $2,641.83 ($13,209.13 x 20% = $2,641.83).

Attachment III "$67,915.64 proceeds support" includes two documents. The first page is the CARMS. The second document containing several pages is produced by the EPA at the time of the sale. It outlines the plant or unit (the owner of the allowances), vintage and total proceeds. Since these proceeds were for allowances sold for units owned by FPL, 100% of the proceeds were recorded.

B) Yes, those amounts represent the proceeds for FPL only as described above.

C) **Attachment IV** is the table as provided in response to Staff's 5th Set of Interrogatories No. 48, which shows the $64,378.96 as 2010 vintage year, not 2017 as stated in the question.

The 2017 proceeds and any other unamortized balances are reflected on Line 1D, pages 47-48 of Form 42-8A. This balance in turn is used to give customers a return based on the overall capital structure approved in FPL's last rate case.

Payment Coupon

/61011000000440533000008326706124370000070010101

General Mail Facility
Miami, FL 33188-0001

B 01100 0000832690 9 0 01 01 01
Please mail this portion with your check

Cust. No.: 440533	Inv. No.: 832690
This Month's Charges Past Due After 07/24/2010	Amount Due This Invoice 9,342.16

Make check payable to FPL in US funds and mail payment to address below

GEORGIA POWER COMPANY

SHANNON PERKINS
9TH FLOOR BIN 10090
241 RALPH MCGILL BLVD
ATLANTA GA 30308

FPL
GENERAL MAIL FACILITY
MIAMI FL 33188-0001

Florida Power & Light Company

Federal Tax ID#: 59-0247775

INVOICE

Customer Name and Address

GEORGIA POWER COMPANY

SHANNON PERKINS
9TH FLOOR BIN 10090
241 RALPH MCGILL BLVD
ATLANTA GA 30308

Customer Number: 440533

Invoice Number: 832690

Invoice Date: 06/24/2010

B 01100 0000832690 9 0 01 01 01
Please Retain This Portion for your Records

CURRENT CHARGES AND CREDITS

Customer No: 440533 Invoice No: 832690

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE EPA PROCEEDS FOR UNIT 4 - PLANT SCHERER	1	9,342.16	9,342.16
For Inquiries Contact: PATTY CROYE Phone: (561) 691-2662	Total Amount Due		$9,342.16
	This Month's Charges Past Due After		07/24/2010

Messages

Florida Power & Light Company
General Mail Facility
Miami, FL 33188-0001

ALLOCATION OF PLANT SCHERER EPA AUCTION PROCEEDS
ALLOCATION BASED ON OWNERSHIP
100% AMOUNT OF $48,857.88
MAY 2010 PAYMENT

UNIT 1	$12,134.90
UNIT 2	$12,234.36
UNIT 3	$12,254.26
UNIT 4	$12,234.36
	$48,857.88

	OPC AT 60% 232-3177	MEAG AT 30.2% 232-3277	DALTON AT 1.4% 232-3377	GULF AT 25% 234-3415	FPL AT 76.36% 232-3530	JEA AT 23.64% 232-3630	GPC	TOTAL
SCHERER 1	$7,280.94	$3,664.74	$169.89				$1,019.33	$12,134.90
SCHERER 2	$7,340.62	$3,694.78	$171.28				$1,027.68	$12,234.36
SCHERER 3				$3,063.57			$9,190.69	$12,254.26
SCHERER 4					$9,342.16	$2,892.20	$0.00	$12,234.36
	$14,621.56	$7,359.52	$341.17	$3,063.57	$9,342.16	$2,892.20	$11,237.70	$48,857.88

20-May-10
JOA/RCM
FILE NAME MISC6

RCM 5/20/10

FOR CAPUMS

5/20/2010 MISC6.xls

Florida Power and Light Company
Docket No. 110007-EI
Staff's 7th Set of Interrogatories
Interrogatory No. 62
Attachment 1
Page 2 of 3

00000128

Date: 03-29-2010
Page: 14 of 19

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
GA	Mitchell (GA)	Georgia Power Company	Chris M Hobson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	3	$2,976.15	$0.31	$2,976.46
March 2010 auction of year 2017 allowances	3	$163.66	$0.02	$163.68
	Plant Totals:	$3,142.81	$0.33	$3,143.14

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
GA	Scherer	Georgia Power Company	Chris M Hobson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	1	$11,601.76	$1.20	$11,602.96
March 2010 auction of year 2017 allowances	1	$631.86	$0.06	$631.92
March 2010 auction of year 2010 allowances	2	$11,696.06	$1.20	$11,697.26
March 2010 auction of year 2017 allowances	2	$637.03	$0.07	$637.10
March 2010 auction of year 2010 allowances	3	$11,614.91	$1.21	$11,616.12
March 2010 auction of year 2017 allowances	3	$638.07	$0.07	$638.14
March 2010 auction of year 2010 allowances	4	$11,696.06	$1.20	$11,697.26
March 2010 auction of year 2017 allowances	4	$637.03	$0.07	$637.10
	Plant Totals:	$48,852.80	$5.08	$48,857.88

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

$12,234.36
x .7636
$9,342.16

Payment Coupon

/61011000000005356500006286913814620000030101011

General Mail Facility
Miami, FL. 33188-0001

B 01100 0000828691 0 3 01 01 01
Please mail this portion with your check

Cust. No.: 53565	Inv. No.: 828691
This Month's Charges Past Due After 06/27/2010	Amount Due This Invoice 2,641.83

Make check payable to FPL in US funds and mail payment to address below

ST JOHNS RIVER POWER PARK

11201 NEW BERLIN ROAD
JACKSONVILLE FL 32226

FPL
GENERAL MAIL FACILITY
MIAMI FL 33188-0001

Florida Power & Light Company

Federal Tax ID#: 59-0247775

INVOICE

Customer Name and Address

ST JOHNS RIVER POWER PARK

11201 NEW BERLIN ROAD
JACKSONVILLE FL 32226

Customer Number: 53565

Invoice Number: 828691

Invoice Date: 04/27/2010

B 01100 0000828691 0 3 01 01 01
Please Retain This Portion for your Records

CURRENT CHARGES AND CREDITS

Customer No: 53565 Invoice No: 828691

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE SO2 EPA ALLOWANCE AUCTION	1	2,641.83	2,641.83

For Inquiries Contact:
SCOTT E. BROWN
Phone: (904) 665-6798

Total Amount Due $2,641.83

This Month's Charges Past Due After 06/27/2010

Messages

Florida Power & Light Company
General Mail Facility
Miami, FL. 33188-0001

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	St. Johns River Power	JEA	Michael Brost

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	1	$6,316.55	$0.66	$6,317.21
March 2010 auction of year 2017 allowances	1	$347.00	$0.04	$347.04
March 2010 auction of year 2010 allowances	2	$6,203.42	$0.64	$6,204.06
March 2010 auction of year 2017 allowances	2	$340.79	$0.03	$340.82
	Plant Totals:	$13,207.76	$1.37	$13,209.13

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

X 20%
= $2,641.82

Payment Coupon

/610110000003120100000082771884651797400025010101

General Mail Facility
Miami, FL. 33188-0001

B 01100 0000027188 2 5 01 01 01
Please mail this portion with your check

Cust. No.: 312010	Inv. No.: 027188
This Month's Charges Past Due After 04/30/2010	Amount Due This Invoice 67,918.64

Make check payable to FPL in US funds and mail payment to address below

US EPA
ACID RAIN PROGRAM
401 M STREET, SW
MAIL CODE 6204J
WASHINGTON DC 20460

FPL
GENERAL MAIL FACILITY
MIAMI FL 33188-0001

Florida Power & Light Company

INVOICE

Customer Name and Address

US EPA
ACID RAIN PROGRAM
401 M STREET, SW
MAIL CODE 6204J
WASHINGTON DC 20460

Federal Tax ID# 59-0247775

Customer Number: 312010

Invoice Number: 027188

Invoice Date: 03/31/2010

B 01100 0000027188 2 5 01 01 01
Please Retain This Portion for your Records

CURRENT CHARGES AND CREDITS

Customer No: 312010 Invoice No: 027188

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES	1	5,201.61	5,201.61
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES-PPM	1	7,280.95	7,280.95
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES-PPL	1	2,148.48	2,148.48
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES-PMT	1	16,268.14	16,268.14
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES-PMG	1	2,944.20	2,944.20
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES-PMR	1	6,406.63	6,406.63
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES - 2010/2017 SO2 EMISSIONS SALES-PEL	1	2,745.27	2,745.27

Florida Power & Light Company
General Mail Facility
Miami, FL. 33188-0001

Customer No: 312010 Invoice No: 827160

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES- 2010/2017 SO2 EMISSIONS SALES-PEH	1	6,823.40	6,823.40
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES- 2010/2017 SO2 EMISSIONS SALES-PPN	1	3,700.14	3,700.14
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES- 2010/2017 SO2 EMISSIONS SALES-PRV	1	4,157.70	4,157.70
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES- 2010/2017 SO2 EMISSIONS SALES-PSN	1	616.69	616.69
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES- 2010/2017 SO2 EMISSIONS SALES-PSR	1	3,759.82	3,759.82
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES- 2010/2017 SO2 EMISSIONS SALES-PTF	1	6,783.61	6,783.61

For Inquiries Contact
LORI VANTUINEN/HAMPP
Phone: (561) 691-2647

Total Amount Due $67,015.64

This Month's Charges Past Due After 04/30/2010

Messages

Florida Power & Light Company
General Mail Facility
Miami, FL 33188-0001

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Cape Canaveral	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PCC1	$2,300.36	$0.24	$2,300.60
March 2010 auction of year 2017 allowances	PCC1	$126.37	$0.01	$126.38
March 2010 auction of year 2010 allowances	PCC2	$2,715.17	$0.29	$2,715.46
March 2010 auction of year 2017 allowances	PCC2	$149.16	$0.01	$149.17
	Plant Totals:	$5,291.06	$0.55	$5,291.61

LOCN 913

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
FL	Fort Myers	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PFM1	$1,734.69	$0.19	$1,734.88
March 2010 auction of year 2017 allowances	PFM1	$95.30	$0.01	$95.31
March 2010 auction of year 2010 allowances	PFM2	$5,166.37	$0.54	$5,166.91
March 2010 auction of year 2017 allowances	PFM2	$283.82	$0.03	$283.85
	Plant Totals:	$7,280.18	$0.77	$7,280.95

LOCN 911

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Credit 254.900 LOCN XXX EAC 790

Florida Power & Light Company
Docket No. 110007-EI
Staff's 7th Set of Interrogatories
Interrogatory No. 52
Attachment No. III
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Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Lauderdale	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	4GT1	$509.10	$0.05	$509.15
March 2010 auction of year 2017 allowances	4GT1	$27.97	$0.00	$27.97
March 2010 auction of year 2010 allowances	4GT2	$509.10	$0.05	$509.15
March 2010 auction of year 2017 allowances	4GT2	$27.97	$0.00	$27.97
March 2010 auction of year 2010 allowances	5GT1	$509.10	$0.05	$509.15
March 2010 auction of year 2017 allowances	5GT1	$27.97	$0.00	$27.97
March 2010 auction of year 2010 allowances	5GT2	$509.10	$0.05	$509.15
March 2010 auction of year 2017 allowances	5GT2	$27.97	$0.00	$27.97
	Plant Totals:	$2,148.28	$0.20	$2,148.48

Loc 928

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
FL	Manatee	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PMT1	$7,523.30	$0.78	$7,524.08
March 2010 auction of year 2017 allowances	PMT1	$413.30	$0.04	$413.34
March 2010 auction of year 2010 allowances	PMT2	$6,938.78	$0.72	$6,939.50
March 2010 auction of year 2017 allowances	PMT2	$381.13	$0.04	$381.22
	Plant Totals:	$15,256.56	$1.58	$15,258.14

Loc 917

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Florida Power & Light Company
Docket No. 110007-EI
Staff's 7th Set of Interrogatories
Interrogatory No. 52
Attachment No. III
Page 4 of 12

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Martin	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	HRSG3A	$697.65	$0.07	$697.72
March 2010 auction of year 2017 allowances	HRSG3A	$38.33	$0.00	$38.33
March 2010 auction of year 2010 allowances	HRSG3B	$697.65	$0.07	$697.72
March 2010 auction of year 2017 allowances	HRSG3B	$38.33	$0.00	$38.33
March 2010 auction of year 2010 allowances	HRSG4A	$697.65	$0.07	$697.72
March 2010 auction of year 2017 allowances	HRSG4A	$38.33	$0.00	$38.33
March 2010 auction of year 2010 allowances	HRSG4B	$697.65	$0.07	$697.72
March 2010 auction of year 2017 allowances	HRSG4B	$38.33	$0.00	$38.33
March 2010 auction of year 2010 allowances	PMR1	$2,771.74	$0.29	$2,772.03
March 2010 auction of year 2017 allowances	PMR1	$152.27	$0.01	$152.28
March 2010 auction of year 2010 allowances	PMR2	$3,299.69	$0.34	$3,300.03
March 2010 auction of year 2017 allowances	PMR2	$181.27	$0.02	$181.29
	Plant Totals:	$9,348.89	$0.94	$9,349.83

Loen 928

2944.20

Loen 918

6405.63

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Florida Power & Light Company
Docket No. 110007-EI
Staff's 7th Set of Interrogatories
Interrogatory No. 52
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Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Port Everglades	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PPE1	$1,282.17	$0.13	$1,282.30
March 2010 auction of year 2017 allowances	PPE1	$70.44	$0.00	$70.44
March 2010 auction of year 2010 allowances	PPE2	$1,319.88	$0.13	$1,320.01
March 2010 auction of year 2017 allowances	PPE2	$72.51	$0.01	$72.52
March 2010 auction of year 2010 allowances	PPE3	$3,205.41	$0.34	$3,205.75
March 2010 auction of year 2017 allowances	PPE3	$176.09	$0.02	$176.11
March 2010 auction of year 2010 allowances	PPE4	$3,261.98	$0.34	$3,262.32
March 2010 auction of year 2017 allowances	PPE4	$179.20	$0.02	$179.22
	Plant Totals:	$9,567.68	$0.99	$9,568.67

Locn 920

Locn 924

2745.27

6823.40

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Putnam	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	HRSG11	$905.06	$0.09	$905.15
March 2010 auction of year 2017 allowances	HRSG11	$49.72	$0.00	$49.72
March 2010 auction of year 2010 allowances	HRSG12	$905.06	$0.09	$905.15
March 2010 auction of year 2017 allowances	HRSG12	$49.72	$0.00	$49.72
March 2010 auction of year 2010 allowances	HRSG21	$848.49	$0.09	$848.58
March 2010 auction of year 2017 allowances	HRSG21	$46.61	$0.01	$46.62
March 2010 auction of year 2010 allowances	HRSG22	$848.49	$0.09	$848.58
March 2010 auction of year 2017 allowances	HRSG22	$46.61	$0.01	$46.62
	Plant Totals:	$3,699.76	$0.38	$3,700.14

LOCN 90S

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Riviera	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PRV2	$56.57	$0.00	$56.57
March 2010 auction of year 2017 allowances	PRV2	$3.11	$0.00	$3.11
March 2010 auction of year 2010 allowances	PRV3	$1,942.10	$0.21	$1,942.31
March 2010 auction of year 2017 allowances	PRV3	$106.69	$0.01	$106.70
March 2010 auction of year 2010 allowances	PRV4	$1,942.10	$0.21	$1,942.31
March 2010 auction of year 2017 allowances	PRV4	$106.69	$0.01	$106.70
	Plant Totals:	$4,157.26	$0.44	$4,157.70

LOCN 904

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
FL	Sanford	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PSN3	$584.52	$0.06	$584.58
March 2010 auction of year 2017 allowances	PSN3	$32.11	$0.00	$32.11
March 2010 auction of year 2010 allowances	PSN4	$1,810.12	$0.18	$1,810.30
March 2010 auction of year 2017 allowances	PSN4	$99.44	$0.01	$99.45
March 2010 auction of year 2010 allowances	PSN5	$1,752.55	$0.18	$1,752.73
March 2010 auction of year 2017 allowances	PSN5	$96.33	$0.01	$96.34
	Plant Totals:	$4,376.07	$0.44	$4,376.51

LOCN 907

LOCN 916

2116.69

3759.82

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Turkey Point	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2010 auction of year 2010 allowances	PTP1	$3,205.41	$0.34	$3,205.75
March 2010 auction of year 2017 allowances	PTP1	$176.09	$0.02	$176.11
March 2010 auction of year 2010 allowances	PTP2	$3,224.27	$0.33	$3,224.60
March 2010 auction of year 2017 allowances	PTP2	$177.13	$0.02	$177.15
	Plant Totals:	$6,782.90	$0.71	$6,783.61

LOCN 926

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

Distribution of Proceeds

The proceeds for each unit are determined by the calculations listed below. The amount you receive from the U.S. Treasury may be for slightly more or less than the amount you calculate for your individual units due to rounding.

Spot:

Unit Proceeds = [Table 2 Column E / 250,000]** x $4,713,844.20

Additional Proceeds* = [Table 2 Column E / 249,974]** x $4,713,844.20 - Unit Proceeds

7-Year Advance:

Unit Proceeds = [Table 2 Column E / 250,000]** x $253,957.19

Additional Proceeds* = [Table 2 Column E / 249,974] x $253,957.19 - Unit Proceeds

To Calculate the Number of Allowances Sold:

Spot Auction Allowances Sold = [Table 2 Column E]** x [125,000 / 250,000]

7-Year Advance Auction Allowances Sold = [Table 2 Column E] x [125,000 / 250,000]

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

** Table 2 and the Phase II formula can be found in 40 CFR Part 73 in the September 28, 1998 FEDERAL REGISTER.

Vantuinen, Lorie

From: Wilkinson, Sheila M
Sent: Monday, March 29, 2010 12:45 PM
To: Larrubia, Ralph; Kiernan, Christian; HOCHMUTH, MELISSA
Cc: Ostertag, Elisa; Vantuinen, Lorie; Hampp, John
Subject: FW: Proceeds Distribution From the Annual U.S. EPA Auction of Sulfur Dioxide Allowances
Attachments: Proceeds.pdf; Proceeds Form.pdf; Pollution Auction SF3881.pdf

Please review for accuracy and set some time with me. Thanks.

Regards,

Sheila M. Wilkinson
PGD General Manager II
Environmental, Water Chemistry, Emission Testing & Central Lab Fleet Team Florida Power & Light 700 Universe Blvd (JSA/JB)
Juno Beach, FL 33408
561-691-2287 office
561-373-7042 cell
561-694-3647 fax

-----Original Message-----
From: EPA Clean Air Markets Division [mailto:IRMC@epa.gov]
Sent: Monday, March 29, 2010 11:37 AM
To: Wilkinson, Sheila M
Cc: Kennedy, Roxane
Subject: Proceeds Distribution From the Annual U.S. EPA Auction of Sulfur Dioxide Allowances

Dear Sheila M Wilkinson,In the near future, you will be receiving proceeds from the 2010 allowance auctions that were held on 03/23/2010.You will receive a direct deposit/electronic funds transfer from the U.S. Treasury for each facility that has a unit or units that had allowances withheld for purposes of the auctions. The proceeds you will receive will match the totals on the attached facility printout.

The proceeds for each unit are determined by the calculations in the attached report. The amount you receive from the U.S. Treasury may be for slightly more or less than the amount you calculate for your individual units due to rounding.

I want to remind you again that EPA will continue to make the proceeds check payable to the same company name as last year unless we receive a revised Notification for Distribution of Proceeds from EPA Auctions Form (signed by the DR) informing us differently. Also, please remember to notify the EPA Las Vegas Finance Center at (702) 798-2492 of any changes to your bank

account information in order to ensure prompt payment. These forms are attached to this e-mail in case you need to use them.

If you have any questions regarding your auction proceeds please call me at (202) 343-9154.

Kenon Smith
Clean Air Markets Division

Date	Reason	Vintage Year	Total Revenue Recog	Total Auction Proceeds
Jan-10	Revenue Recognition	2010	$14,460.86	
Feb-10	Revenue Recognition	2010	$14,460.86	
Mar-10	Revenue Recognition	2010	$14,460.86	
Apr-10	Proceeds - FPL	2010		($64,378.96)
Apr-10	Proceeds - FPL	2017		($3,536.68)
Apr-10	Proceeds - SJRPP	2010		($2,504.25)
Apr-10	Proceeds - SJRPP	2017		($137.57)
Apr-10	Revenue Recognition	2010	$36,755.27	
May-10	Revenue Recognition	2010	$20,034.47	
Jun-10	Revenue Recognition	2010	$24,705.54	
Jun-10	Proceeds - Scherer	2010		($8,855.67)
Jun-10	Proceeds - Scherer	2017		($486.49)
Jul-10	Revenue Recognition	2010	$20,529.15	
Aug-10	Revenue Recognition	2010	$20,772.44	
Sep-10	Revenue Recognition	2010	$20,772.44	
Oct-10	Revenue Recognition	2010	$20,772.44	
Nov-10	Revenue Recognition	2010	$20,772.44	
Dec-10	Revenue Recognition	2010	$20,772.44	
	Totals 2010		$249,269.21	
			$249,269.21	**($79,899.62)**

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 13th day of July, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared H. Antonio Cuba, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 52 from STAFF'S SEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 52) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

H. Antonio Cuba

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 13th day of July, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

8

FPL Responses to Staff's Eigth Set of Interrogatories (Nos. 53-56)

Q. Please refer to FPL's Preliminary List of New Projects (List) for the following questions. Referring to Industrial Boiler MACT Project and page 1 of the List:

- **a. Please specify the compliance requirements of rule DDDDD for the major sources of Hazardous Air Pollutants (HAPs).**
- **b. Please specify the compliance requirements of rule JJJJJ for the area sources of HAPs.**
- **c. Please provide a list of affected FPL facilities which are defined as the major sources of HAPs.**
- **d. Please provide a list of affected FPL facilities which are defined as the area sources of HAPs.**

A.

a. On March 21, 2011 EPA published its final rule to establish emission standards under the hazardous air pollutant regulations for industrial boilers and process heaters at major sources (76 FR 15608). Subsequent to the publication of the final rule, on May 18, 2011 EPA published a notice delaying the effective date of the final rule until the proceedings for judicial review are completed or the EPA completes its reconsideration of the rules, whichever is earlier. In its reasoning for the delay in the effective date, EPA noted that there were several requests for reconsideration and petitions to the court for judicial review of certain aspects of this rule and a final rule for commercial and industrial solid waste incineration units. FPL anticipates that EPA will publish a notice terminating the delay between August 2011 and May 2012, which will require FPL to comply with the rule requirements. Rule requirements for compliance include:

(1) Submittal of initial notifications of applicability to agency
(2) Compliance with work practice standards including biennial tuning
(3) Meet applicable emission limits for oil fired units
(4) Maintain records of compliance with requirements
(5) Submit notifications and reports demonstrating compliance with requirements

b. On March 21, 2011 EPA published its final rule to establish emission standards under the hazardous air pollutant regulations for industrial boilers and process heaters at major sources (76 FR 15554). Unlike the major source rule under Subpart DDDDD, the area source rule (Subpart JJJJJJ) was not delayed and compliance requirements remain in effect. Similar to the Major source rule, requirements for compliance include:

(1) Submit initial notifications of applicability to agency
(2) Comply with work practice standards including biennial tuning
(3) Meet applicable emission limits for oil fired units
(4) Maintain records of compliance with requirements
(5) Submit notifications and reports demonstrating compliance with requirements

c. FPL's facilities that are defined as major sources of HAPs are shown below, with those that have equipment subject to regulation under Subpart DDDDD identified:

- Cutler Plant - **(Facility-wide, no specific units regulated)**
- Canaveral Plant – **Manatee Heater**
- Ft. Myers Plant – **Natural Gas Heaters**
- Lauderdale Plant - **Auxiliary Boiler**
- Martin Plant – **Auxiliary Boiler**
- Manatee Plant - **(Facility-wide, no specific units regulated)**
- Port Everglades Plant- **(Plant-wide, no specific units regulated)**
- Putnam Plant– **Auxiliary Boiler**
- Sanford Plant- **(Facility-wide, no specific units regulated)**
- Turkey Point Plant- **(Facility-wide, no specific units regulated)**
- West County Energy Center– **Auxiliary Boiler & Natural Gas Heaters**

d. FPL's facilities that are defined as area sources of HAPs are shown below, with those that have equipment subject to regulation under Subpart JJJJJJ identified:

- Martin Fuel Oil Terminal – **Fuel Oil Heaters**
- Manatee Fuel Oil Terminal- **(Facility-wide, no specific units regulated)**
- St. Lucie Nuclear Plant- **(Facility-wide, no specific units regulated)**

Q.
Please refer to FPL's Preliminary List of New Projects (List) for the following questions.

Referring to Industrial Boiler MACT Project and page 2 of the List:

a. **Please explain how the $397,000 compliance costs were derived.**
b. **How much of the $397,000 is related to the rule DDDDD compliance, and how much of it is related to the rule JJJJJ compliance?**
c. **Please breakdown the $397,000 into two portions, each respectively relating to the initial test and the energy assessment of the MACT rule compliance requirements.**
d. **Please provide a breakdown of the component activities that comprise the estimated $397,000 of compliance costs, together with the associated affected units or facilities.**
e. **What is the cost estimate for annual emission testing per affected unit or facility?**
f. **What is the cost estimate for fuel testing per affected unit or facility?**
g. **What is the cost estimate for the biennial tune-up per affected unit or facility?**
h. **Do the $397,000 or $26,000 estimates include the expenses for the tune-up?**
i. **Please provide a list of units and facilities associated with the $26,000 compliance cost.**
j. **How much of the $26,000 is related to the rule DDDDD compliance, and how much of it is related to the rule JJJJJ compliance?**

A.
a. FPL estimated its total cost for compliance with both rules by evaluating the equipment that is subject to the rules and determining all incremental activities that are imposed on facilities to comply with the requirements of both rules. Costs for performing the activities were preliminarily estimated using EPA estimates that were included in the technical support documents in the rule docket. FPL has provided as a supporting document a matrix (Attachment I) which identifies all company equipment subject to these rules with the estimated costs for compliance. Also provided as supporting documentation (Attachment II) in the report provided by EPA for the cost estimates to comply with rule requirements.

b. FPL estimates the cost for compliance with JJJJJ at $41,453 and compliance with DDDDD at $356,187. Please see Attachment I.

c. Please see Attachment I.

d. Please see Attachment I.

e. The EPA estimated the cost for stack testing at an average annual cost of $44,000/yr to demonstrate compliance with emission limits for solid fuel units. FPL has estimated that stack required biennial stack testing could be performed at a lower cost based on fewer analyses required for oil fired units and could be performed at a cost of $26,000.

f. EPA has estimated the cost for fuel testing at an average cost of $16,000/yr for liquid fuel fired units.

g. EPA estimated that the annual average cost is $2,875. This includes the impact of an initial set-up cost of $5,000 and an annual average tuning cost of $1000. EPA also provided an estimated one-time cost of $10,143 for construction of test ports on affected units requiring emission testing that do not have existing test ports.

h. No, FPL only included the cost for the analyzer in its estimate and not the incremental labor for performing the biennial tune-up.

i. FPL has one unit that will be affected under DDDDD, the Putnam Auxiliary Boiler, and currently no units that are affected under JJJJJJ. Please see Attachment I.

j. Please refer to the response to i. above.

FPL Industrial Boiler MACT Equipment / Estimated Compliance Costs

Facility	Equipment Type	Location HAP Status	MACT Rule	Rated Heat Input (MMBtu/hr)	Fuel Type 1	Fuel Type 2	Existing / New ?	Test Port?	Biennial Tune-Up?	Stack/Fuel Testing ?	Potential Emission Limits?	Energy Assessment?	Biennial Tune-Up[1]	Test Port Installation[2]	Fuel/Stack Testing[3]	Energy Assessment[4]
Canaveral	Manatee Heater	Major	DDDDD	30	Natural Gas	N/A	New	Unk	Yes	No	No	Yes	$ -	$ -	$ -	$ 18,292
Lauderdale	Auxiliary Boiler	Major	DDDDD	15.5	Propane	N/A	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 18,292
Ft. Myers Plant	Process Heater (3A)	Major	DDDDD	10	Natural Gas	N/A	Existing	Yes	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
Ft. Myers Plant	Process Heater (3B)	Major	DDDDD	10	Natural Gas	N/A	Existing	Yes	Yes	No	No	Yes			$ -	$ 75,000
Martin	Auxiliary Boiler (3&4)	Major	DDDDD	18.3	Natural Gas	N/A	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 75,000
Putnam	Auxiliary Boiler	Major	DDDDD	18.3	Natural Gas	#2 Fuel Oil	Existing	No	Yes	Yes	Yes	Yes	$ 2,875	$ 10,143	$ 28,000	$ 18,292
West County Energy Center	Auxiliary Boiler	Major	DDDDD	98	Natural Gas	N/A	New	Yes	Yes	No	No	Yes	$ 2,875		$ -	$ 18,292
West County Energy Center	Process Heater (1)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (2)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (3)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (4)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
													$ 25,875	$ 81,144	$ 28,000	$ 223,168
Manatee Terminal	Process Heater (A)	Minor (Area)	JJJJJJ	14.6	#2 Fuel Oil	N/A	Existing	Yes	No	No	No	No			$ -	
Manatee Terminal	Process Heater (B)	Minor (Area)	JJJJJJ	12.5	Natural Gas	#2 Fuel Oil	New	Yes	No	No	No	No			$ -	
Martin Terminal	Auxiliary Boiler (A)	Minor (Area)	JJJJJJ	12.5	#2 Fuel Oil	#6 Fuel Oil	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 18,292
Martin Terminal	Auxiliary Boiler (B)	Minor (Area)	JJJJJJ	12.5	#2 Fuel Oil	#6 Fuel Oil	Existing	No	Yes	No	No	Yes		$ 10,143	$ -	
													$ 2,875	$ 20,286	$ -	$ 18,292
													$ 28,750	$ 101,430	$ 28,000	$ 241,460
															Grand Total	$ 397,640

Notes: 1) EPA estimated annualized cost for Biennial Tune-Up = $2,875
2) Test port installation average projected cost of $10,143 per stack
3) Stack testing cost based on EPA estimate reduced for fewer analytical parameters (8/5)
4) EPA Energy Assessment for FPL sites with complex emission units/configuration assumes EPA estimate of $75 k and average cost using EPA estimate of $18,292 for sites with fewer process units.

ERG

MEMORANDUM

TO: Brian Shrager, U.S. Environmental Protection Agency, OAQPS/SPPD

FROM: Amanda Singleton, and Graham Gibson, ERG

DATE: February 17, 2011

SUBJECT: Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source

1.0 INTRODUCTION

The purpose of this memorandum is to discuss the revised methodology used to estimate the costs, emission reductions, and secondary impacts from industrial, commercial, and institutional boilers at major sources of hazardous air pollutants (HAP). These impacts were calculated for existing units and new units projected to be operational by the year 2013, three years after the rule is expected to be promulgated. The results of the impacts analysis are presented for both the regulatory option contained in the promulgated rule and a more stringent regulatory option. The development of the maximum achievable control technology (MACT) floor level of control, projection of new units, and a detailed description of the cost equations used to estimate costs for various control technologies is presented in other memoranda.[1,2,3] This memorandum is organized as follows:

1.0 Introduction
2.0 Overview of Regulatory Options
3.0 Estimating Cost Impacts
4.0 Methodology for Estimating Emission Reductions
5.0 Methodology for Estimating Secondary Impacts
6.0 References

2.0 OVERVIEW OF REGULATORY OPTIONS

Two control options were considered for existing boilers and process heaters at major sources of HAP. A description of the two options is included in this section.

2.1 Existing Units

- The recommended option is the option presented in the preamble and final rule. In this option, small boilers and process heaters (less than 10 mmBtu per her), limited use boilers and process heaters (operating less than 876 hours per year), and boilers burning natural gas, refinery gas, or other on-spec gaseous fuels are subject to work practice standards in lieu of numeric emission limitations. The work practice standard small and limited use units is a biennial tune-up and the work practice standard for larger natural gas, refinery gas, or other on-spec gaseous fuels is an annual boiler tune-up. Boilers not meeting one of those criteria are subject to numeric emission limitations for Hg, PM, HCl, CO, and TEQ dioxins/furans. Boilers combusting at least 10 percent solid fuels, either coal, other fossil solids or biomass are grouped into a single solid fuel subcategory and are subject to identical emission limitations for the fuel-based pollutants Hg, PM, and HCl. For combustion-based pollutants CO, and TEQ dioxins/furans separate combustor design subcategories are considered for coal/fossil solids and biomass. Units designed to burn liquid fuels, units located in non-continental States and United States Territories designed to burn liquid fuels, and units burning off-spec gaseous fuels (other process gases) each have a single subcategory for both fuel and combustor-based HAP.

- The alternative option is identical to the recommended option except that boilers combusting at least 10 percent solid fuels are subject to separate numeric limits depending on the class of solid fuel combusted. Units burning coal or other fossil solids have separate numeric emission limitations from units burning biomass or other bio-based solids for Hg, PM, and HCl.

2.2 New Units

The same two control options for existing units were used for new units. However, since it is projected that no new boilers combusting solid fuel (biomass or coal) will be constructed by 2013, the results of the cost and emission impacts analyses for both options are identical.

3.0 ESTIMATING COST IMPACTS

For each option, the cost impacts analysis compares the baseline emissions for each unit to the corresponding MACT floor emission limit for the unit's subcategory. A control device was applied to the unit if its baseline emissions exceeded their applicable MACT floor emission limit.

A comparison of the overall capital and annualized costs of the recommended option are presented in Table 1. The detailed equations used to estimate the control, testing, monitoring, and work practice costs are discussed in another memorandum.[2] The following logic was used to apply control, testing, and monitoring costs to each boiler or process heater:

3.1 Recommended Option

The recommended option represents an option with a consolidated subcategory for fuel-based HAP from solid fuel units, where every unit must meet numerical emission limits and demonstrate compliance with performance stack testing, monitoring, and fuel analysis with a few exceptions. Units in the gas 1 subcategory, small units (less than 10 mmBtu/hr), and limited use units (less than 876 operating hours per year), qualify for work practices under Section 112(h) of the CAA and work practices consisting of an annual or biennial tune-up replace the traditional compliance demonstrations associated with numeric emission limits.

Control Cost Impacts

Mercury Control

- Fabric filters — a new fabric filter installation was expected to achieve most of the Hg emission limits in the final rule. Where baseline Hg emissions were found to be greater than the MACT floor, the cost of a fabric filter was estimated for an individual boiler or process heater, unless the unit already had a fabric filter installed. A new fabric filter was estimated to be installed at 454 existing boilers and process heaters. This does not include the fabric filters installed in combination with dry injection to achieve HCl controls that are discussed below.
- Activated carbon injection (ACI) — In the case of a unit with a fabric filter emitting Hg above the MACT floor emission limit, the incremental Hg removal efficiency required to meet the MACT floor was calculated, and then the costs to install activated carbon injection (ACI) technology on the boiler were estimated. Incremental ACI equipment was installed for 108 existing boilers and process heaters.
- Wet scrubbers—one of the technologies selected for the cost analysis to reduce emissions of hydrogen chloride (HCl)—is also capable of achieving modest reductions in Hg. Literature suggests that these scrubbers can achieve a 10-percent reduction in Hg

emissions. If a scrubber was being installed for HCl, and baseline Hg emissions were within 10 percent of the MACT floor, the wet scrubber was expected to achieve this level of emission reduction without installing a fabric filter.

Particulate Matter Control

- When baseline particulate (PM) emissions exceeded the MACT floor, the cost of an ESP was estimated, unless a fabric filter had already been included in the cost analysis for Hg reduction. ESP technology was estimated to be installed at 10 existing boilers and process heaters.
- Wet scrubbers are also capable of achieving a modest reduction in PM. Literature suggests that these scrubbers can achieve an 85-percent reduction in PM emissions. If a scrubber was being installed for HCl, and baseline PM emissions were within 85 percent of the MACT floor for PM, the wet scrubber was expected to achieve this level of emission reduction without installing an ESP.

Hydrogen Chloride Control

- When HCl baseline emissions were greater than the MACT floor, the cost of adding a packed bed scrubber, increasing the sorbent rate on an existing scrubber, or installing a combination fabric filter and dry injection (DIFF) system was estimated. Scrubbers and DIFF were estimated to be able to attain similar levels of hydrogen chloride control. Based on input received during the public comment period, many wood product facilities are not permitted to discharge wastewater, thereby restricting the type of controls needed to reduce emissions of HCl and other acid gases. For this analysis, facilities in NAICS codes 321 (wood products manufacturing) and 322 (paper manufacturing) were assumed to not be able to install a packed scrubber due to the regulation of wastewater discharge from those industries. For the remaining units requiring control device installation for hydrogen chloride reduction, the less expensive control option between a packed scrubber and DIFF was assumed to be the control installed. If the boiler already reported having a scrubber installed, a DIFF was not the selected control technology, and the baseline emissions still exceeded the floor, the incremental required HCl removal efficiency was calculated and the then the cost to increase the sorbent injection rate in the scrubber was

estimated in the cost analysis. Wet scrubbers were estimated to be necessary to control HCl emissions at 774 existing boilers and process heaters. DIFF was identified to be necessary to control HCl emissions at 136 existing boilers and process heaters. Incremental sorbent injection was identified to be necessary to control HCl emissions at 7 existing boilers and process heaters.

- Since the fabric filter portion of a DIFF will achieve reductions in both HCl and Hg, the analysis first checked for whether a DIFF was necessary to achieve HCl reductions, and if so, this DIFF was assumed to achieve the MACT floor limits for both HCl and Hg. If a DIFF was not needed for HCl control, but a fabric filter was needed for mercury control, the costs of a fabric filter were estimated.

Dioxin/Furan Control

The final rule requires all units that measure dioxin data below the method detection level to report that congener as zero. Based on the reported dioxin/furan data and associated detection levels available at the time of the final rule, most units will fall below the MACT floor levels if the non-detect congeners are treated as zero, For coal, 17 of the 27 tests would meet the existing limits, 17 of the 22 tests for biomass would meet the existing limits, and all of the liquid and process gas tests would meet the existing limits. Given these results and the fact that some units are installing ACI for mercury control, which is expected to have a co-benefit of reducing dioxin/furan emissions, the cost analysis does not estimate any control costs for achieving the dioxin/furan emission limits.

Carbon Monoxide and Organic HAP Control

- Organic HAP and carbon monoxide can be controlled by either improving the combustion efficiency of the unit, or installing an oxidation catalyst on the exhaust of a combustion unit. The control strategy necessary to meet the MACT floor emission limit will vary depending on the magnitude between the baseline emissions and the CO MACT floor. A step function was used to delineate what type of control strategy should be analyzed in the cost impacts analysis:
    - A boiler tune-up was estimated in the cost impacts analysis if the unit's CO baseline emissions were less than or equal to 1.5 times the applicable numeric CO

emission limit. Some commenters, including facilities and boiler and burner vendors, suggested that the concrete threshold of 400 ppm used in the CO control cost analysis in the proposal was an inappropriate cutoff for determining whether or not a tune-up could achieve the CO emission limits for certain boiler types. Many of these commenters added that significant changes in CO could not be made without a tradeoff in increased NOX emissions. Based on data in the record as well as public comment submittals, CO emissions can fluctuate widely due to operating loads and conditions. Further, most units in the database do not report dedicated combustion controls or CO oxidation catalysts installed to reduce CO emissions. Instead of using a concrete threshold of 400 ppm in final analysis, we estimated that tune-ups could achieve a percent reduction from the unit's baseline emissions. To determine an appropriate threshold level that tune-ups could achieve the limits to demonstrate annual compliance with the CO stack test in the final rule, we looked at best performing units for CO that reported paired CO CEMS emissions and boiler load data. Best performing CO units in the coal/fossil solid stoker, biomass/bio-based solid dutch oven/suspension burner and hybrid suspension grate subcategories biomass had data available. None of these units with paired CO and load data reported having any add-on dedicated CO controls or combustion controls installed on the unit. The WVDupontWashingtonWorks P05 unit reported a wide range of CO emissions at loads greater than 75 percent of its design capacity, the maximum CO value was over 9 times greater than the minimum CO value at the unit. For biomass units, the range is even more pronounced, at TXDibollTemple-Inland PB-44, the maximum CO value at loads greater than 50 percent was nearly 900 times higher than the minimum CO value, and at hybrid suspension grate burners, FLUSSugar, Boiler 8, the maximum CO value was over 1,700 times higher than the minimum CO value. Despite these large ranges, the CO stack test values of these units were all meeting the floor values during their emission stack tests. We settled on a modest threshold condition of assuming that a tune-up would meet the limit if the floor value was within 150% of the baseline emissions. Based on data provided by best performing units, it is reasonable and a conservative estimate that this level of control can be achieved without capital installations.

- If the unit's baseline CO emissions were greater than 1.5 times but less than or equal to 2.5 times the applicable numeric CO emission limit, the cost of a replacement low-NOx burner was estimated to achieve the MACT floor emission limits. Since stokers, fuel cells, or fluidized bed unit do not have replaceable burners, a linkageless boiler management system (LBMS) was the technology estimated to achieve the MACT floor when baseline CO emissions exceeded the floor in lieu of replacement low-NOx burners. A threshold of 2.5 is still less than the reported findings from best performing boilers in the coal and biomass subcategories that demonstrate wide fluctuations in CO emissions without any added CO controls, as discussed above. However, since we do not have similar data available for the liquid and process gas subcategories, we opted to select a conservatively low threshold to address some concerns received from public comments about underestimating the costs of CO control.
- Finally, if the baseline CO emissions were greater than 2.5 times the applicable CO emission limit, the cost impacts analysis estimated that a CO oxidation catalyst would be required to meet MACT floor limits.

Work Practice Costs

- All small boilers (less than 10 mmBtu per hour), limited use boilers (less than 876 hours of operation per year), are required to conduct a biennial boiler tune-up. All large boilers burning natural gas, refinery gas, or other on-spec gaseous fuels are required to conduct an annual tune-up. The cost to conduct an annual tune-up is based on the cost estimate provided in a report by the Industrial Extension Service[16]. This report indicated that the initial set-up for boiler tune-up was $3,000 to $7,000 per boiler; thereafter, annual tuning costs $1,000 per boiler. An average of $5,000 per boiler initial set-up costs was annualized over 5 years at a 7 percent rate, and added to the subsequent year tune-up costs. The resultant annualized cost for an annual tune-up is $2,875 per boiler, as shown in Equation 1.

$$\text{Annual Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008} / X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [Z_{\$2004} * (X_{2008} / X_{2004})] = \$2{,}875 \qquad \textbf{(Equation 1)}$$

Where:

$C_{\$2004}$ = Average set-up cost, $5,000 (from 2004)

X_{2008} = 2008 cost index, 575.4
X_{2004} = 2004 cost index, 442.2
i = interest rate, 7%
y = length of annuity, 5 years
$Z_{\$2004}$ = annual tuning cost, $1,000 (from 2004)

Biennial tune-up costs would provide some cost savings, although the costs of the initial tune-up set-up must be factored into both of the work practice frequencies, so this analysis used a single tune-up cost, which is based on an annual frequency. The annualized cost for a biennial tune-up is $2,228 per boiler, as shown in Equation 2.

$$\text{Biennial Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008}/X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [(Z_{\$2004} / 2) * (X_{2008}/X_{2004})] = \$2{,}228 \qquad \textbf{(Equation 2)}$$

Where:
$C_{\$2004}$ = Average set-up cost, $5,000 (from 2004)
X_{2008} = 2008 cost index, 575.4
X_{2004} = 2004 cost index, 442.2
i = interest rate, 7%
y = length of annuity, 5 years
$Z_{\$2004}$ = annual tuning cost, $1,000 (from 2004)

A total of 12,266 boilers and process heaters meet one of the above criteria and are subject to a tune-up work practice in lieu of add-on controls.

- All facilities are expected to conduct a one-time energy audit. An annual cost of $854 per audit was used for commercial facilities and $18,292 per audit was used for industrial facilities, and these costs are the same as the estimates included in the proposal. Although some commenters indicated EPA underestimated the costs of the assessment, in the final rule EPA has reduced the scope of the assessment in the final rule to an assessment that does not exceed one to three days in length for units consuming less than 1 trillion Btu/year of energy. For larger units, the audit is reduced in scope to assess for at least 20 percent of the energy output of the boiler system. As discussed in the memorandum for Estimating Control Costs from Major Source Boilers and Process Heaters, the cost of an energy audit ranges from $75,000 for industrial-scale energy audits to between $2,000 and $5,000 per energy audit for institutional and commercial-scale audits.[2] This larget estimate is based on costs presented to the 2009 Boiler Small Business Regulatory Flexibility Act panel by an affected small entity, Port Townsend Paper Company. The cost of each type of audit was annualized over 5 years at 7 percent to obtain an

annualized cost estimate. For the cost impacts analysis, 1,639 facilities are expected to conduct an audit, 197 facilities are commercial or institutional and 1,442 facilities are industrial.

Testing and Monitoring Cost Impacts

Testing and monitoring requirements varied depending on the equipment installed on the unit to control emissions, the design capacity of the unit, and the fuel category the unit was assigned to.

Testing Costs

All boilers and process heaters designed to burn solid and gaseous fuels were expected to conduct an annual compliance test for PM, HCl, Hg, D/F, and CO. The cost to conduct stack tests for these five pollutants was estimated to be $44,000 per year for boilers combusting solid or other gaseous fuels. Based on comments received about testing under worst-case conditions, many solid fuel boilers which fire multiple fuel streams or types of fuel are expected to conduct repeated testing for mercury and HCl at a cost of $18,000 per year.

Boilers and process heaters designed to burn liquid fuels were expected to conduct an annual compliance test for PM, D/F, and CO. In lieu of a stack test boilers designed to burn liquid fuels were expected to conduct fuel analysis, or report fuel analyses received from a fuel supplier for chlorine and Hg. Conducting stack tests for PM, D/F, and CO and fuel analysis for chlorine and Hg was estimated to be $16,000 per year. Although other fuels are eligible to comply with the promulgated rule through fuel analysis in lieu of stack testing, this cost estimate conservatively assumed that only units designed to fire liquid fuels would use this compliance alternative. The methods and data sources used to estimate testing and monitoring costs are discussed in other memoranda.[2]

The final rule includes a provision for gaseous fuels other than natural gas and refinery gas to demonstrate that they meet the specifications outlined in the rule for mercury and hydrogen sulfide. We reviewed the database for facilities that had boilers with heat input capacities of at least 10 mmBtu/hr that are firing gaseous fuels other than natural gas or refinery gas, and we estimated that these 45 facilities would need to conduct monthly fuel analysis, at a cost of $600 per month, or $7200 per year. The methods and costs associated with demonstrating

that the gas meets the specifications for mercury and hydrogen sulfide are discussed in another memorandum.[4] Because the fuel spec can be conducted upstream of the combustion equipment, EPA determined that one specification per month, per facility, would be the likely compliance mechanism for units opting to demonstrate that their gaseous fuels meet the specification.

Small boilers often exhaust to small diameter stacks that do not have any test ports or test platforms installed. Similarly, based on the public comments received limited use units often do not have test ports or test platforms installed. For these units, we estimated the additional costs to these costs to construct or rent scaffolding and install test ports. The costs include installation of 4 test ports, 90 degrees opposed to each other, and five weeks rental of temporary scaffolding. EPA estimates that these small sources would incur an additional $196 million to install test ports and rent temporary scaffolding. Many establishments in each industry, commercial, or institutional sector are associated with multiple (as many as a 700) small units. A summary of the costs by fuel category is shown in Table 3-1 below.

Table 3-1: Cost Estimate for Renting Scaffolding and Constructing Test Ports at Limited Use and Small Boilers and Process Heaters

Fuel Category	Number of Limited Use and Small Boilers and Process Heaters	Port Costs ($2008)	Renting Temporary Scaffolding ($2008)	Total Costs ($2008)
Coal	15	164,722	210,000	374,722
Biomass	21	230,610	294,000	524,610
Gas 1	7433	81,624,999	104,062,000	185,686,999
Gas 2	51	560,053	714,000	1,274,053
Liquid	358	3,931,353	5,012,000	8,943,353
Total	7,878	86,511,737	110,292,000	196,803,737

Monitoring Costs

Various monitor configurations were installed based on the size of the unit and the pollution control devices expected to be installed to achieve the MACT floor emission limits. For units expected to install packed bed wet scrubbers, an annualized cost of $5,600 for a scrubber parametric monitor was included in the cost analysis. If a unit was expected to install DIFF, the

cost to monitor sorbent injection rate and add a bag leak detection monitor was included in the analysis, based on the unit's hours of operation. For units expected to install a fabric filter, an annualized cost of $9,700 for a bag leak detection monitor was included in the cost analysis. If a unit was expected to install ACI, the cost to monitor the carbon injection rate was included in the analysis, based on the unit's hours of operation. For units that did not install a PM CEMS and did not install a scrubber to meet HCl limits, an annualized cost of $14,660 for an opacity monitor was included in the cost analysis. While the final rule includes a cutoff of greater than 250 mmBtu/hr, in order to be consistent with the thresholds in the boiler NSPS (40 CFR 60, Subparts Db and Dc) the cost analysis includes the cost of a PM CEMS for units with a heat input capacity of 250 mmBtu/hr or more. Oxygen monitors were required for all boilers and process heaters subject to CO emission limits, these monitors were assumed to be extractive type monitors with an annualized cost of $1,436. Although several units are expected to have O2 monitors installed on the units for other reasons, such as to monitor combustion efficiency, since the number of units with monitors installed and calibrated according to EPA performance specifications is unknown, this analysis applies the cost of an O2 monitor to all units subject to a CO emission limit. No PM CEMS or opacity monitors were assumed for boilers and process heaters designed to gaseous fuels.

Fuel Savings Impacts

This cost analysis includes an estimate of energy savings of one percent for every unit that is expected to install controls to improve combustion, or conduct an annual tune-up or energy audit. Further, documents from the Sustainable Energy Authority of Ireland have charted efficiency gains as a function of boiler fuel type and time elapsed since the previous tune-up.[8] Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. Further boiler tune-ups have been shown to improve the efficiency of a boiler between 1 and 5 percent, depending on the age of the unit and the time lapse since the previous tune-up[10-15, 17-19]. Other combustion controls such as upgrading burners and installation of an LBMS are also expected to improve the efficiency of the unit, thus reducing fuel consumption. This cost analysis assumes an annual fuel savings of 1 percent. The energy savings is estimated using the Equation 3:

Annual Fuel Savings (mmBtu/yr) = DC * CF * Op_{hours}* EG **(Equation 3)**

Where:

DC = unit design capacity (mmBtu/hr)

CF = capacity factor, 90% of design capacity

Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

EG = Efficiency gain, estimated to be 1%

After the fuel savings for each boiler and process heater was calculated, the both industrial and commercial prices for coal, #2 distillate fuel oil, #6 residual fuel oil, and natural gas were obtain from the EIA.[5] The EIA data reported fuel prices as $/ton for coal, $/thousand cubic feet for natural gas, and cents per gallon for fuel oil. The higher heating values were obtained from Table C-1 of the EPA Mandatory Reporting Rule (40 CFR part 98 subpart C) and the higher heating values were used to convert the fuel prices to a standard unit of measure, $ per mmBtu. Using the NAICS code reported by each facility and the fuel category assigned to each combustion unit, the appropriate fuel price was multiplied by the calculated fuel savings. Table 3-2 below shows the distribution of reported NAICS codes considered as industrial versus commercial in terms of fuel pricing.

Table 3-2: Summary of NAICS Code Distribution by Sector

Sector	NAICS Codes
Industrial	221, 311, 312, 313, 314, 316, 321, 322, 323, 324, 325, 326, 327, 331, 332, 333, 334, 335, 336, 337, & 339
Commercial	111, 113, 115, 211, 212, 423, 424, 441, 481, 482, 486, 488, 493, 531, 541, 561, 562, 611, 622, 623, 811, 921, & 928

This cost analysis only estimates the fuel savings from units in the coal, liquid and natural gas and other gaseous fuel categories. A fuel savings was not estimated for units in the biomass fuel category since the price of biomass fuels is variable, and often biomass is an on-site industrial byproduct instead of a purchased fuel. The logic behind the costs analysis for new units were identical to that of existing units for the recommended option with the exception of the energy audit. Energy audits are a recommended beyond-the-floor option for existing units only and therefore no costs for an audit were included in the new source floor analysis.

3.2 Alternative Option

The alternative option includes control device and testing/monitoring cost estimation logic identical to the Recommended Option outlined above, except that units combusting

biomass and coal must meet separate numeric emission limitations for Hg, PM, and HCl. All other aspects of the options are identical. As a result of this modified option and its computed MACT floors, the number of solid fuel units estimated to install controls to meet the limits were adjusted as follows:

- A new fabric filter was estimated to be installed at 451 existing boilers and process heaters to control Hg emissions. This does not include the fabric filters installed in combination with dry injection to achieve HCl control. A new fabric filter is required to be installed on 3 fewer boilers and process heaters under this option when compared to the recommended option.
- Incremental ACI equipment was estimated to be installed at 11 existing boilers and process heaters for the controlling Hg. Incremental ACI equipment is required to be installed on 97 fewer boilers and process heaters compared to the recommended option.
- ESP technology was estimated to be installed at 34 existing boilers and process heaters to control PM. ESP technology is required to be installed on an additional 24 boilers and process heaters under this option when compared to the recommended option.
- Wet scrubbers were estimated to be necessary to control HCl emissions at 774 existing boilers and process heaters. This is identical to the number of sources estimated to install a scrubber for HCl control under the recommended option.
- DIFF was identified to be necessary to control HCl emissions at 390 existing boilers and process heaters. DIFF is estimated to be installed on an additional 254 boilers and process heaters under this option when compared to the recommended option.
- Incremental sorbent injection was identified to be necessary to control HCl emissions at 23 existing boilers and process heaters. Incremental sorbent injection is estimated to be installed on an additional 16 boilers and process heaters under this option compared to the recommended option.

3.3 New Unit Options

The recommended option for new units follows the same logic for estimating control costs as the recommended option for existing units outlined above with one exception. For boilers with a rated heat capacity less than 500,000 Btu per hour, a tune-up cost of $200 was selected. This value was based on research of tune-up costs for similarly sized home boiler programs, which suggested the costs of a tune-up ranged from $60 to $150.[19,20] The alternative

option for new units is also identical to the alternative option for existing units. However, no new boilers or process heaters combusting solid fuels are expected to be constructed by 2013. Since the differences in the recommended and alternative options are focused only on boilers and process heaters combusting solid fuel, there are no differences in the recommended and alternative options for new units. The new unit analysis also projects new gaseous fuels, but based on the EIA data used for the new unit projections all of these new boilers are estimated to be natural gas so no cost for a gas specification is included in the new unit analysis.

3.4 Summary of Cost Impacts

The recommended option is the promulgated option for existing and new boilers and process heaters. Tables 3-3 and 3-4 summarize the costs of the promulgated option for new and existing units. Appendix A of this memorandum provides a detailed summary of the costs according to unit size, subcategory, and individual control device costs. Appendix A also includes a summary of the costs on existing units under the alternative option considered in development of the final rule.

Table 3-3: Summary of Costs of Promulgated Options
Costs shown in 10^6 (2008) with capital recovery estimated at 7%

Type of Unit	Option	Number of Units	TAC	Capital Recovery	Operation & Maintenance TAC	Control Cost	Control Rate
New	Recommended	47	$6.3	$6.1	$0.3	$5.9	$20.9
Existing	Recommended	13,840	$1,804	$1,376	$135	$1,669	$5,082

Table 3-4: Summary of Total Annual Costs by Control Type for Existing Units under Recommended Option
Costs shown in 10^6 (2008) with capital recovery estimated at 7%

Number of Boilers	Fabric Filter	ESP	Wet Scrubber	SDA	Increase Gauge Rate	Combustion Control and Optimize Catalyst	Activated Carbon Injection	Scrubber Wash Facility (Clean Up)	Energy Audit
13,840	391	3.5	578	423	2.0	219	17.5	35.1	26.5

4.0 METHODOLOGY FOR ESTIMATING EMISSION REDUCTIONS

This section discusses the methodology used to estimate emission reductions from boilers and process heaters at both existing and new facilities and it presents a summary of the results for the recommended regulatory options.

4.1 Emission Reductions from Existing Boilers and Process Heaters

The emission reductions analysis for existing combustion units was done for each boiler and process heater in the major source inventory. There are a total of 13,840 boilers and process heaters at major sources that reported data in the 2008 questionnaire (ICR No. 2286.01). Each combustion unit was assigned a unit-specific or average baseline emission factor, depending on the availability of emission data reported for the unit. A detailed discussion of the procedures and results of the baseline emissions analysis is presented in another memorandum.[6]

Emission Reductions for Recommended Option

Emission reductions for PM, HCl, Hg, CO, and dioxins/furans were calculated on a ton per year basis by subtracting the baseline emissions assigned to each unit from the MACT floor emission limits corresponding to each unit's subcategory. A detailed discussion of the procedures and results of the MACT floor analysis is presented in another memorandum.[1] A percent reduction was calculated for CO. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for THC and VOC as was achieved for CO. A percent reduction was also calculated for HCl. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for HF as was achieved for HCl. A combustion unit is assumed to install a scrubber or DIFF for HCl control if it is not currently meeting the HCl floor limit, and if it doesn't already have a scrubber installed. For units required to install a scrubber or DIFF, it was assumed that the control will achieve a reduction from baseline for SO2 equivalent to the reduction in HCl. The logic for estimating SO2 reductions is a change since the proposal of the rule, to address public comments concerned with overestimating SO2 reductions. At proposal we had estimated that all units installing control for HCl removal would achieve a 95 percent reduction in SO2; by reducing the removal efficiency for SO2 to be equivalent to the reduction efficiency for HCl the revised

emission reductions are more in line with the capability of the control devices estimated to be installed. A percent reduction in PM was also calculated in order to estimate total non-Hg metals reductions. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for each non-Hg metallic HAP as was achieved for PM. PM2.5 emissions were assumed to be a fraction of total filterable PM emissions based on fuel and control device configuration installed on the unit. The methods used to derive the contribution of PM2.5 to overall filterable PM are presented in other memoranda.[4] To calculate emission reductions for PM2.5, the emission reductions for PM were multiplied by the applicable PM2.5 fraction. Emission reductions for all pollutants for which there was no floor value were calculated on a ton per year basis.

To convert emission reductions from an emission rate on a heat input basis to an annual emission rate, Equation 4 was used:

Annual Emission Rate (tpy) = $ER_{HI} * 0.0005 * Op_{hours}$ **(Equation 4)**

Where:

ER_{HI} = emission rate (lb/mmBtu)

0.0005 = conversion factor, lbs per ton

Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

To convert emission reductions from a concentration basis to an annual emission rate, Equations 5 and 6 were used:

Annual Emission Rate (tpy) = $ER_C * 0.000001 * Q_S * 60 * Op_{hours} * MW * 0.0026 * 0.0005 * (20.946 - O_2) / (20.946 - \text{Std } O_2)$ **(Equation 5)**

Where:

ER_C = emission concentration (ppm @ 3% O_2)

0.000001 = conversion factor, ppm to parts

Q_S = exhaust flowrate (dscfm)

60 = conversion factor, minutes to hours

Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

MW = molecular weight of pollutant, in lb per lb-mole

0.0026 = conversion factor, lb-mole per dry standard cubic foot of gas

0.0005 = conversion factor, lb per ton

20.946 = percentage of oxygen in ambient air

O_2 = percentage of oxygen assumed in exhaust gas

Std. O_2 = 3 percent oxygen in standardized emission concentration for promulgated rule.

Annual Emission Rate (tpy) = ER_C * 0.0283 * Q_S * 60 * Op_{hours} * 0.000000001 * 0.0022 * 0.0005 * (20.946 – O_2) / (20.946 – Std O_2) **(Equation 6)**

Where:

ER_C = emission concentration (ng/dscm @ 7% O_2)
0.0283 = conversion factor, dry standard cubic meter per dry std. cubic foot
Q_S = exhaust flowrate (dscfm)
60 = conversion factor, minutes per hour
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
0.000000001 = conversion factor, ng to g
0.0022 = conversion factor, g per lb
0.0005 = conversion factor, lb per ton
20.946 = percentage of oxygen in ambient air
O_2 = percentage of oxygen assumed in exhaust gas
Std O_2 = 7 percent oxygen in standardized emission concentration for promulgated rule.

Converting concentrations to an annual emission rate required an oxygen concentration and exhaust flowrate estimated for each specific fuel type. The development of these assumptions and estimates is presented in other memoranda.[2] All conversions required the annual operating hours for each combustion unit reported in the 2008 survey. If no operating hours were reported, the unit was assumed to operate for 8,400 hours per year (two weeks of downtime).

For units not subject to emission limitations, the emission reductions were based on a one percent gain in efficiency expected from the annual tune-up work practice standard. Efficiency gains reduce fuel use, and in turn, emissions of hazardous air pollutants. A one percent reduction in all types of emissions was estimated by multiplying the baseline emissions for each unit by a factor of 0.01.

Emission Reductions for Alternative Option

The same calculations discussed for estimating emission reductions for the recommended option were applied to all units except that boilers and process heaters combusting biomass and coal were subject to separate numeric emission limits for Hg, PM, and HCl. In these cases the adjusted MACT floors under this alternative option were subtracted from baseline emissions and then the remainder of the above calculations for the recommended option was performed.

4.2 Emission Reductions from New Boilers and Process Heaters

Based on industrial and commercial fuel consumption projections from the EIA, there are 47 new boilers and process heaters expected to come on-line by 2013.[5] a discussion of the methodology used to project new boilers and process heaters is discussed in another memorandum.[3]

The New Source Performance Standards for Industrial, Commercial and Institutional Boilers (40 CFR part 60, subparts Db, Dc) (NSPS), was reviewed to identify the expected baseline level of control for projected new units. It was determined that new boilers and process heaters larger than 30 mmBtu/hr and combusting biomass would install an ESP. This technology selection is based on the analysis used to establish the PM NSPS limit for biomass boilers. New coal units larger than 75 mmBtu/hr would have a fabric filter and wet scrubber installed, while new coal units between 30 and 75 mmBtu/hr would only have a fabric filter installed and would meet the SO_2 limits in the NSPS by using coals with low sulfur content. New units larger than 30 mmBtu/hr and combusting liquid fuel would have a fabric filter installed. All new units less than 30 mmBtu/hr would have no add-on controls and liquid fuels were expected to meet the NSPS SO_2 limits using low sulfur fuel oils. Gas-fired units of all sizes were not expected to install controls to meet any of the NSPS limits. For this impacts analysis, it was assumed that all new solid fuel units would be stokers, since stoker boilers are the most common type of solid fuel boilers and all new units would have NOx control installed as a baseline control, regardless of fuel.

After an appropriate baseline level of control was determined for each model unit, an average baseline emission factor calculated for existing units within the same fuel category and having the same level of control was assigned to each model boiler. The NSPS specifies PM and SO2 limits for new solid- and liquid-fired combustion units based on heat input. It was assumed that all new solid and liquid units would be constructed to meet these limits, so they were used as baseline emission values where applicable. The baseline emissions for each unit were subtracted from the new source MACT floor emission limit corresponding to each unit's subcategory. The same calculations discussed in Section 3.1 of this memo were used to estimate the reductions for new units.

Similar to the methods discussed in Section 4.1 of this memorandum, the emission reductions for new units were calculated by subtracting the baseline emissions assigned to each

unit from the MACT floor emission limits corresponding to each unit's subcategory, except for units not subject to numeric emission limits. For units not subject to emission limitations, the emission reductions were based on a one percent gain in efficiency expected from the tune-up work practice standard. A summary of the estimated emission reductions at existing units for both the recommended and alternative options are located in Appendix B-1.

5.0 METHODOLOGY FOR ESTIMATING SECONDARY IMPACTS

Secondary impacts include the solid waste, water, wastewater, electricity required to operate air pollution control devices and the resultant greenhouse gas emissions, as well as the additional energy savings resulting from improved combustion controls or work practices required by the NESHAP. This section documents the inputs and equations used to estimate these secondary impacts, and it summarizes the impacts at existing units under promulgated regulatory option 4 and new units under promulgated regulatory option 1. Table 5-1 summarizes the cost, emission, and secondary impacts of this promulgated NESHAP. Appendices C-1 and C-2 present a detailed breakdown of the secondary waste, water, and energy impacts from each subcategory of new and existing boilers and process heaters, respectively.

Table 5-1: Summary of Secondary Impacts

Impact	New Units (recommended option)	Existing Units (recommended option)
Water (gal/yr)	242,000	671 million
Wastewater (gal/yr)	193,900	266 million
Solid Waste (tons/yr)	580	100,500
Purchased Electricity (kW-hr/yr)	6.2 million	1.4 billion
CO2 Emissions from Purchased Electricity (tons/yr)	4,100	910,000
Energy Savings* (trillion Btu/yr)	0.01	44.5

* Energy savings is calculated for units in the coal, liquid and gas subcategories.

The secondary impacts were calculated using algorithms and assumptions described in another memorandum.[2] These algorithms and assumptions were applied to the existing boiler and process heaters, where the baseline emissions for each unit exceeded the promulgated MACT floor emission limit except for small units (less than 10 mmBtu/hr), limited use units, and units firing natural gas, refinery gas, or other on-spec gaseous fuels. A one percent energy savings was calculated for all units, including the small, limited use and gas-fired units since these units are expected to conduct a tune-up. For new units, the algorithms and assumptions were applied to model units representing units expected to come online between 2010 and 2013, when the baseline emissions for each model exceeded the promulgated MACT floor emission limit for new units except for small units and units firing natural gas, refinery gas, or other on-spec gaseous fuels. Similar to existing units these small and gas-fired units are not required to meet a numerical emission limit, and therefore not expected to incur any secondary waste, water, or electricity impacts from these controls. A one percent energy savings from small units and units burning natural gas, refinery gas, or other on-spec gaseous fuels are included in the energy savings estimate in Table 5-1 since these units are expected to conduct a tune-up. The methodology used to assign baseline emission factors to new and existing units are discussed in another memorandum.[6]

5.1 Wastewater and Water Impacts

The water required to create a slurry in the packed scrubber and the wastewater generated by the effluent of a packed bed scrubber were calculated for every unit expected to install a scrubber to meet the HCl limits in the promulgated rule. Both the water and wastewater calculations required the use of several constants and variables. The constants including the density of gas, moles of salt needed per mole of hydrogen chloride in the exhaust gas, the molecular weight of the salt used, the fraction of the waste stream treated, operating hours per year and the molecular weight of the gas. The data sources for these constants are provided in another memorandum.[2] The variables used to estimate the quantity of water required and wastewater generated were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The variables included: exhaust flow rate from the combustion unit to the control device in actual cubic feet per minute, the inlet loading of hydrogen chloride to the control device (mole fraction), and the

efficiency of the control device in removing hydrogen chloride from the exhaust gas (percent reduction). The calculations used to estimate each variable are provided in another memorandum.[2] The total national water and wastewater amounts in Table 5-1 were determined by adding the per unit water and wastewater estimates for all new and existing units, respectively.

5.2 Solid Waste Impacts

Solid waste is generated from collecting dust and fly ash in fabric filters or ESP control devices, spent carbon associated with ACI, or spent caustic from increasing the caustic injection rate. Solid waste impacts were estimated for every unit expected to install a fabric filter for mercury control or a DIFF for HCl control, ACI for mercury emission limits, or install an ESP to meet PM emission limits. The total national solid waste amounts in Table 5-1 were determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the solid waste contribution from each of these control devices, the variables were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The calculations used to estimate each variable and the quantity of solid waste generated are provided in another memorandum.[2]

The solid waste (dust, fly ash) generated by the use of an electrostatic precipitator was calculated when an electrostatic precipitator was determined to be necessary to meet the NESHAP emission limits for PM. Estimates of the solid waste collected in an ESP was based on several variables including: exhaust flow rate from the combustion unit to the control device (acfm); the inlet loading of particulate matter to the control device (gr/acfm); operating hours (hr/year) and the efficiency of the control device required to meet the PM emission limits in the promulgated NESHAP.

The solid waste generated from the collection of dust and fly ash in a fabric filter was calculated when a fabric filter was determined to be necessary to meet the promulgated NESHAP emission limits for particulate matter and/or mercury. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year) and the inlet loading of particulate matter to the control device (gr/acfm).

For this analysis, the spent carbon collected from units with ACI is assumed to be disposed of instead of being re-generated. The amount of spent carbon created from ACI was calculated when ACI was expected to be necessary to meet the promulgated NESHAP emission limits for mercury or dioxin/furan. The calculation required the use of six variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), required removal efficiency for mercury and dioxin/furan, and an adjustment factor based required removal efficiency of mercury or dioxin /furan.

The solid waste generated by the use of increased caustic was calculated for those units where additional caustic was expected to achieve the promulgated NESHAP emission limits for HCl. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), and the required removal efficiency for HCl.

5.3 Electricity Impacts

The amount of electricity required to operate a control device was calculated for a packed scrubber, electrostatic precipitator, fabric filter, DIFF, CO oxidation catalyst and the fans for the ductwork associated with this equipment. These impacts were assessed for every unit that was estimated to require hydrogen chloride and/or particulate matter control. Electricity requirements are one output of the cost algorithms used in the analyses, so no additional calculations were necessary. For some units, an electrical demand from multiple control devices was estimated. The total national electricity demand in Table 5-1 was determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the electricity demand from each of these control devices, a set of variables were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The constants, variables, and calculations used to estimate each variable and the electricity demand to operate the control devices are provided in another memorandum.[2]

5.4 Greenhouse Gas Emissions from Electricity Usage

Since greenhouse gases are generated from electricity production, an estimate of carbon dioxide emissions was generated for the electricity impacts of the add-on air pollution control devices. The total electricity usage from all control devices was multiplied by the national

average carbon dioxide emission factor for carbon dioxide emissions from EPA's 2005 e-GRID to obtain the expected annual carbon dioxide emissions.[9] No carbon dioxide emissions were estimated for boilers or process heaters conducting a boiler tune-up since no electricity impacts were estimated for those units.

5.5 Energy Savings Impacts

The energy savings from combustion controls such as low NOx burners or linkageless boiler management systems, and work practice standards, including a tune-up, and implementing the energy audit findings with a short-term payback can improvements in efficiency, thereby reducing fuel consumption. This secondary impacts analysis only estimates a one percent efficiency gain from tune-up work practices and installation of combustion controls to be conservative and consistent with the assumptions made in Section 3.1 of this memorandum. No energy savings are attributed to the energy assessment in this analysis. Quantifying the exact gains in efficiency from each of these work practice standards is difficult, and may depend on the baseline operating efficiency of each unit.

Section 3.1 discusses the fuel savings impacts in terms of annualized cost savings to each boiler or process heater, and the national energy savings presented in Table 4.1 of this section follows the same methodology as was discussed in Section 3.1 and reflect the savings from boilers in the coal, gas, and liquid fuel categories only.

5.6 Estimating Secondary Impacts for Existing and New Units

Appendices C-1 and C-2 present a detailed breakdown of the secondary waste, water, and energy impacts from each subcategory of new and existing boilers and process heaters, respectively. The differences presented between the recommended and alternative regulatory options are based on the number of controls estimated to be installed to meet the floor limits associated with each option, which in turn affects the amount of waste, wastewater, water, and energy consumed by the control devices installed for PM, HCl, and Hg.

6.0 REFERENCES

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20. Ed's Heating and Air, Inc. 1099 Pelto Path Woodbury, MN, 55129. http://www.merchantcircle.com/blogs/Eds.Heating.And.Air.Inc.,Woodbury.MN.651-775-7490/2008/10/Furnace-Tune-Up-Cost/126531

21. Five State Heating and Cooling, Charlotte, NC. http://www.fivestarheatingandcooling.com/

Q.
Please refer to FPL's Preliminary List of New Projects (List) for the following questions. Is it correct that FPL's ESPs projects are designed to comply with Subpart DDDDD of the MACT rule, which is currently stayed?

a. **Please provide an update of FPL's ESPs projects.**

A.
No. Rule DDDDD Regulates boilers that are not regulated elsewhere under EPA NESHAPS Rules. EPA has proposed to regulate FPL's coal- and oil-fired electric utility steam generating units under 40 CFR Part 63 Subpart UUUUU.

a. FPL has initiated and is proceeding with its project to install electrostatic precipitators (ESPs) first at Manatee Plant Unit 2 and then sequentially at Manatee Plant Unit 1, Martin Plant Unit 1, and Martin Plant Unit 2. FPL issued a Notice to Proceed to the equipment supplier and installer in April 2011 for the Manatee Plant Unit 2 phase of the project. FPL received the required Manatee County letter of acknowledgement in May 2011. The Florida Department of Environmental Protection issued the Air Construction Permit for the addition of the ESP on Manatee Unit 2 in June 2011. ESP construction at Manatee Plant Unit 2 will begin in September 2011 and with a planned in-service date in May 2012. A tentative construction schedule has been established for the other units.

FPL expects the U. S. Environmental Protection Agency (EPA) to issue the final Air Toxics Rule on November 16, 2011. At that time FPL will determine if the Maximum Achievable Control Technology (MACT), as defined in the Air Toxics Rule, is ESP for control of air toxics regulated under that rule. If EPA's final rule defines emission specifications using ESPs as MACT, then FPL plans to put into effect the currently tentative construction schedule for the ESPs at Manatee Plant Unit 1, Martin Plant Unit 1, and Martin Plant Unit 2 and begin ECRC recovery of costs for control installation at that time.

Q.
Please refer to FPL's Preliminary List of New Projects (List) for the following questions.
Referring to the NPDES Permit Renewal Requirements Project:

a. **Does FPL currently use in-house resources to comply with the existing Whole Effluent Toxicity (WET) requirement ?**
b. **Will FPL use in-house resources, or will it contract out the work, to comply with the new quarterly "chronic" WET testing requirement?**
c. **What activities will be involved in the development of a Storm Water Pollution Prevention Plan (SWPPP)?**
d. **Will FPL use in-house resources, or will it hire consultants, to develop the SWPPP?**
e. **Please explain how the $10,000 per facility SWPPP compliance cost was derived. Please provide the component activities associated with this estimate.**

A.
a. No.

b. FPL will contract out the work.

c. Site visits and actual development of the SWPPP (see discussion below)

d. FPL is planning to hire consultants.

e. In 2010 FPL submitted a Request for Proposal to a contractor that had previously been used for similar work to provide SWPPP for two facilities, Lauderdale and Port Everglades. The contractor broke the work down in to several activities:

1) Site Visits – This includes a stormwater inspection of the facilities, a review of existing relevant documents and previous inspections, a review of potential on-site pollutant sources, and a meeting with each facility's operations staff.

2) SWPPP Development – This included development of the major components of the SWPPP for each site, including: a topographic map/site map, a stormwater management plan, description of Best Management Practices, a waste minimization assessment and identification of a pollution prevention committee. Employee

training and annual site inspections/revision requirements would also be addressed. The proposal also included the draft SWPPPs and one round of response to FPL comments prior to finalization.

The proposed price for completing the SWPPPs was $17,500, or $8,750 per site. Taking into account inflation, contingencies for additional out-of-scope work and travel expenses to FPL facilities, FPL projected the 2011 cost for FPL facilities to be approximately $10,000 per facility.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 8th day of August, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 53 through 55 from STAFF'S EIGHTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 53-56) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 8th day of August, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 3rd day of AUGUST, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ronald Hix, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 56 from STAFF'S EIGHTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 53-56) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

Ronald H. Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of AUGUST, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

9

FPL Responses to Staff's Ninth Set of Interrogatories (Nos. 57-60)

Q. Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for the following questions.

Referring to page 4, lines 10 – 12, of witness Keith's testimony:

(a) What are the preventive maintenance activities to which reference is made?

(b) What is the dollar amount associated with the preventive maintenance that was inadvertently omitted from the 2011 Projection filing?

A.

(a) The Department of Environmental Protection (DEP) mandates Quarterly, Semi Annual and Annual preventive maintenance activities for CEMS equipment. The CEMS preventive maintenance activities are performed on the following equipment: NOX analyzer, CO2 Analyzer, SO2 Analyzer, HVAC, Shelter, Air Purification system, Probe and Umbilical Cord, and Opacity Monitoring equipment.

(b) The preventive maintenance cost is $15,000 per quarter or $60,000 annually.

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for the following questions.

Referring to page 8, lines 9 – 22, of witness Keith's testimony:

(a) What is the function of an ESP Keys Interlock system?

(b) Do each of Units 3 and 4's ESPs require the installation of an ESP Keys Interlock system?

(c) What is the O&M cost associated with the installation of an ESP Keys Interlock system?

(d) Per FPL's response to Staff's Interrogatory No. 1 in Docket 090007-EI, the Port Everglades Units 3 and 4's ESPs were moved into service in 2007. Will these 2007 pollution retrofits satisfy the EPA's newly proposed National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units, issued March 16, 2011? If not, please explain why not.

A.
(a) The purpose of an ESP Key Interlock system is to insure that personnel do not enter an electrically energized area without first de-energizing and grounding the equipment.

(b) Yes, both Units 3&4 ESP's require an independent Key Interlock system. The keys are designed so no key from one unit will open a door on the wrong unit.

(c) The installation cost associated with an ESP interlock system is $30,000 per unit or $60,000 for both units.

(d) FPL assumes the reference to Interrogatory1 of Docket 090007-EI was intended to refer to Interrogatory 2 of that docket. Yes, FPL believes that the ESP's installed on all four fossil steam units at the Port Everglades plant will meet the particulate and toxic metals emission standards of the proposed National Emission Standards for Hazardous Air Pollutants (NESHAP) from Coal- and Oil-fired Electric Utility Steam Generating Units. To better understand why FPL believes

that these units will meet those standards it is helpful to understand how EPA establishes the emission standards in accordance with the requirements of the Clean Air Act (CAA). The CAA requires that EPA establish a Maximum Achievable Control Technology standard for the emission of Hazardous Air Pollutants (HAPs) based on the top 12% performing units in a category (oil-fired electric steam generating units in this case). To determine which are the top performing units EPA conducts an Information Collection Request (ICR) to collect emission and fuel data from power plants. FPL participated in the EPA ICR, for which the Commission approved recovery of those costs to comply with the ICR, which included fuel and emission stack testing of Port Everglades Units 3 & 4. The emission data collected from the Port Everglades units demonstrated that the units performed significantly better than the floor established by EPA and were among the lowest emitting oil-fired units tested. In the final rule EPA added acid gasses to the HAPs to be regulated under the proposed NESHAP. FPL believes that the regulation of acid gasses from oil-fired units is unnecessary and unwarranted. However, FPL has evaluated control options which could reduce acid gasses from its oil-fired steam electric generating units and has identified that the addition of a lime sorbent injection system to units with ESP would reduce acid gas emissions below the proposed acid gas emission standard if that standard is retained in the final rule.

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for the following questions.

Referring to pages 8, lines 1- 23, of witness Labauve's testimony:

(a) Please explain how the $306,000 total O&M costs were derived. (line 2) Please break down this cost amount by year, permitted plants, and sites.

(b) Please explain how the $18,000 O&M costs associated with the 2011 new chronic WET testing requirement were derived. Please break down this cost amount by permitted plants, and sites. Please also explain why this amount differs from what FPL had projected in its Preliminary List of New Project, filed on July 8, 2011.

(c) Please explain how the $55,000 O&M costs associated with the 2012 new chronic WET testing requirement were derived. Please break down the cost amount by permitted plants, and sites. Please also explain why it is different from what FPL has projected in its Preliminary List of New Project, filed on July 8, 2011.

(d) Please identify the contractor(s) who FPL has retained to do the WET testing.

A.

(a) Costs were derived by calculating the expected cost of the chronic whole effluent toxicity (WET) tests that are required by the new NPDES permits and deducting costs of any testing that was previously being conducted at each facility.

Please note that FPL has revised its estimated total O&M cost to $301,400, as shown in Table 1, below. This reflects adjustments made to the projected 2011 and 2012 costs as described in the response to Interrogatory 59. (b) and (c), below. It also includes adjustments for 2013-2015 which reflect a more accurate prediction for the costs for WET testing that will be carried out at Martin and Manatee Plants.

Table 1 - Whole Effluent Toxicity Testing O&M Costs						
Plant	Total 2011	Total 2012	Total 2013	Total 2014	Total 2015	Plant Total
Cape Canaver	$0	$0	$9,200	$18,400	$18,400	**$46,000**
Cutler	$0	$0	$0	$0	$0	**$0**
Lauderdale	$3,000	$6,000	$6,000	$6,000	$6,000	**$27,000**
Ft. Myers	$9,200	$18,400	$18,400	$18,400	$18,400	**$82,800**
Manatee	$1,600	$1,600	$1,600	$1,600	$1,600	**$8,000**
Martin	$0	$0	$0	$1,600	$1,600	**$3,200**
Port Everglad	$4,600	$9,200	$4,800	$0	$0	**$18,600**
Putnam	$0	$0	$4,600	$9,600	$9,600	**$23,800**
Riviera	$0	$0	$0	$4,600	$9,200	**$13,800**
Sanford	$0	$0	$0	$0	$0	**$0**
St. Lucie	$4,600	$18,400	$18,400	$18,400	$18,400	**$78,200**
Total	$23,000	$53,600	$63,000	$78,600	$83,200	**$301,400**

(b) Costs were derived by calculating the expected cost of the chronic WET tests that are required by the new NPDES permits and deducting costs of any testing that was previously being conducted at each facility.

Upon review of the spreadsheets used to summarize the 2011 O&M costs, FPL realized that the $23,000 cost presented in the July 8, 2011 preliminary new projects list is probably more accurate than $18,000 estimate in the August 1, 2011 filing. The difference between the $18,000 and the $23,000 was attributable to rounding and the cost of an additional test for Port Everglades in 2011 ($4,600 – see Table 1, above) that will likely be necessary due to a delay in FDEP revising the Port Everglades NPDES permit to reduce the testing frequency (based on four passed tests) and was not included in the August 1, 2011 filing.

(c) Costs were derived by calculating the expected cost of the chronic WET tests that are required by the new NPDES permits and deducting costs of any previous testing that was previously being conducted at each facility.

Upon review of the worksheets used to summarize the 2012 O&M costs, FPL realized that the cost for WET testing at the Manatee Plant was 50% less than projected ($1,600 rather than $3,200) in the August 1, 2011 filing because the final Manatee NPDES permit required only acute toxicity testing rather than more expensive chronic testing. That $1,600 difference (lower cost), combined with the fact that the "approximately $55,000" value that had been reported previously was actually $55,200 (a difference of $200) resulted in the revised estimate of $53,600 (i.e., $55,000 + $200 - $1,600 = $53,600) shown in the Table 1, above.

(d) Hydrosphere Research
11842 Research Circle
Alachua, FL 32615-6817

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for the following questions.

Referring to pages 11, line 10, through 12, line 2, of witness Labauve's testimony:

(a) Please explain how the $525,000 avoided CWA 316(b) Phase II Project cost was derived. (page 11, lines 11 – 12) Please itemize the activities associated with this cost saving.

(b) Referring to page 10, please clarify the phrase "these activities" on line 10. Do they refer to what is described on lines 3 – 7 and 8 – 10; or, do they solely refer to what described is on lines 8 – 10?

(c) Has FPL incurred any expense for responding to the EPA requirements (page 11, line 3 – 5) since October 11, 2004?

(d) Has FPL incurred any expense for submitting Comprehensive Demonstration Studies (lines 5 – 6) since 2008?

(d) Please specify all the major activities associated with the O&M costs that are reported on Line 1.28 CWA 316(b) Phase II Rule of schedule 42-5E.

(e) Please identify the outside consultant who FPL has retained to assist in developing comments. (page 12, line 1 – 2)

A.
(a) At the time of filing, FPL anticipated substantial expenditures would be required in support of obtaining Supreme Court review of the Second Circuit Court of Appeals decision on the Phase II 316 (b) Rule, especially as it reviewed the application of a cost-benefit test. It also contemplated attempting to have Congress develop new legislation, if required, so a more balanced and equitable rule would eventually be developed. Anticipated costs for this effort were:

1. Bracewell – Giuliani (Law firm): retainer - $35,000/month
2. Bill Horn (lobbyist): retainer - $6,000/month
3. ENSR (now AECOM – Environmental Consultant) - $33,000 total cost
4. Total Cost for 12 months - $525,000

As it turned out, EPA, UWAG and other groups adequately supported the effort to obtain Supreme Court review of the 316 (b) Phase II Rule. As a result of the Supreme Court review, the EPA did not have to revise its proposed rule in ways that would have required FPL to advocate for a legislative solution. Therefore, additional effort by FPL was not required.

(b) FPL assumes the reference to page 10 was intended to refer to page 11.

"These activities" refers to the legal and consulting activities described on Lines 8 – 10.

(c) Yes. See Table 2, below.

Table 2	316 (b) Comprehensive Demonstration Study Expenses - 2004 through June 2011							
	Year							
Category	2004	2005	2006	2007	2008	2009	2010	2011*
Contractors	$252,186	$302,249	$1,467,880	$1,346,505	$341,859	($224,021)	$19,030	$7,709
Payroll	$0	$59,712	$86,834	$25,833	$3,638	$0	$14,915	$30,034
Expenses	$0	$66,732	$4,529	$7,824	$1,152	$787	($856)	($1,415)
Total	**$252,187**	**$428,693**	**$1,559,243**	**$1,380,162**	**$346,648**	**($223,234)**	**$33,088**	**$36,328**
* Represents January through June 2011 Expenses								

(d) Yes. The contractor costs in Table 2, above, for 2008 through June 2011 represent funding for expenses related to Comprehensive Demonstration Study requirements. Please note that the Contractor cost for 2009 represents a credit of $224,021 because the ECRC requires that, if a utility has included costs for environmental studies in base rates and that allocation goes unused, the costs for new studies to be recovered through the ECRC must be offset by the unused portion of the amount in base rates. This was the case in 2009.

(d) See Table 2, above.

Contractor costs were incurred by the use of consultants to address 316 (b) Comprehensive Demonstration Study requirements.
Payroll costs are payroll attributed to personnel hired to support 316 (b) related activities.
Expenses represent employee costs related to travel, cell phone bills, etc., which are incurred by person who generated payroll costs.

(e) AECOM Technical Services, Inc.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 19th day of September, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 57 and 58 a-c from STAFF'S NINTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 57-60) in Docket No. 110007-EI, and that the responses are true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 19th day of September, 2011.

INGRID NICKOLAUS
MY COMMISSION # DD736310
EXPIRES November 20, 2011
(407) 398-0153 FloridaNotaryService.com

Ingrid Nickolaus
Notary Public
State of Florida, at Large

My Commission Expires:
November 20, 2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 16th day of September, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Ronald H. Hix, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory numbers 59 through 60 from STAFF'S NINTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 57-60) in Docket No. 110007-EI, and that the response are true and correct based on his personal knowledge.

Ronald H. Hix

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 16th day of September, 2011.

Lois M Sivia
Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 15th day of September, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 58d from STAFF'S NINTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 57-60) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 15th day of September, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

10

FPL Responses to Staff's Tenth Set of Interrogatories (Nos. 61-67)

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for questions Nos. 61 – 66.

Please refer to Form 42-8E, page 32 of 59, and the worksheet RUST_P2 of the Excel file Form 42-8E.xlsx. It appears that in July 2011, an amount of $345,900.79 was transferred into Reserve Account CIC_8026. Please explain the nature and cause of this reserve transfer. Please also identify the source account from which the amount was transferred.

A.

The reserve transfer for the Underground Storage Tank (UST) was part of the transaction related to the sale of Florida Power & Light's General Office building in Miami. When the retirements were processed in April 2011, the total other recovery (salvage_cash) from the sale was recorded to the predominant depreciation group involved in the sale and none was allocated to the UST. Therefore, a transfer of $345,900.79 was made to the depreciation reserve account for the UST, in order to reflect the UST's proper value after the sale - zero. The source account was 390, Structures & Improvements.

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for questions Nos. 61 – 66.

Please refer to Form 42-8E, pages 33 -34, and the worksheet CAIR_P2 of the Excel file Form 42-8E.xlsx. Please explain why FPL added an amount of $21,396 when calculating the CWIP-Non Interest Bearing in July. From where does this amount come and what does it represent?

A.

As reflected on pages 33-34, the $21,394 represents additional projected expenditures for the month. This amount should have been included in column F line 15 "Expenditure/Additions" on Form 42-8E.xlsx. However, the placement of the entry does not affect calculation of over/under recovery for the period.

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for questions Nos. 61 – 66.

Please refer to Form 42-8E, page 37 of 59 and the worksheet Martin Water_P2 of the Excel file Form 42-8E.xlsx.

a. It appears that in July 2011, an amount of $147,578.17 was transferred out of Plant Account CI9_8035. Please explain the nature and cause of this plant transfer. Please also identify to which account the amount was transferred.

b. It appears that in July 2011, an amount of $129.13 was transferred out of Reserve Account CIC_8035. Please explain the nature and cause of this plant transfer. Please also identify to which account the amount was transferred.

A.

a. The $147,578 plant in service transfer was to move assets originally recorded in FPL's construction asset tracking system to Account 311 – Structures & Improvements in Project 35: Martin Drinking Water System. These assets belong in the same plant account, but in Project 44: Barley Barber Swamp Iron Mitigation Project (please see Form 42-8E, page 52) and thus the $147,578 transfer is reflected between projects in the same account.

b. The $129.13 reserve transfer shown in July 2011 in the filing is the amount of depreciation related to the $147,578 plant transfer discussed in part(a).

Florida Power & Light Company
Docket No. 110007-EI
Staff's 10th Set of Interrogatories
Interrogatory No. 64

Q.
Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for questions Nos. 61 – 66.

Referring to the Return on Deferred Gain on Sales of Emission Allowances reported on pages 53-54 of Form 42-8E, please provide the amounts of the Allowance Auction Proceeds for each month for the period January 2011 through December 2011.

Please also explain how each of the auction proceed amounts, if any, was derived. Please provide supporting documents for your response.

A.
Attachment I, page 1 of 83 provide the amounts of the Allowance Auction Proceeds for each month for the period January 2011 through December 2011 as well as an explanation of how each of the auction proceed amounts were derived. Pages 2 through 19 provide back-up documentation for the Allowance Auction Proceeds.

Also note that in creating the SO2 Acid Rain Program, EPA withheld 2.8% of the allowances allocated to facilities for use in an annual SO2 auction to provide access to allowances for new generating units that would not be allocated free allowances under the program. Each spring EPA auctions 125,000 current year allowances (2011 spot market this year) and 125,000 7-year forward allowances (2018 vintage year). Proceeds from the auction are directed back to facilities based on the number of allowances that were withheld by EPA. Attachment I pages 20 through 81 provide the Federal Register publication of EPA's final rule for allocation of allowances which provides the allocation of allowances to, and the number of allowances withheld from, facilities affected by the rule. This year's auction results are provided in Attachment I, pages 82 through 83 which show that this year's market clearing prices were $2.00 for spot and $0.16 for 7-year forward allowances. The authorized account representative of record for each facility receives the notification of the auction results annually and the EPA transfers proceeds electronically. For FPL's co-owned units the proceeds must be transferred from the receiving company (Georgia Power Company for Scherer Unit 4 and JEA for SJRPP Units 1& 2) to FPL in an amount equal to our ownership share. In addition to FPL's 20% ownership share of SJRPP the purchase power contract identifies that 37.5% of JEA's ownership share would be transferred to FPL.

Florida Power & Light
Sale of Emissions Allowances

Account 254,900 Sales of Emmissions Allowances				
Date	Reason	Vintage Year	Total Auction Proceeds	
Jan-11	Revenue Recognition	2011		
Feb-11	Revenue Recognition	2011		
Mar-11	Revenue Recognition	2011		
Apr-11	Revenue Recognition	2011		
May-11	Revenue Recognition	2011		
May-11	Proceeds - FPL	2011	($4,792.32)	[A]
May-11	Proceeds - SJRPP	2011	($188.42)	[B]
May-11	Proceeds - Scherer	2011	[redacted]	[C]
May-11	Proceeds - FPL	2018	($288.40)	[A]
May-11	Proceeds - SJRPP	2018	[redacted]	[B]
May-11	Proceeds - Scherer	2018	[redacted]	[C]
Jun-11	Revenue Recognition	2011		
Jul-11	Revenue Recognition	2011		
Aug-11	Revenue Recognition	2011		
Sep-11	Revenue Recognition	2011		
Oct-11	Revenue Recognition	2011		
Nov-11	Revenue Recognition	2011		
Dec-11	Revenue Recognition	2011		

∑ [A] = ($5,080.72)
Derivation
Number of FPL auction reserve allowance deductions = 3,414
= 1.3656% of total allowances sold at auction
FPL portion of Auction Proceeds = $ 5,080.20 (rounding) *(FPL % of total allowances sold at auction * Total Auction Proceeds)*

∑ [B] = ($197.64)
Derivation
Number of SJRPP auction reserve allowance deductions = 664
= 0.2656% of total allowances sold at auction
SJRPP portion of Auction Proceeds = $ 988.06 (rounding) *(SJRPP % of total allowances sold at auction * Total Auction Proceeds)*
FPL's ownership share of 20% = $ 197.61 (rounding)

∑ [C] = ($698.89)
Derivation
Number of Scherer Unit 4 auction reserve allowance deduction 615
= 0.2460% of total allowances sold at auction
Scherer 4 portion of Auction Proceeds = $ 915.15 (rounding) *(Scherer 4 % of total allowances sold at auction * Total Auction Proceeds)*
FPL's ownership share of 76.36% = $ 698.81 (rounding)

EPA 2011 SO2 TOTAL Auction Proceeds:
Qty = 250,000
Amount = $ 372,012.04

Payment Coupon

/610110000003120100000852122270805000063010101

General Mail Facility
Miami, FL 33188-0001

B 01100 0000852122 6 3 01 01 01
Please mail this portion with your check

Cust. No.: 312010	Inv. No.: 852122
This Month's Charges Past Due After 06/08/2011	Amount Due This Invoice 5,080.72

Make check payable to FPL in US funds and mail payment to address below

US EPA
ACID RAIN PROGRAM
401 M STREET, SW
MAIL CODE 6204J
WASHINGTON DC 20460

FPL
GENERAL MAIL FACILITY
MIAMI FL 33188-0001

Florida Power & Light Company

INVOICE

Federal Tax ID#: 59-0247775

Customer Name and Address

US EPA
ACID RAIN PROGRAM
401 M STREET, SW
MAIL CODE 6204J
WASHINGTON DC 20460

Customer Number: 312010

Invoice Number: 852122

Invoice Date: 05/09/2011

B 01100 0000852122 6 3 01 01 01
Please Retain This Portion for your Records

CURRENT CHARGES AND CREDITS

Customer No: 312010 Invoice No: 852122

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSION SALES2011/2018-PCC EPA SO2 EMISSION SALES	1	395.86	395.86
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSION SALES2011/2018-PFM EPA SO2 EMISSION SALES	1	544.68	544.68
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PFL-2011/2018 EPA SO2 EMISSIONS SALES	1	160.72	160.72
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PMT-2011/2018 EPA SO2 EMISSIONS SALES	1	1,141.46	1,141.46
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PMG-2011/2018 EPA SO2 EMISSIONS SALES	1	220.28	220.28
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PMR-2011/2018 EPA SO2 EMISSIONS SALES	1	479.20	479.20
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PEL-2011/2018 EPA SO2 EMISSIONS SALES	1	205.36	205.36

Florida Power & Light Company
General Mail Facility
Miami, FL 33188-0001

Customer No: 312010 Invoice No: 852122

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PEH-2011/2018 EPA SO2 EMISSIONS SALES	1	510.44	510.44
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PPN-2011/2018 EPA SO2 EMISSIONS SALES	1	276.80	276.80
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PRV-2011/2018 EPA SO2 EMISSIONS SALES	1	311.02	311.02
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PSN-2011/2018 EPA SO2 EMISSIONS SALES	1	46.14	46.14
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PSR-2011/2018 EPA SO2 EMISSIONS SALES	1	281.28	281.28
ARM-MISCELLANEOUS RECEIVABLE EPA SO2 EMISSIONS SALES-PTF-2011/2018 EPA SO2 EMISSIONS SALES	1	507.48	507.48

For Inquiries Contact:
LORI VANTUINEN
Phone: (561) 691-2847

Total Amount Due **$5,080.72**

This Month's Charges Past Due After 06/08/2011

Messages

Florida Power & Light Company
General Mail Facility
Miami, FL 33188-0001

Obt#852122

Date: 03-30-2011
Page: 1 of 8

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Cape Canaveral	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PCC1	$171.24	$0.01	$171.25
March 2011 auction of year 2018 allowances	PCC1	$10.30	$0.01	$10.31
March 2011 auction of year 2011 allowances	PCC2	$202.12	$0.02	$202.14
March 2011 auction of year 2018 allowances	PCC2	$12.16	$0.00	$12.16
	Plant Totals:	$395.82	$0.04	$395.86

LOCN 913

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
FL	Fort Myers	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PFM1	$129.13	$0.01	$129.14
March 2011 auction of year 2018 allowances	PFM1	$7.77	$0.00	$7.77
March 2011 auction of year 2011 allowances	PFM2	$384.58	$0.04	$384.62
March 2011 auction of year 2018 allowances	PFM2	$23.14	$0.01	~~$23.15~~
	Plant Totals:	$544.62	$0.06	$544.68

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

LOCN 911

254.900-XXX-790

Date: 03-30-2011
Page: 2 of 8

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Lauderdale	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	4GT1	$37.90	$0.00	$37.90
March 2011 auction of year 2018 allowances	4GT1	$2.28	$0.00	$2.28
March 2011 auction of year 2011 allowances	4GT2	$37.90	$0.00	$37.90
March 2011 auction of year 2018 allowances	4GT2	$2.28	$0.00	$2.28
March 2011 auction of year 2011 allowances	5GT1	$37.90	$0.00	$37.90
March 2011 auction of year 2018 allowances	5GT1	$2.28	$0.00	$2.28
March 2011 auction of year 2011 allowances	5GT2	$37.90	$0.00	$37.90
March 2011 auction of year 2018 allowances	5GT2	$2.28	$0.00	$2.28
	Plant Totals:	$160.72	$0.00	$160.72

LOCN 908

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
FL	Manatee	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PMT1	$560.03	$0.06	$560.09
March 2011 auction of year 2018 allowances	PMT1	$33.70	$0.01	$33.71
March 2011 auction of year 2011 allowances	PMT2	$516.52	$0.05	$516.57
March 2011 auction of year 2018 allowances	PMT2	$31.08	$0.01	$31.09
	Plant Totals:	$1,141.33	$0.13	$1,141.46

LOCN 917

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

254.900-XXX-790

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Martin	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	HRSG3A	$51.93	$0.01	$51.94
March 2011 auction of year 2018 allowances	HRSG3A	$3.13	$0.00	$3.13
March 2011 auction of year 2011 allowances	HRSG3B	$51.93	$0.01	$51.94
March 2011 auction of year 2018 allowances	HRSG3B	$3.13	$0.00	$3.13
March 2011 auction of year 2011 allowances	HRSG4A	$51.93	$0.01	$51.94
March 2011 auction of year 2018 allowances	HRSG4A	$3.13	$0.00	$3.13
March 2011 auction of year 2011 allowances	HRSG4B	$51.93	$0.01	$51.94
March 2011 auction of year 2018 allowances	HRSG4B	$3.13	$0.00	$3.13
March 2011 auction of year 2011 allowances	PMR1	$206.33	$0.02	$206.35
March 2011 auction of year 2018 allowances	PMR1	$12.42	$0.00	$12.42
March 2011 auction of year 2011 allowances	PMR2	$245.63	$0.02	$245.65
March 2011 auction of year 2018 allowances	PMR2	$14.78	$0.00	$14.78
	Plant Totals:	$699.40	$0.08	$699.48

928

918

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

U3/4 220.28
U1/2 479.20

254.900-XXX-790

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Port Everglades	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PPE1	$95.44	$0.01	$95.45
March 2011 auction of year 2018 allowances	PPE1	$5.74	$0.00	$5.74
March 2011 auction of year 2011 allowances	PPE2	$98.25	$0.01	$98.26
March 2011 auction of year 2018 allowances	PPE2	$5.91	$0.00	$5.91
March 2011 auction of year 2011 allowances	PPE3	$238.61	$0.02	$238.63
March 2011 auction of year 2018 allowances	PPE3	$14.36	$0.00	$14.36
March 2011 auction of year 2011 allowances	PPE4	$242.82	$0.02	$242.84
March 2011 auction of year 2018 allowances	PPE4	$14.61	$0.00	$14.61
	Plant Totals:	$715.74	$0.06	$715.80

920

924

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

U1/2 205.36
U3/4 510.44

254.900-XXX-790

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Putnam	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	HRSG11	$67.37	$0.01	$67.38
March 2011 auction of year 2018 allowances	HRSG11	$4.05	$0.00	$4.05
March 2011 auction of year 2011 allowances	HRSG12	$67.37	$0.01	$67.38
March 2011 auction of year 2018 allowances	HRSG12	$4.05	$0.00	$4.05
March 2011 auction of year 2011 allowances	HRSG21	$63.16	$0.01	$63.17
March 2011 auction of year 2018 allowances	HRSG21	$3.80	$0.00	$3.80
March 2011 auction of year 2011 allowances	HRSG22	$63.16	$0.01	$63.17
March 2011 auction of year 2018 allowances	HRSG22	$3.80	$0.00	$3.80
	Plant Totals:	$276.76	$0.04	$276.80

905

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

254.900-XXX-790

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Riviera	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PRV2	$4.21	$0.00	$4.21
March 2011 auction of year 2018 allowances	PRV2	$0.25	$0.00	$0.25
March 2011 auction of year 2011 allowances	PRV3	$144.57	$0.01	$144.58
March 2011 auction of year 2018 allowances	PRV3	$8.70	$0.00	$8.70
March 2011 auction of year 2011 allowances	PRV4	$144.57	$0.01	$144.58
March 2011 auction of year 2018 allowances	PRV4	$8.70	$0.00	$8.70
	Plant Totals:	$311.00	$0.02	$311.02

904

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

State	Plant Name	Check Payable To	DR Name
FL	Sanford	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PSN3	$43.51	$0.01	$43.52
March 2011 auction of year 2018 allowances	PSN3	$2.82	$0.00	$2.82
March 2011 auction of year 2011 allowances	PSN4	$134.74	$0.02	$134.76
March 2011 auction of year 2018 allowances	PSN4	$8.11	$0.00	$8.11
March 2011 auction of year 2011 allowances	PSN5	$130.53	$0.02	$130.55
March 2011 auction of year 2018 allowances	PSN5	$7.86	$0.00	$7.86
	Plant Totals:	$327.37	$0.05	$327.42

907

916

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

46.14
281.28

254.900-XXX-790

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	Turkey Point	Florida Power & Light Co.	Sheila M Wilkinson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	PTP1	$238.61	$0.02	$238.63
March 2011 auction of year 2018 allowances	PTP1	$14.36	$0.00	$14.36
March 2011 auction of year 2011 allowances	PTP2	$240.01	$0.03	$240.04
March 2011 auction of year 2018 allowances	PTP2	$14.44	$0.01	$14.45
	Plant Totals:	$507.42	$0.06	$507.48

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

926

254.900-XXX-790

Distribution of Proceeds

The proceeds for each unit are determined by the calculations listed below. The amount you receive from the U.S. Treasury may be for slightly more or less than the amount you calculate for your individual units due to rounding.

Spot:

Unit Proceeds = [Table 2 Column E / 250,000]** x $350,895.24

Additional Proceeds* = [Table 2 Column E / 249,974]** x $350,895.24 - Unit Proceeds

7-Year Advance:

Unit Proceeds = [Table 2 Column E / 250,000]** x $21,116.80

Additional Proceeds* = [Table 2 Column E / 249,974] x $21,116.80 - Unit Proceeds

To Calculate the Number of Allowances Sold:

Spot Auction: Allowances Sold = [Table 2 Column E]** x [125,000 / 250,000]

7-Year Advance Auction: Allowances Sold = [Table 2 Column E] x [125,000 / 250,000]

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

** Table 2 and the Phase II formula can be found in 40 CFR Part 73 in the September 26, 1998 FEDERAL REGISTER.

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258

EPA

Notification For Distribution Of Proceeds From EPA Auctions

Step 1

Provide your Authorized Account Representative (AAR) or Alternate AAR identification:

Name (please print)	AAR ID# (or Alternate)
Phone #	Plant Name and ORIS Code

EPA will send one payment for each plant that you represent for the proceeds from the auctions of allowances. Proceeds payments will be distributed no later than 90 days following the conclusion of the auction. If you are the AAR, or alternate AAR, for multiple plants and the payments are to be made to the same company, either submit a separate form for each plant or attach a list of the plants and ORIS codes. A separate form must be submitted for each plant or list of plants where the payment is made to a different company. You do not need to complete this form for plants that did not have any allowances withheld for the auctions and will not receive proceeds. As the AAR, or alternate AAR, you are responsible for designating to whom proceeds payments should be made. **All payments will be wire transferred to the bank account on record with the EPA Las Vegas Financial Management Center** (call 702-798-2492 to change your company's bank account information).

Step 2

The proceeds payment should be endorsed to:

Company Name
Taxpayer ID. No. __ __ __ __ __ __ __ __ __

Step 3

I understand that EPA will continue to make the payments as indicated above until I give new written instructions to EPA.

Authorized by _____ Date _____
AAR or Alternate AAR

Send this form to one of the following addresses:

for regular or certified mail:

U.S. EPA
Clean Air Markets Division (6204J)
Attention: Kenon Smith
1200 Pennsylvania Avenue, NW
Washington, DC 20460

for overnight mail:

U.S. EPA
Clean Air Markets Division (6204J)
Attention: Kenon Smith
1310 L Street, NW
Room 254A
Washington, DC 20005

EPA Form 7610-11 (12/05)

POLLUTION ALLOWANCE PROCEEDS

ACH VENDOR/MISCELLANEOUS PAYMENT ENROLLMENT FORM

OMB No. 1510-0056

This form is used for Automated Clearing House (ACH) payments with an addendum record that contains payment-related information processed through the Vendor Express Program. Recipients of these payments should bring this information to the attention of their financial institution when presenting this form for completion. See reverse for additional instructions.

PRIVACY ACT STATEMENT

The following information is provided to comply with the Privacy Act of 1974 (P.L. 93-579). All information collected on this form is required under the provisions of 31 U.S.C. 3322 and 31 CFR 210. This information will be used by the Treasury Department to transmit payment data, by electronic means to vendor's financial institution. Failure to provide the requested information may delay or prevent the receipt of payments through the Automated Clearing House Payment System.

AGENCY INFORMATION

FEDERAL PROGRAM AGENCY: U.S. Environmental Protection Agency

AGENCY IDENTIFIER: LVFC

AGENCY LOCATION CODE (ALC): 68128933

ACH FORMAT: [X] CCD+ [ ] CTX

ADDRESS: PO Box 98515

Las Vegas, NV 89193-8515

CONTACT PERSON NAME: Marge Pumphrey Email: pumphrey.margaret@epa.gov

TELEPHONE NUMBER: (702) 798-2492

ADDITIONAL INFORMATION: FAX Number: (702) 798-2423

PAYEE/COMPANY INFORMATION

NAME:

SSN NO. OR TAXPAYER ID NO.:

ADDRESS:

CONTACT PERSON NAME:

TELEPHONE NUMBER: ( )

FINANCIAL INSTITUTION INFORMATION

NAME:

ADDRESS:

ACH COORDINATOR NAME:

TELEPHONE NUMBER: ( )

NINE-DIGIT ROUTING TRANSIT NUMBER: — — — — — — — — —

DEPOSITOR ACCOUNT TITLE:

DEPOSITOR ACCOUNT NUMBER:

LOCKBOX NUMBER:

TYPE OF ACCOUNT: [ ] CHECKING [ ] SAVINGS [ ] LOCKBOX

SIGNATURE AND TITLE OF AUTHORIZED OFFICIAL: (Could be the same as ACH Coordinator)

TELEPHONE NUMBER: ( )

AUTHORIZED FOR LOCAL REPRODUCTION

SF 3881 (Rev. 2/2003)
Prescribed by Department of Treasury
31 U.S.C. 3322; 31 CFR 210

State	Plant Name	Check Payable To	DR Name
GA	Scherer	Georgia Power Company	Chris M Hobson

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*		Total Proceeds
March 2011 auction of year 2011 allowances	1	$856.18	$0.09	907,80	$856.27
March 2011 auction of year 2018 allowances	1	$51.52	$0.01		$51.53
March 2011 auction of year 2011 allowances	2	$863.20	$0.09	915,25	$863.29
March 2011 auction of year 2018 allowances	2	$51.96	$0.00		$51.96
March 2011 auction of year 2011 allowances	3	$864.62	$0.09	916,74	$864.71
March 2011 auction of year 2018 allowances	3	$52.04	$0.01		$52.05
March 2011 auction of year 2011 allowances	4	$863.21	$0.09	915.26	$863.30
March 2011 auction of year 2018 allowances	4	$51.96	$0.00		$51.96
	Plant Totals:	$3,654.69	$0.38		$3,655.07

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

ALLOCATION OF PLANT SCHERER EPA AUCTION PROCEEDS
ALLOCATION BASED ON OWNERSHIP
100% AMOUNT OF $3,655.07
MARCH 2011 PAYMENT

UNIT 1	$907.00
UNIT 2	$915.25
UNIT 3	$916.76
UNIT 4	$915.26
	$3,655.07

	OPC AT 60% 232-3177	MEAG AT 30.2% 232-3277	DALTON AT 1.4% 232-3377	GULF AT 25% 234-3415	FPL AT 76.36% 232-3530	JEA AT 23.64% 232-3630	GPC	TOTAL
SCHERER 1	$544.69	$274.16	$12.71				$76.25	$907.00
SCHERER 2	$549.15	$276.41	$12.81				$76.88	$915.25
SCHERER 3				$229.19			$687.57	$916.76
SCHERER 4					$698.89	$216.37	$0.00	$915.26
	$1,093.83	$550.57	$25.52	$229.19	$698.89	$216.37	$840.70	$3,655.07

FPL

4/7/2011 MISC6.xls

Florida Power & Light Company
Docket No. 110007-EI
Staff's 10th Set of Interrogatories
Interrogatory No. 64 / Attachment I
Page 15 of 83

00000214

Payment Coupon

/610110000004405330000851150788760000000010101

General Mail Facility
Miami, FL 33188-0001

B 01100 0000851150 0 0 01 01 01
Please mail this portion with your check

Cust. No.: 440533	Inv. No.: 851150
This Month's Charges Past Due After 05/22/2011	Amount Due This Invoice 698.89

Make check payable to FPL in US funds and mail payment to address below

GEORGIA POWER COMPANY

SHANNON PERKINS
9TH FLOOR BIN 10090
241 RALPH MCGILL BLVD
ATLANTA GA 30308

FPL
GENERAL MAIL FACILITY
MIAMI FL 33188-0001

Florida Power & Light Company

Federal Tax ID#: 59-0247775

INVOICE

Customer Name and Address

GEORGIA POWER COMPANY

SHANNON PERKINS
9TH FLOOR BIN 10090
241 RALPH MCGILL BLVD
ATLANTA GA 30308

Customer Number: 440533

Invoice Number: 851150

Invoice Date: 04/22/2011

B 01100 0000851150 0 0 01 01 01
Please Retain This Portion for your Records

CURRENT CHARGES AND CREDITS

Customer No: 440533 Invoice No: 851150

DESCRIPTION	QUANTITY	PRICE	AMOUNT
ARM-MISCELLANEOUS RECEIVABLE SCHERER EPA AUCTION REFUND	1	698.89	698.89

For Inquiries Contact:
PERRY FITZGERALD
Phone: (478) 993-3903

Total Amount Due $698.89

This Month's Charges Past Due After 05/22/2011

Messages

Florida Power & Light Company
General Mail Facility
Miami, FL 33188-0001

JEA

ACH TRANSFER REQUEST

FROM: General Accounting DATE: April 28, 2011

TO: Account Payable

PLEASE ISSUE AN ACH TRANSFER IN FAVOR OF:
Florida Power & Light Co.
Ft. Lauderdale, Florida 33340-5367

BANK: NationsBank, Dallas
Credit to: Florida Power and Light
ABA # 111000012
Account # 3750132076

FROM: JEA Revenue Fund
Bank Account REV F510

DESCRIPTION: EPA 2010 allowances auctions proceeds

			AMOUNT
	EPA 2010 allowances auctions proceeds - Saleback	$	296.45
	EPA 2010 allowances auctions proceeds - Ownership		197.64
DR ACCOUNT:	021 Z0000 00000000 00 449103 8020 0000	$	494.09

DATE DUE: **April 29, 2010**

Payment authorized by: Laura Lawrence
Department Director or Appointed

Payment authorized by: [illegible]
Department Director or Appointed

Rectoo instructions are containing signature:

1) Original to A/P

2) Copy to Treasury (Tom McDonald)

Date: 03-30-2011
Page: 3 of 4

Distribution of Proceeds

State	Plant Name	Check Payable To	DR Name
FL	St. Johns River Power	JEA	Michael Brost

Transaction Description	Unit	Proceeds Allocated	Additional Proceeds*	Total Proceeds
March 2011 auction of year 2011 allowances	1	$470.20	$0.05	$470.25
March 2011 auction of year 2018 allowances	1	$28.30	$0.00	$28.30
March 2011 auction of year 2011 allowances	2	$461.78	$0.05	$461.83
March 2011 auction of year 2018 allowances	2	$27.79	$0.00	$27.79
	Plant Totals:	$988.07	$0.10	$988.17

* Additional Proceeds are a pro rata distribution of the proceeds from exempt units that have surrendered their allocated allowances and proceeds distribution.

988.17 ÷ 2 = 494.09

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     RECV              0.00            196.44 EPA  TREAS 310
420111187438719
-------------------------------------------------------------------------
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RECV ACCOUNT NBR     : 2090002205510          RECV ABA T/R : 063000021
ORIG COMPANY ID      : 3101036009             SEC CODE     : CCD
TRANSACTION REF #    : 101036150278051        EFFECTIVE    : 04-28-11

ID: 000000344680112
RECV NAME: JEA ENV SVCS GROUP

PAYMENT INFORMATION:
AMOUNT:            $196.44
EFFECTIVE DATE:    04/28/2011
INPUT FORMAT:      ACHCCD+
RECEIVING PARTY                          ORIGINATING PARTY
ROUTING ID:       063000021              ROUTING ID:       101036151
ACCT:             2090002205510          ACCT:
                                         COMPANY ID:       3101036009
TRACE NUMBER (REF):     020111187438719
PAYEE:                  JEA ENV SVCS GROUP
                        ID CODE: 000000344680112
PAYER:                  EPA  TREAS 310
LINE: 00001
SELLER'S INVOICE NO:    SOUTHSIDE
DESCRIPTION:            AP33LAS VEGAS 702/798-2491


004-------------------------------------------------------------------
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** BANK/ACCOUNT: WBFL 2090002205510       JEA REVENUE FUND
     TYPE            DR AMT            CR AMT   ORIG CO NAME   WB ACH REF
#
     RECV              0.00            988.17 EPA  TREAS 310
420111187438721
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Part IV

Environmental Protection Agency

40 CFR Part 73

Acid Rain Program: 1998 Reallocation of Allowances; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 73

[FRL –6164–1]

RIN 2060–AG86

Acid Rain Program: 1998 Reallocation of Allowances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Title IV of the Clean Air Act, as amended by the Clean Air Act Amendments of 1990, ("the Act") authorizes the Environmental Protection Agency ("EPA" or "Agency") to establish the Acid Rain Program. The purpose of the Acid Rain Program is to reduce significantly emissions of sulfur dioxide and nitrogen oxides from electric generating plants in order to reduce the adverse health and ecological impacts of acidic deposition (or acid rain) resulting from such emissions. On March 23, 1993, the Agency promulgated a final rule ("1993 rule") allocating allowances to utility units. That rule provided the methodology for revising the allocation of allowances for utility units in 1998, as required by Title IV. On December 27, 1996, the Agency proposed changes ("1996 proposal") to unadjusted allowances for certain units. These changes were proposed to respond to litigation over the Agency's interpretation of section 405(c) of the Act, to correct documented Agency errors in making the allocations, and to incorporate more recent information on whether or not certain new units met requirements pertaining to their construction or commencement of commercial operation. On January 7, 1998, the Agency proposed ("1998 proposal") to revise allowance allocations using the methodology in the 1993 rule. Today's rule implements the revision methodology in the 1993 rule, based on the 1998 proposal, and incorporates final changes to unadjusted allowances based on the 1996 proposal.

DATES: This rule is effective October 28, 1998.

ADDRESSES: *Docket.* Docket No. A–97–24, containing supporting information used to develop the rule is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street S.W., Washington, D.C. 20460. Information on the allowance revisions in the 1996 proposal, which are reflected in this rule, is in Docket No. A–95–56. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: Kathy Barylski at (202) 564–9074 or Dwight Alpern at (202) 564–9151, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street S.W., Washington, D.C. 20460; or the Acid Rain Hotline at (202) 564–9620. Electronic copies of this rulemaking and technical support documents can be accessed through the Acid Rain Division website at www.epa.gov/acidrain. These documents are also available in the Docket listed above.

SUPPLEMENTARY INFORMATION:

Judicial Review

Under section 307(b)(1) of the Act, judicial review of this rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of these final rule revisions. Under section 307(b)(2) of the Act, the requirements that are the subject of today's document may not be challenged in civil or criminal proceedings brought by the EPA to enforce these requirements.

I. Affected Entities

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IV. National Allowance Data Base

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B. Unfunded Mandates Act, Executive Orders 12875 and 13084
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I. Affected Entities

Entities potentially regulated by this action are fossil-fuel fired boilers or turbines that serve generators producing electricity for sale. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric service providers.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities that EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated by this action, you should carefully examine the applicability criteria in § 72.6 and the exemptions in §§ 72.7, 72.8 and 72.14 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

II. Background

The overall goal of the Acid Rain Program is to achieve significant environmental benefits through reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X), the primary precursors of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and promotes pollution prevention.

Title IV of the Clean Air Act sets as a primary goal the reduction of annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these SO_2 emissions reductions, the law requires a two-phase tightening of restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. Phase II, beginning in 2000, tightens the annual emissions limits imposed on the large, higher emitting plants regulated in Phase I and also sets restrictions on other smaller or cleaner plants fired by coal, oil, or gas. Title IV also requires certain coal-fired units to reduce their emissions of NO_X to a level achievable through installation of applicable NO_X reduction technology. (*See* 40 CFR part 76.)

The centerpiece of the Acid Rain Program is a unique trading system in which allowances (each authorizing the emission of up to one ton of SO_2) may be bought and sold at prices determined by the free market. Most existing utility units are allocated allowances based on formulas specified in the Act. Affected

utility units are required to limit SO_2 emissions to the number of allowances they hold, but because allowances are transferrable, utilities may meet their emissions control requirements in the most cost-effective manner.

This rule concerns the allocation of allowances for Phase II of the program. Phase II allowances were allocated by the 1993 rule (58 FR 15634, March 23, 1993). However, section 403(a)(1) of the Act requires EPA to publish a revised statement of allowance allocations no later than June 1, 1998. That revision must account for units eligible for allowances under section 405(g)(4) (units commencing operation from 1992 through 1995), section 405(i)(2) (units that reduce their emissions rates), and section 409 (units with approved repowering extensions). The 1993 rule established the methodology for the 1998 revision of allowance allocations, which is codified at 40 CFR § 73.11. This rulemaking implements the revision methodology.

III. Part 73: Allowances

A. Method for Revision

In order to facilitate consideration of the many issues, EPA has chosen to prepare the 1998 revision of allowance allocations in a staged approach. The 1996 proposal (61 FR 68349) was the first stage and included deletion of certain unaffected units from Table 2 of § 73.10, changes in unadjusted allowances of certain units, and deletion of units from and addition of units to Table 3 of § 73.10. The comment period ran from December 27, 1996 through February 10, 1997. The issues raised in the 1996 proposal are discussed primarily in this subsection and subsections B and C below, regarding units under section 405(i)(2) of the Act and surrender of allowances and return and distribution of allowance auction proceeds.

The second stage was the 1998 proposal (63 FR 0714). EPA proposed to follow the 1993 reallocation methodology set forth in the existing §§ 73.11 and 73.12 and apply it to the data in NADB version 2.2, which is discussed below. The technical support document explaining in detail the application of the 1998 reallocation methodology is included in the docket. Docket Item A-97-24 IV-A-02, *Technical Documentation for the 1998 Reallocation of Allowances* (hereinafter, "Technical Documentation"). The comment period ran from January 7, 1998 through March 9, 1998. The issues raised in the 1998 proposal are discussed in subsections B, C, D, and E below, regarding units under section 405(i)(2) of the Act, surrender of allowances and return and distribution of allowance auction proceeds, the repowering reserve, and units listed under Table B of section 405(g)(2) of the Act. Also, as discussed below, the regulatory tables allocating allowances are consolidated into a single, simplified table.

Changes proposed in the first stage (the 1996 proposal) and the second stage (the 1998 proposal) (including the revised allowance allocations resulting from the application of the 1993 reallocation methodology) are finalized in today's action as one final rule, the last stage of the 1998 reallocations. In the 1996 proposal, EPA proposed to revise unadjusted allowances for certain units, to include certain units on the original allocation tables, and to delete some units from the original tables. *See* 61 FR 68340, 68355–362. The 1996 proposal included rule language that would implement these allowance-related revisions by amending specific entries in the original allowance tables (Tables 2 and 3 of § 73.10). These proposed revisions were supported by all commenters that addressed them during the comment period on the 1996 proposal. The proposal to revise the number of unadjusted basic allowances for Rodemacher unit 2 was made final in § 73.10(b)(3) on October 24, 1997. All the other proposed revisions were left to be addressed in today's final rule. 62 FR 55460, 55471 and 55486, October 24, 1997.

However, unlike the 1996 proposal which would have amended the original Tables 2 and 3 of § 73.10, the 1998 proposal would consolidate those tables into one new Table 2 and republish the entire table. Comments on the 1998 proposal supported consolidation and republishing Table 2. EPA is herein adopting that approach and is, for the reasons stated in the 1996 proposal, including in the new table all the allowance-related revisions proposed in 1996. Consequently, the proposed rule language from the 1996 proposal amending entries in the original Tables 2 and 3 is unnecessary and not adopted in today's rule. Further, because Rodemacher unit 2's revised unadjusted basic allowances that were finalized on October 24, 1997 are incorporated in the new Table 2, separate language adopted in the October 1997 rule is no longer necessary and is removed by today's rule. EPA emphasizes that Rodemacher unit 2 retains its revised unadjusted basic allowances which are reflected in the new Table 2 (see the Technical Documentation for details), rather than through a special provision amending the original Table 2.

B. Units Under Section 405(i)(2)

A few units may be eligible for a special allocation method based on eligibility requirements (which include, *inter alia*, a maximum level for the unit's actual emission rate) under section 405(i)(2). In the 1993 rule, EPA preliminarily determined that six units may be eligible and listed those units and resulting allowances in Table 4 of § 73.10(d). Further, EPA required, in § 73.19, that the actual 1997 emission rate be used to determine eligibility for section 405(i)(2) allowances.

In the 1996 proposal, EPA proposed to modify § 73.19 to use 1996 actual SO_2 emissions rate data as reported by the unit's continuous emissions monitoring system (CEMS) under part 75, rather than 1997 emissions data collected by the Energy Information Administration (EIA), to determine whether the units are eligible. In a comment on the 1996 proposal, the owner of one of the affected plants requested that the actual emission rate as of January 1, 2000 be used for determining eligibility and that, if the unit did not qualify, its additional allowances be rescinded and not reallocated. Because the comment raised a significant new option, the 1998 proposal reopened the issue of which calendar year emission rate EPA should use for the determination of eligibility and whether EPA should reallocate any unallocated allowances reserved for allocation under section 405(i)(2) to other utility units after the 1998 rulemaking.

1. Calendar Year Emission Rate

In section 405(i)(2)(B) of the Act, one criterion for eligibility is that the "actual emissions rate is less than 1.2 lbs/mmBtu as of January 1, 2000." In the 1992 allowance allocation proposal (57 FR 29940, 29956, July 7, 1992), EPA concluded that the statutory phrase "as of January 1, 2000" meant that the calendar year 1999 emission rate should be used. However, in the 1992 proposal, EPA also discussed a perceived discrepancy between the use of the 1999 emission rate under section 405(i)(2)(B) and the mandate under section 403(a)(1) that allowance allocations be finalized no later than June 1, 1998. In the 1993 rule (58 FR 15710), EPA decided to use calendar year 1997 emission rates because 1997 would be the latest year of emissions data prior to the required final allocation in 1998.

In the 1998 proposal, EPA requested comment on three options for which calendar year of emissions rate data to use: (1) 1997, as in the 1993 rule; (2) 1999, as requested in a comment on the 1996 proposal; or (3) the first calendar

year, from 1996 up to 1999, when the unit's emissions are less than the required 1.2 lb/mmBtu rate. For all options, emissions data would be that reported using the CEMS under 40 CFR part 75.

Five comments were received on this issue. Two recommended using calendar year 1997. Three recommended option three above, the first year from 1996 through 1999 that the emissions rate is less than 1.2 lb/mmBtu. One comment also recommended that the final rule reflect the understanding that once a unit achieves an emission rate below 1.2 lb/mmBtu, it will be eligible for section 405(i)(2) allowances and no further demonstrations of eligibility will need to be made.

EPA believes that the option of using the first calendar year, from 1996 through 1999, is the best option. In contrast to the other options, this option provides an incentive to units potentially eligible for allowances under section 405(i)(2) to achieve an emission rate of less than 1.2 lb/mmBtu as soon as possible while allowing the full statutory timeframe to achieve such a rate. Further, as discussed below, Table 2 of § 73.10(b) shows the alternate allowance allocations for such units if they qualify or if they fail to qualify for section 405(i)(2) allowances. EPA maintains that this approach reasonably squares section 405(i)(2) with the requirement that EPA finalize allowance allocations in 1998. Allowances calculated for units potentially eligible under section 405(i)(2) will be held in the Allowance Tracking System and will not be available for use or transfer until the units are determined to be eligible for the allowances. If a unit becomes eligible during 1996 through 1999 for such allowances, the allowances will be made available for use or transfer. EPA review of annual CEMS data is generally completed by May following the calendar year of that data. Thus, EPA believes that the allowances could be made available by June following the year for which the eligible unit first has an emission rate of less than 1.2 lb/mmBtu. Also, as requested by the commenter, EPA is clarifying that once the unit achieves an emission rate of less than 1.2 lb/mmBtu, that unit will not be required to make further demonstrations of eligibility.

2. Unallocated Allowances

EPA also sought comment regarding whether any unallocated allowances reserved for allocation under section 405(i)(2) should be reallocated to other utility units after the 1998 rulemaking. EPA proposed that any allowances reserved for allocation under section 405(i)(2) that are not actually allocated based on 1996 through 1999 emissions should not be utilized or otherwise reallocated to other utility units. One commenter believed that this option fulfills the statutory requirements for finalized allowance allocations in 1998 and for using emissions data as of January 1, 2000. Also, the commenter pointed out that section 403(a)(1) does not require EPA to allocate exactly 8.9 million basic allowances, but no more than 8.9 million allowances. As the commenter emphasized, the allocation under section 405(i)(2) is no more than 5000 allowances, or only 0.05 percent of the unadjusted basic allowances. In the 1998 proposal, EPA noted that the administrative burden of reallocating the allowances would be considerable, due to the need to develop allowance software and to recalculate all basic allowances and refinalize Table 2 of § 73.10(b).

A number of other comments were received in this issue. One commenter agreed that reallocation was overly burdensome and not mandated in the statute. Another considered reallocation to be compelled by law but suggested that selling any remaining allowances at the annual auction (and distributing the proceeds on a pro rata basis to the utility units) would be sufficient. Another commenter recommended allocating any remaining allowances to affected "industrial units" that have not received allowance allocations.[1]

EPA has further analyzed section 405(i)(2) and determined that there will, in fact, be no unallocated allowances under section 405(i)(2). Thus, the question of whether or how to reallocate them is moot. Section 405(i)(2) limits the number of allowances available under the section to 5000. The only situation in which there could be unallocated allowances under section 405(i)(2) would be if the total number of allowances for which all units eligible under section 405(i)(2) qualified was less than 5000. Two units (Anclote 1 and 2) are eligible for section 405(i)(2) allowances, based on 1997 CEMS data, and would qualify for more than 5000 allowances if there were no limit on section 405(i)(2) allowances.[2] *See* Docket Item A-97-24 IV-C-01 (letter explaining basis for concluding that Anclote 1 and 2 qualify for section 405(i)(2) allowances). Thus, even if no other units qualify for section 405(i)(2) allowances, all 5000 section 405(i)(2) allowances will still be allocated and there will be no allowances remaining to reallocate or auction.

3. Allocations in Table 2

The allowance allocations for all six potentially eligible units in Table 2 will reflect section 405(i)(2) allowances calculated on the assumption that all six units will in fact be eligible for section 405(i)(2) allowances. Each unit is allocated its proportionate share of the available section 405(i)(2) allowances. Anclote units 1 and 2 have already been determined to be eligible for allowances under section 405(i)(2). As noted above, until units are determined to be eligible for allowance allocations under section 405(i)(2), their additional allowances from this section will be held in the Allowance Tracking System and will not be available for transfer. If the Monroe units are not eligible for section 405(i)(2) allowances as of January 1, 2000, additional 405(i)(2) allowances will be available to Anclote and are shown in footnote 4 of Table 2. Monroe's allowance allocations without additional allowances from section 405(i)(2) are also shown in footnote 4 of Table 2.

Footnote 4 of Table 2 of § 73.10 of the 1998 proposal did not properly reflect the effect of ineligibility by some but not all six units. The methodology used by EPA to calculate the allowances (provided in Appendix C of the Technical Documentation) correctly reflects the effect of ineligibility of units. In today's final rule, EPA is correcting footnote 4 of Table 2 to be consistent with this methodology.

C. Surrender of Allowances and Return and Distribution of Allowance Auction Proceeds

As required under section 416 of the Act and subpart E of part 73, EPA has facilitated the auction of allowances since 1993. Phase I and Phase II allowances are deducted as shown in Tables 1 and 2 of 40 CFR 73.10. Phase II deductions are calculated as a fixed percentage of each unit's unadjusted basic allowances, so the total number of allowances reserved equals 250,000. Each unit's designated representative then receives a portion of the proceeds from the auction based on the number of allowances deducted.

The 1996 proposal changed the unadjusted basic allowances for a few units, deleted many units from Tables 2 and 3 of § 73.10, and added a few units

[1] This comment is also addressed in section IV of this preamble.

[2] Anclote 1 would qualify for 4038 allowances under section 405(i)(2), and Anclote 2 would qualify for 4400 allowances, if allowances under section 405(i)(2) were not limited to 5000. In addition to the allowances for Anclote 1 and 2, Detroit Edison's Monroe 1 would be eligible for 571 allowances, Monroe 2 for 1423, Monroe 3 for 1280, and Monroe 4 for 2676.

to the Tables. The 1996 proposal stated that the designated representative of each unit to be deleted that has received an allowance allocation must surrender the allowances to the Agency and must return any proceeds received from the auction. The 1996 proposal also provided that the Agency would, in a future action, explain how the returned proceeds would be redistributed. No comments were received on the issues of the allowance surrender and return and redistribution of proceeds in the 1996 proposal.

The 1998 proposal clarified how proceeds from the auction would be distributed. In the 1998 proposal, the Agency considered the following objectives: minimization of the number of allowances and proceeds to be surrendered; minimization of any disruption to the Allowance Tracking System; and fair distribution of proceeds. The Agency recognized that five auctions had already taken place and proceeds had been distributed and that providing a complete redistribution of proceeds based on the 1996 proposal would be extremely burdensome to the Agency while providing a minimal benefit to any unit. Therefore, the Agency rejected the option of a complete redistribution of auction proceeds. However, the Agency found that providing no redistribution would be unfair for the few affected units that had their unadjusted basic allowance allocation changed or were found for the first time to be eligible to receive allocations, in the 1996 proposal.[3] Moreover, EPA explained that, as provided in the 1996 proposal, all units deleted from the tables of affected units must surrender any allowances and return any proceeds received. Very few of the units deleted had designated representatives and so were not able to transfer any allowances or receive any proceeds.

The Agency's 1998 proposal provided, for all auctions completed before the finalization of this rulemaking (including the 1998 auction) that: (1) units deleted from Table 2 of § 73.10, and units deleted from Table 3 and not added to Table 2, would surrender any allowances allocated and return any proceeds received; (2) affected units that had changes to their unadjusted basic allowance allocation would receive proceeds based on the changed allocation; and (3) the proceeds for all other units would not be changed. To implement this, the 1998 proposal provided a column in Table 2 listing the number of allowances each unit has provided for each auction taking place from 1993 through 1998 (with modifications from the original Tables 2 and 3 for the 17 units listed in footnote 3 above and for units deleted from Tables 2 or 3). References in proposed § 73.27 to allowances deducted for auctions before June 1, 1998 cited this new column. Five comments were received on this issue in the 1998 proposal. One commenter thought the proposal was fair. However, another stated that the method results in some proceeds from auctions from 1993 through 1998 being retained by the Agency, contrary to law. Two options were posed in comments regarding how remaining proceeds should be dealt with. One option would be for the Agency to redistribute those proceeds on a pro rata basis, although the method for such redistribution need not be as rigorous as a full redistribution. The other option would allow the Agency to dedicate the funds for educational and research activities related to emissions trading. While this second option is innovative, the Agency has decided not to dedicate the funds to education and research because of the lack of express Agency authority to use auction proceeds in this way.

EPA continues to believe, for the reasons stated in the 1996 proposal, that the allowance surrender and return of proceeds are necessary. However, EPA concludes that a simple pro rata redistribution of the proceeds from the allowances meets the requirements of the Act and is not overly burdensome. To fairly redistribute all remaining proceeds, EPA will use values in Column D of new, final Table 2 (1993–98 Purchase Year Reserve Deduction), which were included in the 1998 proposal, to determine each unit's pro rata share of the remaining funds. This methodology is set forth in revised § 73.27(b)(4). Each unit's designated representative will receive one check for all five years of additional auction proceeds.

Also, as explained in the proposal, existing paragraphs (b)(4) and (c)(4) of § 73.27 are unnecessary because allowances from calendar years 2010 and thereafter are not auctioned before 2003. No comments were received concerning the elimination of the paragraphs, which is implemented in today's action.

Finally, today's final rule requires in § 73.10(b)(3) the surrender of allowances and return of proceeds. In order to make clear which specific units are subject to this requirement, the paragraph includes a new table of the units, the number of allowances to be surrendered, and the value of proceeds to be returned. This table replaces the general provisions in the 1996 proposal (§ 73.10(b)(5) and (c)(3)) which required allowance surrender and return of proceeds without naming the units.

Today's final rule also requires completion of the allowance surrender and return of proceeds no later than 60 days after the effective date of this final rule.

D. Revision of the Repowering Reserve

Finalization of the allowance allocations is also dependent upon a reasonably accurate calculation of the number of allowances allocated for units with Phase II repowering extensions under section 409 of the Act. *See* 42 U.S.C. 7651 and 40 CFR 72.44. For the 1993 rule, EPA estimated that a set-aside of up to 500,000 allowances could be needed for repowering extensions. EPA based this number on an estimate of 10 GW of capacity being repowered. To create the set-aside, EPA withheld 50,000 allowances for each year from 2000 through 2009 from Phase II units' basic allowance allocations. 58 FR 15642. In the 1998 proposal, the Agency maintained a set aside of 500,000 allowances for repowering but stated that it would reduce the set-aside in the final rule to the amount necessary to implement all activated approved repowering plans. Today's action, therefore, reduces the reserve to 27,124 allowances.

One commenter pointed out that the 1998 proposal modified the method of calculating repowering allowances in § 73.21. EPA has reviewed the provision and agrees that the Agency inadvertently changed the method of calculating allowances, as opposed to merely correcting a reference. The 1993 rule (at § 73.21) provided that a unit's repowering allowances equal the number of allowances calculated under section 409(c) less the unit's adjusted basic allowances calculated under § 73.11. The commenter correctly noted that the 1998 proposal, which modified § 73.21 to remove reference § 73.11 and to refer instead to proposed Table 2 Column C, had the effect of increasing the repowering reserve. Proposed Table 2 Column C actually reflects a different and generally lower value than adjusted basic allowances; using the lower value in Table 2 Column C increases the calculated repowering allowances and, thus, increases the repowering reserve. However, the commenter recommended that a unit's repowering allowances equal the number of allowances under

[3] A total of 17 units are in this category, as explained in the 1996 proposal. Nine units have changes due to resolution of litigation. Three units have changes due to data errors by the Agency. Four units were found to be eligible for allocations. One unit, Twin Oak 2, as discussed below, is eligible only for allocations under section 405(g)(2).

G. Miscellaneous

EPA proposed a number of modifications and corrections to the allowance rules to eliminate sections that are no longer necessary and to correct references. The proposed modifications and corrections were described in the "Miscellaneous" section of the preamble to the 1998 proposal. No comments were received on these issues, and the Agency has adopted the proposed changes in this final rule.

Aside from the foregoing corrections, one commenter noted that several proposed provisions continued to refer to the direct sales program, which was eliminated by the Agency in 1996 (see 61 FR 28761, June 6, 1996). The Agency has reviewed the 1998 proposal and 40 CFR part 73 and found references to the direct sales program in §§ 73.27(a)(2), 73.27(b) (2), (3) and (5), 73.27(c) (2), (3) and (5), and § 73.70(b). In today's final rule, EPA is eliminating these last references to the direct sales program, as requested by the commenter. Also, § 73.27(a)(2), establishing the auction reserve, is corrected to reflect that the 50,000 allowances formerly in the Direct Sale Subaccount are now incorporated into the Auction Subaccount, making the annual Auction Subaccount total 250,000 allowances.

IV. National Allowance DataBase

Some changes have been made to the National Allowance Data Base (NADB) since issuance of the March 23, 1993 notice of availability of the NADB (58 FR 15720, March 23, 1993). The database used to calculate allowances herein is NADB version 2.2 and is available from the sources listed in the **FOR FURTHER INFORMATION CONTACT** section above.

As stated in the 1998 proposal, NADB version 2.2 includes new data and data corrections discussed in the 1996 proposal. These data and corrections are adopted for the reasons stated in the 1996 proposal. Consistent with the 1993 rule and the 1996 proposal, EPA has not made any other corrections based on alleged errors or any new requests for data changes, except for changes in nonsubstantive identifying information (e.g., boiler identifiers).

Only one comment was received on the 1998 proposal concerning the NADB. The commenter requested EPA to add information on two units (George F. Wheaton Units 1 and 2, which serve generators that provide electricity to the owner's manufacturing plant and are required to make available electricity for sale to certain utilities) to the NADB for purposes of allocating allowances to the units. The commenter suggested that the two units are affected utility units under the Acid Rain Program. According to the commenter, EPA has recognized that "industrial units," such as the commenter's units, should have received allowance allocations. The only "industrial units" specifically identified by the commenter as warranting allowance allocations were its own units.

EPA previously rejected, in a final rulemaking notice issued October 24, 1997, a request by the commenter that allowances be allocated to "industrial units." In today's rulemaking, EPA is not reconsidering its rejection of that claim, which the commenter repeated here. Moreover, EPA here rejects, for two reasons, the new claim that information on the commenter's units be added to the NADB for allowance allocation. First, EPA previously decided that no allowances should be allocated to the units because the commenter failed to submit a timely claim (with supporting information) for allowances. A new, late submission obviously cannot cure this deficiency. Second, the information in the commenters' late submission is deficient on its face.

In the prior rulemaking, this commenter made the same claim that "industrial units" that do not qualify for an exemption from the Acid Rain Program should be allocated allowances.[4] *Compare* 62 FR 55466 and Docket Item A-97-24 II-D-08, Comments of Zinc Corporation of America at 6-7 (March 9, 1998). In the October 24, 1997 notice, EPA rejected that claim. *Id.* As stated in the October 24, 1997 notice, the commenter's claim that allowances should be allocated to "industrial units" "ignores the fact that EPA has previously specified deadlines by which parties claiming an erroneous failure to allocate allowances to a unit were required to submit such claims and necessary supporting information to EPA." 62 FR 55466.

Since the commenter has now, for the first time, submitted information on its units for the NADB, EPA is summarizing here the notices that established the deadlines and data requirements for NADB submissions. In a July 1991 notice, EPA stated that it would allocate allowances based on information in the NADB, a version (NADB version 2.0) of which was made available for public review. EPA also explained what information on a unit and supporting data and documentation had to be submitted to EPA in order to add information to the NADB for purposes of allocating allowances to the unit. 56 FR 33278, 33283 (1991). A major requirement was that any additional information had to be "well-documented." *Id.* For example, the owner or operator of a unit had to submit information on the unit's 1985 SO_2 emissions and, if that value was based on emissions monitoring, the underlying monitoring data or independent emissions inventory. If that value was calculated based on the fuels burned in 1985, the "equation used, percent sulfur in fuel, ash retention of fuel, and any other data used" had to be provided. 56 FR 33284. Similarly, the other data elements needed for allocating allowances (i.e., 1985 SO_2 emission limit, generator summer net dependable capacity, 1985–87 average annual total heat input) had to be submitted with supporting documentation. *Id.* (listed as data elements 16, 20, and 23).[5] Further, EPA noted that "[u]nits eligible for allowances will not be allocated allowances if the final database does not include the information necessary to calculate such allowances." 56 FR 33283.

In a July 1992 notice, EPA provided for public review of NADB version 2.1, as well as a list (referred to as the "Adjunct Data File") of units of "nontraditional utilities" that were not in NADB version 2.1 and that included the commenter's units (albeit listed under the commenter's predecessor-company, St. Joseph Minerals Corporation). EPA indicated that the units in the Adjunct Data File might or might not be affected units and that, in any event, it lacked sufficient information on which to base any allowance allocations for the listed

[4] In fact, in its March 9, 1998 comments in the instant proceeding, the commenter incorporated by reference its February 10, 1997 comments submitted in the prior rulemaking where EPA established an exemption from most Acid Rain Program requirements for industrial-utility units. The February 10, 1997 comments are fully addressed in the preamble of the final rule in the prior proceeding. See 62 FR 55460, 55463–66 (1997). To the extent that portions of either set of comments address issues concerning the industrial-utility units exemption or the applicability of the Acid Rain Program to "industrial units" or the commenter's units, those portions (e.g., the entire section I of the February 10, 1997 comments) are outside the scope of, and so are not addressed, in this rulemaking.

[5] If the commenter's units had qualified for allowances, EPA would have calculated the annual number of basic allowances (for 2000 and thereafter) for each unit, under section 405(d)(2) of the Act, as the unit's 1985–1987 average total heat input times the lesser of the unit's 1985 SO_2 emission rate or 1985 SO_2 emission limit. Annual bonus allowances (for 2000 through 2009) would have been calculated, under section 405(d)(3)(B) of the Act, for each unit using generator summer net dependable capacity and the lesser of the unit's 1985 SO_2 emission rate or 1985 SO_2 emission limit.

units. *Id.* Further, EPA gave notice that if "the data elements required for determining allowance allocations" were not provided within the comment period (i.e., by September 8, 1992) for "a unit that may be affected now or in the future", the unit would not be allocated allowances. *Id.*

Finally, in a March 1993 notice, EPA stated that those units in the Adjunct Data File that were affected units and for which the necessary data had been submitted were being included in the NADB (version 2.11) and would be allocated the appropriate number of allowances. 58 FR 15720, 15727 (1993). Believing that it had corrected all timely identified errors in the NADB and resulting allocations, EPA issued a second March 1993 notice stating that any unit not allocated allowances in the notice "but meeting the applicability requirements [for the Acid Rain Program] * * * will not receive allowance allocations [under the allowance allocation regulations for the Acid Rain Program] * * *" 58 FR 15634, 15641 (1993). Consequently, EPA stated in the 1998 proposal that, except for the issues discussed in the 1996 proposal, EPA would not consider any issues that were addressed in 1992 and 1993 concerning the NADB or "any issues that could have been raised in connection with NADB versions 2.0 and 2.1." 63 FR 718.

As stated in the October 24, 1997 notice, neither the commenter (Zinc Corporation of America) nor its predecessor-company submitted any information or supporting data and documentation concerning the units by the September 8, 1992 submission deadline. 62 FR 55466. On March 9, 1998, on the instant proceeding, the commenter submitted, for the first time, information on, *inter alia*, the unit's 1985 SO_2 emissions, 1985 SO_2 emission limit, generator summer net dependable capacity, and 1985–87 average annual total heat input. The fact that the submission is over five years late is alone sufficient basis for rejecting the submission. *See* 62 FR 55466 (explaining basis for September 8, 1992 submission deadline) In addition, the submission is substantively deficient on its face because the submission included only values for these elements and none of the supporting data or documentation required by the July 1991 and July 1992 notices. For example, the commenter listed the 1985 SO_2 emissions but provided neither monitoring data nor a formula and data for calculating emissions.[6] Similarly, the SO_2 emission limit, generator capacity, and heat input were not documented, whether through a State Implementation Plan or permit, State regulatory records, or other records. *Compare* Comments of Zinc Corporation of America, Exhibit A (March 9, 1998) and 56 FR 33284.

EPA notes that, while the commenter suggests in its comments that the Acid Rain Program is applicable to its units, EPA has not made a determination of whether the units are affected units or whether the exemption for industrial-utility units (under § 72.14) applies to the units. As stated in the October 24, 1997 notice, assuming *arguendo* that the units are affected units without any applicable exemption, the units will be treated like any unit that has not been allocated allowances and is or becomes an affected unit, i.e., no allowances will be allocated, and the units must obtain allowances through the allowance market. 62 FR 55466.

EPA's approach of imposing deadlines and substantive requirements for the submission of information and data for allowance allocation and rejecting submissions when the deadline or the substantive requirements are not met has been upheld by the courts. *See Texas Municipal Power Agency* v. *EPA*, 89 F3d. 858, 870 (D.C. Cir. 1996) (upholding EPA's discretion to specify the information that must be submitted, and the submission deadline, for allowance allocations and to determine how to handle a submission that did not meet these requirements). In the instant proceeding, the commenter's only submission, which was made over five years after the deadline, lacked any of the required supporting data and documentation.[7] Under these circumstances, EPA's rejection of the submission is reasonable.[8] *See id.* at 873 (upholding EPA's refusal to allocate allowances where the owners of units failed to submit necessary information "until well after the deadlines" set by EPA even though the information was available).

V. Administrative Requirements

A. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (October 4, 1993), the Administrator must determine whether the regulatory action is "significant" and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines "significant regulatory action" as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, OMB has determined that this rule is not a "significant regulatory action."

B. Unfunded Mandates Act, Executive Order 12875 and 13084

Section 202 of the Unfunded Mandates Reform Act of 1995 ("UMRA") requires that the Agency prepare a budgetary impact statement before promulgating a rule that includes a federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of $100 million or more in any one year. Section 203 requires the Agency to establish a plan for obtaining input from and informing, educating, and advising any small governments that may be significantly or uniquely affected by the rule.

Under section 205 of the UMRA, the Agency must identify and consider a reasonable number of regulatory alternatives before promulgating a rule for which a budgetary impact statement must be prepared. The Agency must select from those alternatives the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the Agency explains why this alternative is not selected or the selection of this alternative is inconsistent with law.

[6] The commenter does not state clearly whether the emissions data provided in its comments were from continuous emissions monitors or were calculated. In either case, supporting documentation was required.

[7] In contrast, in *Texas Municipal*, one petitioner provided information, but no supporting data, by the submission deadline, and EPA therefore used some of the information plus other, verifiable information to calculate allowances for the petitioner's units. 89 F3d. 869.

[8] The commenter has never indicated that the information concerning its 1985 emissions, 1985 emission limit, capacity, or 1985–87 heat input were not available in 1992. In light of the historical nature of the emission and heat input information and since capacity of a unit does not generally change, EPA maintains that all this information probably was available and could have been submitted prior to the deadline.

Under Executive Order 12875, EPA may not issue a regulation that is not required by statute and creates a mandate on State, local, or tribal governments unless the Federal government providees the funds necessary to cover such mandates or consults with representatives of affected State, local or tribal governments before promulgation. Executive Order 13084 establishes similar requirements regarding regulations the significantly or uniquely affect Indian tribal governments.

Because this rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than $100 million in any one year, the Agency has not prepared a budgetary impact statement under UMRA. Today's rule does not create a mandate for State, local or tribal governments and does not significantly or uniquely affect communities of tribal governments. The rule does not impose any enforceable duties on these entities. Accordingly, the requirements of section 1(a) of Executive Order 12875 and section 3(b) of Executive Order 13084 do not apply to this rule.

The revisions to part 73 will not have a significant effect on regulated entities or State permitting authorities. Since sections 403(a) and 405(a)(3) of the Act set a nationwide cap on annual allowance allocations, any reduction of allowances would result in a small increase to the annual allocations for other units that receive allocations. As discussed in the preamble for the 1996 proposal, the revisions explained in the 1996 proposal and incorporated in today's final rule, do not have a significant adverse impact. 61 FR 68366. The other revisions in today's rule (i.e., the revised qualification requirements for allocations under section 405(i)(2), the redistribution of auction proceeds, and reduced repowering reserve) will also not have a significant impact and, in general, result in increased allocations and proceeds receipts for most units.

C. Paperwork Reduction Act

This action revising the allowance allocations rule will not impose any new information collection burden. OMB has previously approved the information collection requirements contained in the allowance rules, 40 CFR part 73, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* *See* EPA ICR Number 1633.10; OMB Control Number 2060.0258.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Copies of the previously approved ICR may be obtained from Director, Regulatory Information Division; EPA; 401 M. Street S.W. (mail code 2137); Washington, D.C. 20460 or by calling (202) 260–2740. Include the ICR and/or OMB number in any correspondence.

D. Regulatory Flexibility

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions.

In the preamble of the January 11, 1993 core rules for the Acid Rain Program, the Administrator certified that the rules would not have a significant, adverse impact on small entities. 58 FR 3590, 3649. Today's revisions do not add any requirements that would burden small entities. Moreover, as explained above in this preamble and the 1996 proposal (61 FR 68367), the effect of the 1998 allowance adjustments on owners and operators of the units is not significant. Most units gain allowances. The only units losing allowances are: those deemed unaffected units and, therefore, not subject to the requirements of the Acid Rain Program; those that have requested to receive fewer basic allowances in order to receive bonus allowances; and those that have been determined to be ineligible for certain allocations, based on information supplied by the utilities. Thus, the 1998 allowance revisions take allowances only from units when the units are not eligible to receive them or when the unit's owner or operator prefers an alternative allocation. For these reasons, EPA has determined that this rule will not have a significant, economic impact on a substantial number of small entities.

E. Children's Health Protection

This final rule is not subject to E.O. 13045, entitled Protection of Children from Environmental Health Risks and Safety Risks (62 FR 19885, April 23, 1997), because it does not involve decisions on environmental health risks or safety risks that may disproportionately affect children.

F. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Pub. L. No. 104–113, 15 U.S.C. 272 note, directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specification, test methods, sampling procedures, business practices, etc.) that are developed or adopted by voluntary consensus standards bodies. The NTTAA requires EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This final rule does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the NTTAA.

G. Submission to Congress and to the General Accounting Office

The Congressional Review Act, 5 U.S.C. 801, *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress to the Comptroller General of the United States. EPA will submit a report containing this action and any other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the General Accounting Office prior to publication of this document in the **Federal Register**. This action is not a "major rule" as defined in 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 73

Environmental protection, Acid rain, Air pollution control, Electric utilities, Reporting and recordkeeping requirements, Sulfur dioxide,

Dated: September 15, 1998.

Carol M. Browner,

Administrator.

For the reasons set forth in the preamble, 40 CFR part 73 is amended as set forth below.

PART 73—[AMENDED]

1. The authority citation for part 73 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 73.10 is amended by:

a. In paragraph (b)(1) revising the words "Table 2 Column E" to read "Table 2 Column C"; and removing the words ", except that units listed in both Table 2 and Table 4 will be allocated allowances as specified in Table 4 Column C, multiplied by .9011, reduced by 1.3185 times Table 2 Column B, and increased by Table 2 Columns C and D";

b. In paragraph (b)(2) revising the words "Table 2 Column I" to read "Table 2 Column F"; and removing the words ", except that units listed in both Table 2 and Table 4 will be allocated allowances as specified in Table 4 Column F, multiplied by .8987, reduced by Table 2 Column G, and increased by Table 2 Column H";

c. Removing paragraphs (c) and (d) (including Tables 3 and 4); and

d. Revising Table 2 of paragraph (b) and paragraph (b)(3) to read as follows:

§ 73.10 Initial allocations for phase I and phase II.

* * * * *

(b) * * *

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Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
AL	Barry	1	113	1	3881	112	112	3890
AL	Barry	2	124	1	4291	124	124	4299
AL	Barry	3	256	3	8808	255	255	8827
AL	Barry	4	292	3	10048	291	291	10069
AL	Barry	5	721	9	24827	718	720	24878
AL	Charles R Lowman	1	34	0	1853	34	34	1184
AL	Charles R Lowman	2	204	2	7024	203	203	7038
AL	Charles R Lowman	3	171	2	5893	171	171	5906
AL	Chickasaw	110	3	0	111	3	3	111
AL	Colbert	1	165	2	5852	165	165	5863
AL	Colbert	2	186	2	6600	186	186	6613
AL	Colbert	3	188	2	6639	187	187	6653
AL	Colbert	4	188	2	6644	187	187	6659
AL	Colbert	5	453	5	16028	452	452	16060
AL	E C Gaston	1	220	2	7803	220	220	7818
AL	E C Gaston	2	226	2	7994	225	226	8009
AL	E C Gaston	3	223	2	7894	222	223	7910
AL	E C Gaston	4	235	3	8310	234	234	8328
AL	E C Gaston	5	730	9	25796	728	729	25848
AL	Gadsden	1	57	1	1956	57	57	1961
AL	Gadsden	2	59	1	2023	59	59	2027
AL	Gorgas	10	651	8	22435	649	650	22483
AL	Gorgas	5	36	0	1756	36	36	1251
AL	Gorgas	6	65	1	3035	64	65	2232
AL	Gorgas	7	72	1	3138	72	72	2500
AL	Gorgas	8	136	1	4758	136	136	4707
AL	Gorgas	9	135	1	4746	134	134	4653
AL	Greene County	1	246	3	8485	246	246	8502
AL	Greene County	2	230	2	7921	229	229	7938
AL	James H Miller Jr	1	351	4	14213	350	350	12122
AL	James H Miller Jr	2	515	7	17762	514	514	17800
AL	James H Miller Jr	3	505	5	17417	504	504	17453
AL	James H Miller Jr	4	233	3	8046	233	233	8063
AL	McIntosh-CAES	**1	27	0	938	27	27	939
AL	McWilliams	**4	0	0	0	0	0	0
AL	Widows Creek	1	70	1	3339	70	70	2417
AL	Widows Creek	2	61	1	3211	61	61	2118
AL	Widows Creek	3	71	1	3355	71	71	2457
AL	Widows Creek	4	78	1	3453	78	78	2686
AL	Widows Creek	5	85	1	3564	85	85	2946
AL	Widows Creek	6	66	1	3278	66	66	2280
AL	Widows Creek	7	161	2	7803	161	161	5573
AL	Widows Creek	8	153	2	7458	153	153	5290
AZ	Agua Fria	1	0	0	54	0	1	34
AZ	Agua Fria	2	0	0	65	0	1	39

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
AZ	Agua Fria	3	0	0	77	0	2	67
AZ	Apache Station	1	10	0	331	10	10	332
AZ	Apache Station	2	41	0	1609	41	41	1420
AZ	Apache Station	3	82	1	3010	82	82	2836
AZ	Cholla	**5	0	0	0	0	0	0
AZ	Cholla	1	59	1	2222	59	59	2034
AZ	Cholla	2	147	2	5441	146	146	5067
AZ	Cholla	3	141	2	5145	140	140	4858
AZ	Cholla	4	225	2	8332	225	225	7784
AZ	Coronado	U1B	151	2	5731	150	150	5199
AZ	Coronado	U2B	158	2	5901	158	158	5465
AZ	De Moss Petrie	4	0	0	0	0	0	0
AZ	Gila Bend	**GT1	0	0	0	0	0	0
AZ	Gila Bend	**GT2	0	0	0	0	0	0
AZ	Gila Bend	**GT3	0	0	0	0	0	0
AZ	Gila Bend	**GT4	0	0	0	0	0	0
AZ	Irvington	1	0	0	16	0	0	14
AZ	Irvington	2	0	0	28	0	1	40
AZ	Irvington	3	0	0	0	0	0	2
AZ	Irvington	4	81	1	2853	81	81	2805
AZ	Kyrene	K-1	0	0	7	0	0	7
AZ	Kyrene	K-2	0	0	18	0	0	16
AZ	Navajo	1	723	9	26211	721	722	24949
AZ	Navajo	2	676	8	24254	674	676	23354
AZ	Navajo	3	686	8	25034	684	686	23693
AZ	Ocotillo	1	0	0	56	0	1	40
AZ	Ocotillo	2	3	0	132	3	4	129
AZ	Saguaro	1	5	0	204	5	5	189
AZ	Saguaro	2	0	0	25	0	1	22
AZ	Springerville	1	177	2	6564	176	176	6099
AZ	Springerville	2	167	2	5754	166	167	5765
AZ	Springerville	3	0	0	0	0	0	0
AZ	West Phoenix	4	0	0	11	0	0	9
AZ	West Phoenix	6	0	0	22	0	0	15
AZ	Yuma Axis	1	0	0	42	0	1	40
AR	Carl Bailey	01	0	0	10	0	0	8
AR	Cecil Lynch	1	0	0	0	0	0	0
AR	Cecil Lynch	2	0	0	0	0	0	0
AR	Cecil Lynch	3	0	0	3	0	0	0
AR	Flint Creek	1	421	5	15187	420	421	14556
AR	Hamilton Moses	1	0	0	0	0	0	0
AR	Hamilton Moses	2	0	0	0	0	0	0
AR	Harvey Couch	1	0	0	7	0	0	3
AR	Harvey Couch	2	0	0	112	0	3	113
AR	Independence	1	496	5	18150	494	495	17123

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AR	Independence	2	496	5	18396	495	495	17142
AR	Lake Catherine	1	0	0	0	0	0	0
AR	Lake Catherine	2	0	0	0	0	0	0
AR	Lake Catherine	3	0	0	8	0	0	6
AR	Lake Catherine	4	3	0	156	3	10	337
AR	McClellan	01	0	0	15	0	0	13
AR	Robert E Ritchie	1	0	0	53	0	2	67
AR	Robert E Ritchie	2	62	1	2147	62	62	2138
AR	Thomas Fitzhugh	1	0	0	1	0	0	1
AR	White Bluff	1	582	7	20933	581	581	20116
AR	White Bluff	2	668	8	23892	666	667	23059
CA	Alamitos	1	78	1	2774	78	78	2703
CA	Alamitos	2	0	0	105	0	0	17
CA	Alamitos	3	0	0	290	0	2	81
CA	Alamitos	4	16	0	819	16	16	541
CA	Alamitos	5	112	1	4226	112	112	3868
CA	Alamitos	6	27	0	1484	27	27	936
CA	Avon	1	0	0	17	0	0	14
CA	Avon	2	0	0	0	0	0	14
CA	Avon	3	0	0	0	0	0	14
CA	Broadway	B1	4	0	127	4	4	124
CA	Broadway	B2	4	0	164	4	4	155
CA	Broadway	B3	0	0	74	0	2	71
CA	Contra Costa	1	0	0	125	1	0	16
CA	Contra Costa	10	115	1	4285	115	115	3978
CA	Contra Costa	2	0	0	2	0	0	23
CA	Contra Costa	3	0	0	0	0	0	20
CA	Contra Costa	4	0	0	0	0	0	15
CA	Contra Costa	5	0	0	0	0	0	16
CA	Contra Costa	6	0	0	0	0	0	13
CA	Contra Costa	7	0	0	28	0	1	28
CA	Contra Costa	8	0	0	53	0	1	40
CA	Contra Costa	9	1	0	356	0	9	303
CA	Cool Water	1	0	0	10	0	0	11
CA	Cool Water	2	0	0	6	0	0	8
CA	El Centro	3	17	0	614	17	17	579
CA	El Centro	4	16	0	586	16	16	560
CA	El Segundo	1	10	0	440	10	10	357
CA	El Segundo	2	0	0	90	0	2	62
CA	El Segundo	3	1	0	182	1	5	171
CA	El Segundo	4	2	0	370	2	10	363
CA	Encina	1	13	0	491	13	13	446
CA	Encina	2	30	0	1131	30	30	1042
CA	Encina	3	20	0	737	20	20	680
CA	Encina	4	53	1	1945	52	52	1816

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CA	Encina	5	69	1	2494	69	69	2399
CA	Etiwanda	1	3	0	117	3	3	94
CA	Etiwanda	2	0	0	29	0	1	17
CA	Etiwanda	3	34	0	1372	34	34	1169
CA	Etiwanda	4	1	0	261	1	8	271
CA	Glenarm	16	0	0	0	1	0	0
CA	Glenarm	17	0	0	0	2	0	0
CA	Grayson	4	3	0	102	2	3	87
CA	Grayson	5	1	0	36	3	1	42
CA	Harbor Gen Station	**10A	20	0	699	20	20	700
CA	Harbor Gen Station	**10B	20	0	699	20	20	700
CA	Harbor Gen Station	1	2	0	68	0	2	61
CA	Harbor Gen Station	2	3	0	121	0	3	107
CA	Harbor Gen Station	3	3	0	94	0	2	86
CA	Harbor Gen Station	4	3	0	104	0	3	98
CA	Harbor Gen Station	5	4	0	171	0	4	154
CA	Haynes Gen Station	1	17	0	681	17	17	571
CA	Haynes Gen Station	2	9	0	338	9	9	328
CA	Haynes Gen Station	3	33	0	1244	33	33	1131
CA	Haynes Gen Station	4	25	0	1002	25	25	851
CA	Haynes Gen Station	5	35	0	1401	35	35	1205
CA	Haynes Gen Station	6	37	0	1527	37	37	1270
CA	Highgrove	1	0	0	4	0	0	3
CA	Highgrove	2	0	0	1	0	0	0
CA	Highgrove	3	0	0	1	0	0	1
CA	Highgrove	4	0	0	3	0	0	3
CA	Humboldt Bay	1	10	0	358	10	10	341
CA	Humboldt Bay	2	0	0	24	0	1	26
CA	Hunters Point	3	0	0	76	0	1	47
CA	Hunters Point	4	0	0	5	0	1	48
CA	Hunters Point	5	0	0	74	0	1	42
CA	Hunters Point	6	0	0	1	0	1	37
CA	Hunters Point	7	0	0	192	0	5	170
CA	Huntington Beach	1	33	0	1325	33	33	1153
CA	Huntington Beach	2	28	0	1134	28	28	970
CA	Huntington Beach	3	1	0	161	1	2	62
CA	Huntington Beach	4	1	0	176	1	2	76
CA	Kern	1	0	0	3	0	0	2
CA	Kern	2	0	0	0	0	0	3
CA	Kern	3	0	0	13	0	0	3
CA	Kern	4	0	0	0	0	0	3
CA	Magnolia	M4	1	0	37	1	1	33
CA	Mandalay	1	34	0	1379	33	33	1159
CA	Mandalay	2	32	0	1291	31	31	1090
CA	Martinez	1	0	0	1	0	0	1

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
CA	Martinez	2	0	0	1	0	0	1
CA	Martinez	3	0	0	1	0	0	1
CA	Morro Bay	1	41	0	1561	41	41	1410
CA	Morro Bay	2	0	0	139	0	3	98
CA	Morro Bay	3	101	1	3821	101	101	3496
CA	Morro Bay	4	83	1	3052	83	83	2884
CA	Moss Landing	1	0	0	122	0	0	17
CA	Moss Landing	2	0	0	0	0	0	15
CA	Moss Landing	3	0	0	0	0	0	19
CA	Moss Landing	4	0	0	0	0	0	21
CA	Moss Landing	5	0	0	0	0	0	21
CA	Moss Landing	6	0	0	0	0	0	14
CA	Moss Landing	6-1	235	3	8921	235	235	8125
CA	Moss Landing	7	0	0	79	0	1	52
CA	Moss Landing	7-1	2	0	976	2	20	694
CA	Moss Landing	8	13	0	466	13	13	435
CA	Oleum	1	4	0	146	4	4	122
CA	Oleum	2	4	0	138	4	4	138
CA	Oleum	3	8	0	244	8	8	242
CA	Oleum	4	2	0	102	2	2	102
CA	Oleum	5	6	0	174	6	6	174
CA	Oleum	6	6	0	204	6	6	204
CA	Olive	01	3	0	133	3	3	121
CA	Olive	02	0	0	25	0	1	47
CA	Ormond Beach	1	110	1	4519	109	109	3785
CA	Ormond Beach	2	118	1	4585	118	118	4092
CA	Pittsburg	1	43	0	1641	43	43	1494
CA	Pittsburg	2	36	0	1350	35	36	1228
CA	Pittsburg	3	42	0	1586	42	42	1443
CA	Pittsburg	4	42	0	1581	42	42	1452
CA	Pittsburg	5	0	0	285	0	8	288
CA	Pittsburg	6	104	1	3753	103	103	3578
CA	Pittsburg	7	1	0	740	1	18	625
CA	Potrero	3-1	0	0	321	0	8	266
CA	Redondo Beach	11	0	0	36	0	0	4
CA	Redondo Beach	12	0	0	0	0	0	2
CA	Redondo Beach	13	0	0	0	1	0	4
CA	Redondo Beach	14	0	0	0	1	0	4
CA	Redondo Beach	15	0	0	0	0	0	3
CA	Redondo Beach	16	0	0	0	0	0	5
CA	Redondo Beach	17	0	0	0	0	0	6
CA	Redondo Beach	5	0	0	80	0	4	126
CA	Redondo Beach	6	0	0	105	0	3	103
CA	Redondo Beach	7	1	0	554	0	14	483
CA	Redondo Beach	8	1	0	597	0	14	496

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
CA	San Bernardino	1	3	0	118	3	3	105
CA	San Bernardino	2	0	0	17	0	1	19
CA	Scattergood Gen Sta	1	19	0	752	19	19	641
CA	Scattergood Gen Sta	2	17	0	658	17	17	571
CA	Scattergood Gen Sta	3	0	0	262	0	7	250
CA	Silver Gate	1	0	0	0	0	0	0
CA	Silver Gate	2	0	0	0	0	0	0
CA	Silver Gate	3	0	0	0	0	0	0
CA	Silver Gate	4	0	0	0	0	0	0
CA	Silver Gate	5	0	0	0	0	0	0
CA	Silver Gate	6	0	0	0	0	0	0
CA	South Bay	1	67	1	2491	66	67	2303
CA	South Bay	2	49	1	1774	49	49	1683
CA	South Bay	3	59	1	2176	58	59	2024
CA	South Bay	4	16	0	603	16	16	554
CA	Valley Gen Station	1	3	0	122	3	3	101
CA	Valley Gen Station	2	3	0	141	3	3	120
CA	Valley Gen Station	3	11	0	389	11	11	389
CA	Valley Gen Station	4	9	0	351	9	9	295
CO	Arapahoe	1	6	0	221	6	6	208
CO	Arapahoe	2	7	0	247	7	7	229
CO	Arapahoe	3	5	0	181	5	5	172
CO	Arapahoe	4	53	1	1926	53	53	1829
CO	Cameo	2	25	0	904	25	25	852
CO	Cherokee	1	59	1	2137	59	59	2035
CO	Cherokee	2	79	1	2837	79	79	2722
CO	Cherokee	3	103	1	3760	103	103	3562
CO	Cherokee	4	206	2	7533	206	206	7132
CO	Comanche	1	213	2	7696	213	213	7363
CO	Comanche	2	187	2	6912	186	186	6450
CO	Craig	C1	222	2	8216	222	222	7678
CO	Craig	C2	213	2	7843	212	213	7352
CO	Craig	C3	62	1	2601	62	62	2149
CO	Hayden	H1	167	2	6061	167	167	5776
CO	Hayden	H2	255	3	9227	254	255	8810
CO	Martin Drake	5	32	0	1149	31	31	1089
CO	Martin Drake	6	55	1	2029	55	55	1911
CO	Martin Drake	7	88	1	3218	88	88	3043
CO	Nucla	1	33	0	1122	33	33	1124
CO	Pawnee	**2	0	0	0	0	0	0
CO	Pawnee	1	398	4	14439	397	398	13761
CO	Rawhide	101	39	0	1800	39	39	1352
CO	Ray D Nixon	**NA1	0	0	0	0	0	0
CO	Ray D Nixon	1	122	1	4476	122	122	4217
CO	Valmont	14	0	0	4	0	0	0

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
CO	Valmont	21	0	0	20	0	0	20
CO	Valmont	24	0	0	0	0	0	0
CO	Valmont	5	86	1	3136	86	86	2983
CO	Zuni	1	10	0	340	10	10	341
CO	Zuni	2	0	0	0	0	0	6
CO	Zuni	3	0	0	5	0	0	9
CT	Bridgeport Harbor	BHB1	60	1	2078	60	60	2082
CT	Bridgeport Harbor	BHB2	137	1	4726	137	137	4735
CT	Bridgeport Harbor	BHB3	333	4	11477	332	332	11501
CT	Devon	3	28	0	980	28	28	981
CT	Devon	4A	5	0	170	5	5	171
CT	Devon	4B	5	0	171	5	5	172
CT	Devon	5A	4	0	155	4	4	156
CT	Devon	5B	4	0	155	4	4	156
CT	Devon	6	26	0	898	26	26	899
CT	Devon	7	81	1	2807	81	81	2813
CT	Devon	8	87	1	3002	87	87	3008
CT	English	EB13	3	0	114	3	3	113
CT	English	EB14	5	0	157	5	5	157
CT	Middletown	1	13	0	461	13	13	462
CT	Middletown	2	39	0	1328	38	38	1332
CT	Middletown	3	97	1	3338	97	97	3345
CT	Middletown	4	69	1	2389	69	69	2393
CT	Montville	5	35	0	1208	35	35	1210
CT	Montville	6	165	2	5673	164	164	5686
CT	New Haven Harbor	NHB1	379	4	13066	378	378	13092
CT	Norwalk Harbor	1	149	2	5139	149	149	5150
CT	Norwalk Harbor	2	158	2	5456	158	158	5467
DE	Edge Moor	3	103	1	3557	103	103	3564
DE	Edge Moor	4	183	2	6293	182	182	6307
DE	Edge Moor	5	187	2	6461	187	187	6473
DE	Hay Road	**3	5	0	158	5	5	158
DE	Indian River	1	87	1	2997	87	87	3002
DE	Indian River	2	92	1	3181	92	92	3188
DE	Indian River	3	158	2	5439	157	158	5451
DE	Indian River	4	389	4	13410	388	388	13438
DE	McKee Run	3	54	1	2584	53	53	1850
DE	Van Sant	**11	4	0	138	4	4	138
DC	Benning	15	15	0	517	15	15	518
DC	Benning	16	25	0	856	25	25	857
FL	Anclote (4)	1	298	3	13022	297	298	10297
FL	Anclote (4)	2	315	3	12950	314	315	10894
FL	Arvah B Hopkins	1	1	0	81	1	2	85
FL	Arvah B Hopkins	2	160	2	5522	160	160	5532
FL	Avon Park	2	14	0	495	14	14	495

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
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FL	Big Bend	BB01	352	4	12132	351	351	12156
FL	Big Bend	BB02	354	4	12196	353	353	12221
FL	Big Bend	BB03	332	4	11444	331	331	11468
FL	Big Bend	BB04	255	3	8780	254	254	8799
FL	C D McIntosh Jr	1	26	0	907	26	26	908
FL	C D McIntosh Jr	2	30	0	1029	30	30	1031
FL	C D McIntosh Jr	3	288	3	9928	287	288	9948
FL	Cape Canaveral	PCC1	123	1	4224	122	122	4232
FL	Cape Canaveral	PCC2	144	2	4961	143	144	4969
FL	Combined Cycle 1	32432	2	0	60	2	2	60
FL	Crist	1	1	0	35	1	1	35
FL	Crist	2	0	0	3	0	0	3
FL	Crist	3	0	0	4	0	0	4
FL	Crist	4	72	1	2467	71	71	2473
FL	Crist	5	70	1	2430	70	70	2435
FL	Crist	6	244	3	8396	243	243	8413
FL	Crist	7	363	4	12522	362	363	12545
FL	Crystal River	1	360	4	12425	359	360	12449
FL	Crystal River	2	415	4	14291	413	414	14320
FL	Crystal River	4	686	8	23651	684	686	23697
FL	Crystal River	5	734	9	25248	732	732	25301
FL	CT	**1	0	0	0	0	0	0
FL	CT	**2	0	0	0	0	0	0
FL	CT	**3	0	0	0	0	0	0
FL	CT	**4	0	0	0	0	0	0
FL	Cutler	PCU5	0	0	0	0	0	4
FL	Cutler	PCU6	0	0	0	0	0	9
FL	Debary	**10	20	0	705	20	20	706
FL	Debary	**7	20	0	705	20	20	706
FL	Debary	**8	20	0	705	20	20	706
FL	Debary	**9	20	0	705	20	20	706
FL	Deerhaven	**NA2	0	0	0	0	0	0
FL	Deerhaven	B1	1	0	98	1	3	114
FL	Deerhaven	B2	240	3	8268	239	239	8286
FL	Deerhaven	CT3	0	0	0	0	0	0
FL	F J Gannon	GB01	97	1	3842	97	97	3358
FL	F J Gannon	GB02	120	1	4425	120	120	4148
FL	F J Gannon	GB03	164	2	5664	164	164	5675
FL	F J Gannon	GB04	179	2	6223	179	179	6185
FL	F J Gannon	GB05	190	2	6537	189	189	6551
FL	F J Gannon	GB06	292	3	10081	292	292	10101
FL	Fort Myers	PFM1	93	1	3188	92	92	3194
FL	Fort Myers	PFM2	274	3	9457	273	274	9475
FL	G E Turner	2	2	0	543	2	2	82
FL	G E Turner	3	21	0	718	21	21	720

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
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FL	G E Turner	4	18	0	611	18	18	611
FL	Henry D King	7	2	0	63	2	2	65
FL	Henry D King	8	0	0	26	0	1	34
FL	Higgins	1	12	0	423	12	12	423
FL	Higgins	2	14	0	475	14	14	475
FL	Higgins	3	13	0	969	13	13	434
FL	Hookers Point	HB01	4	0	177	4	4	177
FL	Hookers Point	HB02	5	0	207	5	5	205
FL	Hookers Point	HB03	13	0	469	13	13	468
FL	Hookers Point	HB04	20	0	701	20	20	702
FL	Hookers Point	HB05	36	0	1253	36	36	1252
FL	Hookers Point	HB06	14	0	478	14	14	478
FL	Indian River	**C	0	0	0	0	0	0
FL	Indian River	**D	19	0	639	18	18	640
FL	Indian River	1	35	0	1192	34	34	1194
FL	Indian River	2	46	0	1569	45	45	1572
FL	Indian River	3	106	1	3646	105	106	3652
FL	Intercession City	**10	20	0	705	20	20	706
FL	Intercession City	**7	20	0	705	20	20	706
FL	Intercession City	**8	20	0	705	20	20	706
FL	Intercession City	**9	20	0	705	20	20	706
FL	J D Kennedy	10	57	1	1975	57	57	1980
FL	J D Kennedy	8	6	0	196	6	6	196
FL	J D Kennedy	9	16	0	553	16	16	553
FL	J R Kelly	JRK8	1	0	58	1	2	67
FL	Lansing Smith	1	188	2	6476	187	188	6489
FL	Lansing Smith	2	221	2	7601	220	220	7616
FL	Larsen Memorial	**8	19	0	665	19	19	666
FL	Larsen Memorial	**9	0	0	0	0	0	0
FL	Larsen Memorial	7	9	0	307	9	9	308
FL	Lauderdale	4GT1	28	0	948	27	27	950
FL	Lauderdale	4GT2	28	0	948	27	27	950
FL	Lauderdale	5GT1	28	0	948	27	27	950
FL	Lauderdale	5GT2	28	0	948	27	27	950
FL	Manatee	PMT1	400	4	13773	398	399	13799
FL	Manatee	PMT2	368	4	12697	367	368	12716
FL	Martin	HRSG3A	37	0	1275	37	37	1277
FL	Martin	HRSG3B	37	0	1275	37	37	1277
FL	Martin	HRSG4A	37	0	1275	37	37	1277
FL	Martin	HRSG4B	37	0	1275	37	37	1277
FL	Martin	PMR1	148	2	5092	147	147	5102
FL	Martin	PMR2	175	2	6039	175	175	6049
FL	NA 1 – 7238	**1	0	0	0	0	0	0
FL	Northside	1	142	2	6222	141	142	4897
FL	Northside	2	30	0	6268	30	30	1048

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
FL	Northside	3	193	2	11124	192	192	6658
FL	P L Bartow	1	71	1	2805	71	71	2455
FL	P L Bartow	2	70	1	2961	70	70	2431
FL	P L Bartow	3	157	2	5428	157	157	5439
FL	Port Everglades	PPE1	68	1	2339	68	68	2343
FL	Port Everglades	PPE2	70	1	2413	70	70	2417
FL	Port Everglades	PPE3	171	2	5880	170	170	5891
FL	Port Everglades	PPE4	173	2	5962	172	173	5973
FL	Putnam	HRSG1	48	1	1643	48	48	1647
FL	Putnam	HRSG1	48	1	1643	48	48	1647
FL	Putnam	HRSG2	45	0	1568	45	45	1570
FL	Putnam	HRSG2	45	0	1568	45	45	1570
FL	Riviera	PRV2	3	0	94	3	3	94
FL	Riviera	PRV3	104	1	3573	103	103	3580
FL	Riviera	PRV4	103	1	3545	102	103	3551
FL	S O Purdom	7	13	0	443	13	13	444
FL	Sanford	PSN3	31	0	1085	31	31	1087
FL	Sanford	PSN4	96	1	8614	96	96	3323
FL	Sanford	PSN5	93	1	3221	93	93	3220
FL	Scholz	1	57	1	1958	57	57	1963
FL	Scholz	2	59	1	2050	59	59	2054
FL	Seminole	1	533	7	18381	532	532	18420
FL	Seminole	2	533	7	18381	532	532	18420
FL	Southside	1	27	0	930	27	27	932
FL	Southside	2	28	0	963	28	28	964
FL	Southside	3	7	0	227	7	7	227
FL	Southside	4	18	0	616	18	18	617
FL	Southside	5	53	1	1810	52	52	1815
FL	St Johns River Pwr	1	336	4	11582	335	335	11605
FL	St Johns River Pwr	2	330	4	11370	329	329	11395
FL	Stanton Energy	1	328	4	11290	327	327	11314
FL	Stanton Energy	2	0	0	0	0	0	0
FL	Stock Island	1	75	1	2571	74	74	2578
FL	Stock Island D1	**NA1	3	0	100	3	3	100
FL	Stock Island D2	**NA2	3	0	100	3	3	100
FL	Suwannee River	1	7	0	254	7	7	255
FL	Suwannee River	2	7	0	253	7	7	253
FL	Suwannee River	3	19	0	649	19	19	649
FL	Tom G Smith	S-3	0	0	9	0	0	11
FL	Tom G Smith	S-4	2	0	80	2	2	80
FL	Turkey Point	PTP1	170	2	5868	170	170	5879
FL	Turkey Point	PTP2	172	2	5911	171	171	5924
FL	Vero Beach Munic	**5	9	0	317	9	9	318
FL	Vero Beach Munic	3	9	0	315	9	9	316
FL	Vero Beach Munic	4	2	0	107	2	3	116

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
GA	Arkwright	1	37	0	1449	37	37	1291
GA	Arkwright	2	39	0	1470	39	39	1354
GA	Arkwright	3	45	0	1539	45	45	1542
GA	Arkwright	4	36	0	1255	36	36	1257
GA	Atkinson	A1A	0	0	2	0	0	2
GA	Atkinson	A1B	0	0	2	0	0	2
GA	Atkinson	A2	0	0	4	0	0	4
GA	Atkinson	A3	0	0	6	0	0	5
GA	Atkinson	A4	0	0	5	0	0	5
GA	Bowen	1BLR	667	8	23609	665	667	23656
GA	Bowen	2BLR	686	8	24280	684	686	24329
GA	Bowen	3BLR	875	10	30932	873	874	30994
GA	Bowen	4BLR	875	10	30924	873	873	30987
GA	Hammond	1	107	1	3785	107	107	3793
GA	Hammond	2	112	1	3974	112	112	3981
GA	Hammond	3	109	1	3841	108	108	3850
GA	Hammond	4	459	5	16227	457	458	16260
GA	Harllee Branch	1	286	3	9856	285	285	9876
GA	Harllee Branch	2	338	4	11657	337	338	11681
GA	Harllee Branch	3	465	5	16039	464	464	16072
GA	Harllee Branch	4	462	5	15916	461	461	15949
GA	Jack McDonough	MB1	243	3	8581	242	242	8599
GA	Jack McDonough	MB2	251	3	8882	250	251	8900
GA	Kraft	1	44	0	1530	44	44	1533
GA	Kraft	2	42	0	1510	42	42	1466
GA	Kraft	3	86	1	2963	86	86	2968
GA	Kraft	4	13	0	436	13	13	437
GA	McIntosh	1	161	2	5554	161	161	5565
GA	McManus	1	3	0	844	3	3	89
GA	McManus	2	6	0	1279	6	6	198
GA	Mitchell	3	158	2	5461	158	158	5472
GA	Riverside	12	0	0	5	0	0	5
GA	Scherer	1	611	8	21075	610	610	21121
GA	Scherer	2	616	8	21224	614	615	21270
GA	Scherer	3	617	8	21258	615	616	21304
GA	Scherer	4	616	8	21234	614	615	21280
GA	Wansley	1	863	10	30507	861	862	30567
GA	Wansley	2	798	10	28201	796	797	28259
GA	Yates	Y1BR	88	1	3106	88	88	3113
GA	Yates	Y2BR	86	1	3035	86	86	3041
GA	Yates	Y3BR	85	1	2997	84	85	3003
GA	Yates	Y4BR	109	1	3842	108	108	3851
GA	Yates	Y5BR	115	1	4055	114	114	4063
GA	Yates	Y6BR	302	3	10675	301	301	10696
GA	Yates	Y7BR	297	3	10499	296	296	10521

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
IL	Baldwin	1	512	7	18109	510	511	18146
IL	Baldwin	2	541	7	19147	540	540	19186
IL	Baldwin	3	518	7	18343	517	518	18380
IL	Coffeen	01	144	2	5083	143	143	5094
IL	Coffeen	02	434	5	15376	433	434	15406
IL	Collins	1	38	0	1327	38	38	1329
IL	Collins	2	33	0	1133	33	33	1135
IL	Collins	3	58	1	2000	58	58	2004
IL	Collins	4	47	1	1632	47	47	1636
IL	Collins	5	52	1	1809	52	52	1812
IL	Crawford	7	105	1	7235	104	105	3617
IL	Crawford	8	162	2	9848	162	162	5602
IL	Dallman	31	40	0	1385	40	40	1388
IL	Dallman	32	45	0	1568	45	45	1570
IL	Dallman	33	151	2	5197	150	151	5208
IL	Duck Creek	1	325	4	11197	324	324	11220
IL	E D Edwards	1	70	1	2898	70	70	2414
IL	E D Edwards	2	196	2	6914	195	195	6760
IL	E D Edwards	3	251	3	9122	250	250	8663
IL	Fisk	19	104	1	10031	104	104	3602
IL	Grand Tower	07	7	0	248	7	7	248
IL	Grand Tower	08	7	0	235	7	7	236
IL	Grand Tower	09	72	1	2546	72	72	2551
IL	Havana	1	0	0	35	0	0	35
IL	Havana	2	0	0	45	0	0	45
IL	Havana	3	0	0	35	0	0	35
IL	Havana	4	0	0	35	0	0	35
IL	Havana	5	0	0	35	0	0	35
IL	Havana	6	0	0	35	0	0	35
IL	Havana	7	0	0	35	0	0	35
IL	Havana	8	0	0	35	0	0	35
IL	Havana	9	195	2	8803	194	195	6731
IL	Hennepin	1	59	1	2017	58	58	2023
IL	Hennepin	2	224	2	7938	224	224	7953
IL	Hutsonville	05	64	1	2222	64	64	2227
IL	Hutsonville	06	67	1	2301	67	67	2306
IL	Joliet 29	71	169	2	7578	169	169	5837
IL	Joliet 29	72	138	1	6176	137	138	4757
IL	Joliet 29	81	158	2	7294	158	158	5471
IL	Joliet 29	82	164	2	7556	164	164	5668
IL	Joliet 9	5	170	2	8674	170	170	5886
IL	Joppa Steam	1	153	2	5286	153	153	5297
IL	Joppa Steam	2	131	1	4522	131	131	4530
IL	Joppa Steam	3	149	2	5151	149	149	5162
IL	Joppa Steam	4	138	2	4771	138	138	4781

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
IL	Joppa Steam	5	139	2	4793	139	139	4803
IL	Joppa Steam	6	129	1	4459	129	129	4467
IL	Kincaid	1	384	4	13592	383	383	13620
IL	Kincaid	2	423	5	14977	422	423	15006
IL	Lakeside	7	74	1	2553	74	18	633
IL	Lakeside	8	42	0	1446	42	9	326
IL	Marion	1	60	1	2079	60	14	468
IL	Marion	2	62	1	2129	62	14	479
IL	Marion	3	67	1	2309	67	15	520
IL	Marion	4	198	2	6839	198	198	6853
IL	Meredosia	01	9	0	298	9	9	299
IL	Meredosia	02	9	0	322	9	9	322
IL	Meredosia	03	8	0	280	8	8	281
IL	Meredosia	04	7	0	255	7	7	255
IL	Meredosia	05	169	2	5989	169	169	6000
IL	Meredosia	06	1	0	46	1	1	46
IL	Newton	1	453	5	15620	452	452	15652
IL	Newton	2	404	4	13928	403	403	13956
IL	Powerton	51	244	3	10701	244	244	8443
IL	Powerton	52	241	3	10571	241	241	8341
IL	Powerton	61	248	3	10513	248	248	8580
IL	Powerton	62	250	3	10596	250	250	8647
IL	R S Wallace	10	5	0	2432	5	5	177
IL	R S Wallace	9	2	0	901	2	2	61
IL	Venice	1	0	0	5	0	0	5
IL	Venice	2	0	0	2	0	0	2
IL	Venice	3	0	0	17	0	0	17
IL	Venice	4	0	0	14	0	0	14
IL	Venice	5	0	0	10	0	0	10
IL	Venice	6	0	0	10	0	0	10
IL	Venice	7	0	0	2	0	0	2
IL	Venice	8	0	0	2	0	0	2
IL	Vermillion	1	82	1	2834	82	82	2840
IL	Vermillion	2	108	1	3830	108	108	3837
IL	Waukegan	17	43	0	3104	182	43	1501
IL	Waukegan	7	183	2	8212	145	183	6314
IL	Waukegan	8	145	2	7838	43	145	5005
IL	Will County	1	74	1	5321	74	74	2554
IL	Will County	2	73	1	4849	72	72	2505
IL	Will County	3	150	2	6993	150	150	5197
IL	Will County	4	264	3	13801	264	264	9133
IL	Wood River	1	0	0	3	0	0	3
IL	Wood River	2	0	0	3	0	0	3
IL	Wood River	3	0	0	3	0	0	3
IL	Wood River	4	51	1	2258	51	51	1761

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
IL	Wood River	5	275	3	9478	274	274	9498
IN	A B Brown	**4	19	0	639	18	18	640
IN	A B Brown	1	155	2	5356	155	155	5368
IN	A B Brown	2	131	1	4529	131	131	4538
IN	Bailly	7	136	1	4811	136	136	4819
IN	Bailly	8	194	2	6869	194	194	6882
IN	Breed	1	225	2	7975	225	225	7990
IN	Cayuga	1	407	4	14386	405	406	14415
IN	Cayuga	2	416	5	14710	415	415	14740
IN	Cayuga	4	0	0	0	0	0	0
IN	Cayuga	5	0	0	0	0	0	0
IN	Cayuga	6	0	0	0	0	0	0
IN	Clifty Creek	1	246	3	8462	245	245	8480
IN	Clifty Creek	2	241	3	8321	241	241	8338
IN	Clifty Creek	3	249	3	8570	248	248	8589
IN	Clifty Creek	4	245	3	8431	244	244	8449
IN	Clifty Creek	5	236	3	8129	235	235	8146
IN	Clifty Creek	6	248	3	8557	248	248	8574
IN	Dean H Mitchell	11	35	0	2658	35	35	1225
IN	Dean H Mitchell	4	43	0	3116	43	43	1473
IN	Dean H Mitchell	5	54	1	3017	54	54	1860
IN	Dean H Mitchell	6	48	1	2969	48	48	1672
IN	Edwardsport	6-1	0	0	0	0	0	0
IN	Edwardsport	7-1	10	0	347	10	10	348
IN	Edwardsport	7-2	10	0	354	10	10	355
IN	Edwardsport	8-1	11	0	375	11	11	375
IN	Elmer W Stout	1	0	0	0	0	0	0
IN	Elmer W Stout	2	0	0	0	0	0	0
IN	Elmer W Stout	3	0	0	0	0	0	0
IN	Elmer W Stout	4	0	0	0	0	0	0
IN	Elmer W Stout	5	0	0	0	0	0	0
IN	Elmer W Stout	6	0	0	0	0	0	0
IN	Elmer W Stout	7	0	0	0	0	0	0
IN	Elmer W Stout	8	0	0	0	0	0	0
IN	Elmer W Stout	9	0	0	1	0	0	1
IN	Elmer W Stout	10	0	0	2	0	0	2
IN	Elmer W Stout	50	47	1	1673	47	47	1677
IN	Elmer W Stout	60	58	1	2057	58	58	2061
IN	Elmer W Stout	70	288	3	10177	287	287	10198
IN	F B Culley	1	24	0	827	24	24	828
IN	F B Culley	2	50	1	1758	50	50	1762
IN	F B Culley	3	207	2	7316	206	206	7332
IN	Frank E Ratts	1SG1	102	1	3592	101	101	3600
IN	Frank E Ratts	2SG1	103	1	3659	103	103	3666
IN	Gibson	1	492	5	17415	491	491	17449

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
IN	Gibson	2	500	5	17678	498	499	17713
IN	Gibson	3	500	5	17709	499	500	17743
IN	Gibson	4	491	5	17384	490	490	17419
IN	Gibson	5	527	7	18180	526	527	18217
IN	H T Pritchard	1	0	0	0	0	0	0
IN	H T Pritchard	2	0	0	1	0	0	1
IN	H T Pritchard	3	7	0	240	7	7	240
IN	H T Pritchard	4	15	0	533	15	15	534
IN	H T Pritchard	5	17	0	596	17	17	597
IN	H T Pritchard	6	70	1	2487	70	70	2492
IN	Merom	1SG1	433	5	14920	432	432	14951
IN	Merom	2SG1	430	5	14818	429	429	14850
IN	Michigan City	12	284	3	10049	283	283	10069
IN	Michigan City	4	26	0	909	26	26	912
IN	Michigan City	5	29	0	1010	29	29	1012
IN	Michigan City	6	30	0	1019	30	30	1021
IN	NA 1 – 7221	**1	0	0	0	0	0	0
IN	NA 1 – 7221	**3	0	0	0	0	0	0
IN	NA 1 – 7221	**4	0	0	0	0	0	0
IN	Noblesville	1	2	0	66	2	2	66
IN	Noblesville	2	2	0	54	2	2	54
IN	Noblesville	3	1	0	40	1	1	40
IN	Petersburg	1	200	2	7086	200	200	7100
IN	Petersburg	2	395	4	13961	393	394	13988
IN	Petersburg	3	490	5	16881	488	489	16916
IN	Petersburg	4	469	5	16150	467	468	16183
IN	R Gallagher	1	82	1	2908	82	82	2914
IN	R Gallagher	2	89	1	3137	88	89	3144
IN	R Gallagher	3	80	1	2814	79	79	2821
IN	R Gallagher	4	83	1	2932	83	83	2938
IN	R M Schahfer	14	141	2	10355	141	141	4868
IN	R M Schahfer	15	129	1	10692	129	129	4461
IN	R M Schahfer	17	151	2	5222	151	151	5233
IN	R M Schahfer	18	151	2	5187	150	150	5199
IN	Rockport	MB1	958	11	32992	956	957	33061
IN	Rockport	MB2	958	11	32992	956	957	33061
IN	State Line	3	100	1	4725	100	100	3452
IN	State Line	4	175	2	6922	174	174	6033
IN	Tanners Creek	U1	59	1	2775	59	59	2037
IN	Tanners Creek	U2	62	1	2797	62	62	2138
IN	Tanners Creek	U3	66	1	4079	66	66	2287
IN	Tanners Creek	U4	302	3	10702	302	302	10722
IN	Wabash River	1	49	1	1722	49	49	1726
IN	Wabash River	2	39	0	1392	39	39	1394
IN	Wabash River	3	46	0	1616	46	46	1619

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
IN	Wabash River	4	44	0	1532	44	44	1534
IN	Wabash River	5	45	0	1582	45	45	1584
IN	Wabash River	6	150	2	5293	149	149	5304
IN	Warrick	4	297	3	10506	296	296	10527
IN	Whitewater Valley	1	65	1	2236	65	65	2241
IN	Whitewater Valley	2	194	2	6693	194	194	6706
IA	Ames	7	12	0	403	12	12	403
IA	Ames	8	53	1	1833	53	53	1837
IA	Burlington	1	130	1	4498	130	130	4507
IA	Council Bluffs	1	19	0	1110	19	19	653
IA	Council Bluffs	2	27	0	1651	27	27	928
IA	Council Bluffs	3	463	5	15951	462	462	15985
IA	Des Moines	**5	0	0	0	0	0	0
IA	Des Moines	10	5	0	163	5	5	164
IA	Des Moines	11	7	0	244	7	7	245
IA	Dubuque	1	32	0	1120	32	32	1122
IA	Dubuque	5	9	0	305	9	9	306
IA	Earl F Wisdom	1	11	0	379	11	11	380
IA	Fair Station	2	162	2	5573	161	161	5585
IA	George Neal North	1	67	1	2309	67	67	2314
IA	George Neal North	2	128	1	9081	127	127	4405
IA	George Neal North	3	248	3	12293	247	247	8556
IA	George Neal South	4	439	5	15139	438	438	15171
IA	Graettinger	2	0	0	10	0	0	10
IA	Grinnell	**2	6	0	189	6	6	190
IA	Lansing	3	14	0	478	14	14	479
IA	Lansing	4	126	1	4628	125	126	4344
IA	Lime Creek	**1	7	0	255	7	7	255
IA	Lime Creek	**2	7	0	255	7	7	255
IA	Louisa	101	452	5	15588	451	451	15620
IA	Maynard Station	1	1	0	31	1	1	31
IA	Milton Knapp	2	168	2	5793	168	168	5805
IA	Muscatine	8	39	0	1362	39	39	1364
IA	Muscatine	9	59	1	2026	59	59	2030
IA	NA 1 – 7230	**2	0	0	0	0	0	0
IA	Ottumwa	1	554	7	19088	552	553	19127
IA	Pella	6	22	0	757	22	22	758
IA	Pella	7	28	0	978	28	28	979
IA	Pella	8	1	0	68	1	1	27
IA	Prairie Creek	3	21	0	725	21	21	727
IA	Prairie Creek	4	100	1	3433	99	99	3440
IA	Riverside	9	51	1	1744	50	51	1748
IA	Sixth Street	1	24	0	814	24	24	815
IA	Sixth Street	2	6	0	177	6	6	177
IA	Sixth Street	3	6	0	154	6	6	154

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
IA	Sixth Street	4	1	0	77	1	1	77
IA	Sixth Street	5	10	0	308	10	10	308
IA	Streeter Station	7	16	0	554	16	16	555
IA	Sutherland	1	6	0	199	6	6	200
IA	Sutherland	2	11	0	376	11	11	376
IA	Sutherland	3	64	1	2190	63	63	2196
KS	Arthur Mullergren	3	0	0	1	0	0	1
KS	Cimarron River	1	0	0	12	0	0	11
KS	Coffeyville	4	0	0	11	0	0	10
KS	East 12th Street	4	0	0	10	0	0	8
KS	Garden City	S-2	0	0	0	0	0	0
KS	Gordon Evans	1	0	0	64	0	2	56
KS	Gordon Evans	2	0	0	25	0	1	21
KS	Holcomb	SGU1	116	1	4010	116	116	4018
KS	Hutchinson	1	0	0	0	0	0	0
KS	Hutchinson	2	0	0	0	0	0	0
KS	Hutchinson	3	0	0	0	0	0	0
KS	Hutchinson	4	0	0	18	0	0	16
KS	Jeffery Energy Ctr	1	496	5	17108	495	495	17143
KS	Jeffery Energy Ctr	2	525	7	18080	523	524	18118
KS	Jeffery Energy Ctr	3	598	7	20628	597	597	20672
KS	Judson Large	4	0	0	39	0	1	34
KS	Kaw	1	23	0	787	23	23	789
KS	Kaw	2	18	0	619	18	18	620
KS	Kaw	3	15	0	516	15	15	517
KS	Kingman	**9	1	0	51	1	1	51
KS	LaCygne	1	417	5	17941	416	416	14405
KS	LaCygne	2	437	5	15056	436	436	15087
KS	Lawrence	2	0	0	2	0	0	2
KS	Lawrence	3	18	0	2148	18	18	625
KS	Lawrence	4	27	0	1819	27	27	948
KS	Lawrence	5	109	1	5376	108	108	3752
KS	McPherson 2	1	0	0	1	0	0	1
KS	Mulvane	**7	0	0	5	0	0	5
KS	Mulvane	**8	0	0	5	0	0	5
KS	Murray Gill	1	0	0	1	0	0	1
KS	Murray Gill	2	0	0	5	0	0	5
KS	Murray Gill	3	0	0	50	0	1	44
KS	Murray Gill	4	0	0	62	0	2	54
KS	Nearman Creek	N1	201	2	6928	200	201	6942
KS	Neosho	7	0	0	13	0	0	13
KS	Quindaro	1	59	1	2031	59	59	2035
KS	Quindaro	2	60	1	2078	60	60	2082
KS	Riverton	39	30	0	1039	30	30	1041
KS	Riverton	40	51	1	1763	51	51	1766

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
KS	Russell	**11	1	0	31	1	1	31
KS	Russell	**12	1	0	30	1	1	30
KS	Tecumseh	10	43	0	3916	42	43	1470
KS	Tecumseh	9	27	0	2256	27	27	921
KS	Wamego	7	0	0	0	0	0	0
KY	Big Sandy	BSU1	186	2	6428	186	186	6441
KY	Big Sandy	BSU2	538	7	19711	537	537	18584
KY	Cane Run	**12	0	0	0	0	0	0
KY	Cane Run	**13	0	0	0	0	0	0
KY	Cane Run	3	1	0	39	1	1	39
KY	Cane Run	4	79	1	4521	79	79	2726
KY	Cane Run	5	125	1	4340	125	125	4330
KY	Cane Run	6	157	2	5498	157	157	5436
KY	Coleman	C1	137	1	4853	137	137	4862
KY	Coleman	C2	156	2	5534	156	156	5545
KY	Coleman	C3	150	2	5322	150	150	5332
KY	Cooper	1	91	1	3209	90	91	3216
KY	Cooper	2	187	2	6606	186	186	6619
KY	D B Wilson	W1	362	4	12461	361	361	12487
KY	Dale	3	49	1	1983	49	49	1693
KY	Dale	4	41	0	1847	40	40	1400
KY	E W Brown	1	87	1	3065	86	86	3071
KY	E W Brown	2	164	2	5805	164	164	5817
KY	E W Brown	3	318	3	11251	317	317	11273
KY	East Bend	2	531	7	18315	530	530	18354
KY	Elmer Smith	1	79	1	2804	79	79	2810
KY	Elmer Smith	2	176	2	6211	175	175	6224
KY	Ghent	1	346	4	12248	345	346	12272
KY	Ghent	2	291	3	12734	290	290	10038
KY	Ghent	3	405	4	13956	404	404	13985
KY	Ghent	4	398	4	13713	397	397	13742
KY	Green River	1	0	0	130	0	0	2
KY	Green River	2	0	0	851	0	0	16
KY	Green River	3	0	0	744	0	0	13
KY	Green River	4	82	1	2825	82	82	2830
KY	Green River	5	95	1	3371	95	95	3377
KY	H L Spurlock	1	278	3	9821	277	277	9841
KY	H L Spurlock	2	481	5	16586	480	480	16621
KY	Henderson 1	6	24	0	810	23	23	812
KY	HMP&L Station 2	H1	163	2	5756	162	162	5769
KY	HMP&L Station 2	H2	168	2	5934	167	167	5946
KY	Mill Creek	1	223	2	8080	222	222	7696
KY	Mill Creek	2	227	2	8140	227	227	7855
KY	Mill Creek	3	319	3	10979	318	318	11001
KY	Mill Creek	4	395	4	13618	394	394	13645

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
KY	NA 1 – 7220	**3	0	0	0	0	0	0
KY	NA 1 – 7220	**4	0	0	0	0	0	0
KY	NA 1 – 7220	**5	0	0	0	0	0	0
KY	Paradise	1	314	3	10818	313	313	10841
KY	Paradise	2	357	4	12300	356	356	12326
KY	Paradise	3	722	9	25504	720	721	25556
KY	Pineville	3	12	0	914	12	12	424
KY	R D Green	G1	154	2	5292	153	153	5303
KY	R D Green	G2	185	2	6376	184	185	6389
KY	Robert Reid	R1	27	0	942	27	27	944
KY	Shawnee	1	76	1	3643	76	76	2622
KY	Shawnee	10	138	2	4893	138	138	4903
KY	Shawnee	2	78	1	3672	78	78	2702
KY	Shawnee	3	88	1	3707	88	88	3043
KY	Shawnee	4	88	1	3593	87	87	3025
KY	Shawnee	5	86	1	3825	85	85	2954
KY	Shawnee	6	94	1	3711	94	94	3242
KY	Shawnee	7	104	1	3639	103	104	3581
KY	Shawnee	8	99	1	3570	99	99	3427
KY	Shawnee	9	106	1	3665	106	106	3672
KY	Trimble County	1	279	3	9631	279	279	9651
KY	Tyrone	1	0	0	0	0	0	0
KY	Tyrone	2	0	0	0	0	0	0
KY	Tyrone	3	0	0	0	0	0	0
KY	Tyrone	4	0	0	0	0	0	0
KY	Tyrone	5	20	0	1713	20	20	675
LA	A B Paterson	3	0	0	7	0	0	4
LA	A B Paterson	4	0	0	8	0	0	6
LA	Arsenal Hill	5A	0	0	30	0	1	18
LA	Big Cajun 1	1B1	0	0	27	0	1	37
LA	Big Cajun 1	1B2	0	0	27	0	1	34
LA	Big Cajun 2	2B1	415	4	14864	414	414	14322
LA	Big Cajun 2	2B2	409	4	14636	408	409	14142
LA	Big Cajun 2	2B3	408	4	14653	407	408	14106
LA	Coughlin	6	0	0	46	0	1	34
LA	Coughlin	7	0	0	128	0	4	139
LA	D G Hunter	3	0	0	0	0	0	9
LA	D G Hunter	4	0	0	32	0	1	24
LA	Doc Bonin	1	0	0	12	0	0	17
LA	Doc Bonin	2	0	0	24	0	1	30
LA	Doc Bonin	3	0	0	45	0	3	89
LA	Dolet Hills	1	595	7	20494	593	593	20535
LA	Houma	15	0	0	10	0	0	14
LA	Houma	16	0	0	14	0	1	28
LA	Lieberman	3	0	0	86	0	2	85

section 409(c) less the unit's unadjusted basic allowances. While this would result in a smaller repowering reserve, it is not consistent with the 1993 rule.

As stated in the 1998 proposal, EPA is using the method of calculation from the 1993 rule. To implement that method in today's final rule, EPA is including, in place of the reference to § 73.11, a table listing the units with activated repowering plans and the estimated maximum number of adjusted basic allowances for which they qualify. *See* Technical Documentation, Appendix A.

Of the 16 petitions for repowering that were filed prior to the 1998 proposal, only two plans have been activated, representing 11 units. Using the calculation method from the 1993 rule, the maximum number of allowances needed for the repowering reserve is 27,124 allowances. *See* Docket Item A-97-24 IV-B-01 (explaining calculation of maximum number of repowering allowances). While EPA is estimating the units' maximum repowering allowances in order to estimate more accurately the number of allowances to reserve for repowering, these estimates are not final determinations of the allowances to be allocated to specific units. The final determinations will be made in case-by-case proceedings on each repowering extension plan, and the actual allocations may differ from the estimates. The allowances for this reserve are provided by deducting one-tenth of the reserve from unit allowance allocations for each year from 2000 through 2009. Because this reserve is much smaller than that proposed, most units are allocated more allowances in today's final Table 2, for years 2000 through 2009 than in the 1998 proposal. Note that, because repowering allowances have not been allocated, the reserve is set at the maximum that may be needed to implement the two activated plans. If fewer repowering allowances are allocated than provided in the reserve, EPA will use the allowance forfeiture and reallocation provisions at § 73.21(c) to reallocate any remaining allowances.

Because the reserve is not evenly divisible over the ten years, EPA has had to consider the best method of setting aside allowances for the reserve. If EPA were to set aside a smaller number of allowances than will be needed for the reserve (2712 each year for ten years) and create four additional allowances to complete the reserve, those four allowances would be in excess of the 8.9 million cap. As an alternative, EPA could set aside more allowances annually (2713) and provide a method whereby the excess six allowances (27130 minus 27124) would be equitably distributed. EPA believes the second approach better reflects the intent of title IV. As mentioned above, any allowances remaining in the repowering reserve will be distributed by the allowance forfeiture formula in the repowering regulations.

However, as with setting the reserve, using the existing allowance forfeiture equation at § 73.21(c)(2), if the number of allowances to be forfeited is not evenly divisible by ten, will result in allowances remaining after forfeiture. EPA has reviewed the existing rule and has determined that it is not necessary to spread forfeited allowances across ten years. To create the repowering reserve, allowances were taken from ten years' allowance accounts. However, all allowances in the reserve were renumbered to have a use date of 2000. Therefore, EPA does not consider it necessary to renumber again any forfeited allowances for use years other than 2000. This change also makes it unnecessary to address situations where the number of forfeited allowances is not divisible by ten.

In addition, EPA has determined that it is necessary to clarify that the allowances to be reallocated are only those allowances from the repowering reserve. Under section 405(a)(2) only repowering allowances for 2000 are set aside (i.e., are put in the reserve) from unit accounts. Allowances for 2001 through 2003 are above the allowance cap. Therefore, only allowances forfeited in 2000 will need to be reallocated to unit accounts.

The repowering allowance forfeiture and reallocation provisions at § 73.21(c) are revised to reflect these changes.

E. Treatment of Allocations to Certain Units Under Table B

As explained in the 1998 proposal, most units receive Phase II allowance allocations based on various formulae specified in the Act. However, eleven units are specified in Table B of section 405(g)(2) to receive a fixed number of basic allowances. As provided in the 1993 rule, the owner or operator of any of these units would receive the Table B allowances unless it elected to receive allowances under another section of the Act for which the unit is eligible. 57 FR 29955. Only three units (Clover 1 and 2 and Twin Oak 1) elected to receive allowances under another section (in all three cases, section 405(g)(4)) if they were eligible. Clover 1 and 2 demonstrated eligibility for allowances under section 405(g)(4) and are provided their allowance allocations in Table 2. The 1996 proposal stated that Twin Oak 1 did not commence operation in time to be eligible for section 405(g)(4) and, so, would receive allowances under section 405(g)(2). As provided in the 1993 rule, all other units listed in Table B of section 405(g)(2) would receive allowances listed in Table B as unadjusted basic allowances. No comments were received concerning section 405(g)(2), and for the reasons stated in the proposal, these units are allocated allowances as proposed, except for adjustments to reflect the reduced repowering reserve, discussed in section III.D. of this preamble.

F. Revised Tables

The 1993 final allocation of allowances included three allowance tables—Table 2 listing most affected units, Table 3 listing units expected to be eligible under section 405(g)(4), and Table 4 listing units expected to be eligible under section 405(i)(2). Tables 3 and 4 in the 1993 rule were provided to assist unit owners in identifying the appropriate units for which additional information was required under the rule.

As noted above, for the 1998 reallocation of allowances, EPA proposed in the 1998 proposal to consolidate the tables and to include in Table 2 only the information necessary for the operation of the program. To provide for distribution of proceeds from the allowance auction and sale, EPA proposed that the table include the special allowance reserve values for 2000 and 2010. Also, the Agency proposed that the table list the repowering reserve values in case any repowering allowances are subsequently forfeited due to failure of the repowering project under § 72.44(g) or due to overstatement of the repowering reserve. Final allocations for 2000 and 2010 were listed. Additional information is provided in the Technical Documentation. Also, as noted above, the proposed table provided a column listing the reserve deductions for the auctions that took place from 1993 through 1998.

Two comments were received, both supporting consolidation and streamlining of the tables. EPA has adopted that approach here. One commenter also noted that two footnotes in the proposed tables contained technical errors. The commenter is correct, and the footnotes have been corrected for the final rule. In addition, consistent with the approach in the proposal, a reference to Table 3 in § 73.21(c) has been eliminated.

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
LA	Lieberman	4	0	0	72	0	2	63
LA	Little Gypsy	1	1	0	245	1	6	223
LA	Little Gypsy	2	2	0	378	2	10	351
LA	Little Gypsy	3	3	0	543	3	14	473
LA	Louisiana 1	1A	0	0	116	0	0	17
LA	Louisiana 1	2A	0	0	2	0	0	17
LA	Louisiana 1	3A	0	0	2	0	0	17
LA	Louisiana 2	10	0	0	0	0	0	0
LA	Louisiana 2	11	0	0	0	0	0	0
LA	Louisiana 2	12	0	0	0	0	0	0
LA	Michoud	1	0	0	71	0	2	83
LA	Michoud	2	0	0	106	0	4	138
LA	Michoud	3	1	0	491	1	13	467
LA	Monroe	11	0	0	13	0	0	12
LA	Monroe	12	0	0	45	0	1	38
LA	Morgan City	4	0	0	5	0	0	5
LA	Natchitoches	10	0	0	0	0	0	0
LA	Ninemile Point	1	1	0	62	1	2	65
LA	Ninemile Point	2	1	0	112	1	3	103
LA	Ninemile Point	3	1	0	96	1	3	86
LA	Ninemile Point	4	3	0	691	3	18	611
LA	Ninemile Point	5	4	0	930	4	23	811
LA	Opelousas	10	0	0	1	0	0	1
LA	R S Nelson	3	0	0	39	0	1	26
LA	R S Nelson	4	0	0	123	0	8	279
LA	R S Nelson	6	541	7	19562	540	540	18701
LA	Rodemacher	1	86	1	3248	86	86	2975
LA	Rodemacher	2	527	7	18902	526	526	18212
LA	Ruston	2	0	0	4	0	0	6
LA	Ruston	3	0	0	5	0	1	22
LA	Sterlington	10	1	0	174	1	5	156
LA	Sterlington	7AB	0	0	72	0	2	72
LA	Teche	2	0	0	27	0	1	22
LA	Teche	3	0	0	446	0	11	368
LA	Waterford 1 & 2	1	124	1	4553	123	123	4269
LA	Waterford 1 & 2	2	96	1	3534	96	96	3313
LA	Willow Glen	1	0	0	99	0	3	87
LA	Willow Glen	2	0	0	26	0	1	20
LA	Willow Glen	3	0	0	93	0	1	32
LA	Willow Glen	4	0	0	291	0	9	295
LA	Willow Glen	5	1	0	458	1	13	437
ME	Graham Station	5	10	0	344	10	10	344
ME	Mason Steam	3	0	0	2	0	0	2
ME	Mason Steam	4	0	0	1	0	0	1
ME	Mason Steam	5	0	0	1	0	0	1

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
ME	William F Wyman	1	14	0	1159	13	13	467
ME	William F Wyman	2	16	0	1161	16	16	549
ME	William F Wyman	3	78	1	2945	78	78	2693
ME	William F Wyman	4	182	2	6272	181	182	6284
MD	Brandon Shores	1	537	7	18503	535	536	18542
MD	Brandon Shores	2	226	2	7793	225	226	7808
MD	C P Crane	1	126	1	4348	126	126	4356
MD	C P Crane	2	117	1	4042	117	117	4049
MD	Chalk Point	**GT3	21	0	707	20	20	709
MD	Chalk Point	**GT4	21	0	707	20	20	709
MD	Chalk Point	**GT5	26	0	894	26	26	896
MD	Chalk Point	**GT6	26	0	894	26	26	896
MD	Chalk Point	1	267	3	9199	266	266	9218
MD	Chalk Point	2	296	3	10216	296	296	10236
MD	Chalk Point	3	151	2	12501	151	151	5229
MD	Chalk Point	4	75	1	2599	75	75	2605
MD	Dickerson	1	170	2	5846	169	169	5859
MD	Dickerson	2	160	2	5498	159	159	5510
MD	Dickerson	3	170	2	5844	169	169	5856
MD	Dickerson	CW1	0	0	0	0	0	0
MD	Dickerson	GT2	31	0	1082	31	31	1084
MD	Dickerson	GT3	31	0	1082	31	31	1084
MD	Dickerson	HCT3	0	0	0	0	0	0
MD	Dickerson	HCT4	0	0	0	0	0	0
MD	Easton 2	**25	0	0	0	0	0	0
MD	Easton 2	**26	0	0	0	0	0	0
MD	Easton 2	**27	0	0	0	0	0	0
MD	Gould Street	3	24	0	821	24	24	823
MD	Herbert A Wagner	1	37	0	1291	37	37	1293
MD	Herbert A Wagner	2	38	0	1299	38	38	1301
MD	Herbert A Wagner	3	243	3	8378	242	243	8395
MD	Herbert A Wagner	4	44	0	1520	44	44	1523
MD	Morgantown	1	491	5	16927	490	490	16962
MD	Morgantown	2	469	5	16184	468	469	16216
MD	Nanticoke	**ST1	0	0	0	0	0	0
MD	Perryman	**51	0	0	0	0	0	0
MD	Perryman	**52	0	0	0	0	0	0
MD	Perryman	**61	0	0	0	0	0	0
MD	Perryman	**62	0	0	0	0	0	0
MD	R P Smith	11	66	1	2313	66	66	2272
MD	R P Smith	9	8	0	634	8	8	281
MD	Riverside	1	5	0	189	5	5	190
MD	Riverside	2	5	0	171	5	5	172
MD	Riverside	3	10	0	354	10	10	354
MD	Riverside	4	13	0	455	13	13	456

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
MD	Riverside	5	9	0	294	9	9	295
MD	Vienna	8	53	1	3644	53	53	1819
MD	Westport	3	5	0	186	5	5	187
MD	Westport	4	8	0	258	7	7	259
MA	Brayton Point	1	246	3	8478	245	246	8496
MA	Brayton Point	2	258	3	8908	258	258	8926
MA	Brayton Point	3	540	7	18618	539	539	18658
MA	Brayton Point	4	336	4	12135	336	336	11621
MA	Canal	1	357	4	13231	356	356	12327
MA	Canal	2	522	6	17993	521	521	18031
MA	Cannon Street	3	11†	0	374	11	11	374
MA	Cleary Flood	8	4	0	143	4	4	143
MA	Cleary Flood	9	46	0	2679	46	46	1577
MA	Kendall Square	1	5	0	199	5	5	198
MA	Kendall Square	2	6	0	208	5	5	208
MA	Kendall Square	3	12	0	421	12	12	422
MA	Mount Tom	1	163	2	5609	162	162	5622
MA	Mystic	4	76	1	2606	75	75	2612
MA	Mystic	5	90	1	3091	89	90	3098
MA	Mystic	6	89	1	3075	89	89	3081
MA	Mystic	7	500	5	17239	499	499	17274
MA	New Boston	1	179	2	6156	178	178	6169
MA	New Boston	2	183	2	6322	183	183	6335
MA	Salem Harbor	1	97	1	3338	97	97	3345
MA	Salem Harbor	2	99	1	3407	99	99	3414
MA	Salem Harbor	3	158	2	5459	158	158	5470
MA	Salem Harbor	4	357	4	12567	356	357	12346
MA	Somerset	1	0	0	0	0	0	0
MA	Somerset	2	0	0	0	0	0	0
MA	Somerset	3	0	0	0	0	0	0
MA	Somerset	4	0	0	0	0	0	0
MA	Somerset	5	0	0	0	0	0	0
MA	Somerset	6	0	0	0	0	0	0
MA	Somerset	7	80	1	2764	80	80	2770
MA	Somerset	8	116	1	3984	115	115	3993
MA	Waters River	**2	7	0	247	7	7	247
MA	West Springfield	1	11	0	378	11	11	379
MA	West Springfield	2	10	0	356	10	10	356
MA	West Springfield	3	87	1	3011	87	87	3017
MI	491 E. 48th Street	**7	9	0	298	9	9	299
MI	491 E. 48th Street	**8	9	0	298	9	9	299
MI	B C Cobb	1	13	0	1142	13	13	442
MI	B C Cobb	2	14	0	1229	13	14	475
MI	B C Cobb	3	13	0	1223	13	13	473
MI	B C Cobb	4	133	1	4572	132	132	4582

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
MI	B C Cobb	5	136	1	4694	136	136	4702
MI	Belle River	1	537	6	18499	535	536	18536
MI	Belle River	2	544	6	18763	543	545	18801
MI	Conners Creek	15	17	0	4285	17	17	589
MI	Conners Creek	16	17	0	4279	17	17	581
MI	Conners Creek	17	15	0	4034	15	15	554
MI	Conners Creek	18	13	0	3353	13	13	450
MI	Dan E Karn	1	227	2	7809	226	226	7825
MI	Dan E Karn	2	248	3	8564	248	248	8582
MI	Dan E Karn	3	30	0	1020	30	30	1023
MI	Dan E Karn	4	27	0	948	27	27	949
MI	Delray	10	0	0	14	0	0	14
MI	Delray	12	0	0	14	0	0	12
MI	Delray	7	0	0	0	0	0	0
MI	Delray	8	0	0	12	0	0	12
MI	Delray	9	0	0	0	0	0	0
MI	Eckert Station	1	34	0	1298	34	34	1176
MI	Eckert Station	2	35	0	1354	35	35	1225
MI	Eckert Station	3	32	0	1327	32	32	1116
MI	Eckert Station	4	64	1	2222	64	64	2227
MI	Eckert Station	5	77	1	2665	77	77	2670
MI	Eckert Station	6	68	1	2342	68	68	2347
MI	Ednicott Generating	1	53	1	1809	52	52	1814
MI	Erickson	1	193	2	6644	192	192	6659
MI	Greenwood	1	16	0	539	16	16	541
MI	Harbor Beach	1	41	0	3520	41	41	1427
MI	J B Sims	3	43	0	1484	43	43	1487
MI	J C Weadock	7	138	1	4744	137	137	4754
MI	J C Weadock	8	136	1	4690	136	136	4699
MI	J H Campbell	1	235	3	8095	234	234	8113
MI	J H Campbell	2	281	3	9682	280	280	9702
MI	J H Campbell	3	798	10	27471	796	797	27529
MI	J R Whiting	1	99	1	3411	99	99	3418
MI	J R Whiting	2	101	1	3493	101	101	3500
MI	J R Whiting	3	130	1	4467	129	129	4477
MI	James De Young	5	30	0	1048	30	30	1050
MI	Marysville	10	13	0	1261	13	13	432
MI	Marysville	11	13	0	1315	13	13	450
MI	Marysville	12	11	0	1061	11	11	363
MI	Marysville	9	16	0	1637	16	16	560
MI	Mistersky	5	7	0	257	7	7	257
MI	Mistersky	6	13	0	437	13	13	438
MI	Mistersky	7	14	0	485	14	14	487
MI	Monroe (4)	1	692	9	23830	690	691	23882
MI	Monroe (4)	2	719	9	24731	716	717	24785

Table 2 - Phase II Allowance Allocations

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
MI	Monroe (4)	3	672	8	23151	670	672	23200
MI	Monroe (4)	4	739	9	25424	737	737	25478
MI	Presque Isle	2	7	0	637	7	7	246
MI	Presque Isle	3	55	1	1906	55	55	1910
MI	Presque Isle	4	48	1	1676	48	48	1673
MI	Presque Isle	5	85	1	2933	85	85	2938
MI	Presque Isle	6	85	1	2940	85	85	2946
MI	Presque Isle	7	63	1	2215	63	63	2173
MI	Presque Isle	8	59	1	2191	59	59	2050
MI	Presque Isle	9	44	0	2346	44	44	1511
MI	River Rouge	1	2	0	79	2	2	79
MI	River Rouge	2	180	2	6321	179	179	6203
MI	River Rouge	3	264	3	9100	263	264	9118
MI	Shiras	3	15	0	500	14	14	502
MI	St Clair	1	106	1	3665	106	106	3672
MI	St Clair	2	103	1	3542	103	103	3549
MI	St Clair	3	102	1	3524	102	102	3530
MI	St Clair	4	98	1	3395	98	98	3402
MI	St Clair	5	0	0	0	0	0	0
MI	St Clair	6	213	2	7340	212	213	7355
MI	St Clair	7	390	4	13455	389	390	13482
MI	Trenton Channel	16	67	0	3292	66	66	2297
MI	Trenton Channel	17	16	0	767	16	16	534
MI	Trenton Channel	18	72	0	3563	72	72	2485
MI	Trenton Channel	19	14	0	698	14	14	488
MI	Trenton Channel	9A	421	5	14502	420	420	14532
MI	Wyandotte	5	15	0	960	15	15	549
MI	Wyandotte	7	15	0	953	15	15	545
MN	Allen S King	1	453	5	15623	452	452	15655
MN	Black Dog	1	10	0	1914	10	10	331
MN	Black Dog	2	13	0	3683	13	13	458
MN	Black Dog	3	29	0	2275	29	29	989
MN	Black Dog	4	62	1	4055	62	62	2130
MN	Clay Boswell	1	36	0	1827	36	36	1248
MN	Clay Boswell	2	34	0	1800	34	34	1188
MN	Clay Boswell	3	286	3	9863	285	286	9882
MN	Clay Boswell	4	299	3	10321	299	299	10342
MN	Fox Lake	3	31	0	2069	31	31	1068
MN	High Bridge	3	23	0	2118	23	23	795
MN	High Bridge	4	18	0	1458	18	18	614
MN	High Bridge	5	31	0	2194	31	31	1087
MN	High Bridge	6	54	1	1851	54	54	1855
MN	Hoot Lake	2	9	0	1242	9	9	310
MN	Hoot Lake	3	31	0	1978	31	31	1078
MN	M L Hibbard	3	1	0	987	1	1	30

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
MN	M L Hibbard	4	0	0	1094	0	0	10
MN	Minnesota Valley	4	2	0	938	2	2	62
MN	Northeast Station	NEPP	31	0	1052	30	30	1055
MN	Riverside	6	7	0	3076	7	7	227
MN	Riverside	7	3	0	1339	3	3	90
MN	Riverside	8	109	1	5067	109	109	3779
MN	Sherburne County	1	380	4	13087	379	379	13115
MN	Sherburne County	2	382	4	13180	381	382	13206
MN	Sherburne County	3	376	4	12952	375	375	12979
MN	Silver Lake	4	91	1	3132	91	91	3138
MN	Syl Laskin	1	9	0	1692	9	9	321
MN	Syl Laskin	2	4	0	1649	4	4	139
MS	Baxter Wilson	1	1	0	360	1	9	321
MS	Baxter Wilson	2	103	1	3563	103	103	3570
MS	Delta	1	0	0	26	0	1	24
MS	Delta	2	1	0	50	1	1	48
MS	Gerald Andrus	1	95	1	3281	95	95	3287
MS	Jack Watson	1	5	0	172	5	5	173
MS	Jack Watson	2	5	0	180	5	5	181
MS	Jack Watson	3	8	0	273	8	8	273
MS	Jack Watson	4	218	2	7523	218	218	7537
MS	Jack Watson	5	447	5	15410	446	446	15442
MS	Moselle	**4	0	0	0	0	0	0
MS	Moselle	**5	0	0	0	0	0	0
MS	Moselle	**6	0	0	0	0	0	0
MS	Moselle	**7	0	0	0	0	0	0
MS	Moselle	1	0	0	35	0	1	33
MS	Moselle	2	1	0	76	1	2	70
MS	Moselle	3	0	0	42	0	1	38
MS	Natchez	1	0	0	2	0	0	3
MS	R D Morrow	1	139	2	4798	139	139	4808
MS	R D Morrow	2	152	2	5252	152	152	5263
MS	Rex Brown	1A	0	0	6	0	0	5
MS	Rex Brown	1B	0	0	6	0	0	5
MS	Rex Brown	3	0	0	41	0	1	37
MS	Rex Brown	4	0	0	159	0	4	139
MS	Sweatt	1	2	0	78	2	2	78
MS	Sweatt	2	3	0	86	2	2	86
MS	Victor J Daniel Jr	1	287	3	11225	286	287	9916
MS	Victor J Daniel Jr	2	414	4	14273	413	413	14303
MO	Asbury	1	197	2	6973	196	197	6986
MO	Blue Valley	3	135	1	4669	135	135	4678
MO	Chamois	2	158	2	5455	158	158	5466
MO	Columbia	6	26	0	903	26	26	905
MO	Columbia	7	105	1	3630	104	104	3639

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
MO	Columbia	8	3	0	125	3	3	125
MO	Combustion Turbine 1	**1	0	0	0	0	0	0
MO	Combustion Turbine 1	**NA4	0	0	0	0	0	0
MO	Combustion Turbine 1	**NA5	0	0	0	0	0	0
MO	Combustion Turbine 1	**NA6	0	0	0	0	0	0
MO	Combustion Turbine 2	**2	0	0	0	0	0	0
MO	Combustion Turbine 3	**3	0	0	0	0	0	0
MO	Hawthorn	5	356	4	12769	355	356	12309
MO	Iatan	**2	0	0	0	0	0	0
MO	Iatan	1	470	5	16203	469	469	16236
MO	James River	**GT2	18	0	604	18	18	605
MO	James River	3	96	1	3326	96	20	681
MO	James River	4	173	2	5973	173	36	1253
MO	James River	5	60	1	2132	60	60	2136
MO	Jim Hill	**1	0	0	0	0	0	0
MO	Labadie	1	496	5	17548	495	495	17583
MO	Labadie	2	462	5	16358	461	461	16391
MO	Labadie	3	494	5	17482	493	493	17516
MO	Labadie	4	440	5	15579	439	439	15611
MO	Lake Road	6	18	0	605	18	18	606
MO	Meramec	1	30	0	2745	30	30	1029
MO	Meramec	2	32	0	2778	32	32	1105
MO	Meramec	3	68	1	6057	68	68	2362
MO	Meramec	4	74	1	7174	74	74	2554
MO	Montrose	1	90	1	3188	90	90	3194
MO	Montrose	2	100	1	3534	100	100	3541
MO	Montrose	3	123	1	4348	123	123	4356
MO	NA1 – 7223	**1	0	0	0	0	0	0
MO	NA 1 – 7223	**2	0	0	0	0	0	0
MO	NA 1 – 7223	**3	0	0	0	0	0	0
MO	NA 1 – 7226	**1	0	0	0	0	0	0
MO	New Madrid	1	344	4	12174	343	343	12198
MO	New Madrid	2	396	4	14005	395	395	14033
MO	RG 1 & 2	**1	0	0	0	0	0	0
MO	RG 1 & 2	**2	0	0	0	0	0	0
MO	Rush Island	1	402	4	14956	401	402	13900
MO	Rush Island	2	449	5	15647	448	449	15518
MO	Sibley	1	15	0	519	15	15	520
MO	Sibley	2	18	0	638	18	18	639
MO	Sibley	3	216	2	7632	215	215	7648
MO	Sikeston	1	197	2	6789	196	197	6802
MO	Sioux	1	306	3	10820	305	305	10842
MO	Sioux	2	268	3	9489	267	268	9507
MO	Southwest	1	119	1	4183	119	119	4127
MO	Thomas Hill	MB1	125	1	4420	125	125	4429

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MO	Thomas Hill	MB2	210	2	7430	209	210	7444
MO	Thomas Hill	MB3	529	6	18251	528	529	18288
MT	Colstrip	1	213	2	7857	213	213	7372
MT	Colstrip	2	213	2	7868	212	212	7349
MT	Colstrip	3	106	1	4404	106	106	3678
MT	Colstrip	4	85	1	2916	84	84	2923
MT	Frank Bird	1	0	0	0	0	0	0
MT	J E Corette	2	141	2	5060	141	141	4884
MT	Lewis & Clark	B1	41	0	1444	41	41	1403
NE	Bluffs	4	1	0	18	1	1	18
NE	C W Burdick	B-3	0	0	0	0	0	0
NE	Canaday	1	18	0	627	18	18	628
NE	Gerald Gentleman	1	259	3	10802	259	259	8960
NE	Gerald Gentleman	2	510	6	17566	508	509	17693
NE	Gerald T Whelan	1	68	1	2334	68	68	2338
NE	Harold Kramer	1	0	0	38	0	0	3
NE	Harold Kramer	2	0	0	40	0	0	3
NE	Harold Kramer	3	5	0	1052	5	5	168
NE	Harold Kramer	4	6	0	2079	6	6	198
NE	Lon Wright	8	34	0	2044	34	34	1184
NE	NA 1 – 7019	**NA1	0	0	0	0	0	0
NE	Nebraska City	1	383	4	13190	382	382	13217
NE	North Omaha	1	30	0	2388	30	30	1045
NE	North Omaha	2	47	1	3286	47	47	1614
NE	North Omaha	3	55	1	3207	55	55	1900
NE	North Omaha	4	73	1	3848	73	73	2515
NE	North Omaha	5	88	1	4646	88	88	3043
NE	Platte	1	85	1	2926	85	85	2932
NE	Sheldon	1	23	0	2168	23	23	792
NE	Sheldon	2	24	0	2280	24	24	846
NV	Clark	1	0	0	20	0	1	22
NV	Clark	2	8	0	273	8	8	261
NV	Clark	3	0	0	18	0	0	16
NV	Fort Churchill	1	10	0	371	10	10	356
NV	Fort Churchill	2	16	0	577	16	16	544
NV	Harry Allen	**1	0	0	0	0	0	0
NV	Harry Allen	**2	0	0	0	0	0	0
NV	Harry Allen	**3	0	0	0	0	0	0
NV	Harry Allen	**4	0	0	0	0	0	0
NV	Harry Allen	**GT1	0	0	0	0	0	0
NV	Harry Allen	**GT2	0	0	0	0	0	0
NV	Harry Allen	**GT3	0	0	0	0	0	0
NV	Harry Allen	**GT4	0	0	0	0	0	0
NV	Mohave	1	759	9	26651	757	757	26165
NV	Mohave	2	756	9	26547	753	754	26059

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NV	North Valmy	1	190	2	6958	190	190	6569
NV	North Valmy	2	115	1	4261	115	115	3966
NV	Reid Gardner	1	57	1	2172	57	57	1985
NV	Reid Gardner	2	59	1	2201	59	59	2025
NV	Reid Gardner	3	57	1	2124	57	57	1968
NV	Reid Gardner	4	68	1	2813	68	68	2342
NV	Sunrise	1	1	0	50	1	2	52
NV	Tracy	1	0	0	15	0	0	14
NV	Tracy	2	1	0	46	1	1	42
NV	Tracy	3	9	0	314	9	9	304
NH	Merrimack	1	124	1	4287	124	124	4296
NH	Merrimack	2	268	3	9239	267	268	9257
NH	Newington	1	307	3	11660	306	307	10613
NH	Schiller	4	42	0	1514	42	42	1440
NH	Schiller	5	38	0	1457	38	38	1298
NH	Schiller	6	48	1	1642	48	48	1646
NJ	B L England	1	111	1	3810	110	110	3818
NJ	B L England	2	143	2	4929	143	143	4939
NJ	B L England	3	70	1	2419	70	70	2424
NJ	Bergen	1	57	1	1977	57	57	1981
NJ	Bergen	2	59	1	2043	59	59	2047
NJ	Burlington	7	16	0	561	16	16	562
NJ	Deepwater	1	34	0	1164	34	34	1166
NJ	Deepwater	3	0	0	11	0	0	11
NJ	Deepwater	4	2	0	59	2	2	58
NJ	Deepwater	5	0	0	5	0	0	5
NJ	Deepwater	6	2	0	59	2	2	58
NJ	Deepwater	8	80	1	2743	79	79	2751
NJ	Deepwater	9	53	1	1813	52	53	1817
NJ	Gilbert	01	2	0	60	2	2	60
NJ	Gilbert	02	2	0	37	2	2	37
NJ	Gilbert	03	20	0	700	20	20	701
NJ	Gilbert	04	17	0	600	17	17	601
NJ	Gilbert	05	17	0	596	17	17	597
NJ	Gilbert	06	17	0	593	17	17	594
NJ	Gilbert	07	18	0	605	18	18	606
NJ	Hudson	1	35	0	1197	35	35	1199
NJ	Hudson	2	440	5	15967	439	440	15209
NJ	Kearny	7	4	0	145	4	4	146
NJ	Kearny	8	4	0	153	4	4	154
NJ	Linden	11	28	0	968	28	28	970
NJ	Linden	12	19	0	665	19	19	666
NJ	Linden	13	25	0	877	25	25	879
NJ	Linden	2	19	0	644	19	19	645
NJ	Linden	4	12	0	423	12	12	423

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NJ	Mercer	1	221	2	7681	220	220	7616
NJ	Mercer	2	203	2	7437	202	203	7008
NJ	Sayreville	02	0	0	2	0	0	2
NJ	Sayreville	03	0	0	2	0	0	2
NJ	Sayreville	05	0	0	41	0	0	41
NJ	Sayreville	06	0	0	39	0	0	39
NJ	Sayreville	07	22	0	766	22	22	767
NJ	Sayreville	08	26	0	892	26	26	893
NJ	Sewaren	1	3	0	117	3	3	117
NJ	Sewaren	2	10	0	340	10	10	341
NJ	Sewaren	3	7	0	254	7	7	255
NJ	Sewaren	4	17	0	574	17	17	575
NJ	Sewaren	5	0	0	0	0	0	0
NJ	Werner	04	6	0	194	6	6	195
NM	Cunningham	121B	0	0	42	0	1	44
NM	Cunningham	122B	0	0	269	0	6	203
NM	Escalante	1	42	0	1874	42	42	1468
NM	Four Corners	1	96	1	3592	96	96	3323
NM	Four Corners	2	96	1	3588	96	96	3323
NM	Four Corners	3	120	1	4477	120	120	4162
NM	Four Corners	4	344	4	12503	343	343	11881
NM	Four Corners	5	356	4	13271	355	356	12305
NM	Maddox	051B	0	0	170	0	4	122
NM	North Lovington	S2	0	0	0	0	0	0
NM	Person	3	0	0	0	0	0	0
NM	Person	4	0	0	0	0	0	0
NM	Reeves	1	0	0	4	0	0	6
NM	Reeves	2	0	0	7	0	0	5
NM	Reeves	3	3	0	104	3	3	101
NM	Rio Grande	6	0	0	3	0	0	5
NM	Rio Grande	7	0	0	1	0	0	1
NM	Rio Grande	8	0	0	80	0	2	62
NM	San Juan	1	214	2	7939	213	213	7384
NM	San Juan	2	157	2	5920	156	156	5410
NM	San Juan	3	376	4	13874	375	376	13002
NM	San Juan	4	353	4	13043	352	353	12200
NY	59TH Street	110	2	0	64	2	2	64
NY	74TH Street	120	13	0	447	13	13	448
NY	74TH Street	121	13	0	449	13	13	450
NY	74TH Street	122	13	0	447	13	13	448
NY	Albany	1	52	1	1800	52	52	1803
NY	Albany	2	45	0	1556	45	45	1558
NY	Albany	3	46	1	1592	46	46	1597
NY	Albany	4	49	1	1686	49	49	1690
NY	Arthur Kill	20	43	0	1478	43	43	1480

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NY	Arthur Kill	30	69	1	2368	68	69	2371
NY	Astoria	10	35	0	1216	35	35	1218
NY	Astoria	20	45	0	1554	45	45	1556
NY	Astoria	30	88	1	3023	87	88	3029
NY	Astoria	40	69	1	2375	69	69	2380
NY	Astoria	50	78	1	2699	78	78	2705
NY	Bowline Point	1	123	1	4239	123	123	4247
NY	Bowline Point	2	123	1	4240	123	123	4248
NY	C R Huntley	63	71	1	2656	71	71	2465
NY	C R Huntley	64	76	1	2663	76	76	2624
NY	C R Huntley	65	78	1	2692	78	78	2697
NY	C R Huntley	66	79	1	2728	79	79	2733
NY	C R Huntley	67	168	2	5773	167	167	5785
NY	C R Huntley	68	156	2	5379	156	156	5390
NY	Charles Poletti	001	187	2	6436	186	186	6450
NY	Danskammer	1	28	0	948	27	27	950
NY	Danskammer	2	27	0	920	27	27	921
NY	Danskammer	3	91	1	3128	91	91	3134
NY	Danskammer	4	175	2	6028	174	175	6041
NY	Dunkirk	1	82	1	2842	82	82	2848
NY	Dunkirk	2	94	1	3228	93	93	3235
NY	Dunkirk	3	153	2	5290	153	153	5300
NY	Dunkirk	4	171	2	5904	171	171	5916
NY	E F Barrett	10	69	1	2371	69	69	2375
NY	E F Barrett	20	68	1	2336	68	68	2341
NY	East River	50	41	0	1396	40	40	1400
NY	East River	60	41	0	1430	41	41	1432
NY	East River	70	30	0	1033	30	30	1035
NY	Far Rockaway	40	14	0	469	14	14	470
NY	Glenwood	40	27	0	939	27	27	940
NY	Glenwood	50	26	0	903	26	26	905
NY	Goudey	11	23	0	792	23	23	793
NY	Goudey	12	23	0	780	23	23	782
NY	Goudey	13	95	1	3287	95	95	3293
NY	Greenidge	4	28	0	982	28	28	983
NY	Greenidge	5	28	0	980	28	28	981
NY	Greenidge	6	92	1	3184	92	92	3190
NY	Hickling	1	21	0	725	20	20	709
NY	Hickling	2	21	0	725	20	20	709
NY	Hickling	3	25	0	895	25	25	849
NY	Hickling	4	26	0	933	26	26	885
NY	Jennison	1	17	0	650	17	17	600
NY	Jennison	2	18	0	676	18	18	624
NY	Jennison	3	18	0	724	18	18	626
NY	Jennison	4	18	0	724	18	18	626

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NY	Kintigh	1	403	4	13885	402	402	13913
NY	Lovett	3	7	0	225	7	7	226
NY	Lovett	4	133	1	4568	132	132	4578
NY	Lovett	5	145	2	4986	144	144	4997
NY	Milliken	1	143	2	4926	143	143	4936
NY	Milliken	2	151	2	5213	151	151	5224
NY	Northport	1	241	3	8320	241	241	8337
NY	Northport	2	294	3	10127	293	293	10147
NY	Northport	3	323	4	11118	322	322	11142
NY	Northport	4	168	2	5792	168	168	5803
NY	Oswego	1	0	0	0	0	0	0
NY	Oswego	2	0	0	0	0	0	0
NY	Oswego	3	3	0	90	3	3	90
NY	Oswego	4	12	0	398	12	12	398
NY	Oswego	5	241	3	17239	240	241	8327
NY	Oswego	6	139	2	4806	139	139	4816
NY	Port Jefferson	1	14	0	475	14	14	476
NY	Port Jefferson	2	14	0	498	14	14	499
NY	Port Jefferson	3	128	1	4396	127	127	4405
NY	Port Jefferson	4	150	2	5179	150	150	5190
NY	Ravenswood	10	92	1	3164	92	92	3170
NY	Ravenswood	20	78	1	2677	77	78	2682
NY	Ravenswood	30	145	2	4990	144	145	5000
NY	Rochester 3	12	66	1	2268	66	66	2273
NY	Rochester 3	3	0	0	2	0	0	2
NY	Rochester 3	7	2	0	201	2	2	62
NY	Rochester 3	8	0	0	0	0	0	0
NY	Rochester 7	1	32	0	1093	32	32	1095
NY	Rochester 7	2	47	1	1625	47	47	1629
NY	Rochester 7	3	46	0	1586	46	46	1589
NY	Rochester 7	4	64	1	2212	64	64	2217
NY	Roseton	1	421	5	15579	420	420	14532
NY	Roseton	2	375	4	14908	374	375	12962
NY	S A Carlson	10	19	0	673	19	19	674
NY	S A Carlson	11	13	0	424	19	13	426
NY	S A Carlson	12	37	0	1276	13	37	1278
NY	S A Carlson	9	19	0	664	36	19	666
NY	Waterside	41	7	0	252	7	7	253
NY	Waterside	42	7	0	247	7	7	248
NY	Waterside	51	13	0	416	13	13	416
NY	Waterside	52	13	0	417	12	12	418
NY	Waterside	61	12	0	431	12	12	431
NY	Waterside	62	14	0	507	14	14	507
NY	Waterside	80	33	0	1128	33	33	1129
NY	Waterside	90	35	0	1234	35	35	1236

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NC	Asheville	1	192	2	6620	192	192	6633
NC	Asheville	2	153	2	5259	152	152	5271
NC	Belews Creek	1	898	11	30900	895	896	30966
NC	Belews Creek	2	945	11	32549	943	944	32616
NC	Buck	5	0	0	1031	0	0	2
NC	Buck	6	0	0	589	0	0	1
NC	Buck	7	10	0	1058	10	10	344
NC	Buck	8	17	0	2322	17	17	602
NC	Buck	9	53	1	2870	53	53	1818
NC	Cape Fear	3	0	0	599	0	0	0
NC	Cape Fear	4	0	0	599	0	0	0
NC	Cape Fear	5	84	1	3381	84	84	2895
NC	Cape Fear	6	86	1	3912	86	86	2961
NC	Cliffside	1	0	0	898	0	0	1
NC	Cliffside	2	0	0	872	0	0	1
NC	Cliffside	3	1	0	1291	1	1	21
NC	Cliffside	4	1	0	1305	1	1	17
NC	Cliffside	5	343	4	14036	342	343	11861
NC	Dan River	1	11	0	1909	11	11	363
NC	Dan River	2	10	0	2779	10	10	334
NC	Dan River	3	17	0	2792	17	17	597
NC	G G Allen	1	1	0	2427	1	1	31
NC	G G Allen	2	1	0	2813	1	1	34
NC	G G Allen	3	130	1	6120	130	130	4491
NC	G G Allen	4	93	1	5743	93	93	3207
NC	G G Allen	5	113	1	5970	112	112	3886
NC	L V Sutton	1	21	0	2051	21	21	722
NC	L V Sutton	2	35	0	2270	34	34	1193
NC	L V Sutton	3	148	2	8296	148	148	5111
NC	Lee	1	19	0	1636	19	19	649
NC	Lee	2	24	0	1685	24	24	831
NC	Lee	3	141	2	5762	140	140	4855
NC	Marshall	1	209	2	8763	208	208	7211
NC	Marshall	2	236	3	9262	235	235	8146
NC	Marshall	3	432	5	15859	431	431	14914
NC	Marshall	4	387	4	15132	386	387	13373
NC	Mayo	1A	371	4	12781	370	370	12807
NC	Mayo	1B	371	4	12781	370	370	12807
NC	Riverbend	10	34	0	2626	39	34	1174
NC	Riverbend	7	39	0	2152	36	39	1349
NC	Riverbend	8	36	0	2113	10	36	1245
NC	Riverbend	9	10	0	2267	34	10	356
NC	Roxboro	1	322	3	11085	321	321	11108
NC	Roxboro	2	570	6	19636	568	569	19676
NC	Roxboro	3A	258	3	9093	257	257	8902

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
NC	Roxboro	3B	258	3	9093	257	257	8902
NC	Roxboro	4A	302	3	10404	301	301	10425
NC	Roxboro	4B	302	3	10404	301	301	10425
NC	W H Weatherspoon	1	14	0	1122	13	14	467
NC	W H Weatherspoon	2	14	0	1125	14	14	473
NC	W H Weatherspoon	3	27	0	1626	27	27	937
ND	Antelope Valley	B1	346	4	11943	346	346	11968
ND	Antelope Valley	B2	323	4	11127	322	322	11151
ND	Coal Creek	1	676	8	23302	674	676	23350
ND	Coal Creek	2	615	8	21179	613	613	21226
ND	Coyote	B1	469	5	16177	468	468	16210
ND	Leland Olds	1	264	3	9102	263	264	9120
ND	Leland Olds	2	767	9	26392	765	765	26448
ND	Milton R Young	B1	376	4	12947	375	375	12973
ND	Milton R Young	B2	461	5	15880	459	460	15913
ND	R M Heskett	B2	93	1	3201	93	93	3207
ND	Stanton	1	216	2	7445	215	216	7460
ND	Stanton	10	39	0	1334	39	39	1337
OH	Acme	11	0	0	7	0	0	7
OH	Acme	13	0	0	1846	0	0	9
OH	Acme	14	0	0	2519	0	0	14
OH	Acme	15	0	0	3365	0	0	19
OH	Acme	16	59	1	2420	59	59	2030
OH	Acme	9	0	0	1	0	0	1
OH	Acme	91	23	0	2012	22	23	778
OH	Acme	92	20	0	1800	20	20	696
OH	Ashtabula	10	53	0	1795	52	52	1801
OH	Ashtabula	11	54	0	1890	54	54	1894
OH	Ashtabula	7	204	2	7218	203	204	7231
OH	Ashtabula	8	67	0	2337	67	67	2340
OH	Ashtabula	9	58	0	1990	58	58	1995
OH	Avon Lake	10	65	1	2253	65	65	2258
OH	Avon Lake	11	142	2	5023	142	142	5034
OH	Avon Lake	12	429	5	15194	428	429	15225
OH	Avon Lake	9	74	1	2566	74	74	2572
OH	Bay Shore	1	137	1	4718	136	137	4726
OH	Bay Shore	2	130	1	4494	130	130	4503
OH	Bay Shore	3	124	1	4276	124	124	4284
OH	Bay Shore	4	204	2	7036	204	204	7050
OH	Cardinal	1	418	5	14773	416	417	14803
OH	Cardinal	2	467	5	16521	466	466	16554
OH	Cardinal	3	485	5	17296	484	484	16747
OH	Cardinal/Tidd	**1	21	0	714	21	21	715
OH	Conesville	1	51	1	1813	51	51	1817
OH	Conesville	2	60	1	2109	59	60	2114

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
OH	Conesville	3	67	1	2369	67	67	2373
OH	Conesville	4	594	6	21025	593	593	21067
OH	Conesville	5	208	2	9023	207	208	7179
OH	Conesville	6	230	2	9392	230	230	7951
OH	Dover	**6	4	0	153	4	4	154
OH	Eastlake	1	95	1	3365	95	95	3371
OH	Eastlake	2	105	1	3724	105	105	3732
OH	Eastlake	3	122	1	4318	122	122	4327
OH	Eastlake	4	177	2	6256	176	176	6269
OH	Eastlake	5	469	5	16600	468	468	16633
OH	Edgewater	11	25	0	878	25	12	422
OH	Edgewater	12	27	0	947	27	13	455
OH	Edgewater	13	62	1	2178	61	61	2183
OH	Gen J M Gavin	1	964	11	34088	962	963	34158
OH	Gen J M Gavin	2	982	12	34726	980	981	34797
OH	Gorge	25	43	0	1498	43	21	720
OH	Gorge	26	49	1	1676	49	23	807
OH	Hamilton	9	34	0	1665	34	34	1162
OH	J M Stuart	1	569	6	19626	568	568	19666
OH	J M Stuart	2	540	6	18605	538	539	18643
OH	J M Stuart	3	535	6	18448	534	534	18486
OH	J M Stuart	4	566	6	19497	564	565	19537
OH	Killen Station	2	491	5	16923	490	490	16958
OH	Kyger Creek	1	235	3	8097	234	235	8114
OH	Kyger Creek	2	226	2	7795	226	226	7810
OH	Kyger Creek	3	218	2	7522	218	218	7536
OH	Kyger Creek	4	228	2	7858	227	228	7873
OH	Kyger Creek	5	228	2	7872	228	228	7887
OH	Lake Road	6	0	0	1340	0	0	0
OH	Lake Shore	18	145	2	6031	145	145	5014
OH	Lake Shore	91	1	0	47	1	1	47
OH	Lake Shore	92	2	0	84	2	2	84
OH	Lake Shore	93	2	0	65	2	2	65
OH	Lake Shore	94	3	0	107	3	3	107
OH	Miami Fort	5-1	4	0	144	4	4	143
OH	Miami Fort	5-2	4	0	144	4	4	143
OH	Miami Fort	6	139	2	4906	138	138	4917
OH	Miami Fort	7	469	5	16602	468	468	16635
OH	Miami Fort	8	529	6	18227	527	528	18264
OH	Muskingum River	1	181	2	6412	181	181	6425
OH	Muskingum River	2	173	2	6106	172	172	6119
OH	Muskingum River	3	170	2	6016	170	170	6027
OH	Muskingum River	4	143	2	5078	143	143	5088
OH	Muskingum River	5	493	5	17445	492	492	17479
OH	Niles	1	85	1	2994	84	84	3000

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
OH	Niles	2	111	1	3923	111	111	3930
OH	O H Hutchings	H-1	11	0	1736	11	11	398
OH	O H Hutchings	H-2	9	0	1671	9	9	309
OH	O H Hutchings	H-3	17	0	1603	17	17	585
OH	O H Hutchings	H-4	19	0	1623	19	19	641
OH	O H Hutchings	H-5	15	0	1630	15	15	514
OH	O H Hutchings	H-6	11	0	1660	11	11	371
OH	Picway	9	60	1	2127	60	60	2131
OH	Poston	1	23	0	787	23	23	789
OH	Poston	2	21	0	731	21	21	733
OH	Poston	3	28	0	957	28	28	958
OH	R E Burger	1	36	0	1233	36	17	593
OH	R E Burger	2	35	0	1206	35	17	579
OH	R E Burger	3	36	0	1246	36	17	599
OH	R E Burger	4	37	0	1275	37	18	613
OH	R E Burger	5	38	0	1327	37	37	1331
OH	R E Burger	6	37	0	1325	37	37	1327
OH	R E Burger	7	131	1	4647	131	131	4656
OH	R E Burger	8	151	2	5359	151	151	5370
OH	Refuse & Coal	001	12	0	426	12	12	426
OH	Refuse & Coal	002	12	0	381	12	12	381
OH	Refuse & Coal	003	12	0	402	12	12	402
OH	Refuse & Coal	004	12	0	438	12	12	441
OH	Refuse & Coal	005	12	0	375	12	12	375
OH	Refuse & Coal	006	12	0	366	12	12	363
OH	Richard H Gorsuch	1	178	2	6150	178	178	6162
OH	Richard H Gorsuch	2	146	2	5062	146	146	5072
OH	Richard H Gorsuch	3	200	2	6878	198	200	6892
OH	Richard H Gorsuch	4	40	0	1404	40	40	1404
OH	Toronto	10	97	0	3343	97	47	1608
OH	Toronto	11	105	0	3612	105	49	1738
OH	Toronto	9	54	0	1873	54	26	900
OH	W H Sammis	1	181	2	6237	180	181	6250
OH	W H Sammis	2	159	2	5470	158	158	5482
OH	W H Sammis	3	181	2	6236	180	181	6249
OH	W H Sammis	4	160	2	5527	160	160	5538
OH	W H Sammis	5	294	3	10419	294	294	10439
OH	W H Sammis	6	564	6	19947	562	563	19987
OH	W H Sammis	7	527	6	18633	525	526	18670
OH	W H Zimmer	1	468	5	16149	467	468	16181
OH	Walter C Beckjord	1	14	0	1834	14	14	472
OH	Walter C Beckjord	2	21	0	1859	21	21	711
OH	Walter C Beckjord	3	31	0	2530	31	31	1077
OH	Walter C Beckjord	4	62	1	3261	62	62	2141
OH	Walter C Beckjord	5	109	1	3857	109	109	3864

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
OH	Walter C Beckjord	6	280	3	9922	280	280	9942
OH	Woodsdale	**GT1	9	0	294	9	9	295
OH	Woodsdale	**GT10	0	0	0	0	0	0
OH	Woodsdale	**GT11	0	0	0	0	0	0
OH	Woodsdale	**GT12	0	0	0	0	0	0
OH	Woodsdale	**GT2	9	0	294	9	9	295
OH	Woodsdale	**GT3	9	0	294	9	9	295
OH	Woodsdale	**GT4	9	0	294	9	9	295
OH	Woodsdale	**GT5	9	0	294	9	9	295
OH	Woodsdale	**GT6	9	0	294	9	9	295
OH	Woodsdale	**GT7	0	0	0	0	0	0
OH	Woodsdale	**GT8	0	0	0	0	0	0
OH	Woodsdale	**GT9	0	0	0	0	0	0
OK	Anadarko	3	0	0	0	0	0	1
OK	Arbuckle	ARB	0	0	45	0	1	50
OK	Comanche	7251	0	0	333	0	4	144
OK	Comanche	7252	0	0	2	0	4	144
OK	Conoco	**1	6	0	222	6	6	222
OK	Conoco	**2	6	0	222	6	6	222
OK	GRDA	1	405	4	14638	403	404	13973
OK	GRDA	2	242	3	8393	242	242	8372
OK	Horseshoe Lake	6	0	0	173	0	5	160
OK	Horseshoe Lake	7	0	0	231	0	6	207
OK	Horseshoe Lake	8	0	0	313	0	10	358
OK	Hugo	1	332	4	11873	331	332	11475
OK	Mooreland	1	0	0	0	0	0	1
OK	Mooreland	2	0	0	44	0	2	57
OK	Mooreland	3	0	0	7	0	0	17
OK	Muskogee	3	0	0	141	0	4	137
OK	Muskogee	4	257	3	9308	256	257	8880
OK	Muskogee	5	227	2	8275	226	226	7835
OK	Muskogee	6	403	4	14421	402	403	13931
OK	Mustang	1	0	0	32	0	1	26
OK	Mustang	2	0	0	26	0	1	25
OK	Mustang	3	0	0	1	0	2	81
OK	Mustang	4	0	0	163	0	6	191
OK	NA 1 – 5030	**1	0	0	0	0	0	0
OK	NA 1 – 5030	**2	0	0	0	0	0	0
OK	NA 1 – 5030	**3	0	0	0	0	0	0
OK	Northeastern	3301	48	1	1741	48	48	1646
OK	Northeastern	3302	161	2	5933	161	161	5578
OK	Northeastern	3313	384	4	13829	383	383	13249
OK	Northeastern	3314	415	5	14879	414	414	14337
OK	Ponca	2	0	0	0	0	0	0
OK	Riverside	1501	0	0	519	0	12	417

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
OK	Riverside	1502	0	0	285	0	10	335
OK	Seminole	1	0	0	412	0	11	383
OK	Seminole	2	0	0	453	0	12	432
OK	Seminole	3	1	0	494	1	15	505
OK	Sooner	1	288	3	10468	287	287	9938
OK	Sooner	2	274	3	9976	273	273	9451
OK	Southwestern	8002	0	0	15	0	1	17
OK	Southwestern	8003	0	0	164	0	5	165
OK	Southwestern	801N	0	0	3	0	0	5
OK	Southwestern	801S	0	0	0	0	0	3
OK	Tulsa	1402	0	0	98	0	1	45
OK	Tulsa	1403	0	0	4	0	0	3
OK	Tulsa	1404	0	0	58	0	2	64
OR	Boardman	1SG	388	4	13373	387	387	13401
PA	Armstrong	1	176	2	6213	175	175	6226
PA	Armstrong	2	188	2	6652	188	188	6665
PA	Bruce Mansfield	1	369	4	12713	368	368	12740
PA	Bruce Mansfield	2	408	4	14065	407	407	14094
PA	Bruce Mansfield	3	420	5	14468	419	419	14498
PA	Brunner Island	1	338	4	11968	337	338	11992
PA	Brunner Island	2	379	4	13410	378	378	13437
PA	Brunner Island	3	656	8	23201	654	655	23250
PA	Cheswick	1	477	5	16886	476	476	16919
PA	Conemaugh	1	734	9	25929	732	733	25982
PA	Conemaugh	2	813	10	28742	811	812	28800
PA	Cromby	1	64	1	2202	64	64	2207
PA	Cromby	2	61	1	2109	61	61	2114
PA	Delaware	71	22	0	743	22	22	745
PA	Delaware	81	16	0	537	16	16	538
PA	Eddystone	1	74	1	2844	74	74	2560
PA	Eddystone	2	73	1	3004	72	72	2504
PA	Eddystone	3	55	1	1894	55	55	1899
PA	Eddystone	4	58	1	2010	58	58	2015
PA	Elrama	1	21	0	1650	21	21	711
PA	Elrama	2	19	0	1616	19	19	662
PA	Elrama	3	44	0	1568	44	44	1528
PA	Elrama	4	75	1	2579	75	75	2584
PA	F R Phillips	1	3	0	663	3	3	145
PA	F R Phillips	2	3	0	504	3	3	110
PA	F R Phillips	3	8	0	1165	8	8	253
PA	F R Phillips	4	7	0	1112	7	7	242
PA	F R Phillips	5	7	0	1131	7	7	247
PA	F R Phillips	6	32	0	2022	32	32	1109
PA	Front Street	10	36	0	1176	36	36	1176
PA	Front Street	7	9	0	294	9	9	295

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
PA	Front Street	8	9	0	294	9	9	295
PA	Front Street	9	36	0	1176	36	36	1176
PA	Hatfield's Ferry	1	461	5	16308	460	460	16340
PA	Hatfield's Ferry	2	455	5	16089	453	454	16122
PA	Hatfield's Ferry	3	491	5	17360	489	490	17394
PA	Holtwood	17	104	1	3570	103	103	3578
PA	Homer City	1	515	6	17753	514	514	17790
PA	Homer City	2	447	5	16309	446	446	15441
PA	Homer City	3	802	10	27619	800	801	27676
PA	Hunlock Power	6	65	1	2256	65	65	2261
PA	Keystone	1	819	10	28209	817	818	28267
PA	Keystone	2	872	10	30035	870	871	30098
PA	Martins Creek	1	154	2	5455	154	154	5467
PA	Martins Creek	2	156	2	5526	156	156	5538
PA	Martins Creek	3	382	4	13179	381	382	13205
PA	Martins Creek	4	352	4	12123	351	351	12148
PA	Mitchell	1	0	0	0	0	0	0
PA	Mitchell	2	0	0	1	0	0	1
PA	Mitchell	3	0	0	0	0	0	0
PA	Mitchell	33	90	1	3528	90	90	3103
PA	Montour	1	696	9	24182	693	695	24018
PA	Montour	2	717	9	24671	714	716	24723
PA	New Castle	1	37	0	1292	37	18	621
PA	New Castle	2	41	0	1439	41	20	692
PA	New Castle	3	82	1	2842	82	82	2848
PA	New Castle	4	75	1	2816	75	75	2607
PA	New Castle	5	131	1	4513	131	131	4522
PA	Portland	1	72	1	2559	72	72	2565
PA	Portland	2	125	1	4412	124	124	4421
PA	Schuykill	1	17	0	572	17	17	573
PA	Seward	12	32	0	1096	32	32	1098
PA	Seward	14	32	0	1096	32	32	1098
PA	Seward	15	145	2	5000	145	145	5010
PA	Shawville	1	125	1	4429	125	125	4437
PA	Shawville	2	126	1	4455	126	126	4463
PA	Shawville	3	173	2	6109	172	172	6122
PA	Shawville	4	171	2	6068	171	171	6081
PA	Springdale	77	0	0	0	0	0	0
PA	Springdale	88	0	0	0	0	0	0
PA	Sunbury	1A	52	0	1818	52	52	1822
PA	Sunbury	1B	52	0	1817	52	52	1821
PA	Sunbury	2A	52	0	1818	52	52	1822
PA	Sunbury	2B	52	0	1818	52	52	1822
PA	Sunbury	3	115	1	4028	115	115	4036
PA	Sunbury	4	148	2	5248	148	148	5259

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
PA	Titus	1	55	1	2149	55	55	1901
PA	Titus	2	63	1	2271	63	63	2179
PA	Titus	3	58	1	2194	58	58	1994
PA	Warren	1	21	0	720	21	21	721
PA	Warren	2	21	0	720	21	21	721
PA	Warren	3	21	0	740	21	21	741
PA	Warren	4	21	0	740	21	21	741
PA	Williamsburg	11	27	0	935	27	27	936
RI	Manchester Street	12	14	0	512	14	14	485
RI	Manchester Street	6	19	0	693	19	19	657
RI	Manchester Street	7	13	0	458	13	13	435
RI	South Street	121	30	0	1086	30	30	1048
RI	South Street	122	28	0	946	28	28	950
SC	Canadys Steam	CAN1	85	1	3247	85	85	2937
SC	Canadys Steam	CAN2	67	1	2978	67	67	2309
SC	Canadys Steam	CAN3	90	1	4222	90	90	3105
SC	Cope Station	COP1	76	1	2615	76	76	2620
SC	Cross	1	162	2	5601	162	162	5612
SC	Cross	2	259	3	8938	259	259	8956
SC	Dolphus M Grainger	1	90	1	3113	90	90	3119
SC	Dolphus M Grainger	2	8	0	277	8	8	277
SC	H B Robinson	1	84	1	3814	84	84	2908
SC	Hagood	HAG1	0	0	3	0	0	3
SC	Hagood	HAG2	0	0	451	0	0	2
SC	Hagood	HAG3	0	0	787	0	0	6
SC	Hagood	HAG4	28	0	948	27	27	951
SC	Jefferies	1	0	0	0	0	0	0
SC	Jefferies	2	0	0	1	0	0	1
SC	Jefferies	3	98	1	3885	98	98	3378
SC	Jefferies	4	91	1	3742	91	91	3155
SC	McMeekin	MCM1	118	1	4079	118	118	4087
SC	McMeekin	MCM2	117	1	4037	117	117	4045
SC	NA 1 – 7106	**GT1	0	0	0	0	0	0
SC	Urquhart	URQ1	64	1	2194	64	64	2199
SC	Urquhart	URQ2	49	1	1926	49	49	1685
SC	Urquhart	URQ3	84	1	2913	84	84	2919
SC	W S Lee	1	26	0	2133	26	26	900
SC	W S Lee	2	33	0	2277	33	33	1132
SC	W S Lee	3	51	1	3443	51	51	1773
SC	Wateree	WAT1	282	3	9714	281	281	9735
SC	Wateree	WAT2	261	3	9267	261	261	9022
SC	Williams	WIL1	459	5	15816	458	458	15849
SC	Winyah	1	220	2	7572	219	219	7588
SC	Winyah	2	148	2	6232	148	148	5128
SC	Winyah	3	73	1	3609	72	73	2508

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
SC	Winyah	4	99	1	3426	99	99	3433
SD	Angus Anson Site	2	25	0	851	25	25	853
SD	Angus Anson Site	3	30	0	1020	30	30	1022
SD	Big Stone	1	376	4	13711	375	375	12973
SD	Huron	**2A	2	0	80	2	2	80
SD	Huron	**2B	3	0	103	3	3	103
SD	Pathfinder	11	0	0	11	0	0	11
SD	Pathfinder	12	0	0	2	0	0	2
SD	Pathfinder	13	0	0	2	0	0	2
TN	Allen	1	187	2	6606	186	186	6619
TN	Allen	2	204	2	7229	204	204	7243
TN	Allen	3	191	2	6754	190	191	6767
TN	Bull Run	1	727	9	25038	725	726	25090
TN	Cumberland	1	1057	12	37374	1054	1055	37451
TN	Cumberland	2	1156	14	40882	1153	1154	40967
TN	Gallatin	1	215	2	7603	214	214	7618
TN	Gallatin	2	211	2	7462	210	211	7476
TN	Gallatin	3	244	3	8632	243	244	8649
TN	Gallatin	4	259	3	9165	258	259	9183
TN	John Sevier	1	184	2	6359	184	184	6372
TN	John Sevier	2	184	2	6356	184	184	6369
TN	John Sevier	3	189	2	6517	189	189	6531
TN	John Sevier	4	193	2	6667	193	193	6680
TN	Johnsonville	1	95	1	3357	95	95	3364
TN	Johnsonville	10	92	1	3255	92	92	3262
TN	Johnsonville	2	98	1	3464	98	98	3471
TN	Johnsonville	3	102	1	3627	102	102	3633
TN	Johnsonville	4	97	1	3442	97	97	3449
TN	Johnsonville	5	100	1	3552	100	100	3558
TN	Johnsonville	6	96	1	3403	96	96	3410
TN	Johnsonville	7	109	1	3870	109	109	3878
TN	Johnsonville	8	106	1	3752	106	106	3759
TN	Johnsonville	9	86	1	3051	86	86	3057
TN	Kingston	1	120	1	4151	120	120	4158
TN	Kingston	2	115	1	3991	115	115	3966
TN	Kingston	3	138	1	4750	137	138	4760
TN	Kingston	4	146	2	5039	146	146	5050
TN	Kingston	5	180	2	6192	179	179	6206
TN	Kingston	6	184	2	6345	184	184	6358
TN	Kingston	7	179	2	6187	179	179	6200
TN	Kingston	8	168	2	5782	167	167	5794
TN	Kingston	9	186	2	6403	185	185	6417
TN	Watts Bar	A	0	0	0	0	0	0
TN	Watts Bar	B	0	0	0	0	0	0
TN	Watts Bar	C	0	0	0	0	0	0

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
TN	Watts Bar	D	0	0	0	0	0	0
TX	Barney M Davis	1	1	0	496	1	12	412
TX	Barney M Davis	2	1	0	398	1	11	384
TX	Big Brown	1	584	6	20979	582	583	20161
TX	Big Brown	2	558	6	19872	557	557	19286
TX	Bryan	6	0	0	19	0	1	22
TX	C E Newman	BW5	0	0	3	0	0	4
TX	Cedar Bayou	CBY1	0	0	814	0	20	702
TX	Cedar Bayou	CBY2	0	0	921	0	25	857
TX	Cedar Bayou	CBY3	0	0	725	0	20	707
TX	Coleto Creek	**2	0	0	0	0	0	0
TX	Coleto Creek	1	400	4	14717	399	399	13807
TX	Collin	1	1	0	92	1	3	94
TX	Concho	7	0	0	11	0	0	13
TX	Dallas	3	0	0	27	0	1	23
TX	Dallas	9	0	0	26	0	1	25
TX	Dansby	1	1	0	94	1	3	106
TX	Decker Creek	1	0	0	128	0	4	150
TX	Decker Creek	2	0	0	195	0	5	181
TX	Decordova	1	1	0	1018	1	25	881
TX	Deepwater	DWP9	0	0	28	0	1	37
TX	E S Joslin	1	0	0	260	0	6	210
TX	Eagle Mountain	1	0	0	52	0	1	43
TX	Eagle Mountain	2	1	0	140	1	3	116
TX	Eagle Mountain	3	0	0	100	0	3	109
TX	Forest Grove	**1	0	0	0	0	0	0
TX	Fort Phantom	1	0	0	126	0	4	129
TX	Fort Phantom	2	1	0	187	1	6	192
TX	Generic Station	**1	0	0	0	0	0	0
TX	Generic Station	**2	0	0	0	0	0	0
TX	Gibbons Creek	1	403	4	14410	401	402	13904
TX	Graham	1	0	0	235	0	6	194
TX	Graham	2	1	0	496	1	12	406
TX	Greens Bayou	GBY1	0	0	1	0	0	3
TX	Greens Bayou	GBY2	0	0	2	0	0	3
TX	Greens Bayou	GBY3	0	0	15	0	0	6
TX	Greens Bayou	GBY4	0	0	19	0	0	8
TX	Greens Bayou	GBY5	1	0	352	1	9	308
TX	Handley	1A	0	0	7	0	0	3
TX	Handley	1B	0	0	0	0	0	3
TX	Handley	2	0	0	21	0	0	15
TX	Handley	3	1	0	423	1	11	393
TX	Handley	4	0	0	118	0	3	112
TX	Handley	5	1	0	136	1	4	127
TX	Harrington Station	061B	223	2	8232	223	223	7711

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
TX	Harrington Station	062B	237	3	8718	237	237	8197
TX	Harrington Station	063B	253	3	9266	252	253	8741
TX	Hiram Clarke	HOC1	0	0	0	0	0	0
TX	Hiram Clarke	HOC2	0	0	0	0	0	0
TX	Hiram Clarke	HOC3	0	0	3	0	0	2
TX	Hiram Clarke	HOC4	0	0	2	0	0	1
TX	Holly Ave	1	0	0	59	0	2	71
TX	Holly Ave	2	0	0	71	0	2	76
TX	Holly Street	1	0	0	49	0	0	17
TX	Holly Street	2	0	0	31	0	1	18
TX	Holly Street	3	0	0	68	0	2	66
TX	Holly Street	4	0	0	43	0	2	82
TX	J K Spruce	**2	0	0	0	0	0	0
TX	J K Spruce	BLR1	194	2	6690	194	194	6703
TX	J L Bates	1	0	0	48	0	1	46
TX	J L Bates	2	0	0	124	0	3	101
TX	J T Deely	1	364	4	13132	363	363	12571
TX	J T Deely	2	380	4	13701	379	379	13113
TX	Jones Station	151B	0	0	125	0	2	74
TX	Jones Station	152B	0	0	93	0	2	67
TX	Knox Lee	2	0	0	0	0	0	0
TX	Knox Lee	3	0	0	5	0	0	2
TX	Knox Lee	4	0	0	29	0	0	13
TX	Knox Lee	5	0	0	251	0	4	149
TX	La Palma	7	0	0	178	0	4	153
TX	Lake Creek	1	0	0	39	0	1	29
TX	Lake Creek	2	0	0	191	0	4	141
TX	Lake Hubbard	1	1	0	170	1	6	201
TX	Lake Hubbard	2	2	0	604	2	17	578
TX	Laredo	1	0	0	15	0	0	16
TX	Laredo	2	0	0	14	0	0	14
TX	Laredo	3	0	0	85	0	3	116
TX	Leon Creek	3	0	0	2	0	0	2
TX	Leon Creek	4	0	0	10	0	0	8
TX	Lewis Creek	1	0	0	317	0	8	263
TX	Lewis Creek	2	0	0	271	0	7	257
TX	Limesetone	LIM1	687	8	23779	685	687	23725
TX	Limesetone	LIM2	411	4	14154	409	410	14182
TX	Lon C Hill	1	0	0	9	0	0	7
TX	Lon C Hill	2	0	0	10	0	0	7
TX	Lon C Hill	3	0	0	179	0	3	91
TX	Lon C Hill	4	0	0	197	0	7	238
TX	Lone Star	1	0	0	0	0	0	10
TX	Malakoff	**1	45	0	1539	45	45	1542
TX	Malakoff	**2	0	0	0	0	0	0

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
TX	Martin Lake	1	933	11	33220	931	932	32202
TX	Martin Lake	2	905	11	32255	903	903	31222
TX	Martin Lake	3	940	11	33425	937	938	32429
TX	Mission Road	3	0	0	3	0	0	8
TX	Monticello	1	659	8	23633	657	659	22760
TX	Monticello	2	639	8	22930	637	638	22061
TX	Monticello	3	987	12	35220	984	985	34043
TX	Morgan Creek	3	0	0	8	0	0	6
TX	Morgan Creek	4	0	0	72	0	2	56
TX	Morgan Creek	5	0	0	154	0	5	164
TX	Morgan Creek	6	6	0	836	6	22	777
TX	Mountain Creek	2	0	0	4	0	0	3
TX	Mountain Creek	3A	0	0	11	0	0	5
TX	Mountain Creek	3B	0	0	2	0	0	5
TX	Mountain Creek	6	1	0	63	1	2	74
TX	Mountain Creek	7	0	0	62	0	2	58
TX	Mountain Creek	8	1	0	527	1	15	535
TX	NA 1 – 7219	**1	0	0	0	0	0	0
TX	NA 1 – 7219	**2	0	0	0	0	0	0
TX	NA 2 – 4274	**NA1	0	0	0	0	0	0
TX	Neches	11	0	0	0	0	0	0
TX	Neches	13	0	0	0	0	0	0
TX	Neches	15	0	0	0	0	0	0
TX	Neches	18	0	0	0	0	0	0
TX	Newman	1	0	0	14	0	1	18
TX	Newman	2	0	0	29	0	1	41
TX	Newman	3	0	0	88	0	3	94
TX	Newman	HRSG1	0	0	99	0	4	138
TX	Nichols Station	141B	0	0	77	0	2	82
TX	Nichols Station	142B	0	0	86	0	2	76
TX	Nichols Station	143B	0	0	50	0	1	31
TX	North Lake	1	1	0	131	1	4	129
TX	North Lake	2	1	0	150	1	4	141
TX	North Lake	3	2	0	294	2	7	255
TX	North Main	4	0	0	42	0	1	35
TX	North Texas	3	0	0	13	0	0	8
TX	Nueces Bay	5	0	0	1	0	0	1
TX	Nueces Bay	6	0	0	140	0	3	114
TX	Nueces Bay	7	0	0	496	0	12	431
TX	O W Sommers	1	2	0	478	2	14	477
TX	O W Sommers	2	0	0	188	0	9	322
TX	Oak Creek	1	0	0	106	0	3	107
TX	Oklaunion	1	228	2	7857	227	228	7872
TX	P H Robinson	PHR1	0	0	645	0	13	435
TX	P H Robinson	PHR2	0	0	494	0	14	491

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
TX	P H Robinson	PHR3	0	0	685	0	15	506
TX	P H Robinson	PHR4	0	0	796	0	18	620
TX	Paint Creek	1	0	0	11	0	0	10
TX	Paint Creek	2	0	0	11	0	0	11
TX	Paint Creek	3	1	0	28	1	2	53
TX	Paint Creek	4	0	0	105	0	3	103
TX	Parkdale	1	0	0	34	0	1	36
TX	Parkdale	2	0	0	62	0	2	66
TX	Parkdale	3	1	0	61	1	2	76
TX	Permian Basin	5	0	0	103	0	3	105
TX	Permian Basin	6	8	0	804	8	24	828
TX	Pirkey	1	574	6	20526	572	573	19809
TX	Plant X	111B	0	0	0	0	0	0
TX	Plant X	112B	0	0	2	0	0	1
TX	Plant X	113B	0	0	89	0	1	30
TX	Plant X	114B	0	0	0	0	0	3
TX	Powerlane Plant	2	13	0	459	13	14	467
TX	Powerlane Plant	3	1	0	37	1	1	38
TX	R W Miller	**4	25	0	851	25	25	853
TX	R W Miller	**5	25	0	851	25	25	853
TX	R W Miller	1	0	0	55	0	2	54
TX	R W Miller	2	0	0	98	0	3	98
TX	R W Miller	3	0	0	218	0	5	181
TX	Ray Olinger	BW2	0	0	60	0	2	52
TX	Ray Olinger	BW3	0	0	79	0	2	86
TX	Ray Olinger	CE1	0	0	42	0	1	33
TX	Rio Pecos	5	0	0	64	0	2	69
TX	Rio Pecos	6	0	0	179	0	5	172
TX	River Crest	1	1	0	61	1	2	70
TX	Sabine	1	0	0	152	0	6	204
TX	Sabine	2	0	0	164	0	6	197
TX	Sabine	3	0	0	576	0	15	503
TX	Sabine	4	0	0	504	0	18	626
TX	Sabine	5	0	0	323	0	11	392
TX	Sam Bertron	SRB1	0	0	57	0	1	49
TX	Sam Bertron	SRB2	0	0	18	0	1	33
TX	Sam Bertron	SRB3	0	0	120	0	3	90
TX	Sam Bertron	SRB4	0	0	79	0	2	79
TX	Sam Seymour	1	437	5	15905	436	436	15087
TX	Sam Seymour	2	476	5	17391	475	475	16435
TX	Sam Seymour	3	304	3	10491	304	304	10513
TX	San Angelo	2	0	0	161	0	5	164
TX	San Miguel	SM-1	482	5	17211	481	481	16651
TX	Sandow	4	722	9	25689	719	721	24915
TX	Seaholm	9	0	0	4	0	0	3

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State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
TX	Sim Gideon	1	0	0	47	0	1	51
TX	Sim Gideon	2	0	0	56	0	2	58
TX	Sim Gideon	3	0	0	277	0	9	321
TX	Spencer	4	0	0	19	0	1	17
TX	Spencer	5	0	0	23	0	1	22
TX	Stryker Creek	1	0	0	170	0	4	138
TX	Stryker Creek	2	1	0	525	1	16	563
TX	T C Fergusen	1	0	0	253	0	7	254
TX	T H Wharton	THW1	0	0	7	0	0	5
TX	T H Wharton	THW2	0	0	97	0	2	82
TX	TNP One	U1	62	1	2122	61	61	2127
TX	TNP One	U2	102	1	3499	101	101	3507
TX	Tolk Station	171B	407	4	14777	406	406	14057
TX	Tolk Station	172B	403	4	14440	402	402	13925
TX	Tradinghouse	1	0	0	593	0	15	516
TX	Tradinghouse	2	1	0	995	1	26	903
TX	Trinidad	7	0	0	6	0	0	4
TX	Trinidad	8	0	0	1	0	0	3
TX	Trinidad	9	0	0	135	0	3	115
TX	Twin Oak	1	232	3	8012	232	232	8028
TX	Twin Oak	2	45	0	1540	45	45	1542
TX	V H Braunig	1	0	0	78	0	4	122
TX	V H Braunig	2	0	0	121	0	4	140
TX	V H Braunig	3	0	0	416	0	11	392
TX	Valley	1	0	0	77	0	3	97
TX	Valley	2	1	0	518	1	16	540
TX	Valley	3	0	0	124	0	4	129
TX	Victoria	5	0	0	6	0	0	6
TX	Victoria	6	0	0	8	0	0	4
TX	Victoria	7	0	0	110	0	3	102
TX	Victoria	8	0	0	238	0	6	224
TX	W A Parish	WAP1	0	0	57	0	1	51
TX	W A Parish	WAP2	0	0	56	0	1	45
TX	W A Parish	WAP3	0	0	245	0	5	158
TX	W A Parish	WAP4	0	0	558	0	15	511
TX	W A Parish	WAP5	634	8	22870	632	632	21881
TX	W A Parish	WAP6	573	6	20755	572	572	19803
TX	W A Parish	WAP7	416	5	15137	415	415	14365
TX	W A Parish	WAP8	186	2	7285	185	186	6421
TX	W B Tuttle	1	0	0	2	0	0	3
TX	W B Tuttle	2	0	0	19	0	1	17
TX	W B Tuttle	3	0	0	11	0	0	14
TX	W B Tuttle	4	0	0	48	0	2	52
TX	Webster	WEB1	0	0	14	0	0	5
TX	Webster	WEB2	0	0	17	0	0	7

Table 2 - Phase II Allowance Allocations

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
TX	Webster	WEB3	0	0	343	0	9	320
TX	Welsh	1	370	4	13325	369	369	12772
TX	Welsh	2	357	4	12842	356	356	12334
TX	Welsh	3	420	5	15215	419	420	14517
TX	Willkes	1	0	0	30	0	2	58
TX	Willkes	2	0	0	118	0	3	93
TX	Willkes	3	0	0	129	0	2	74
UH	Bonanza	1-1	255	3	10782	255	255	8818
UH	Carbon	1	55	1	1912	55	55	1917
UH	Carbon	2	72	1	2498	72	72	2503
UH	Gadsby	1	1	0	24	1	1	24
UH	Gadsby	2	12	0	1690	12	12	408
UH	Gadsby	3	44	0	2265	44	44	1520
UH	Hale	1	0	0	1	0	0	1
UH	Hunter (Emery)	1	216	2	7452	216	216	7466
UH	Hunter (Emery)	2	231	3	7957	230	230	7974
UH	Hunter (Emery)	3	326	4	11250	326	326	11273
UH	Huntington	1	230	2	7923	229	229	7940
UH	Huntington	2	283	3	9750	282	282	9771
UH	Intermountain	1SGA	83	1	2874	83	83	2880
UH	Intermountain	2SGA	84	1	2894	84	84	2900
VT	J C McNeil	1	1	0	104	1	1	38
VA	Bremo Power Station	3	51	1	2028	51	51	1768
VA	Bremo Power Station	4	150	2	5158	149	149	5170
VA	Chesapeake	1	22	0	2117	22	22	764
VA	Chesapeake	2	29	0	2210	29	29	1000
VA	Chesapeake	3	132	1	4559	132	132	4567
VA	Chesapeake	4	170	2	5870	169	169	5861
VA	Chesterfield	**8A	40	0	1387	40	40	1390
VA	Chesterfield	3	54	1	2560	54	54	1856
VA	Chesterfield	4	135	1	4669	135	135	4678
VA	Chesterfield	5	266	3	9163	265	265	9182
VA	Chesterfield	6	477	5	17134	476	476	16470
VA	Clinch River	1	154	2	5346	153	153	5302
VA	Clinch River	2	177	2	6111	177	177	6123
VA	Clinch River	3	164	2	5649	163	164	5661
VA	Clover	1	85	1	2937	85	85	2943
VA	Clover	2	85	1	2937	85	85	2943
VA	East Chandler	**2	0	0	0	0	0	0
VA	Glen Lyn	51	24	0	1152	24	24	815
VA	Glen Lyn	52	23	0	1113	23	23	787
VA	Glen Lyn	6	152	2	5533	152	152	5251
VA	Possum Point	1	0	0	0	0	0	0
VA	Possum Point	2	0	0	0	0	0	0
VA	Possum Point	3	65	1	2646	65	65	2253

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			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
VA	Possum Point	4	195	2	6723	194	195	6736
VA	Possum Point	5	126	1	4335	125	126	4343
VA	Potomac River	1	48	1	2333	48	48	1650
VA	Potomac River	2	49	1	2308	48	48	1677
VA	Potomac River	3	80	1	2755	80	80	2761
VA	Potomac River	4	88	1	3036	88	88	3043
VA	Potomac River	5	84	1	2912	84	84	2918
VA	Yorktown	1	135	1	4670	135	135	4679
VA	Yorktown	2	130	1	4673	130	130	4503
VA	Yorktown	3	183	2	6303	182	183	6316
WA	Centralia	BW21	553	6	19070	552	552	19108
WA	Centralia	BW22	590	6	20331	588	589	20373
WA	Shuffleton	1	0	0	0	0	0	0
WA	Shuffleton	2	0	0	0	0	0	0
WA	Shuffleton	3	0	0	0	0	0	0
WV	Albright	1	57	1	1973	57	57	1978
WV	Albright	2	60	1	2053	59	59	2058
WV	Albright	3	130	1	4597	130	130	4606
WV	Fort Martin	1	507	5	17930	505	506	17965
WV	Fort Martin	2	502	5	17762	501	501	17797
WV	Harrison	1	592	6	20960	591	591	21002
WV	Harrison	2	562	6	19896	561	561	19936
WV	Harrison	3	506	5	17893	504	505	17928
WV	John E Amos	1	655	8	22581	653	654	22630
WV	John E Amos	2	752	9	25890	750	751	25944
WV	John E Amos	3	1205	14	41498	1202	1203	41584
WV	Kammer	1	228	2	8080	228	228	8095
WV	Kammer	2	237	3	8387	236	237	8404
WV	Kammer	3	212	2	7497	211	211	7512
WV	Kanawha River	1	115	1	4461	115	115	3981
WV	Kanawha River	2	103	1	4290	102	102	3545
WV	Mitchell	1	536	6	18957	534	535	18995
WV	Mitchell	2	554	6	19616	553	553	19656
WV	Mountaineer (1301)	1	1023	12	35211	1020	1021	35285
WV	Mt Storm	1	533	6	18849	531	532	18887
WV	Mt Storm	2	500	5	17683	498	499	17718
WV	Mt Storm	3	517	6	18290	516	516	18327
WV	Phil Sporn	11	70	1	3129	70	70	2434
WV	Phil Sporn	21	59	1	2964	59	59	2048
WV	Phil Sporn	31	85	1	3312	85	85	2932
WV	Phil Sporn	41	67	1	3052	66	67	2302
WV	Phil Sporn	51	305	3	10614	304	304	10519
WV	Pleasants	1	511	6	17597	509	510	17633
WV	Pleasants	2	586	6	20188	584	585	20229
WV	Rivesville	7	20	0	1237	20	20	696

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
WV	Rivesville	8	60	1	2528	60	60	2086
WV	Willow Island	1	28	0	1496	28	28	961
WV	Willow Island	2	117	1	4683	116	116	4029
WI	Alma	B4	35	0	1193	34	35	1194
WI	Alma	B5	55	1	1905	55	55	1910
WI	Bay Front	1	14	0	1046	14	14	512
WI	Bay Front	2	16	0	529	16	16	530
WI	Bay Front	3	0	0	0	0	0	0
WI	Bay Front	4	0	0	33	0	0	16
WI	Bay Front	5	4	0	281	4	4	135
WI	Blount Street	11	0	0	1	0	0	1
WI	Blount Street	3	0	0	6	0	0	6
WI	Blount Street	5	0	0	7	0	0	7
WI	Blount Street	6	0	0	7	0	0	7
WI	Blount Street	7	3	0	1476	3	3	101
WI	Blount Street	8	12	0	1130	12	12	415
WI	Blount Street	9	16	0	1183	16	16	555
WI	Columbia	1	449	5	15479	448	448	15512
WI	Columbia	2	254	3	8755	253	254	8772
WI	Combustion Turbine	**2	0	0	0	0	0	0
WI	Commerce	25	0	0	4	0	0	4
WI	Concord	**1	4	0	126	4	4	126
WI	Concord	**2	4	0	126	4	4	126
WI	Concord	**3	4	0	126	4	4	126
WI	Concord	**4	4	0	126	4	4	126
WI	Edgewater	3	36	0	1237	36	36	1239
WI	Edgewater	4	302	3	10393	301	301	10415
WI	Edgewater	5	332	4	11455	331	332	11479
WI	Genoa	1	233	3	8016	232	232	8034
WI	J P Madgett	B1	209	2	7434	208	209	7219
WI	Manitowoc	6	18	0	672	18	18	672
WI	Manitowoc	7	24	0	814	24	24	813
WI	Manitowoc	8	7	0	238	7	7	238
WI	NA 1 – 7205	**1	0	0	0	0	0	0
WI	NA 1 – 7205	**2	0	0	0	0	0	0
WI	NA 1 – 7205	**3	0	0	0	0	0	0
WI	NA3	**1	0	0	0	0	0	0
WI	NA4	**1	0	0	0	0	0	0
WI	Nelson Dewey	1	73	1	2523	73	73	2528
WI	Nelson Dewey	2	81	1	2807	81	81	2813
WI	North Oak Creek	1	61	1	2118	61	61	2122
WI	North Oak Creek	2	60	1	2080	60	60	2084
WI	North Oak Creek	3	62	1	2129	62	62	2133
WI	North Oak Creek	4	72	1	2481	72	72	2487
WI	Paris	**1	4	0	124	4	4	124

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repowering Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
WI	Paris	**2	4	0	124	4	4	124
WI	Paris	**3	4	0	124	4	4	124
WI	Paris	**4	4	0	124	4	4	124
WI	Pleasant Prairie	1	342	4	11798	341	342	11822
WI	Pleasant Prairie	2	484	5	16675	482	483	16709
WI	Port Washington	1	15	0	529	15	15	530
WI	Port Washington	2	30	0	1031	30	30	1033
WI	Port Washington	3	25	0	858	25	25	860
WI	Port Washington	4	23	0	804	23	23	806
WI	Port Washington	5	31	0	1061	31	31	1063
WI	Pulliam	3	4	0	140	4	4	139
WI	Pulliam	4	6	0	208	6	6	209
WI	Pulliam	5	18	0	607	18	18	608
WI	Pulliam	6	23	0	791	23	23	792
WI	Pulliam	7	59	1	2035	59	59	2039
WI	Pulliam	8	91	1	3152	91	91	3159
WI	Rock River	1	45	0	1560	45	45	1562
WI	Rock River	2	43	0	1482	43	43	1484
WI	South Fond du Lac	**CT1	19	0	639	18	18	640
WI	South Fond du Lac	**CT2	1	0	39	1	1	39
WI	South Fond du Lac	**CT3	1	0	39	1	1	39
WI	South Fond du Lac	**CT4	0	0	0	0	0	0
WI	South Oak Creek	5	113	1	3884	112	113	3892
WI	South Oak Creek	6	141	2	4859	141	141	4870
WI	South Oak Creek	7	189	2	6502	188	188	6516
WI	South Oak Creek	8	185	2	6390	185	185	6402
WI	Stoneman	B1	6	0	177	6	6	176
WI	Stoneman	B2	6	0	223	6	6	224
WI	Valley	1	45	0	1805	45	45	1570
WI	Valley	2	46	0	1824	46	46	1586
WI	Valley	3	42	0	1954	42	42	1453
WI	Valley	4	41	0	1900	41	41	1414
WI	West Marinette	**33	22	0	765	22	22	766
WI	Weston	1	22	0	762	22	22	764
WI	Weston	2	53	1	1809	52	52	1813
WI	Weston	3	281	3	9701	281	281	9721
WY	Dave Johnston	BW41	131	1	4705	130	131	4519
WY	Dave Johnston	BW42	127	1	4571	127	127	4396
WY	Dave Johnston	BW43	246	3	8827	246	246	8513
WY	Dave Johnston	BW44	185	2	6802	184	184	6381
WY	Jim Bridger	BW71	583	6	20907	581	582	20134
WY	Jim Bridger	BW72	571	6	20464	569	570	19712
WY	Jim Bridger	BW73	547	6	19584	545	546	18876
WY	Jim Bridger	BW74	96	1	4064	96	96	3329
WY	Laramie River	1	122	1	5112	122	122	4228

Table 2 - Phase II Allowance Allocations

State	Plant Name	Boiler1	Allowances for Years 2000-2009				Years 2010 and Beyond	
			(A) Auction Reserve Deduction	(B) Repower-ing Deduction	(C)2 Total Annual Phase II	(D) 1993-1998 Auction Deduction	(E) Auction Reserve Deduction	(F)3 Total Annual Phase II
WY	Laramie River	2	104	1	4302	104	104	3590
WY	Laramie River	3	93	1	3822	93	93	3208
WY	Naughton	1	144	2	5201	144	144	4972
WY	Naughton	2	185	2	6741	185	185	6400
WY	Naughton	3	141	2	5214	141	141	4879
WY	Wyodak	BW91	513	6	18311	512	512	17731

Footnotes:

1 "**" in the boiler identifier denotes a planned unit or a unit for which the boiler number is unavailable.

2 Column (C) is calculated as follows: Adjusted basic allowances for 2000 (not shown) - Column A - Column B - Conservation/Renewable reserve deduction (not shown) + Additional basic (section 405(a)(3)) (not shown) + Total bonus (not shown)

3 Column (F) is calculated as follows: Adjusted basic allowances for 2010 (not shown) - Column E + Additional basic (section 405(a)(3)) (not shown)

4 The allowances shown in this table assume that these units fully qualify for section 405(i)(2). If Monroe units 1 through 4 do not qualify, instead of the allowances listed above, Anclote units 1 and 2 and Monroe units 1 through 4 will receive the following allocations:

Plant	Boiler	Column A	Column B	Col. C	Column D	Column E	Column F
Anclote	1	323	4	13887	297	323	11165
Anclote	2	343	4	13892	314	342	11839
Monroe	1	686	8	23660	690	686	23708
Monroe	2	707	8	24298	716	705	24350
Monroe	3	660	8	22763	670	660	22810
Monroe	4	716	9	24608	737	714	24664

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(3) The owner of each unit listed in the following table shall surrender, for each allowance listed in Column A or B of such table, an allowance of the same or earlier compliance use date and shall return to the Administrator any proceeds received from allowances withheld from the unit, as listed in Column C of such table. The allowances shall be surrendered and the proceeds shall be returned by December 28, 1998.

State	Plant name	Unit	Allowances for 2000 through 2009 column (A)	Allowances for 2010 and thereafter column (B)	Proceeds
CA	El Centro	2	285	272	$2749.48
CO	Valmont	11	4	0	0
FL	Lauderdale	PFL4	776	781	7904.74
FL	Lauderdale	PFL5	796	802	7904.74
LA	R S Nelson	1	30	34	0
LA	R S Nelson	2	33	32	0
MD	R P Smith	9	0	56	687.37
NM	Maddox	**3	85	85	687.37
SD	Mobile	**2	17	17	0
VA	Chesterfield	**8B	409	411	4124.21
WI	Blount Street	7	0	13	343.68
WI	Blount Street	8	0	294	3093.16
WI	Blount Street	9	0	355	3436.84

§ 73.11 [Removed and Reserved]

3. Section 73.11 is removed and reserved.

§ 73.12 [Removed and Reserved]

4. Paragraph (b) of § 73.12 is removed and reserved.

§ 73.13 [Amended]

5. Paragraph (b) of § 73.13 is amended by revising the words "§§ 73.16, 73.18," to read "§§ 73.18,".

§ 73.16 [Removed and Reserved]

6. Section 73.16 is removed and reserved.

7. Section 73.19 is amended by revising paragraph (a)(5) and removing and reserving paragraph (b) to read as follows:

§ 73.19 Certain units with declining SO_2 rates.

(a) * * *

(5) Its actual SO_2 emission rate is less than 1.2 lb/mmBtu in any one calendar year from 1996 through 1999, as reported under part 75 of this chapter;

* * * * *

8. Section 73.21 is amended by:

a. In paragraph (a) revising the words "§ 73.11" to read "§ 73.10(b)"; and revising the words "=Unit's Year 2000 Adjusted Basic Allowances as calculated at § 73.11(a)(3)" to read "are as listed in the following table" and adding a table as set forth below:

b. In paragraph (b) revising the words "§ 73.11(a) and (b)" to read "§ 73.10(b)";

c. In paragraph (c)(1) revising the words "=Unit's Year 2000 Adjusted Basic Allowances as calculated at § 73.11(a)(3)" to read "are as listed in the table in paragraph (a) of this section."; and

d. Revising paragraph (c)(2) to read as follows:

§ 73.21 Phase II repowering allowances.

(a) * * *

Unit	Year 2000 adjusted basic allowances
RE Burger 1	1273
RE Burger 2	1245
RE Burger 3	1286
RE Burger 4	1316
RE Burger 5	1336
RE Burger 6	1332
New Castle 1	1334
New Castle 2	1485
New Castle 3	2935
New Castle 4	2686
New Castle 5	5481

(c)(2) The Administrator will reallocate any allowances forfeited in paragraph (c)(1) of this section with a compliance use date of 2000 or any allowances remaining in the repowering reserve to all Table 2 units' years 2000 through 2009 subaccounts in the following manner:

$$\text{Reallocation} = \text{Forfeited Repowering Allowances} \times \frac{\text{Unit's Deductions at Table 2 Column B}}{27124}$$

9. Section 73.27 is amended by removing paragraph (a)(3) and revising paragraphs (a)(2), (b)(2) through (5), and (c)(2) through (5) to read as follows:

§ 73.27 Special allowance reserve.

(a) Establishment of reserve. * * *

(2) The Administrator will allocate 250,000 allowances annually for calendar year 2000 and each year thereafter to the Auction Subaccount of the Special Allowance Reserve.

(b) Distribution of proceeds. * * *

(2) Until June 1, 1998, monetary proceeds from the auctions of allowances from the Special Allowance Reserve (under subpart E of this part) for use in calendar years 2000 through 2009 will be distributed to the designated representative of each unit listed in Table 2 according to the following equation:

$$\text{Units Proceeds} = \left[\frac{\text{Unit's Deduction Table 2 Column D}}{250{,}000}\right] \times \text{Total Proceeds}$$

(3) On or after June 1, 1998, monetary proceeds from the auctions of allowances from the Special Allowance Reserve (under subpart E of this part) for use in calendar years 2000 through 2009 will be distributed to the designated representative of each unit listed in Table 2 according to the following equation:

$$\text{Unit Proceeds} = \left[\frac{\text{Unit's Deduction at Table 2 Column A}}{250{,}000}\right] \times \text{Total Proceeds}$$

(4) Monetary proceeds from the auctions of allowances from the Special Allowance Reserve (under subpart E of this part) from years of purchase from 1993 through 1998, remaining in the U.S. Treasury as a result of the surrender of allowances and return of proceeds under § 73.10(b)(3), will be distributed to the designated representative of each unit listed in Table 2 according to the following equation:

$$\text{Unit Proceeds} = \left[\frac{\text{Unit's Deduction at Table 2 Column D}}{250{,}000}\right] \times \text{Remaining Proceeds}$$

(5) Monetary proceeds from the auctions of allowances from the Special Allowance Reserve (under subpart E of this part) for use in calendar years 2010 and thereafter will be distributed to the designated representative of each unit listed in Table 2 according to the following equation:

$$\text{Unit Proceeds} = \left[\frac{\text{Unit's Deduction at Table 2 Column E}}{250{,}000}\right] \times \text{Total Proceeds}$$

(c) * * *

(2) Until June 1, 1998, allowances, for use in calendar years 2000 through 2009, remaining in the Special Allowance Reserve at the end of each year, following that year's auction (under subpart E of this part), will be reallocated to the unit's Allowance Tracking System account according to the following equation:

$$\text{Unit Allowances} = \left[\frac{\text{Unit's Deduction at Table 2 Column D}}{250{,}000}\right] \times \text{Allowances Remaining}$$

(3) On or after June 1, 1998, allowances, for use in calendar years 2000 through 2009, remaining in the Special Allowance Reserve at the end of each year, following that year's auction (under subpart E of this part), will be reallocated to the unit's Allowance Tracking System account according to the following equation:

$$\text{Unit Allowances} = \left[\frac{\text{Unit's Deduction at Table 2 Column A}}{250{,}000}\right] \times \text{Allowances Remaining}$$

(4) [Reserved]

(5) Allowances, for use in calendar years 2010 and thereafter, remaining in the Special Allowance Reserve at the end of each year, following that year's auction (under subpart E of this part), will be reallocated to the unit's Allowance Tracking System account according to the following equation:

$$\text{Unit Allowances} = \left[\frac{\text{Unit's Deduction at Table 2 Column E}}{250{,}000}\right] \times \text{Allowances Remaining}$$

* * * * *

10. Paragraph (b) of § 73.70 is revised to read as follows:

§ 73.70 Auctions.

* * * * *

(b) *Timing of the auctions.* The spot auction and the advance auction will be held on the same day, selected each year by the Administrator, but no later than March 31 of each year. The Administrator will conduct one spot auction and one advance auction in each calendar year.

* * * * *

[FR Doc. 98-25317 Filed 9-25-98; 8:45 am]

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Clean Air Markets

You are here: EPA Home Air & Radiation Clean Air Markets Allowance Trading Annual Auction 2011 2011 EPA Allowance Auction Results

2011 EPA Allowance Auction Results

Allowances Available for Auction		
Origin of Allowances	**Spot Auction (First Usable in 2011)**	**7 Year Advance Auction (First Usable in 2018)**
EPA	125,000	125,000
Privately Offered	0	0
Total	125,000	125,000

Spot Auction Results			
Allowances	**Number of Bids**	**Number of Bidders**	**Bid Price**
Bid For: 550,131	Successful: 16	Successful: 6	Highest: $66.67
Sold: 125,000	Unsuccessful: 14	Unsuccessful: 3	**Clearing: $2.00** (the clearing price is the lowest price at which a successful bid was made)
	Total: 30	Total: 9	Lowest: $.06
			Weighted Average of Winning Bids: $2.81

7 Year Advance Auction Results			
Allowances	**Number of Bids**	**Number of Bidders**	**Bid Price**
Bid For: 375,160	Successful: 4	Successful: 4	Highest: $25.00
Sold: 125,000	Unsuccessful: 2	Unsuccessful: 2	**Clearing: $.16** (the clearing price is the lowest price at which a successful bid was made)
	Total: 6	Total: 6	Lowest: $.08
			Weighted Average of Winning Bids: $.17

Spot Auction Winners http://www.epa.gov/airmarkets/trading/2011/11summary.html

Last updated on Tuesday, March 29, 2011

Bidder's Name	Quantity	Percentage of Total Allowances	Amount Paid
Ohio Valley Electric Corporation	84,869	67.895	$207,238.00
Indianapolis Power & Light	40,000	32.000	$142,000.00
Acid Rain Retirement Fund	68	0.054	$448.80
Bates College Environmental Econ A	25	0.020	$112.50
Bates College Environmental Econ B	23	0.018	$95.89
University of Tampa Environmental Protection Coalition	15	0.012	$1,000.05
TOTALS	**125,000**	**100%**	**$350,895.24**

7 Year Advance Auction Winners

Bidder's Name	Quantity	Percentage of Total Allowances	Amount Paid
Evolution Markets	124,840	99.872	$19,974.40
Acid Rain Retirement Fund	100	0.080	$100.00
University of Tampa Environmental Protection Coalition	40	0.032	$1,000.00
Bates College Environmental Econ B	20	0.016	$42.40
TOTALS	**125,000**	**100%**	**$21,116.80**
		Total Auction Proceeds	**$372,012.04**

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for questions Nos. 61 – 66.

According to page 38 of Form 42-8A, FPL filed on April 1, 2011, the 2010 End of Year Amount of CWIP-Non Interest Bearing for the DeSoto Solar Project is $21,109. According to page 41 of Form 42-8E, as well as the Form 42-8E_ Revised.xlsx, the Company filed on August 1, 2011, the 2011 Beginning of Period Amount of CWIP-Non Interest Bearing of the DeSoto Solar Project as $21,831. Please reconcile these two records.

A.

Please note that the Beginning of Period Amount of CWIP for January 2011 as reflected in the August 1, 2011 filing was $20,831; not $21,831 as shown in the question above. The difference of $278 was due to a minor system error, which was corrected when all expenditures were moved from CWIP to Plant In Service. FPL will be filing a revised capital schedule for the DeSoto Next Generation Solar Energy Center (Form 42-8E, pages 41 and 42) for the Actual/Estimated period of January 2011 through December 2011, which will correct the Beginning of Period Amount of CWIP for January 2011 from $20,831 to $21,109. This correction will reduce the 2011 Actual/Estimated true-up amount by $9.

Q.

Please refer to FPL's Estimated/Actual True-up and testimonies filed on August 1, 2011, for questions Nos. 61 – 66.

Please refer to Form 42-8E, page 45 of 59, and the worksheet Martin Solar-Martin_P1 of the Excel file Form 42-8E.xlsx.

a. It appears that in February 2011, an amount of $94,476.14 was transferred into Plant Account CI9_8039. Please explain the nature and cause of this reserve transfer. Please also identify the source account from which the amount was transferred.

b. It appears that in February 2011, an amount of $758.81 was transferred into Reserve Account CIC_8039. Please explain the nature and cause of this plant transfer. Please also identify from which account the amount was transferred.

A.

a. The plant transfer of $94,476.14 represents the correction of assets (work order 02666-003-0441-000) recorded in Account 366.6 – Underground Conduit, in February 2011 associated with Martin Solar. Although the $94,476.14 was recorded in the correct plant account, a review of the Martin Solar work order revealed that these dollars were recorded to the wrong expense type. Therefore, an intra-account transfer was made to reflect this transaction in the ECRC clause.

b. The reserve transfer of $758.81 was associated with part (a) of this response (see above).

Q.
Please refer to FPL's Projection Testimony and Exhibits filed on August 26, 2011, for the following questions.

Referring to page 3, line 23, through page 4, line 1, of witness LaBauve's testimony, it appears that FPL has only included costs for compliance with Subpart JJJJJ of Industrial Boiler (IB) MACT in its 2012 ECRC projections. Referring to Exhibit RRL-10, the aforementioned costs are

$2,875 (biennial tune-up, Martin aux. boiler A)
+ $20,286 (test point installation, Martin aux. boiler A & B)
+ $18,292 (energy assessment, Martin aux. boiler A)
=$41,453.

Referring to Form 42-2P, the 12-month total O&M cost FPL has projected for 2012 for the IB MACT project is $365,854. (Line Item 1.48) Please clarify how the $365,854 compliance cost was derived.

A.
FPL inadvertently included cost projections related to Subpart DDDDD activities in the IB MACT project in Form 42-2P. FPL will file a revised Form 42-2P, which will only include cost projections related to Subpart JJJJJJ, which are $41,453.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 3rd day of October, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared H. Antonio Cuba, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 61 through 66 from STAFF'S TENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 61-67) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

H. Antonio Cuba

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 3rd day of October, 2011.

Carolyn J Smith
Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 26th day of September, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 67 from STAFF'S TENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 61-67) in Docket No. 110007-EI, and that the response is true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 26th day of September, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

11

FPL Responses to Staff's Eleventh Set of Interrogatories (Nos. 68-71)

Q.
For purposes of the following requests, please refer to Exhibit TJK-3, Form 42-2P, pages 1-2, line 48. Amounts are shown beginning in February 2012 and the total for 2012 is indicated to be $365,854 for the year.

a. **Does this amount include costs for both rule JJJJJ and rule DDDDD?**
b. **If the response to (a) is affirmative, please identify the amounts associated with each of the two rules.**
c. **If the response to (a) is negative, please reconcile the total amount shown on line 48 of Form 42-2P, with the amount shown on Exhibit RRL-10, which appears to show total estimated compliance costs for rule JJJJJ to be $41,453.**

A.
a. Yes. As discussed in the response to Interrogatory 67 of Staff's 10th Set, FPL identified that the costs for compliance with Subpart DDDDD had been inadvertently included in Exhibit 42-2P, pages 1-2, line 48. FPL will file a revised Exhibit 42-2P which will include only those costs for compliance with Subpart JJJJJJ which FPL has estimated at $41,453.

b. Please see Attachment I for cost estimates associated with both JJJJJJ and DDDDD rules. Please note that since FPL's August 26, 2011 filing, FPL has subsequently determined that the Cape Canaveral facility will become a minor source of HAPs following modernization and would be subject to JJJJJJ instead of DDDDD as originally projected. Because the gas-fired manatee heater has no compliance requirements under JJJJJJ, and has been exempted from permitting requirements by the FDEP, costs associated with DDDDD at Cape Canaveral have been removed.

FPL Industrial Boiler MACT Equipment

Facility	Equipment Type	Location HAP Status	MACT Rule	Rated Heat Input (MMBtu/hr)	Fuel Type 1	Fuel Type 2	Existing / New ?	Test Port?	Biennial Tune-Up?	Stack/Fuel Testing ?	Potential Emission Limits?	Energy Assessment?	Estimated Compliance Costs: Biennial Tune-Up[1]	Test Port Installation[2]	Fuel/Stack Testing[3]	Energy Assessment[4]
Lauderdale	Auxilliary Boiler	Major	DDDDD	15.5	Propane	N/A	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 18,292
Ft. Myers Plant	Process Heater (3A)	Major	DDDDD	10	Natural Gas	N/A	Existing	Yes	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
Ft. Myers Plant	Process Heater (3B)	Major	DDDDD	10	Natural Gas	N/A	Existing	Yes	Yes	No	No	Yes			$ -	$ 75,000
Martin	Auxilliary Boiler (3&4)	Major	DDDDD	16.3	Natural Gas	N/A	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 75,000
Putnam	Auxilliary Boiler	Major	DDDDD	16.3	Natural Gas	#2 Fuel Oil	Existing	No	Yes	Yes	Yes	Yes	$ 2,875	$ 10,143	$ 26,000	$ 18,292
West County Energy Center	Auxilliary Boiler	Major	DDDDD	98	Natural Gas	N/A	New	Yes	Yes	No	No	Yes	$ 2,875		$ -	$ 18,292
West County Energy Center	Process Heater (1)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (2)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (3)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (4)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
													$ 25,875	$ 81,144	$ 26,000	$ 204,876
Canaveral	Manatee Heater[5]	Minor (Area)	JJJJJJ	30	Natural Gas	N/A	New	Unk	Yes	No	No	Yes			$ -	
Manatee Terminal	Process Heater (A)	Minor (Area)	JJJJJJ	14.5	Natural Gas	#2 Fuel Oil	Existing	Yes	No	No	No	No			$ -	
Manatee Terminal	Process Heater (B)	Minor (Area)	JJJJJJ	12.5	Natural Gas	#2 Fuel Oil	New	Yes	No	No	No	No			$ -	
Martin Terminal	Auxilliary Boiler (A)	Minor (Area)	JJJJJJ	12.5	#2 Fuel Oil	#6 Fuel Oil	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 18,292
Martin Terminal	Auxilliary Boiler (B)	Minor (Area)	JJJJJJ	12.5	#2 Fuel Oil	#6 Fuel Oil	Existing	No	Yes	No	No	Yes		$ 10,143	$ -	
													$ 2,875	$ 20,286	$ -	$ 18,292
													$ 28,750	$ 101,430	$ 26,000	$ 223,168
															Grand Total	$ 379,348

Notes: 1) EPA estimated annualized cost for Biennial Tune-Up = $2,875
2) Test port installation average projected cost of $10,143 per stack
3) Stack testing cost based on EPA estimate reduced for fewer analytical parameters (3/5)
4) EPA Energy Assessment for FPL sites with complex emission units/configuration assumes EPA estimate of $75 k and average cost using EPA estimate of $18,292 for sites with fewer process units.
5) FPL's demolition of the Canaveral steam units for modernization will now classify the site as minor for HAPs which do not regulate gas fired units under JJJJJJ

Q.
For purposes of the following requests, please refer to witness LaBauve's testimony, page 6, lines 14-17, where it states "FPL also plans to begin performing in 2012 the energy assessments at affected area sources that are required by Subpart JJJJJ and, once the stay of Subpart DDDDD is lifted, FPL will proceed with required facility energy assessments at the affected major-source facilities."

a. **Are any amounts included in this year's ECRC filing to recover any costs associated with Subpart DDDDD?**

b. **If the response to (a) is affirmative, please identify the amount(s) included that relate to Subpart DDDDD, and in which Form(s) they are included.**

A.
a. As discussed in the response to Interrogatory 67 of Staff's 10th Set, FPL identified that the costs for compliance with Subpart DDDDD had been inadvertently included in Exhibit 42-2P, pages 1-2, line 48. FPL will file a revised Exhibit 42-2P which will include only those costs for compliance with Subpart JJJJJ.

b. NA

Q.

For purposes of the following requests, please refer to FPL's Notice of Additional Activities required for Manatee Temporary Heating System, filed on January 4, 2011, and FPL's responses to Nos. 19 – 25 of Staff's First Set of Interrogatories.

a. Referring to the company's response to Interrogatory No. 20, has FPL decided whether the 800 horsepower heater will be utilized between 2011 and 2013?

b. Please provide updated information regarding the "additional" Canaveral Manatee project including: i) its total capital and O&M costs; ii) its capital and O&M costs for 2011, 2012 and 2013, respectively; and iii) its major component activities.

c. Please update Table 1 attached to FPL's response to interrogatory No. 25.

A.

a. Yes, the 800 horsepower gas fired supplemental heater will be utilized between 2011 and 2013.

b. See matrix below for updated information on the additional Canaveral activities under the Manatee Temporary Heating System:

FPL's Manatee Protection Costs - Additional

Plant Cape Canaveral	Capital				O&M			
Major Component Activities	2011	2012	2013	Total	2011	2012	2013	Total
Sheet-pile Wall	$411,464	$0	$0	$411,464	$0	$0	$0	$0
Piping	$37,100	$0	$0	$37,100	$0	$0	$0	$0
Electrical Panel/Wiring	$42,400	$0	$0	$42,400	$0	$0	$0	$0
Concrete Pad	$28,620	$0	$0	$28,620	$0	$0	$0	$0
Natural Gas Line - 4 inch	$63,600	$0	$0	$63,600	$0	$0	$0	$0
800 HP Supplemental Lease/Operate	$0	$0	$0	$0	$230,801	$0	$0	$230,801
800 HP Supplemental Lease/Operate	$0	$0	$0	$0	$0	$245,802	$0	$245,802
800 HP Supplemental Lease/Operate	$0	$0	$0	$0	$0	$0	$107,901	$107,901
Total	**$583,184**	**$0**	**$0**	**$583,184**	**$230,801**	**$245,802**	**$107,901**	**$584,504**

c. See attachment for updated Table 1, incorporating the Capital and O&M dollars from item b

Table 1: FPL's Manatee Protection Costs									
	Incurred / To be Incurred Costs ($)								
	Capital	**O&M**	**Mobilization & Installation**	**Dismantle & Demob**	**Leasing Payment / month**	**Nos of Month to Lease**	**Light Oil Consumption per month**	**Total**	**Corresponding Period mm/yy-mm/yy**
Plant Canaveral									
FPL's heating system	$4,532,542	$98,163						$4,630,705	06/10-10/10
Discharge pipe mod	$78,400							$78,400	12/10
200 HP heater lease	$0	$59,136	$8,125	$13,525	$19,712	3	$18,707	$136,907	12/10-3/11
800 HP heater lease	$0	$233,932	$13,750	$36,850	$58,483	4	$70,993	$568,504	12/10-3/11
Sheet-pile Wall	**$411,464**							**$411,464**	**07/11-10/11**
Piping	**$37,100**							**$37,100**	**07/11-10/11**
Electrical Panel/Wiring	**$42,400**							**$42,400**	**07/11-10/11**
Concrete Pad	**$28,620**							**$28,620**	**07/11-10/11**
Natural Gas Line - 4 inch	**$63,600**							**$63,600**	**07/11-10/11**
800 HP Supplemental Lease/Operate		**$122,901**	**$92,900**		**$30,967**	**3**	**$5,000**	**$230,801**	**10/11 - 12/11**
800 HP Supplemental Lease/Operate		**$215,802**			**$30,967**	**6**	**$5,000**	**$245,802**	**01/12 - 03/12, & 10/12-12/12**
800 HP Supplemental Lease/Operate		**$92,901**			**$30,967**	**3**	**$5,000**	**$107,901**	**01/13 - 03/13**
Total	**$5,194,126**	**$822,835**	**$114,775**	**$50,375**				**$6,582,204**	
Plant Riviera									
Original heating system	$2,967,000	$0						$2,967,000	04/09-11/09
Modification	$0	$30,281						$30,281	10/10
Total	**$2,967,000**	**$30,281**						**$2,997,281**	
Grand Total	**$8,161,126**	**$853,116**	**$114,775**	**$50,375**				**$9,579,485**	

FPL Notes:

1. The O&M and other recurring costs above are estimated amounts for the 2010-2011 heating season which ends Mar 31 2011. FPL will be evaluating in 2011 the most cost-effective way to continue providing supplemental heating in subsequent heating seasons.
2. Only 3 monthly lease payments are anticipated for the 200 HP heater since it was temporarily unavailable due to maintenance issues.
3. The O&M costs associated with the leased supplemental heater are broken out by year 2011, 2012 and 2013.
4. Capital cost for system modifications identified during 2010/2011 heating season and installed during the 2nd and 3rd quarter of 2011.
5. FPL employees will operate heating system Oct. 2012 - March 2013. Contractors will operate system 2011 and Jan. 2012 - March 2012 (monthly estimate $10,000).
6. The Lease payment is calculated and totaled in the spreadsheet under the "O&M" column for the 2011, 2012 & 2013 years and then added to the "Total" column.

Q.
For purposes of the following requests, please refer to FPL's monthly Solar Plant Operation Status Reports.

a. Based on the actual data provided in FPL's monthly solar operation status reports, please explain why the output of the DeSoto Next Generation Solar Center in June 2011 was relatively low when compared to projected performance.

b. Based on the actual data provided in FPL's monthly solar operation status reports, please explain why the output of the Martin Next Generation Solar Center in the first seven months of 2011 has been relatively low when compared to projected performance.

c. Please provide a summary of FPL's findings, at this time, with respect to the performance of FPL's DeSoto, Space Coast, and Martin solar facilities. Please include a discussion about the facilities' performance during peak periods and any potential contribution as peak capacity.

d. Based on the actual data provided by FPL in its solar operation status reports please explain the reason for negative hourly output (e.g., parasitic load associated with on-site lighting).

A.
a) Desoto experienced an underground cable fault between Desoto's main feeder breaker and Sunshine Substation on May 31, 2011 which caused the loss of the entire 25 MW site. Desoto was returned to service on June 10 after the feeder cables were replaced and damaged switchgear equipment repaired. The cause of the cable failure was determined to be a manufacturing defect in which a splice was inadvertently left in the cable to connect two reels of raw conductor together prior to application of insulation material. The splice was not intended to remain in the cable and should have been cut out prior to shipment.

b) Martin Solar was removed from service from 4/07/11 to 5/24/11 due to a Martin Unit 8 planned overhaul that was unrelated to the solar equipment. Martin Solar returned to service on 5/24/11 and operated until 6/01/11 at almost full capacity. On 06/01/11, Martin Solar experienced a high pressure excursion on the Heat Transfer Fluid (HTF) system which lifted a safety relief valve on an overflow vessel. This caused a release of the HTF in the form of a vapor plume which condensed on the Martin Solar power block and south side of the Martin Unit 8. The high pressure excursion was the result of a leak in the feedwater preheaters

which in turn allowed water to get into the HTF and turn into high pressure steam. This condition prevents safe operation of the system. Martin Solar has remained shut down to perform preheater repairs and implement design and protection improvements to ensure safe and reliable operation of the solar site.

c) Desoto and Space Coast solar sites have had good performance with capacity factors of 25.2% and 23.0%, respectively, for January through July 2011. Desoto's capacity factor is slightly lower than expected (26.6%) due to the cable failure described in the response to Interrogatory 71(a) above. Space Coast's capacity factor is slightly above expected (22.6%). Martin Solar's performance was lower than expected with a capacity factor of 6% for January through July 2011. The primary reason for the lower than expected performance at Martin Solar is the feedwater preheater leaks. The Martin Solar site has proven in initial testing that it will achieve or exceed its rated 75 MW capacity when all equipment is operational.

Peak load periods during the winter months are typically in the early evening after the sun has gone down, (i.e., lighting peak). As such, the solar sites do not provide much contribution during winter time peaks. During the spring, fall, and summer, the peak load periods are earlier in the day (typically around 5:00 pm) and the solar sites contribute substantially to the peak loads. This is shown by the table below listing the peak load hours for the months of January - July, 2011, and solar generation from the FPL monthly solar operation status report. Desoto will produce more than Space Coast during peak load periods due to operation of the trackers which follow the sun from east to west. Martin Solar generation is not representative of expected output due to the previously described equipment issues limiting output. Martin Solar is expected to have more contribution to summer time peak generation than Desoto or Space Coast due to the large amount of thermal energy that is stored in the HTF after the solar power is removed. This is demonstrated by looking at May generation for Martin Solar in which the site was generating power until 10:00 pm.

Peak KWH Output					
Month	Hour of Day	Peak Demand (MW)	Desoto	Space Coast	Martin
January	19	12640	-53	-23	2039
February	20	13128	-48	-22	1474
March	17	13493	14606	4319	32238
April	17	16906	18689	5751	10712
May	17	17588	16224	4995	9230
June	16	18839	10076	5505	935
July	16	19122	13754	5837	-156

d) When the solar sites are not producing power (night time, extremely cloudy days, or equipment outage), there are still auxiliary equipment loads that must remain energized, which account for the negative hourly output. For Desoto and Space Coast, the auxiliary loads include: inverter control system power, battery chargers, HVAC, computers, lighting. For Martin Solar, the auxiliary loads include: HTF pumps, auxiliary pumps and valves, control system equipment, HVAC, and lighting. These loads consume power that is not produced by the solar plant and therefore, are shown as negative and subtracted from the gross output. Note that the MW values for Martin Solar is a calculated value as the plant only produces steam that is converted to electrical power output from the Martin 8 steam generator.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 27th day of September, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared John Hampp, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory numbers 68 and 69 from STAFF'S ELEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 68-71) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

John Hampp

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 27th day of September, 2011.

Lois M Sivia

Notary Public
State of Florida, at Large

My Commission Expires:

Notary Public State of Florida
Lois M Sivia
My Commission DD731588
Expires 11/05/2011

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF PALM BEACH)

I hereby certify that on this 4th day of October, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared Roxane Kennedy, who is personally known to me, and she acknowledged before me that she provided the answers to interrogatory numbers 70 and 71 from STAFF'S ELEVENTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NOS. 68-71) in Docket No. 110007-EI, and that the responses are true and correct based on her personal knowledge.

Roxane Kennedy

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 4th day of October, 2011.

INGRID NICKOLAUS
Notary Public - State of Florida
My Comm. Expires Nov 20, 2015
Commission # EE 120553
Bonded Through National Notary Assn.

Ingrid Nickolaus
Notary Public
State of Florida, at Large

My Commission Expires:
November 20, 2015

12

FPL Responses to Staff's Twelfth Set of Interrogatories (No. 72)

Q.
Please refer to Appendix I of witness T. J. Keith's testimony and Exhibit filed on August 26, 2011.

- **a.** **With respect to the Return on Deferred Gain on Sales of Emission Allowances reported on pages 53-54 of Form 42-4P, please provide the projected amounts of the Allowance Auction Proceeds for each month, if any, for the period January 2012 through December 2012.**
- **b.** **Please explain how the amounts shown on Line 1d '254.900 Other Regulatory Liabilities-Gains' were derived.**
- **c.** **Please provide the formula FPL used in its calculation.**

A.
A. For projected year 2012, FPL expects to receive auction proceeds only in the month of May 2012 in the amount of $3013.00 for allowances sold of vintage year 2012 and $1607.00 for allowances sold of vintage year 2019, for a total allowance proceeds amount of $4620.

Note that the amortization of vintage year 2012 proceeds will begin January 2012 and be amortized through December 2012 along with all of the other proceeds from vintage year 2012 allowances sold that have accumulated over the last 7 years. The amortization of vintage year 2019 proceeds will not start until year 2019. Once the proceeds are received in May 2012 they will become part of balance in account 254.900 reflected in Line 1d.

B. The amounts on line 1d reflect the Balance Sheet balance for account 254.900. The change in balance is driven by the amortization amount recorded.

Example

Beginning Period: (1/1/12) Amount of "Line 1d '254.900 Other Regulatory Liabilities-Gains'"	(1,797,695)
Less: Current month (January) amortization amount of "Line 6a 'Gains from Dispositions of Allowances'"	49,790
Ending balance: Amount of "Line 1d '254.900 Other Regulatory Liabilities-Gains'"	(1,747,905)

C. Please see formula provided in response to part B.

AFFIDAVIT

STATE OF FLORIDA)

COUNTY OF MIAMI DADE)

I hereby certify that on this 11th day of October, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared H. Antonio Cuba, who is personally known to me, and he acknowledged before me that he provided the answer to interrogatory number 72 from STAFF'S TWELFTH SET OF INTERROGATORIES TO FLORIDA POWER & LIGHT COMPANY (NO. 72) in Docket No. 110007-EI, and that the responses is true and correct based on his personal knowledge.

H. Antonio Cuba

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 11th day of October, 2011.

Notary Public
State of Florida, at Large

My Commission Expires:

CAROLYN J SMITH
Notary Public - State of Florida
My Comm. Expires Sep 11, 2014
Commission # EE 19792