RTP ENVIRONMENTAL ASSOCIATES INC.®

AIR · WATER · SOLID WASTE CONSULTANTS

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March 17, 1998

PSD-FL-219
0810010

RECEIVED
MAR 23 1998
BUREAU OF
AIR REGULATION

Mr. Brian Beals
U.S. EPA - Region IV
100 Alabama Street, N.W.
Atlanta, GA 30303

Dear Mr. Beals:

I've enclosed additional written information concerning our comments on the Orimulsion project proposed by Florida Power & Light (FP&L) for their Manatee power station. As I indicated to you during our phone conversation, we have considerable concerns related to this application and its processing. The most serious issue relates to the calculation of historical actual, and future predicted emissions for nitrogen oxides (NO_x). We believe there has been a clear miscalculation in the current permitting case, such that PSD review should be required. Additionally, numerous changes have occurred throughout the project that would necessitate reissuing a draft permit for public review.

I've enclosed some back-up calculations related to the NO_x issues to support our contention. Additionally, I understand Manasotta 88 submitted separately a copy of an issues book with references as part of the PSD permit. These contain our additional comments on the application process.

I appreciate your current staff difficulties in terms of availability, but feel that this project is extremely sensitive nationwide as well as within Region IV, and deserves a high priority.

Please feel free to give me a call at (732) 968-9600 if you wish to discuss the enclosed materials or require any further information.

Sincerely,

RTP ENVIRONMENTAL ASSOCIATES, INC.®

Donald F. Elias

Donald F. Elias
Principal

DFE/trp
Enclosures
cc: G. Worley
C. Fancy
L. Curtin
Proj. File - HKOR

ISSUE # 5: Historical Actual Emissions for NO_x Overstated

Historical actual emissions for NO_x are incorrectly calculated and require a further reduction either in emission rate or unit availability to avoid PSD review.

BASIS: Historical actual NO_x emissions as presented in the application and recent applicant exhibits disagree with the annual operating reports filed by the applicant. Since both were filed as true, complete, and accurate, obviously one must be corrected. Assuming the current information filed with the application is correct, it states 7318 tons per year as the historical actuals. This seems to be based on the permit allowables rather than actuals. If you calculate the actuals used by the average of the CEM data, rather than the permit allowables, total average annual actual NO_x emissions based on the '93-'94 data would be 5478 tons/year. Since the facility now operates with steam atomization to reduce NO_x, the "representative" facility rate is the current rate represented by the CEM data times the historical capacity factor. In order to avoid a significant increase for NO_x, future actuals would need to be reduced either by reducing the emission rate or by reducing the operating hours.

BASIS: 1993 and 1994 Annual Operating Reports, Exhibit R-50 from Kosky deposition, CEM data for the Manatee Generating Station, and copy of calculations.

MEMORANDUM

TO: Donald F. Elias
FROM: Brian L. Lubbert & A. Roger Greenway
DATE: 23-Jan-98
SUBJECT: Comparison of Actual Historical Emissions

Comparison of Actual Historical Emissions

Pollutant	Average Emissions Em. Stmt.93 -94	'94 Permit- App. Table 3-3 Emissions	FL-DEP Draft Permit Table 1	Kosky Exhibit 6	Additional Stack Test Data	CEM Data
NOx	7198	7581	6827	7318	6813	5478
TSP.	2516	3159	1707	1768-1792	1627	NA

See Attached Calculations, Exhibits, and Emission Statements

DEP - B3 1/15/95

NOx - 7294

caused by switch in heat content from 151,890 Btu/lb to 152,381 Btu/lb

CALCULATIONS
NOx Emissions

Emission Statements

1993	44 lb /kgal	X	313,830.67	kgal	6904	Tons	Average=	7198 T
1994	45.71 lb /kgal	X	327,800.00	kgal	7492	Tons		

**44 lb/kgal is AP-42, 45.71 lbs/kgal is the product of 0.3 lbs/MMBtu by 152,381 Btu/gal

1994 Permit App.

1993	45.564 lb /kgal	X	313,830.68	kgal*	7150	Tons	Average=	7581 T
1994	45.564 lb /kgal	X	351,644.08	kgal*	8011	Tons		

1994 est on fuel usage *Calculated from Table A-10 (bbls)

**45.594 lbs/kgal is the approx. the product of 0.3 lbs/MMBtu by 151,980 Btu/gal

NOTE: calculation must use 45.564 lbs/kgal to equal what is in permit app.

FL-DEP Permit PA 94-35 PSD-FL-219

0.280 lbs/MMBtu	X	48,785,409	MMBtu	6827	Tons	Average=	6827 T

**Fuel usage/Heat Input based on Kosky Exhibit 10 (average 1993/94).

Emission Factor based on average emissions from stack test reports (see Table 1 footnote a) in Draft Permit PA-35 nPSD-FL-219

Kosky Exhibit 6

0.3 lbs/MMBtu	X	48,785,409	MMBtu	7318	Tons	Average=	7318 T

**Fuel usage/Heat Input based on Kosky Exhibit 10 (average 1993/94)

CEM data

Boiler #1(93)	0.219 lbs/MMBtu	X	20,749,229	MMBtu	2272	Tons		
Boiler #2(93)	0.229 lbs/MMBtu	X	27,072,589	MMBtu	3100	Tons		
		1993:	47,821,818	MMBtu	5372	Tons		
Boiler #1(94)	0.219 lbs/MMBtu	X	22,451,949	MMBtu	2458	Tons		
Boiler #2(94)	0.229 lbs/MMBtu	X	27,297,050	MMBtu	3126	Tons		
		1994:	49,748,999	MMBtu	5584	Tons		
**Fuel usage/Heat Input based on KoskyExhibit 10							Average=	5478 T

1993/1994 Emissions Compliance Test for Boilers #1 and #2

Boiler #1(93)	0.29 lbs/MMBtu	X	20,749,229	MMBtu	3009	Tons		
Boiler #2(93)	0.29 lbs/MMBtu	X	27,072,589	MMBtu	3926	Tons		
		1993:	47,821,818	MMBtu	6934	Tons		
Boiler #1(94)	0.28 lbs/MMBtu	X	22,451,949	MMBtu	3143	Tons		
Boiler #2(94)	0.26 lbs/MMBtu	X	27,297,050	MMBtu	3549	Tons		
		1994:	49,748,999	MMBtu	6692	Tons		
							Average=	6813 T

Compliance test data is used to estimate the actual historical emissions during the year the stack test was taken.
Compliance test data for Boiler #1 is from 4/1/93 and 5/12/94.
Compliance test data for Boiler #2 is from 4/22/93 and 6/8/94.
**Fuel usage/Heat Input based on KoskyExhibit 10
Annual emissions estimates are based on calculation format used in Kosky Exhibit 10

Emission Compliance Test (1993/94 assuming Worst-case results of 0.29 lbs/MMBtu)

0.29 lbs/MMBtu	X	48,785,409	MMBtu	7074	Tons	Average=	7074 T

Emission Factor based on worst-case results of 1993 and 1994 stack tests.
** Fuel usage/Heat Input based on Kosky Exhibit 10 (average 1993/94)

CALCULATIONS
CEM Test Data: 3Q, 4Q 1996 and 1Q, 2Q, 1997 (Kosky Exhibit 10 12/11/97)

NOx
Boiler #1

1993	136,167	kGal/yr	1994	147,341	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	20,749,229	MMBtu		22,451,949	MMBtu
x	0.219	(EF)lbs/MMBtu	x	0.219	(EF)lbs/MMBtu
	2272	T (NOx)/year		2458	T (NOx)/year

Boiler #2

1993	177,664	kGal/yr	1994	179,137	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	27,072,589	MMBtu		27,297,050	MMBtu
x	0.229	(EF)lbs/MMBtu	x	0.229	(EF)lbs/MMBtu
	3100	T (NOx)/year		3126	T (NOx)/year

Total Emissions	Boiler #1	Boiler #2	Total	
1993	2272	3100	5372	T (NOx)/year
1994	2458	3126	5584	T (NOx)/year
Average	2365	3113	5478	T (NOx)/year

(Kosky Exhibit 10 12/11/97)
PM
Boiler #1

1993	136,167	kGal/yr	1994	147,341	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	20,749,229	MMBtu		22,451,949	MMBtu
x	0.05875	(EF)lbs/MMBtu	x	0.07	(EF)lbs/MMBtu
	610	T (PM)/year		786	T (PM)/year

EF determined as 87.5% of operation: Sootblowing at 0.06 lbs/MMBtu
plus 12.5% of operation: Steady State at 0.05 lbs/MMBtu
EQ: 87.5%x0.06 + 12.5%x0.05 = 0.05875

EF determined as 0.07 =sootblowing=steady state

Boiler #2

1993	177,664	kGal/yr	1994	179,137	kGal/yr
x	152.381	MMBtu/kgal	x	152.381	MMBtu/kgal
	27,072,589	MMBtu		27,297,050	MMBtu
x	0.08	(EF)lbs/MMBtu	x	0.0775	(EF)lbs/MMBtu
	1083	T (PM)/year		1058	T (PM)/year

EF determined as 0.08 =sootblowing=steady state

EF determined by 87.5% of operation: Sootblowing at 0.08 lbs/MMBtu
plus 12.5% of operation: Steady State at 0.06 lbs/MMBtu
EQ: 87.5%x0.08 + 12.5%x0.06 = 0.0775

Total Emissions	Boiler #1	Boiler #2	Total	
1993	610	1083	1693	T (PM)/year
1994	786	1058	1844	T (PM)/year
Average	698	1071	1769	T (PM)/year

NOTE: annual fuel usage is rounded to nearest kgal, MMBtu as shown above calculated (apparently) from actual gallons
Fuel usage numbers/Heat Input based on Exhibit 10)

CALCULATIONS

Annual Emissions Statement(s)

Total Emissions	Boiler #1	Boiler #2	Total	
1993	828	1080	1908	T (PM)/year
1994	1404	1719	3123	T (PM)/year
Average	1116	1400	2516	T (PM)/year

Annual Emissions Statement(s)

Total Emissions	Boiler #1	Boiler #2	Total	
1993	2996	3909	6905	T (NOx)/year
1994	3367	4124	7491	T (NOx)/year
Average	3182	4017	7198	T (NOx)/year

See Attached Emission Statements

DEP-B3

Comment: The application states the current actual emissions to be the highest emissions while firing low sulfur fuel oil (LSFO), although actual emissions are defined in Rule 62-212.200(2) (a), FAC., to be "in general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the source actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the source". Using the date of application, September 30, 1994, as the "particular date" please provide the actual emissions for the two-year period preceding it. Include your calculations, revise any tables as necessary, and revise or add any modeling as necessary. For example, a review of FPL's annual operating report data, which was submitted for 1992 and 1993, indicates that the increase in particulate matter and PM10 is PSD-significant.

Response: The emission data for the two units at the Manatee Plant presented in the Site Certification Application (SCA) represent actual emission data for the two units for 1993 and 1994. As discussed in the SCA, the 1994 data were based on actual fuel consumption through July 31, 1994, and prorated to the remainder of the year. These data were considered to represent the emissions from the normal operation of the two units for a 2-year period. Although another 2-year period might also be considered, the net changes in actual emissions from the units exceed the PSD significant emission rates for only nitrogen oxides (NO_x) and carbon monoxide (CO), regardless of which 2-year period is considered representative. The net changes in actual emissions are similar even if the last 3 years are considered in the evaluation. As a result, the PSD applicability analyses and review process do not change from those presented in the SCA. The suggestion that the increases in particulate matter and PM10 emissions are PSD-significant is incorrect.

Comparisons of actual annual emissions for the existing units at the Manatee Plant were performed by evaluating fuel usage data over the last 3 years, (1992 through 1994). As requested, an evaluation was performed for September 1992 through September 1994, the 2-year period preceding the application submittal date of September 30, 1994; an evaluation has also been performed for 1993 and 1994 using actual fuel use data for August through December 1994 that was not available at the time of SCA submittal. Summaries of the fuel usage and annual capacity factors for each unit are presented in Table DEP-B3-1 for the period of September 1992 through September 1994; and Table DEP-B3-2 for the years 1993 and 1994. These tables are comparable to Table A-10 presented in the Appendix 10.1.5, Volume II of the SCA.

Comparisons of the maximum estimated annual emissions for existing low sulfur fuel oil (LSFO) and the proposed firing of Orimulsion for the selected periods are presented in Table DEP-B3-3. Emissions are shown for sulfur dioxide, particulate matter, nitrogen oxides, carbon monoxide, volatile organic compounds, and lead. Emissions of other regulated pollutants presented in the SCA (i.e., sulfuric acid mist, fluorides, mercury, beryllium, and arsenic) were added together and summarized. As shown, although there are some differences in the net emission changes for all pollutants among the evaluations, NO_x and CO continue to be the only two pollutants for which there is a PSD-significant net emission increase. For the other regulated pollutants, there is a net decrease in emissions requiring no PSD review. As shown in the footnote, the average annual capacity factors for the plant for the evaluated time periods are within 3 percent, indicating the relatively minor differences in plant operation among the time periods. It should be noted that the emission data for 1992 may not be representative of actual plant operation because of planned outages for equipment upgrades that occur about once every 15 years (the units were not operating for about 25 percent of the year). Therefore, the use of emission data for this year is not necessarily representative of annual plant emissions.

The maximum emissions estimated for the AORs are different than those presented in the Air Permit Application. The information reported in the AORs are based on average emission factors obtained from the EPA document, "Compilation of Air Pollutant Emission Factors," which is referred to as AP-42. These factors do not account for "excess emissions" which are allowed under DEP regulations (Rule 62-210.700, Excess Emissions) and were incorporated in the air permit for each unit. For example, under steady-state operating conditions, each unit has a PM emission limit of 0.1 lb/MMBtu. However, during sootblowing and load changing, each unit can emit up to 0.3 lb/MMBtu for 3 hours in a 24-hour period . As an example, PM emissions for 1992 and 1993 reported in the AORs were estimated to be 1,896 TPY. For this same time period, by accounting for sootblowing, the PM emissions are estimated to be 2,953 TPY. Also, source specific allowable emissions can be assumed equivalent to actual emissions provided that the source specific allowable emissions are federally enforceable (see Rule 62-212.200(2)). These federally enforceable emission limiting standards are codified in Rule 62-296.405 for PM,

SO_2, and NO_x. As a result, the emission limits for these pollutants were used in estimating actual emissions when each unit is firing LSFO.

It should be noted that even using the AORs for 1992 and 1993, PSD applicability for PM/PM10 would not change. As noted above the AORs presented average annual PM/PM10 emissions of 1,896 TPY for 1992/1993. The representative actual PM/PM10 emissions when firing Orimulsion would be 1,749 TPY which is a 147 TPY decrease in PM/PM10 emissions even though sootblowing emissions were not expressly accounted for in the AORs; thus, PSD applicability would not be triggered.

No additional air modeling is required because the impacts due to firing Orimulsion or HSFO assumed the maximum emission rate for each pollutant and did not account for the difference in emissions between firing these fuels and LSFO. For example, the air quality modeling analyses for the Manatee Plant after conversion to Orimulsion that addressed compliance with the NO_2 maximum allowable PSD Class II and I increments did not include the existing Manatee Plant (see Section 7.3 and 7.4, Appendix 10.1.5, Volume II of the SCA). As a result, the increment consumption would be lower than the maximum value reported (increment consumption due to the Manatee Plant is the difference in impacts between the proposed future operations and actual existing operations).

Table DEP-B3-1. Existing Fuel Oil Usage at the FPL Manatee Plant (9/29/92 to 9/28/94)

Parameter	Values for FPL Units	
	Unit 1	Unit 2
Fuel Usage (bbls)		
9/29/92 to 9/28/94	6,639,726	7,951,034
Average	3,319,863	3,975,517
Maximum	11,877,957	11,877,957
Capacity Factor (a)		
9/29/92 to 9/28/94	27.95%	33.47%
Average	27.95%	33.47%
Sulfur Content:		
1992	0.989%	0.986%
1993	0.973%	0.973%
1994	0.973%	0.976%

(a) Based on maximum heat input of 8,650 MMBtu/hr per unit and fuel oil with heat content and density of 18,300 Btu/lb and 8.3 lb/gal, respectively.

Table DEP–B3–2. Existing Fuel Oil Usage at the FPL Manatee Plant (1993/1994) – Actual Fuel Use

Parameter	Values for FPL Units: Unit 1	Unit 2
Fuel Usage (bbls)		
1993	3,242,067	4,230,092
1994	3,508,117	4,265,164
Average	3,375,092	4,247,628
Maximum	11,877,957	11,877,957
Capacity Factor (a)		
1993	27.29%	35.61%
1994	29.53%	35.91%
Average	28.41%	35.76%
Sulfur Content:		
1993	0.973%	0.973%
1994	0.973%	0.976%

(a) Based on maximum heat input of 8,650 MMBtu/hr per unit and fuel oil with heat content and density of 18,300 Btu/lb and 8.3 lb/gal, respectively.

Table DEP–B3–3. Comparison of Maximum Estimated Annual Emissions for Existing Low Sulfur Fuel Oil (Actual) and Proposed Orimulsion Representative Actual) Firing at FPL Manatee Units 1 and 2

Pollutant	Emissions (TPY)– Existing Units: Low Sulfur Fuel Oil	Emissions (TPY)– Orimulsion: 2 Units	Emissions (TPY)– Orimulsion: Difference (Orimulsion–LSFO)	PSD Significant Net Emission Rate (TPY)	Significant Net Emission Increase ?
Actual Emissions Based on 1993/1994 – presented in SCA (1)					
Sulfur Dioxide	27,617	13,635	–13,982	40	No
Particulate Matter	3,159	1,749	–1,410	25	No
Particulate Matter (PM10)	2,274	1,749	–525	15	No
Nitrogen Oxides	7,581	17,491	9,910	40	Yes
Carbon Monoxide	16,026	18,948	2,922	100	Yes
Volatile Organic Compounds	126.4	117.6	–8.8	40	No
Lead	0.708	0.163	–0.544	0.6	No
Other Regulated Pollutants (2)	1,162	420	–743	(2)	No
Actual Emissions Based on 1993/1994 Actual Fuel Usage (3)					
Sulfur Dioxide	26,573	13,635	–12,938	40	No
Particulate Matter	3,039	1,749	–1,290	25	No
Particulate Matter (PM10)	2,188	1,749	–439	15	No
Nitrogen Oxides	7,294	17,491	10,196	40	Yes
Carbon Monoxide	15,420	18,948	3,528	100	Yes
Volatile Organic Compounds	121.7	117.6	–4.1	40	No
Lead	0.681	0.163	–0.518	0.6	No
Other Regulated Pollutants (2)	1,119	420	–699	(2)	No
Actual Emissions Based on 9/92 to 9/94 (4)					
Sulfur Dioxide	25,432	13,635	–11,797	40	No
Particulate Matter	2,909	1,749	–1,160	25	No
Particulate Matter (PM10)	2,094	1,749	–345	15	No
Nitrogen Oxides	6,981	17,491	10,510	40	Yes
Carbon Monoxide	14,758	18,948	4,190	100	Yes
Volatile Organic Compounds	116.4	117.6	1.2	40	No
Lead	0.652	0.163	–0.488	0.6	No
Other Regulated Pollutants (2)	1,071	420	–651	(2)	No

(1) See Table 3–3 and Table A–11, Appendix 10.1.5, Volume II, Site Certification Application; fuel usage from 1993 and 1994 (fuel usage through 7/31/94 prorated to entire year).

(2) Other regulated pollutants include sulfuric acid mist (7 TPY), fluorides (3 TPY), mercury (0.1 TPY), beryllium (0.0004 TPY), and arsenic (0 TPY) [Numbers in parentheses in this footnote are the PSD significant emission rates for each specific pollutant).

(3) Based on actual fuel usage from 1993 and 1994.

(4) Based on maximum allowable emission rates/test data from SCA and fuel usage from September 29, 1992 through September 28, 1994.

FLORIDA

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Permit Number: PA 94-35
PSD-FL-219
Expiration Date: December 31, 1998
County: Manatee
Location: Hwy 62, 5 miles NE of Parrish, FL
UTM: 17-367.3 km E 3054.1 km N
Project: Manatee Power Plant Modification
Orimulsion Conversion Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-200 through 297 & Chapter 62-4. The above named permittee is hereby authorized to perform the work or operate the facility shown an the application and approved drawing(s), plans, and other documents, attached hereto or on file with the department and made a part hereof and specifically described as follows:

For modification of existing emission units

01 Unit #1 - Fossil fuel-fired steam generating unit
02 Unit #2 - Fossil fuel-fired steam generating unit

including adding additional sootblowers and increasing heat surface area of the boilers to accommodate the firing of Orimulsion fuel, and High (maximum 3.0% by weight) Sulfur Fuel Oil (HSFO) when Orimulsion is unavailable, in addition to the Low (1.0% or less) Sulfur Fuel Oil (LSFO) currently fired in the units. Air pollution control equipment, including a Pure Air flue gas desulfurization (FGD) system with a minimum sulfur dioxide removal efficiency of 95%, Pure Air electrostatic precipitators (ESP) with a minimum particulate removal efficiency of 90%, and low-NOx burners, will be installed to reduce emissions of sulfur dioxide, particulate matter, and nitrogen oxides; and

For construction of new emission units for handling and storage of limerock/limestone, flyash, and gypsum as listed below:

- 03 Limerock/Limestone Truck Unloading - fugitive emissions
- 04 Limerock Rail Unloading - fugitive emissions
- 05 Limestone Storage Pile - fugitive emissions
- 06 Limerock Storage Pile - fugitive emissions
- 07 Limerock/Limestone Receiving Hoppers - fugitive emissions
- 08 Limestone Blending Silo with dust collector/bag filter vent

Table 1: Significant and Net Emission Rates (Tons per Year)

Pollutant	Low Sulfur Fuel Oil Actual Emissions[a]	Projected Maximum Emissions[b]	Proposed Net Emissions Increase	Significant Emission Rate	Applicable Pollutant (Yes/No)
PM **	1,707	1,707	0	25	No
PM_{10} **	1,707	1,707	0	15	No
SO_2	24,492	13,643	-10,849	40	No
NO_X	6,827	15,742 *	8,915	40	Yes
CO	15,463	18,948	3,485	100	Yes
VOC	122	117 ***	-5	40	No
Lead	0.683	0.163 +	-0.520	0.6	No
Mercury	0.078	0.006 ***	-0.072	0.1	No
Beryllium	0.10240	0.00036 ***	-0.10205	0.0004	No
Fluorides	0.15	0.037 +	-0.117	3	No
Sulfuric Acid Mist	1,122	420 ***	-702	7	No

a--NO_X and particulate emission rates based on 1993 and 1994 fuel data, heat content of 152 mmBtu/kgal and average emissions from stack test reports. SO_2 emissions based on annual operating report (AOR). Emission rates for other pollutants based on emission factors.

b--based on 87 percent capacity factor and a maximum continuous heat input rating of 7,650 mmBtu/hr firing Orimulsion.

* Based on NO_X emission limit of 0.27 lb/mmBtu as provided by FPL. Annual NO_X emissions with a limit of 0.17 lb/mmBtu would be 9,912 TPY.

** Annual PM/PM_{10} emissions capped at previous actual emission level by permit condition.

*** Based on emission rates from tests on Orimulsion submitted by FPL.

+ Based on EPA emission factor and 90% control.

BEST AVAILABLE COPY

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

PLANT: MANATEE
UNIT: 1
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	RUN 1	RUN 2	RUN 3
DATE OF RUN	04/01/93	04/01/93	04/01/93
GROSS LOAD (AVG MMBTU/HR)	7311	7311	7311
START TIME (24-HR CLOCK)	1129	1403	1538
END TIME (24-HR CLOCK)	1229	1503	1638
CO2 (CORRECTED % DRY)	13.2	13.5	13.4
O2 (CORRECTED % DRY)	4.1	3.9	4.0
Fo TEST	1.273	1.259	1.261
NET TIME OF RUN (MIN)	60	60	60
MEASURED CONCENTRATION (PPM NOx)	213.0	207.4	206.6
AVG ZERO BIAS CHECK (PPM NOx)	0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)	205.0	205.0	205.0
AVG UPSCALE BIAS CHECK (PPM NOx)	202.3	200.3	199.4
CORRECTED CONCENTRATION (PPM NOx)	215.9	212.4	212.4
HEAT INPUT OIL (%)	100.0	100.0	100.0
HEAT INPUT GAS (%)	0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190.0
NOx EMISSIONS (LB/MMBTU)	0.294	0.286	0.288
AVERAGE NOx EMISSIONS (LB/MMBTU)		0.29	
NOx EMISSIONS STANDARD (LB/MMBTU)		0.30	

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

PLANT: MANATEE
UNIT: 2
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	RUN 1	RUN 2	RUN 3
DATE OF RUN	04/22/93	04/22/93	04/22/93
GROSS LOAD (AVG MMBTU/HR)	7231	7231	7231
START TIME (24-HR CLOCK)	1116	1255	1434
END TIME (24-HR CLOCK)	1216	1355	1534
CO2 (CORRECTED % DRY)	13.7	13.7	13.7
O2 (CORRECTED % DRY)	3.7	3.7	3.6
Fo TEST	1.255	1.255	1.263
NET TIME OF RUN (MIN)	60	60	60
MEASURED CONCENTRATION (PPM NOx)	211.7	214.8	214.0
AVG ZERO BIAS CHECK (PPM NOx)	0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NOx)	128.9	128.9	128.9
AVG UPSCALE BIAS CHECK (PPM NOx)	125.5	126.5	126.5
CORRECTED CONCENTRATION (PPM NOx)	217.5	218.9	218.0
HEAT INPUT OIL (%)	100.0	100.0	100.0
HEAT INPUT GAS (%)	0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190.0
NOx EMISSIONS (LB/MMBTU)	0.289	0.291	0.288

AVERAGE NOx EMISSIONS (LB/MMBTU)	0.29
NOx EMISSIONS STANDARD (LB/MMBTU)	0.30

FLORIDA POWER AND LIGHT COMPANY
PLANT SERVICES OPERATIONS SUPPORT
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NOx EMISSION TEST

PLANT: MANATEE
UNIT: 2
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	RUN 1	RUN 2	RUN 3
DATE OF RUN	06/08/94	06/08/94	06/08/94
GROSS LOAD (AVG MMBTU/HR)	7602	7602	7602
START TIME (24-HR CLOCK)	1100	1232	1400
END TIME (24-HR CLOCK)	1200	1332	1500
CO2 (CORRECTED % DRY)	13.1	13.2	13.4
O2 (CORRECTED % DRY)	4.0	4.0	3.8
Fo TEST	1.293	1.280	1.276
NET TIME OF RUN (MIN)	60	60	60
MEASURED CONCENTRATION (PPM NOx)	193.5	197.1	193.7
AVG ZERO BIAS CHECK (PPM NOx)	0.0	0.5	1.0
UPSCALE CAIBRATION GAS (PPM NOx)	210.0	210.0	210.0
AVG UPSCALE BIAS CHECK (PPM NOx)	208.5	210.5	211.0
CORRECTED CONCENTRATION (PPM NOx)	194.8	196.6	192.7
HEAT INPUT OIL (%)	100.0	100.0	100.0
HEAT INPUT GAS (%)	0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190.0
NOx EMISSIONS (LB/MMBTU)	0.264	0.266	0.258
AVERAGE NOx EMISSIONS (LB/MMBTU)		0.26	
NOx EMISSIONS STANDARD (LB/MMBTU)		0.30	

FLORIDA POWER AND LIGHT COMPANY
OPERATIONS SERVICES EMISSION TEST GROUP
700 UNIVERSE BLVD.
JUNO BEACH, FLORIDA 33408-0240

NO EMISSION TEST

PLANT: MANATEE
UNIT: 1
TEST: NITROGEN OXIDE EMISSIONS
METHOD: 40 CFR Pt. 60, App. A, 3A & 7E

	TOTAL RUN 1	TOTAL RUN 2	TOTAL RUN 3
DATE OF RUN	05/12/94	05/12/94	05/12/94
GROSS LOAD (AVG MMBTU/HR)	7514	7514	7514
START TIME (24-HR CLOCK)	949	1127	1314
END TIME (24-HR CLOCK)	1049	1227	1414
CO2 (CORRECTED % DRY)	13.6	13.6	13.5
O2 (CORRECTED % DRY)	3.7	3.8	3.6
Fo TEST	1.265	1.257	1.281
NET TIME OF RUN (MIN)	60	60	60
MEASURED CONCENTRATION (PPM NO)	210.96	212.90	204.89
AVG ZERO BIAS CHECK (PPM NO)	0.0	0.0	0.0
UPSCALE CAIBRATION GAS (PPM NO)	129.7	129.7	129.7
AVG UPSCALE BIAS CHECK (PPM NO)	127.4	127.3	127.0
CORRECTED CONCENTRATION (PPM NO)	214.8	217.0	209.2
HEAT INPUT OIL (%)	100.0	100.0	100.0
HEAT INPUT GAS (%)	0.0	0.0	0.0
WEIGHTED AVERAGE F FACTOR (DSCF/MMBTU)	9190.0	9190.0	9190.0
NO EMISSIONS (LB/MMBTU)	0.286	0.290	0.277
AVERAGE NO EMISSIONS (LB/MMBTU)		0.28	
NO EMISSIONS STANDARD (LB/MMBTU)		0.30	

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ISSUE # 7: Future Projected Actuals Are Incorrectly Calculated

Projected actuals for PM/PM_{10} and NO_x use hourly emission rates that are less than the permitted levels. Additionally, no limits exist for CO and V~~OC~~ for HSFO and LSFO, and VOC has no hourly limit for Orimulsion. Also, SO_2 has a higher emission limit for HSFO and LSFO. These limits must be revised and permit limits established that demonstrate compliance with the future actual projections.

BASIS: WEPCO Rule 57 FR 32323, "The future actual projection is the product of: (1) the hourly emissions rate, which is based on the unit's physical and operational capabilities following the change and federally enforceable operational restrictions that would effect the hourly emissions rate following this change; and (2) projected capacity utilization, which is based on (a) the unit's historical annual utilization, and (b) all available information regarding the unit's likely post-change capacity utilization."

Also WEPCO ruling.

"WEPCO Rule"

whether a utility unit is "less environmentally beneficial" after controls than it was before controls. Accordingly, the final rule allows consideration of all environmental impacts—beneficial and adverse—in making a determination.

B. Representative Actual Annual Emissions

1. Background

The EPA proposed to clarify its methodology for calculating emissions increases at electric utility steam generating sources that had begun normal operations. The EPA proposed to compare actual emissions before and after changes for all physical or operational changes at an existing electric utility steam generating unit other than the addition of a new unit or the replacement of an existing unit. The EPA proposed to consider a unit to be replaced if it would constitute a reconstructed unit within the meaning of 40 CFR 60.15. Since there is no relevant operating history for wholly new units and replaced units, it is not possible to reasonably project post-change utilization for these units, and hence, their future level of "representative annual actual emissions." For other changes, past operating history, and other relevant information, provides a basis for reasonable projections.

As proposed, the "representative actual annual emissions" methodology requires the utility to compare its baseline emissions with its future actual emissions to determine if the proposed change will increase actual emissions. The EPA's existing regulations define baseline emissions as "the average rate, in tpy, at which the unit actually emitted the pollutant during a 2-year period which precedes the particular date and which is representative of normal source operation" (see, e.g., 40 CFR 52.21). The Administrator "shall" allow use of a different time period "upon a determination that it is more representative of normal source operation." *Id.* Although not required by the regulations, EPA has historically used the 2 years immediately preceding the proposed change to establish the baseline [see 45 FR 52676, 52705, 52718 (1980)]. However, in some cases it has allowed the use of earlier periods. For example, in *WEPCO,* EPA found the fourth and fifth years prior to the modification more representative of WEPCO's normal operations since the source's capacity was reduced due to physical problems. The EPA proposed to retain this regulatory language, but to adopt a new presumption regarding its implementation.

Under the proposed action, the Administrator would presume that any 2 consecutive years within the 5 years prior to the proposed change is representative of normal source operations for a utility. This presumption is consistent with the 5-year period for "contemporaneous" emissions increases and decreases in 40 CFR 52.21(b)(3)(i)(b).[17] Source owners or operators desiring to use other than a 2-year period or a baseline period prior to the last 5 years may seek the Administrator's specific determination that such period is more representative of normal operations.[18]

The future actual projection is the product of: (1) The hourly emissions rate, which is based on the unit's physical and operational capabilities following the change and federally-enforceable operational restrictions that would affect the hourly emissions rate following this change; and (2) projected capacity utilization, which is based on (a) the unit's historical annual utilization, and (b) all available information regarding the unit's likely post-change capacity utilization.[19] The projection of post-change capacity utilization for applicability purposes should be based on a projection of utilization for a period after the physical or operational change. Specifically, EPA proposed to allow sources to base the projection of utilization on the 2 years after the change; or a different consecutive 2-year period within the 10 years after the change, where the Administrator determines that such period is more representative of normal source operations.

2. Comments Generally Favoring the EPA Proposal

a. Several commenters favored the expansion of the time period for establishing the pre-change emissions baseline. Suggestions included:

(1) Allow the use of any 2 consecutive years within the last 5 years of operation to allow for a more representative baseline for units that have been shut down;

(2) Allow utilities to request to use periods of representative high utilization outside the 5 year time period;

(3) Add the "any 2 out of the prior 5 year baseline period" discussed in the preamble to 40 CFR parts 51, 52, and 60;

(4) Allow utilities to use the maximum utilization in any 1 year within at least the last 10 years, since 10 years is a more relevant capacity investment planning horizon than 5 years;

(5) Clarify that the source will be able to select the relevant 2-year period with approval of the reviewing authority required only when the pre-change baseline is outside of the 5-year period proceeding the change;

(6) Expand the baseline calculation period from 5 years to 10 years to be consistent with the after-change calculation period and to address a more representative time period;

(7) Allow the use of any 2 years (rather than consecutive years) due to long reserve shutdowns and because maintenance planning requires that utility boilers be operated in "abnormal" conditions for long durations; and

(8) Require sources to back up the choice of which 2 years to use with a short-term standard using an hourly rate, use the same 2-year period for determining the short-term and annual rates, and codify the 2 years used for the limit.

Several comments that recommended expanding the proposal to include industrial sources in the NSR exemption also noted that a "5-year window" is not satisfactory for industrial sources which do not always have representative periods of emissions immediately before a physical change. One industrial commenter suggested the use of any 2-year period be allowed.

Commenters in favor of the future actual emissions calculation method noted that it will alleviate uncertainty, for nonroutine repair, replacement, and maintenance projects while still protecting local air quality; the future-actual method reduces speculation and allows more reliance on factual data; and the actual-to-future-actual emissions comparison is more appropriate to look at the operating history and projected capacity of an existing unit to determine whether a change will increase emissions. One commenter stated that the actual-to-potential method discouraged environmentally beneficial modifications, but suggested that the

[17] This presumption does not apply to past modifications at an emissions unit for the purpose of determining contemporaneous emission changes at a source and cannot be used to extend the 5 year period specified in that provision [see 40 CFR 52.21(b)(3)(i)(b)].

[18] The level of baseline emissions selected must be consistent with current assumptions regarding the source's emissions that are used under the SIP for planning or permitting purposes. Thus, the source may not select a level of baseline emissions higher than that used by the permitting authority in issuing a PSD or other construction permit to a source in the area, if such higher level would result in a NAAQS or increment violation, or violate a visibility limitation.

[19] In projecting future utilization and emissions factors, the permitting authority may consider the company's historical operational data, its own representations, filings with Federal, State or local regulatory authorities, and compliance plans developed under title IV of the 1990 Amendments;

Wepco Court Case #4.48 8

compare representative actual emissions for the baseline period to estimated future actual emissions based on all the available facts in the record. Specifically, in calculating post-renovation actual emissions, this approach takes into account 1) physical changes and operational restrictions that would affect the hourly emissions rate following the renovation, 2) WEPCO's pre-renovation capacity utilization, and 3) factors affecting WEPCO's likely post-renovation capacity utilization.

To quantify WEPCO's estimated future actual emissions after the proposed changes EPA relied heavily on projected and historical operational data (e.g., fuel consumption, MMBTU consumed) representative of the source. Specifically, the Agency considered available information regarding (1) projected post-change capacity utilization filed with public utility commissions; (2) Federal and State regulatory filings; (3) the source's own representations; and (4) the source's historical operating data. As described below, EPA determined an appropriate utilization factor for future operations and combined this with post-change emissions factors (to the extent they are or will be made federally enforceable) to estimate a future level of annual emissions for the purpose of determining whether the proposed physical and operational changes would be considered a major modification for PSD purposes. Where a significant emissions increase is projected to occur, WEPCO could voluntarily agree to federally-enforceable limits on any aspect of its future operation (including physical capacity and hours of operation) to ensure that no significant emissions increase will occur.

IV. THE AGENCY'S REVISED PSD APPLICABILITY DETERMINATION

A. Estimated Future Actual Emissions.

The Agency has revised its October 14, 1989 PSD applicability determination for WEPCO's proposed Port Washington renovation based on a "representative actual" to "estimated future actual emissions" comparison (as outlined above). As previously discussed, estimated future actual emissions projections take into account the likelihood that the plant will operate in the future as it has in the past.

The stated purpose of WEPCO's renovations is to refurbish the power plant units to an "as-new" condition in terms of their capacity, efficiency, and availability. Consequently, EPA has used actual, historical, operational data representative of the plant's past operations, approximating an "as-new" configuration, to calculate "estimated future actual emissions." The Agency has verified these data by comparison to WEPCO's own projections of post-renovation capacity utilization and industry averages.

As to the emissions factors used to calculate future emissions, EPA has used WEPCO's own emissions factors for future hourly emissions rates. These emissions factors are based on WEPCO's own assumptions regarding future sulfur in fuel and control technology performance levels. However, since these assumptions go beyond current State implementation plan (SIP) requirements, they must be made federally enforceable for EPA to continue to consider them for PSD applicability purposes.

Operational data (i.e., heat input) from the years 1978-1979 show a capacity utilization factor of 42 percent. These data points represent the closest projection of WEPCO's operational characteristics, approximating an "as-new" state, as currently available to EPA. The data currently available to us regarding WEPCO's past operational levels are limited to a 10-year period. The Agency believes that these historical levels of operation are representative of the plant's past operations in an "as-new" condition. In addition, the 1978-79 data points appear consistent with WEPCO's own projection of future operations for the year 2010 (as submitted to the Wisconsin Department of Natural Resources on March 29, 1990) and common capacity levels for the utility industry, in general, for new units. However, by this letter, EPA is requesting that WEPCO submit operational data from previous years (i.e., pre-1978), if such data show heat input levels notably higher than the 1978-1979 levels.

As previously mentioned, to calculate future emissions levels for each pollutant, EPA assumed that the amount of future coal consumed in terms of heat input to the plant would be comparable to WEPCO's annual average 1978-1979 coal-consumption figure. On March 29, 1990, WEPCO submitted to the Wisconsin Department of Natural Resources information which contained estimates of future emissions for different levels of coal and heat input to the plant. The Agency used these estimates to establish future emissions based on 1978-1979 heat-input values. Again, it is important to note that EPA's calculation of "estimated future actual emissions" is based on WEPCO's projection of control technology performance levels and/or fuel sulfur content for post-renovation operations. Consequently, EPA's PSD applicability determination is valid only to the extent that the emissions factors (based on control technology performance levels and sulfur in fuel) used to calculate future emissions are made federally enforceable. Otherwise, the calculation of estimated future actual emissions for each pollutant will need to be revised by EPA based on existing federally-enforceable limits (i.e., applicable SIP, NSPS). The use of current, federally-enforceable emissions in the current SIP would result in higher projected future emissions than assumed in EPA's calculations and, consequently, could affect the indicated PSD applicability finding.