MEMORANDUM

DATE: December 21, 2006

SUBJECT: Impacts of Applying Management Practices to a Single Oil and Natural Gas Production Area Source Facility

FROM: Heather P. Brown, P.E.

TO: Greg Nizich, EPA/OAQPS/SPPD/CCG

I. INTRODUCTION AND BACKGROUND

On July 8, 2005, (70 FR 39443), the United States Environmental Protection Agency (EPA) issued a supplemental proposal to the February 6, 1998 (63 FR 6288), proposed standards for oil and natural gas production area sources. In response to comments received on the two proposals, EPA is requiring certain triethylene glycol (TEG) dehydration units located at area source oil and natural gas production facilities to reduce emissions by implementing the management practice of optimizing the glycol circulation rate.

Most dehydration systems use TEG as an absorbent to remove water from natural gas. As the TEG absorbs water, it also absorbs methane and any other hazardous air pollutants (HAP) or volatile organic compounds (VOC) entrained in the methane. As the TEG is regenerated in the reboiler, any absorbed compounds (i.e., methane, HAP, and VOC) are vented to the atmosphere. The amount of methane absorbed and vented is directly proportional to the TEG circulation rate. According to the Natural Gas STAR Partners, many wells operate below their original design capacity but continue to circulate the TEG at rates two to three times higher than needed for a particular water removal rate.[a] Therefore, by reducing the glycol circulation rate, HAP emissions can be reduced.

In addition to reducing HAP emissions, reducing the glycol circulation rate also reduces the TEG circulation rate has the added benefit of reducing the amount of natural gas absorbed by the TEG and subsequently emitted through the reboiler vent thereby resulting in a natural gas savings. Furthermore, optimizing the TEG circulation rate can be achieved without sacrificing the performance of the TEG dehydration unit, does not require the presence of an on-site operator to maintain, can be optimized for minimal capital cost (e.g., a new pump may be required), and could result in an annual cost savings due to the reduction of the natural gas losses. The purpose of this memorandum is to estimate air emission and cost impacts associated with reducing the glycol circulation rate to an optimized level for a single TEG dehydration unit.

[a] Lessons Learned: From Natural Gas STAR Partners. "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators." http://www.epa.gov/gasstar/pdf/lessons/ll_flashtanks3.pdf

II. AIR EMISSIONS IMPACTS

In order to estimate the air emissions impact from reducing the TEG circulation rate to an optimum level, GRI-GLYCalc Version 4.0 (GLYCalc) was used to estimate baseline emissions and emissions from the optimized TEG circulation rate.

Table 1 presents baseline emissions estimated using the following inputs for GLYCalc:

- The glycol recirculation ratio was set at the industry average of 5.9 gallons of glycol per pound of water removed (gal TEG/lb H_2O).[b] This corresponds to a circulation rate of approximately 37 gallons of TEG per hour (gal TEG/hr).
- Because emissions are proportional to the natural gas throughput, the emission reduction is not impacted by the throughput level (i.e., TEG dehydration units with a natural gas throughputs of 3 MMSCF/D and 5 MMSCF/D have the same emission reduction of 45 percent). Therefore, the natural gas throughput was set at the applicability cutoff of 3 million standard cubic feet per day (MMSCF/D).
- According to Natural Gas STAR Partners, smaller and older units are not equipped with a flash tank. Therefore, no flash tank was used.[c]
- According to Natural Gas STAR Partners, remote gas fields do not have electrical power and instead use energy-exchange (or gas injection) pumps. Therefore, the pump type was set as a gas injection pump.[d]
- Other program inputs were chosen to be consistent with values used in previous impacts calculations.[e]

Attachment 1 contains the summary of input values and emissions data generated by the GLYCalc program for baseline emissions.

To calculate emissions at the optimal glycol circulation rate, a glycol recirculation ratio of 3 gal TEG/lb H_2O was used. This ratio is considered the rule-of-thumb for the industry[f] and corresponds to a TEG circulation rate of approximately 19 gal TEG/hr. The remaining inputs were the same as those used to estimate baseline emissions. Emissions at the optimal glycol circulation rate are also presented in Table 1 (a summary of input values and emissions data is presented in Attachment 2).

As shown in Table 1, optimizing the glycol circulation rate reduces HAP emission by approximately 45 percent. Likewise, VOC emissions were reduced by 48 percent and benzene emissions were reduced by 47 percent.

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[b] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage. Background Information Document for Proposed Standards. Page 3-4. EPA-453/R-94-079a.

[c] See footnote a.

[d] See footnote a.

[e] Memorandum from Brown, H.P., EC/R Incorporated to Nizich, G., United States Environmental Protection Agency. Revised Impacts for Area Sources in the Oil and Natural Gas Production Source Category. June 25, 2006.

[f] See footnote a.

NMED Exhibit 76 - 0002

Table 1. Emissions Impacts of Reducing TEG Circulation Rate for a Single TEG Dehydration Unit[1]

Pollutant	Emissions at Baseline Circulation Rate (tpy)[2]	Emissions at Optimized Circulation Rate (tpy)[3]	Emission Reduction (%)
HAP	6.1482	3.376	45
VOC	15.281	7.9982	48
Benzene	1.8076	0.9498	47

[1] Emissions for the baseline circulation rate and optimized circulation rate were generated using GLYCalc. Input summaries and emissions results are presented in Attachments 1 and 2, respectively.

[2] Baseline circulation rate = 37 gal/hr (corresponding to a baseline recirculation ratio of 5.9 gal TEG/lb H_2O).

[3] Optimized circulation rate = 19 gal/hr (corresponding to an optimal recirculation ratio of 3 gal TEG/lb H_2O).

NMED Exhibit 76 - 0003

III. COST IMPACTS

While some facilities may be able to adjust the circulation rate without replacing equipment, it was assumed that at a minimum, the glycol pump would have to be replaced. Therefore, cost impacts were generated to represent the costs related to pump replacement.

Equipment costs were developed based on information from Kimray, Inc., a pump vendor (See Attachment 3).[g] Table 2 presents the capital costs for installing a new pump to achieve the optimized TEG circulation rate. The total capital investment for installing a new pump was estimated to be $1,540. The annual costs were estimated to be $914 per year for a single unit and are presented in Table 3. For sources that do not have to purchase a new pump to meet the optimal circulation rate, the only costs associated with the implementing the optimal TEG circulation rate are related to operational costs. The annual cost of implementing the optimal circulation rate without replacing the pump was approximately $600 per year and is presented in Table 4.

[g] Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006. Available on the Internet at http://www.kimray.com/pricebook.html

NMED Exhibit 76 - 0004

Table 2. Capital Costs for Installation of a New Glycol Pump for an Existing TEG Dehydration Unit

Cost Item	Description	Size	Factor	July '06 Cost
DIRECT COSTS				
Purchased equipment cost				
Glycol Pump (EC)	Gas assisted pump	average	NOTE 1	$ 922
Instrumentation	(assume no instrumentation is necessary)			
Sales Taxes		7% of EC		$ 65
Freight		5% of EC	NOTE 2	$ 46
Purchased equipment cost, PEC				$ 1,033
Direct Installation Costs[a]				
Piping		2% of PEC	NOTE 2	$ 21
Direct Installation Cost				$ 21
Total Direct Cost, DC				$ 1,054
INDIRECT COSTS				
Engineering		10% of PEC	NOTE 2	$ 103
Construction and field expenses		5% of PEC	NOTE 2	$ 52
Startup		2% of PEC	NOTE 2	$ 21
Contingencies		3% of PEC	NOTE 2	$ 310
Total Indirect Cost, IC				$ 485
Total Capital Investment = DC + IC				$ 1,539

a - The only direct installation cost is for piping changes necessary to fit the new pump. No site preparation and building necessary

NOTE 1: New Pump Purchase Price = $ 922 (Pressure Volume Pump, capacity range 12-40 gal/hr, working pressure range 400-1500 psig)
Average of four pumps of this size, Model 4015V
(Reference: Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006 http://www.kimray.com/pricebook.html)

NOTE 2: OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

NMED Exhibit 76 - 0005

Table 3. Annual Costs for Installation of a New Glycol Pump on an Existing TEG Dehydration Unit

Cost Item	Suggested Factor	Cost	Factor	July '06 Cost
DIRECT ANNUAL COSTS, DC				
Operating Labor				
Operator	26 hr/yr	$25/hr	NOTE 1	$ 650.00
Supervisor	15% of operator		NOTE 2	$ 97.50
Maintenance				
Labor	8 hr/y	$25/hr	NOTE 3	$ 200.00
Materials	Average repair kit price	$ 63.06 (Ref 3)		$ 63.06
Natural Gas Consumption	3.9 scf/gal	7.51 $/mcf	NOTE 4	$ 4,787.63
Total DC				$ 5,798.19
INDIRECT ANNUAL COSTS, IC				
Overhead	60% of operating and labor costs		NOTE 2	$ 606.34
Administrative charges	2% of TCI		NOTE 2	$ 30.78
Property taxes	1% of TCI		NOTE 2	$ 15.39
Insurance	1% of TCI		NOTE 2	$ 15.39
Capital Recovery Factor	0.1627 of TCI		NOTE 2	$ 250.47
	10% interest, 10 yr equp life			
Total IC				$ 918.37
Gas Savings Credit for reducing the circulation rate			NOTE 5	$ (5,802.47)
Total Annual Cost				$ 914.10

NOTE 1: The resources needed 1/2 hr of labor at $25/hr, assumed to be on a weekly basis. (Reference: Lessons Learned: From Natural Gas STAR Partners. "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators." .http://www.epa.gov/gasstar/pdf/lessons/ll_flashtanks3.pdf)

NOTE 2: OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

NOTE 3: Assumed one day of maintenance per year because very little maintenance is needed. (Reference: Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006 http://www.kimray.com/pricebook.html)

NOTE 4: Wellhead price of natural gas published by the Energy Information Administration for 2005. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

NOTE 5: Value of gas saved = [Original TEG Circulation Rate - Optimal TEG Circulation Rate] * [TEG Absorption Rate + Energy-Exchange Pump gas] * Hours/yr * Gas Price/1000

Original TEG Circulation Rate = 36.66 gal/hr (@ industry average of 5.9 gal/lb H2O, see Attachment 1)

Optimal TEG Circulation Rate = 18.66 gal/hr (@ opbimized rate of 3 gal/lb H2O, see Attachment 2)

Value of gas saved = $ 5,802

NMED Exhibit 76 - 0006

Table 4. Annual Costs Associated with Operating TEG Dehydration Unit at Optimal Circulation Rate

Cost Item	Suggested Factor	Cost	Factor	July '06 Cost
DIRECT ANNUAL COSTS, DC				
Operating Labor				
Operator	26 hr/yr	$25/hr	NOTE 1	$ 650.00
Supervisor	15% of operator		NOTE 2	$ 97.50
Maintenance				
Labor	8 hr/y	$25/hr	NOTE 3	$ 200.00
Materials	Average repair kit price	$ 63.06 (Ref 3)		$ 63.06
Natural Gas Consumption	3.9 scf/gal	7.51 $/mcf	NOTE 4	$ 4,787.63
Total DC				$ 5,798.19
INDIRECT ANNUAL COSTS, IC				
Overhead	60% of operating and labor costs		NOTE 2	$ 606.34
Total IC				$ 606.34
Gas Savings Credit for reducing the circulation rate			NOTE 5	$ (5,802.47)
Total Annual Cost				$ 602.06

NOTE 1: The resources needed 1/2 hr of labor at $25/hr, assumed to be on a weekly basis. (Reference: Lessons Learned: From Natural Gas STAR Partners. "Optimize Glycol Circulation and Install Flash Tank Separators in Glycol Dehydrators." .http://www.epa.gov/gasstar/pdf/lessons/ll_flashtanks3.pdf)

NOTE 2: OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

NOTE 3: Assumed one day of maintenance per year because very little maintenance is needed. (Reference: Kimray, Inc. Oil and Gas Equipment and Controls. Price Book, July 1, 2006 http://www.kimray.com/pricebook.html)

NOTE 4: Wellhead price of natural gas published by the Energy Information Administration for 2005. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

NOTE 5: Value of gas saved = [Original TEG Circulation Rate - Optimal TEG Circulation Rate] * [TEG Absorption Rate + Energy-Exchange Pump gas] * Hours/yr * Gas Price/1000

Original TEG Circulation Rate = 36.66 gal/hr (@ industry average of 5.9 gal/lb H2O, see Attachment 1)

Optimal TEG Circulation Rate = 18.66 gal/hr (@ opbimized rate of 3 gal/lb H2O, see Attachment 2)

Value of gas saved = $ 5,802

NMED Exhibit 76 - 0007

Attachment 1

GRI-GLYCalc, Version 4.0 Input Summary and Aggregate Emissions Summary for Baseline Glycol Circulation Rate (5 gal TEG/lb H_2O)

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: BMP Baseline
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 5_9 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 5.9
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 3.0 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Gas Injection
Gas Injection Pump Volume Ratio: 0.080 acfm gas/gpm glycol

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: BMP Baseline
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 5_9 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 5.9
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	6.5143	156.344	28.5328
Ethane	0.9196	22.070	4.0278
Propane	0.4047	9.713	1.7726
n-Butane	0.6887	16.528	3.0164
n-Pentane	0.8590	20.616	3.7624
n-Hexane	0.0633	1.520	0.2774
Other Hexanes	0.1029	2.468	0.4505
Heptanes	0.0299	0.717	0.1309
2,2,4-Trimethylpentane	0.0344	0.825	0.1505
Benzene	0.4127	9.905	1.8076
Toluene	0.3763	9.031	1.6481
Ethylbenzene	0.0616	1.477	0.2696
Xylenes	0.4555	10.931	1.9949
Total Emissions	10.9227	262.146	47.8416
Total Hydrocarbon Emissions	10.9227	262.146	47.8416
Total VOC Emissions	3.4888	83.732	15.2810
Total HAP Emissions	1.4037	33.689	6.1482
Total BTEX Emissions	1.3060	31.344	5.7203

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature:	90.0 deg. F
Pressure:	700.0 psig
Dry Gas Flow Rate:	3.0000 MMSCF/day
Glycol Losses with Dry Gas:	0.0180 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.33%	56.67%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.33%	99.67%
n-Hexane	0.39%	99.61%
Other Hexanes	0.72%	99.28%
Heptanes	0.43%	99.57%
2,2,4-Trimethylpentane	1.11%	98.89%
Benzene	4.96%	95.04%
Toluene	7.86%	92.14%
Ethylbenzene	10.37%	89.63%
Xylenes	12.88%	87.12%

STREAM REPORTS:

WET GAS STREAM

Temperature:	90.00 deg. F
Pressure:	714.70 psia
Flow Rate:	1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e+000
Carbon Dioxide	9.99e-001	1.45e+002
Methane	8.99e+001	4.76e+003
Ethane	5.29e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.30e+002
n-Pentane	9.99e-001	2.38e+002
n-Hexane	4.19e-002	1.19e+001
Other Hexanes	8.39e-002	2.39e+001
Heptanes	9.99e-003	3.30e+000
2,2,4-Trimethylpentane	2.00e-002	7.53e+000
Benzene	1.04e-002	2.68e+000
Toluene	5.59e-003	1.70e+000
Ethylbenzene	5.99e-004	2.10e-001
Xylenes	3.40e-003	1.19e+000
Total Components	100.00	6.14e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	3.62e-001
Carbon Dioxide	9.98e-001	1.45e+002
Methane	9.00e+001	4.76e+003
Ethane	5.30e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.29e+002
n-Pentane	9.98e-001	2.37e+002
n-Hexane	4.18e-002	1.19e+001
Other Hexanes	8.38e-002	2.38e+001
Heptanes	9.92e-003	3.28e+000
2,2,4-Trimethylpentane	1.99e-002	7.50e+000
Benzene	8.81e-003	2.27e+000
Toluene	4.37e-003	1.33e+000
Ethylbenzene	4.25e-004	1.49e-001
Xylenes	2.10e-003	7.35e-001
Total Components	100.00	6.13e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 6.11e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	3.39e+002
Water	1.50e+000	5.16e+000
Carbon Dioxide	9.88e-012	3.40e-011
Methane	7.59e-018	2.61e-017
Ethane	3.93e-008	1.35e-007

Propane	2.09e-009	7.20e-009
n-Butane	2.97e-009	1.02e-008
n-Pentane	8.36e-004	2.88e-003
n-Hexane	7.15e-005	2.46e-004
Other Hexanes	2.17e-004	7.48e-004
Heptanes	3.78e-005	1.30e-004
2,2,4-Trimethylpentane	1.12e-004	3.85e-004
Benzene	6.26e-003	2.16e-002
Toluene	9.33e-003	3.21e-002
Ethylbenzene	2.07e-003	7.12e-003
Xylenes	1.96e-002	6.73e-002
Total Components	100.00	3.44e+002

RICH GLYCOL AND PUMP GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 6.50e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.35e+001	3.39e+002
Water	3.29e+000	1.19e+001
Carbon Dioxide	1.42e-001	5.15e-001
Methane	1.80e+000	6.51e+000
Ethane	2.54e-001	9.20e-001
Propane	1.12e-001	4.05e-001
n-Butane	1.90e-001	6.89e-001
n-Pentane	2.38e-001	8.62e-001
n-Hexane	1.76e-002	6.36e-002
Other Hexanes	2.86e-002	1.04e-001
Heptanes	8.29e-003	3.00e-002
2,2,4-Trimethylpentane	9.59e-003	3.47e-002
Benzene	1.20e-001	4.34e-001
Toluene	1.13e-001	4.08e-001
Ethylbenzene	1.90e-002	6.87e-002
Xylenes	1.44e-001	5.23e-001
Total Components	100.00	3.62e+002

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.31e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	4.29e+001	6.75e+000
Carbon Dioxide	1.34e+000	5.15e-001
Methane	4.65e+001	6.51e+000
Ethane	3.50e+000	9.20e-001
Propane	1.05e+000	4.05e-001
n-Butane	1.36e+000	6.89e-001
n-Pentane	1.36e+000	8.59e-001

n-Hexane	8.42e-002	6.33e-002
Other Hexanes	1.37e-001	1.03e-001
Heptanes	3.42e-002	2.99e-002
2,2,4-Trimethylpentane	3.45e-002	3.44e-002
Benzene	6.05e-001	4.13e-001
Toluene	4.68e-001	3.76e-001
Ethylbenzene	6.64e-002	6.16e-002
Xylenes	4.91e-001	4.55e-001
Total Components	100.00	1.82e+001

ANNUAL AIR-COOLED CONDENSER PERFORMANCE:

ANNUAL AIR-COOLED CONDENSER PERFORMANCE

Nearest Site for Air Temperature Data: Amarillo, TX

Ambient Air Dry Bulb Temperature (deg. F)	Frequency (%)	Condenser Outlet Temperature (deg. F)
<=50	39.18	<=70
51-55	7.45	71-75
56-60	8.35	76-80
61-65	9.54	81-85
66-70	10.13	86-90
71-75	8.17	91-95
76-80	6.28	96-100
81-85	4.74	101-105
86-90	3.53	106-110
91-95	1.97	111-115
96-100	0.59	116-120
>100	0.09	>120

Condenser outlet temperature approach to ambient: 20.00 deg. F

Annual air-cooled condenser emissions and control efficiency:

	Uncontrolled emissions tons/year	Controlled emissions tons/year	% Control
Benzene	1.808	1.808	0.00
BTEX	5.720	5.720	0.00
Total HAP	6.148	6.148	0.00
VOC	15.281	15.281	0.00

Attachment 2

GRI-GLYCalc, Version 4.0 Input Summary and Aggregate Emissions Summary for Optimized Glycol Circulation Rate (3 gal TEG/lb H_2O)

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: BMP Case
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 3 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 3
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 3.0 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 3.0 gal/lb H2O

PUMP:

Glycol Pump Type: Gas Injection
Gas Injection Pump Volume Ratio: 0.080 acfm gas/gpm glycol

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: BMP Case
File Name: D:\My Documents\Oil and Gas\Promulgation\Condenser Operation\GLYCalc\BMP runs\3mmscf per day flash tank 3 recirc.ddf
Date: December 08, 2006

DESCRIPTION:

Description: 3 mmscf/d actual throughput
BTEX content = 200 ppmv; Recirc Rate 3
No Flash Tank
Gas Injection Pump

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	3.3565	80.555	14.7013
Ethane	0.4679	11.230	2.0495
Propane	0.2070	4.967	0.9065
n-Butane	0.3493	8.382	1.5298
n-Pentane	0.4329	10.390	1.8962
n-Hexane	0.0316	0.758	0.1384
Other Hexanes	0.0514	1.235	0.2253
Heptanes	0.0147	0.353	0.0644
2,2,4-Trimethylpentane	0.0170	0.408	0.0745
Benzene	0.2168	5.204	0.9498
Toluene	0.2026	4.862	0.8873
Ethylbenzene	0.0342	0.821	0.1499
Xylenes	0.2685	6.444	1.1761
Total Emissions	5.6504	135.611	24.7489
Total Hydrocarbon Emissions	5.6504	135.611	24.7489
Total VOC Emissions	1.8261	43.826	7.9982
Total HAP Emissions	0.7708	18.499	3.3760
Total BTEX Emissions	0.7222	17.332	3.1631

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 4.24 lbs. H2O/MMSCF

Temperature:	90.0 deg. F
Pressure:	700.0 psig
Dry Gas Flow Rate:	3.0000 MMSCF/day
Glycol Losses with Dry Gas:	0.0180 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	3.00 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	7.45%	92.55%
Carbon Dioxide	99.88%	0.12%
Methane	99.99%	0.01%
Ethane	99.97%	0.03%
Propane	99.95%	0.05%
n-Butane	99.91%	0.09%
n-Pentane	99.88%	0.12%
n-Hexane	99.80%	0.20%
Other Hexanes	99.85%	0.15%
Heptanes	99.62%	0.38%
2,2,4-Trimethylpentane	99.84%	0.16%
Benzene	91.96%	8.04%
Toluene	88.15%	11.85%
Ethylbenzene	83.76%	16.24%
Xylenes	77.48%	22.52%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	28.52%	71.48%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.33%	99.67%
n-Hexane	0.38%	99.62%
Other Hexanes	0.71%	99.29%
Heptanes	0.43%	99.57%
2,2,4-Trimethylpentane	1.09%	98.91%
Benzene	4.96%	95.04%
Toluene	7.87%	92.13%
Ethylbenzene	10.38%	89.62%
Xylenes	12.90%	87.10%

STREAM REPORTS:

WET GAS STREAM

Temperature:	90.00 deg. F
Pressure:	714.70 psia
Flow Rate:	1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e+000
Carbon Dioxide	9.99e-001	1.45e+002
Methane	8.99e+001	4.76e+003
Ethane	5.29e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.30e+002
n-Pentane	9.99e-001	2.38e+002
n-Hexane	4.19e-002	1.19e+001
Other Hexanes	8.39e-002	2.39e+001
Heptanes	9.99e-003	3.30e+000
2,2,4-Trimethylpentane	2.00e-002	7.53e+000
Benzene	1.04e-002	2.68e+000
Toluene	5.59e-003	1.70e+000
Ethylbenzene	5.99e-004	2.10e-001
Xylenes	3.40e-003	1.19e+000
Total Components	100.00	6.14e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	8.92e-003	5.30e-001
Carbon Dioxide	9.99e-001	1.45e+002
Methane	9.00e+001	4.76e+003
Ethane	5.30e+000	5.25e+002
Propane	1.30e+000	1.89e+002
n-Butane	1.20e+000	2.30e+002
n-Pentane	9.99e-001	2.37e+002
n-Hexane	4.19e-002	1.19e+001
Other Hexanes	8.39e-002	2.38e+001
Heptanes	9.96e-003	3.29e+000
2,2,4-Trimethylpentane	2.00e-002	7.52e+000
Benzene	9.56e-003	2.46e+000
Toluene	4.94e-003	1.50e+000
Ethylbenzene	5.03e-004	1.76e-001
Xylenes	2.63e-003	9.22e-001
Total Components	100.00	6.14e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 3.11e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	1.72e+002
Water	1.50e+000	2.63e+000
Carbon Dioxide	9.78e-012	1.71e-011
Methane	7.36e-018	1.29e-017
Ethane	3.77e-008	6.60e-008

Propane	2.07e-009	3.62e-009
n-Butane	2.92e-009	5.10e-009
n-Pentane	8.17e-004	1.43e-003
n-Hexane	6.93e-005	1.21e-004
Other Hexanes	2.11e-004	3.69e-004
Heptanes	3.63e-005	6.35e-005
2,2,4-Trimethylpentane	1.07e-004	1.87e-004
Benzene	6.47e-003	1.13e-002
Toluene	9.89e-003	1.73e-002
Ethylbenzene	2.26e-003	3.96e-003
Xylenes	2.27e-002	3.98e-002
Total Components	100.00	1.75e+002

RICH GLYCOL AND PUMP GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.37e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.19e+001	1.72e+002
Water	4.91e+000	9.20e+000
Carbon Dioxide	1.40e-001	2.62e-001
Methane	1.79e+000	3.36e+000
Ethane	2.50e-001	4.68e-001
Propane	1.10e-001	2.07e-001
n-Butane	1.86e-001	3.49e-001
n-Pentane	2.32e-001	4.34e-001
n-Hexane	1.69e-002	3.17e-002
Other Hexanes	2.77e-002	5.18e-002
Heptanes	7.88e-003	1.48e-002
2,2,4-Trimethylpentane	9.18e-003	1.72e-002
Benzene	1.22e-001	2.28e-001
Toluene	1.17e-001	2.20e-001
Ethylbenzene	2.04e-002	3.82e-002
Xylenes	1.65e-001	3.08e-001
Total Components	100.00	1.87e+002

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.36e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	5.87e+001	6.58e+000
Carbon Dioxide	9.56e-001	2.62e-001
Methane	3.37e+001	3.36e+000
Ethane	2.50e+000	4.68e-001
Propane	7.55e-001	2.07e-001
n-Butane	9.66e-001	3.49e-001
n-Pentane	9.65e-001	4.33e-001

n-Hexane	5.90e-002	3.16e-002
Other Hexanes	9.60e-002	5.14e-002
Heptanes	2.36e-002	1.47e-002
2,2,4-Trimethylpentane	2.39e-002	1.70e-002
Benzene	4.46e-001	2.17e-001
Toluene	3.54e-001	2.03e-001
Ethylbenzene	5.18e-002	3.42e-002
Xylenes	4.07e-001	2.69e-001
Total Components	100.00	1.25e+001

ANNUAL AIR-COOLED CONDENSER PERFORMANCE:

ANNUAL AIR-COOLED CONDENSER PERFORMANCE

Nearest Site for Air Temperature Data: Amarillo, TX

Ambient Air Dry Bulb Temperature (deg. F)	Frequency (%)	Condenser Outlet Temperature (deg. F)
<=50	39.18	<=70
51-55	7.45	71-75
56-60	8.35	76-80
61-65	9.54	81-85
66-70	10.13	86-90
71-75	8.17	91-95
76-80	6.28	96-100
81-85	4.74	101-105
86-90	3.53	106-110
91-95	1.97	111-115
96-100	0.59	116-120
>100	0.09	>120

Condenser outlet temperature approach to ambient: 20.00 deg. F

Annual air-cooled condenser emissions and control efficiency:

	Uncontrolled emissions tons/year	Controlled emissions tons/year	% Control
Benzene	0.950	0.950	0.00
BTEX	3.163	3.163	0.00
Total HAP	3.376	3.376	0.00
VOC	7.998	7.998	0.00

MEMORANDUM

DATE: June 25, 2005

SUBJECT: Revised Impacts for Area Sources in the Oil and Natural Gas Production Source Category

FROM: Heather P. Brown, P.E.

TO: Greg Nizich, EPA/OAQPS/ESD/WCPG

On February 6, 1998 (63 FR 6288), the United States Environmental Protection Agency (EPA) proposed standards for major and area sources in the Oil and Natural Gas Production Source Category. When the major source rule was finalized on June 17, 1999 (64 FR 32610) under 40 CFR part 63, subpart HH, the regulation of oil and natural production area source facilities was deferred. EPA is now proposing amendments to subpart HH to add regulatory language for area sources. The proposed amendments require area sources to reduce HAP emissions from each triethylene glycol (TEG) dehydration unit with a natural gas throughput greater than or equal to 3 million standard cubic feet per day (MMscf/d) or with benzene emissions greater than or equal to 1 ton per year (tpy) by 95 percent or to a level such that benzene emissions are less than 1 tpy.

The purpose of this memorandum is to present the revised impacts for area source TEG units in the oil and natural gas production source category. The impacts presented include primary air impacts, secondary environmental impacts (air pollution, water and solid waste impacts), energy impacts, and cost impacts. In addition, the incremental cost effectiveness evaluation is documented in this memorandum.

PRIMARY ENVIRONMENTAL IMPACTS

This section presents the revised nationwide primary air pollution impacts (i.e., the reduction of HAP emissions) associated with the proposed area source standards. EPA estimated that there are potentially 38,067 area source TEG dehydration units in the United States. Throughput categories were established and the number of TEG dehydration units were distributed across these categories. The basis for the distribution of facilities is presented in another memorandum.[1] Table 1 presents the throughput categories and the number of units within each category.

[1]Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., United States Environmental Protection Agency. Methodology for Estimating the Number of Area Sources in the Oil and Natural Gas Production Source Category. June 15, 2005.

NMED Exhibit 78 - 0001

Table 1. Throughput Category Distribution of Area Source TEG Dehydration Units

Throughput category (MMscf/d)	Average Throughput (MMscf/d)	Number of TEG Dehydration Units	Number of TEG Dehydration Units Without Flash Tank	Number of TEG Dehydration Units With Flash Tank
≤ 0.1	0.1	7,050	6,345	705
>0.1 and ≤ 0.2	0.2	5,837	5,253	584
>0.2 and ≤ 0.3	0.3	4,833	4,350	483
>0.3 and ≤ 0.4	0.4	4,002	3,602	400
>0.4 and ≤ 0.5	0.5	3,313	2,982	331
>0.5 and ≤ 0.6	0.6	2,743	2,469	274
>0.6 and ≤ 0.7	0.7	2,272	2,045	227
>0.7 and ≤ 0.8	0.8	1,881	1,693	188
>0.8 and ≤ 0.9	0.9	1,557	1,401	156
>0.9 and ≤ 1	1	1,289	1,160	129
>1 and ≤ 2	2	1,068	961	107
>2 and ≤ 3	3	884	796	88
>3 and ≤ 4	4	732	659	73
>4 and ≤ 5	5	606	545	61
	Total	38,067	34,261	3,806

For the purposes of estimating baseline emissions, EPA estimated that 10 percent of the existing TEG dehydration units would be equipped with a flash tank.[2] The number of units within each throughput category with and without flash tanks are also presented in Table 1 as well as the average throughput for each category.

Baseline emissions were estimated using GRI-GLYCalc (Version 4.0)©. Attachment A contains the input summary files for each run. The following inputs were used for each GRI-GLYCalc© run:

- Temperature = 90^{O}F;
- Pressure = 700 psig;
- Dry gas water content = 7 lb/MMscf/d; and
- Glycol Circulation rate = 5.9 gal glycol/lb water removed

Table 2 presents baseline HAP, VOC, and benzene emissions for a single TEG dehydration unit within each throughput category.

Nationwide baseline emissions were estimated based on the number of TEG units per throughput category (Table 1) and baseline single unit emissions (Table 2). Nationwide baseline emissions are presented in Table 3.

Controlled emissions were estimated for area source TEG dehydration units that would be subject to area source standards. Each area source TEG dehydration unit with a throughput greater than or equal to 3 MMscf/d or benzene emissions greater than or equal to 1 tpy must choose between two control scenarios. Under Control Scenario 1, TEG dehydration units would reduce emissions by 95 percent. Area sources also have the option of reducing emissions to a level such that benzene emissions are less than 1 tpy, defined as Control Scenario 2. Controlled emissions are presented for Control Scenario 1 in Table 3 (95-percent emission reduction) and for Control Scenario 2 in Table 4 (1 tpy benzene). Table 5 presents the total emission reductions for each control scenario.

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage. Background Information Document for Proposed Standards. EPA-453/R-94-079a.

NMED Exhibit 78 - 0003

Table 2. Baseline Emissions For Area Source TEG Dehydration Units

	No Flash Tank			Flash Tank		
Throughput category (MMscf/d)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
≤ 0.1	0.20	0.38	0.06	0.20	0.38	0.06
>0.1 and ≤ 0.2	0.40	0.77	0.12	0.40	0.77	0.12
>0.2 and ≤ 0.3	0.60	1.15	0.18	0.60	1.15	0.18
>0.3 and ≤ 0.4	0.80	1.54	0.24	0.80	1.54	0.24
>0.4 and ≤ 0.5	1.00	1.92	0.30	1.00	1.92	0.30
>0.5 and ≤ 0.6	1.20	2.31	0.36	1.20	2.31	0.36
>0.6 and ≤ 0.7	1.40	2.69	0.42	1.40	2.69	0.42
>0.7 and ≤ 0.8	1.60	3.08	0.48	1.53	3.08	0.48
>0.8 and ≤ 0.9	1.80	3.46	0.54	1.80	3.46	0.54
>0.9 and ≤ 1	2.01	3.85	0.60	2.01	3.85	0.60
>1 and ≤ 2	4.01	7.69	1.20	4.01	7.69	1.20
>2 and ≤ 3	6.02	11.54	1.79	6.02	11.54	1.79
>3 and ≤ 4	8.02	15.38	2.39	8.02	15.38	2.39
>4 and ≤ 5	10.02	19.23	2.99	10.03	19.23	2.99
Total	39.00	75.00	12.00	39.00	75.00	12.00

NMED Exhibit 78 - 0004

Table 3. Nationwide Baseline Emissions and Controlled Emissions for Area Sources Applying 95 Percent Control (Control Scenario 1)

Throughput category (MMscf/d)	Nationwide						Emissions after 95-Percent Emission Reduction					
	No Flash Tank			Flash Tank			No Flash Tank			Flash Tank		
	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
≤ 0.1	1,272	2,440	379	141	271	42	1,272	2,440	379	141	271	42
>0.1 and ≤ 0.2	2,107	4,041	628	234	449	70	2,107	4,041	628	234	449	70
>0.2 and ≤ 0.3	2,617	5,019	782	291	557	87	2,617	5,019	782	291	557	87
>0.3 and ≤ 0.4	2,889	5,541	861	321	615	96	2,889	5,541	861	321	615	96
>0.4 and ≤0.5	2,990	5,735	891	332	636	99	2,990	5,735	891	332	636	99
>0.5 and ≤0.6	2,971	5,698	886	330	632	98	2,971	5,698	886	330	632	98
>0.6 and ≤0.7	2,869	5,504	856	319	611	95	2,869	5,504	856	319	611	95
>0.7 and ≤0.8	2,715	5,208	810	302	578	90	2,715	5,208	810	302	578	90
>0.8 and ≤0.9	2,529	4,850	754	282	540	84	2,529	4,850	754	282	540	84
>0.9 and ≤1	2,327	4,463	694	259	496	77	2,327	4,463	694	259	496	77
>1 and ≤2	3,852	7,389	1,149	429	823	128	3,852	7,389	1,149	429	823	128
>2 and ≤3	4,788	9,183	1,428	529	1,015	158	239	459	71	26	51	8
>3 and ≤4	5,284	10,136	1,576	585	1,123	175	264	507	79	29	56	9
>4 and ≤5	5,461	10,480	1,629	612	1,173	182	273	524	81	31	59	9
Total	44,669	85,686	13,322	4,,964	9,521	1480	29,913	57,376	8,921	3,324	6,376	991

NMED Exhibit 78 - 0005

Table 4. Nationwide Baseline Emissions and Controlled Emissions for Area Sources Reducing Benzene Emissions to 1 tpy (Control Scenario 2)

Throughput category (MMscf/d)	Nationwide						Emissions Reduced to Achieve ≤1 tpy Benzene					
	No Flash Tank			Flash Tank			No Flash Tank			Flash Tank		
	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP Emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
≤ 0.1	1,272	2,440	379	141	271	42	1,272	2,440	379	141	271	42
>0.1and≤0.2	2,107	4,041	628	234	449	70	2,107	4,041	628	234	449	70
>0.2and≤0.3	2,617	5,019	782	291	557	87	2,617	5,019	782	291	557	87
>0.3and≤0.4	2,889	5,541	861	321	615	96	2,889	5,541	861	321	615	96
>0.4and≤0.5	2,990	5,735	891	332	636	99	2,990	5,735	891	332	636	99
>0.5and≤0.6	2,971	5,698	886	330	632	98	2,971	5,698	886	330	632	98
>0.6and≤0.7	2,869	5,504	856	319	611	95	2,869	5,504	856	319	611	95
>0.7and≤0.8	2,715	5,208	810	302	578	90	2,715	5,208	810	302	578	90
>0.8and≤0.9	2,529	4,850	754	282	540	84	2,529	4,850	754	282	540	84
>0.9and≤1	2,327	4,463	694	259	496	77	2,327	4,463	694	259	496	77
>1and≤2	3,852	7,389	1,149	429	823	128	3,852	7,389	1,149	429	823	128
>2and≤3	4,788	9,183	1,428	529	1,015	158	2,669	5,120	796	295	566	88
>3and≤4	5,284	10,136	1,576	585	1,123	175	2,210	4,239	659	245	470	73
>4and≤5	5,461	10,480	1,629	612	1,173	182	1,827	3,506	545	205	392	61
Total	44,669	85,686	13,322	4,964	9,521	1,480	35,842	68,751	10,690	3,982	7,638	1,187

NMED Exhibit 78 - 0006

Table 5. Emission Reductions

Pollutant	Control Scenario 1	Control Scenario 2
HAP	16,396	9,809
VOC	31,455	18,817
Benzene	4,890	2,925

[1] 95-percent Control Emission Reduction.
[2] Reduce benzene emissions to 1 tpy.

NMED Exhibit 78 - 0007

SECONDARY ENVIRONMENTAL IMPACTS

Although the intent of the area source standards is to reduce HAP emissions, the application of control technologies can lead to other secondary environmental impacts. These secondary impacts can have a positive environmental impact, such as the reduction of VOC emissions, or a negative impact. Negative impacts may result from air pollutants emitted as a result of combustion sources (e.g., flares) or generation of a solid or liquid waste stream. The secondary impacts on air pollution and water and solid waste are discussed in this section.

Air Pollution

The primary method of HAP control from area source TEG dehydration units is the installation of a condenser and, if not present, a gas condensate glycol separator (GCG separator or flash tank). The secondary air pollution impacts associated with the application of this type of control are the decreased VOC emissions resulting from capture and control of HAP emissions.

Other secondary environmental impacts are those associated with the operation of certain air emission control devices, (i.e., flares). If a facility does not have the ability to handle the collected vapor for use as a fuel or recycle the collected vapor back into the process. In such cases, the collected vapors may be directed to an on-site flare. EPA estimated that 10 percent of the facilities would direct all collected vapors to an on-site flare.[3] The adverse secondary air impacts resulting from the use of a flare would be minimal in comparison to the primary HAP reduction benefits from implementing the proposed control options for area sources. Table 6 presents the secondary air impacts due to the use of flares for area sources.

Water and Solid Waste Impacts

The water impacts associated the installation of a condenser system for the TEG dehydration unit reboiler vent would be minimal. The condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.[4]

There is no solid waste generated from the control of HAP emissions using a condenser. Therefore, we do not anticipate any adverse solid waste impacts from the implementation of the area source standards.

[3]Reference 2, page 5-2.

[4]Reference 2, page 5-6.

NMED Exhibit 78 - 0008

Table 6. Secondary Air Pollutant Impacts Due to the Use of a Flare for Area Sources in the Oil and Natural Gas Production Source Category

Pollutant	Estimated Emissions per Flare (lb/yr)[a]	Estimated Number of Units Installing a Flare	Nationwide Emissions (tpy)
SO_X	2	222	<1
NO_X	106	222	12
CO	22	222	2

[a]Reference 2, page 5-7.

NMED Exhibit 78 - 0009

ENERGY IMPACTS

Energy impacts are those energy requirements associated with the operation of emission control devices. There would be no national energy demand increase from the operation of any of the control options analyzed under the proposed oil and natural gas production standards for area sources. The proposed area source standards encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate, that can be used on-site as fuel or reprocessed, within the production process, for sale. Thus, the proposed standards have a positive impact associated with the recovery of non-renewable energy resources.

COST IMPACTS

The cost impacts due to the application of control devices to meet the proposed area source standards include the cost of the control equipment that must be purchased, along with the cost of the installation of that control equipment. There are also costs for the operation and maintenance of the equipment. Finally, there are costs associated with the required monitoring, inspection, recordkeeping, and reporting (MIRR). This section presents the estimated costs associated with compliance with the area source standards. These cost estimates apply to both control scenarios.

Cost estimates for condensers were developed for the 1998 proposal and are documented in the Background Information Document (BID).[5] The original cost estimates were based on 1993 cost data. Therefore, these estimates were revised to reflect 2004 prices. The following tables present these revised cost estimates. Equipment costs were updated to represent 2004 prices using the Chemical Engineering[6] cost index. In addition, labor rates were updated to 2004 prices using information from the Bureau of Labor Statistics.[7,8] Table 7 presents the updated capital costs for installing a condenser on a TEG dehydration unit that does not have existing flash tanks and must install a flash tank to comply with the area source standards. Table 8 presents a summary of the updated capital costs for installing a condenser on a TEG dehydration units that are equipped with a flash tank. Table 9 presents the updated annual cost for condensers and Table 10 presents the costs associated with MIRR. Finally, Table 11 presents the nationwide costs for the oil and natural gas production industry.

[5]Reference 2, Chapter 6.

[6]Chemical Engineering. http://www.che.com. August 2004. Economic Indicators.

[7]Bureau of Labor Statistics. http://www.bls.gov/ncs/ect/home.htm. Employer Costs for Employee Compensation - March 2004. Table 11.

[8]Bureau of Labor Statistics. http://www.bls.gov/ces/ The Employment Situation. Table B-3Employer Costs for Employee Compensation - March 2004. Table 11.

Table 7. Updated Condenser Capital Costs for TEG Dehydration Units without Existing Flash Tanks

Equipment	Description	Size	Factor	Jul-93 Cost	Apr-04 Cost
Condenser	Condenser, piping to control device	All	Reference 9	$6,800	$8,598
Condensate storage vessel	Fixed-roof tank	50 gal	2.72 (Vtank) + 1,960 Reference 10	$2,210	$2,794
Flash tank	Low pressure separator	125 psig	Reference 11	$1,750	$2,213
Purchased equipment cost (PEC)				$10,760	$13,606
Enhanced monitoring equipment (EM)			0.10(PEC)	$1,076	$1,361
Total capital investment for a new unit (TCIN)			PEC + EM	**$11,840**	**$14,970**
Total capital investment for an existing unit (TCIE) [a]			1.15(TCIN)	**$13,620**	**$17,220**

a - Total capital investment for an existing unit accounts for a retrofit factor of 1.15.

Notes

All dollar amounts are in July 1993 dollars and scaled to 2004 costs using the following cost indeces

July 1993 cost index = 394.4

Apr 2004 Cost Index = 498.7

Direct and indirect costs are included in the condenser cost.

The estimated cost for a flash tank has been added to the capital cost.

[9]Rule 71.5, Glycol Dehydrators (Draft Staff Report). Executive Summary. Ventura County Air Pollution Control District, California. August 8, 1994.

[10]OAQPS Control Cost Manual: Fourth Edition (EPA 450/3-90-006, January 1990). U.S. Environmental Protection Agency. Research Triangle Park, NC.

[11]BTEX Emissions from Gas/Glycol Dehydrators: Air Quality Case Histories. Alan S. Owens. Proceedings of the 1994 GRI Glycol Dehydrator/Gas Processing Air Toxics Conference. Gas Research Institute. Chicago, IL. June 1994.

NMED Exhibit 78 - 0011

Table 8. Updated Condenser Capital Costs for TEG Dehydration Units with Existing Flash Tanks

Equipment	Description	Size	Factor	Jul-93 Cost	Apr-04 Cost
Condenser	Condenser, piping to control device	All	Reference 9	$6,800	$8,598.28
Condensate storage vessel	Fixed-roof tank	50 gal	2.72 (Vtank) + 1,960 Reference 10	$2,210	$2,794.44
Purchased equipment cost (PEC)				$9,010	$11,393
Enhanced monitoring equipment (EM)			0.10(PEC)	$901	$1,139
Total capital investment for a new unit (TCIN)			PEC + EM	**$9,910**	**$12,530**
Total capital investment for an existing unit (TCIE) [a]			1.15(TCIN)	**$11,400**	**$14,410**

a - Total capital investment for an existing unit accounts for a retrofit factor of 1.15.

Notes

All dollar amounts are in July 1993 dollars and scaled to 2004 costs using the following cost indeces

July 1993 cost index = 394.4

Apr 2004 Cost Index = 498.7

Direct and indirect costs are included in the condenser cost.

These model plants already have flash tanks.

NMED Exhibit 78 - 0012

Table 9. Condenser Annual Costs for TEG Dehydration Units

		TEG-A		TEG-A'	
Direct Annual Costs (DAC)					
Operating labor	130 hours/yr x $24.24/hr (Reference 13)	$3,151		$3,151	
Supervising labor	0.15 x Operating labor	473		473	
Operating materials	None required	0		0	
Maintenance					
Labor	130 hours/yr x $26.63/hr	3,462	26.627273	3,462	26.627273
Material	0.50 x Maintenance labor	1,731		1,731	
Utilities	None required	0	$8,816	0	$8,816
Indirect Annual Costs (IAC)					
Overhead	0.60 x Total labor plus Maintenance materials	$4,251		$4,251	
Administrative	0.02 x TCIE	344		288	
Property tax	0.01 x TCIE	172		144	
Insurance	0.01 x TCIE	172	$4,940	144	$4,828
Capital recovery (a)	0.1098 x TCIE	1,891		1,582	
Recovery credits (b)					
Condensate	Barrels/yr x $/barrel(c)	($141)		($141)	
Total Net Annual Cost (DAC + IAC)		$15,500		$15,100	

a - Capital recovery is based on equipment life of 15 years and an interest rate of 7%.

b - Numbers in parentheses reflect a savings.

c- $/barrel is the average US crude price (Reference 12) 38.54

All dollar amounts are in July 1993 dollars and scaled to 2004 costs using the following cost indeces
July 1993 cost index = 394.4
Apr 2004 Cost Index = 498.7

TEG-A' has a flash tank. TEG-A does not and a flash tank has been added to the capital cost.
It is assumed that all new sources will have flash tanks.

[12]Oil and Gas Journal Online. September 3, 2004. http://ogj.pennnet.com/industrystats/industrystats.cfm?Section=Stats

[13]Bureau of Labor Statistics (http://www.bls.gov/news.release/pdf/empsit.pdf) Table B-3, June 2004

NMED Exhibit 78 - 0013

Table 10. Annual MIRR Costs per Glycol Dehydration Unit

Activity	Technical hours per activity (A)	Number of activities per year (B)	Activity cost parameters Technical hours per year (C)	Management hours per activity (D)	Clerical hours per activity (E)	Total annual costs in $ per year (F)
Read rule and instructions	1.5	2	3	0.15	0.3	$ 137.88
Plan activities	3	1	3	0.15	0.3	$ 137.88
Training	1	1	1	0.05	0.1	$ 45.96
Testing/Development	20	1	20	1	2	$ 919.22
Monitoring/Inspection	0.1	52	5.2	0.26	0.52	$ 239.00
Process/Review	1.5	1	1.5	0.08	0.15	$ 69.25
Complete reports	5	1	5	0.25	0.5	$ 229.80
Record/Report	0.5	6	3	0.15	0.3	$ 137.88
Store/Maintain data	0.5	12	6	0.3	0.6	$ 275.76
Totals[a]			47.7	2.39	4.77	$ 2,192.64

Activity cost parameters

C = A x B
D = 0.05 x C
E = 0.10 x C
F = ($tech x C) + ($mgmt x D) + ($clerical x E)

a - Total hours are rounded to nearest hour and total dollars rounded to nearest $100.

Technical Labor Hourly Rate = 39.75
Management Labor Hourly Rate = 62.39
Clerical Labor Hourly Rate = 30.92
(Reference 14. All labor rates are multiplied by 1.5 to account for overhead)

[14]Bureau of Labor Statistics (http://www.bls.gov/news.release/pdf/ecec.pdf) Table 11. March 2004

NMED Exhibit 78 - 0014

Table 11. Nationwide Cost Impacts for Area Sources

	National Revised Costs	
	TEG-A	**TEG-A'**
Estimated Number of Impacted Units	2,000	222
Capital Costs	17,220	14,410
Annualized Capital Costs	1,891	1,582
O&M	8,816	8,816
Other Annual Costs (Admin., taxes, ins.)	4,940	4,828
Product Recovery	(141)	(141)
MIRR (c)	2,193	2,193
Cost Impact Summary for one Model Unit		
Total Capital Investment	17,220	14,410
Total Annual Cost	17,699	17,278
Nationwide Impacts		
Total Capital Investment	34,440,000	3,199,020
Total Annual Cost	35,397,951	3,835,724
	39,233,675	

a- Costs for the proposed rule are in July 1993 dollars

b- Revised costs are in April 2004 dollars

c- Labor cost for MIRR was updated based on March 2004 data f

REGULATORY ACTION LEVELS

In the preamble to the proposed area source standard (63 FR 6288), four regulatory alternatives were evaluated. Each regulatory alternative was characterized in terms of an action level, above which HAP emissions must be controlled. Action levels were expressed as the actual annual average flow rate of natural gas to the TEG dehydration unit (MMscf/d). For the proposed amendments, four similar action levels were evaluated for Control Scenarios 1 and 2 (95-percent control and 1-tpy benzene emissions, respectively). Table 12 presents the regulatory action levels for Control Scenario 1 (reduce emissions by 95 percent). Table 13 presents the regulatory action levels for Control Scenario 2 (control emissions so that benzene emissions are less than 1 tpy).

Tables 12 and 13 also present the cost effectiveness of each regulatory action level as well as the incremental cost effectiveness. As shown in Table 12, the incremental cost effectiveness between the 3-MMscf/d action level and the 2-MMscf/d is approximately $4,600 per ton for sources that would apply 95 percent control (Control Scenario 1). However, when considering the incremental cost effectiveness between the same to action levels for Control Scenario 2 (reducing benzene emissions to less than 1 tpy), the value is approximately $27,000 per ton. Since it is more likely that sources will opt for Control Scenario 2, which is less stringent than Control Scenario 1, the 3-MMScf/d regulatory action level is appropriate.

NMED Exhibit 78 - 0016

Table 12. Regulatory Action Levels for Area Source Glycol Dehydration Units - Control Scenario 1[1]

Size-Based Action Level (MMSCF/D)	Number of Units Impacted	HAP Reduction (1,000 tpy)	Total Capital Costs ($million)	Annual Costs ($million)	MIRR Costs ($million)	Total Annual Costs ($million)	Cost Effectiveness ($/ton HAP)	Incremental Cost Effectiveness ($/ton HAP)
4	1,338	11.35	22.7	20.7	2.9	23.6	2,082	--
3	2,222	16.40	37.6	34.4	4.9	39.2	2,392	3,089
2	3,289	20.46	55.7	50.9	7.2	58.1	2,838	4,634
0.3	25,180	43.59	426.5	389.3	55.2	444.5	10,198	16,713

[1] Control Scenario 1 - Reduce emissions by 95 percent.

Table 13. Regulatory Action Levels for Area Source Glycol Dehydration Units - Control Scenario 2[1]

Size-Based Action Level (MMSCF/D)	Number of Units Impacted	HAP Reduction (1,000 tpy)	Total Capital Costs ($million)	Annual Costs ($million)	MIRR Costs ($million)	Total Annual Costs ($million)	Cost Effectiveness ($/ton HAP)	Incremental Cost Effectiveness ($/ton HAP)
4	1,338	7.46	22.7	20.7	2.9	23.6	3,168	--
3	2,222	9.81	37.6	34.4	4.9	39.2	3,999	6,633
2	3,289	10.51	55.7	50.9	7.2	58.1	5,525	26,896
0.3	3,289	10.51	55.7	50.9	7.2	58.1	5,525	--

[1] Control Scenario 2 - Units with benzene emissions greater than or equal to 1 tpy of benzene will reduce emissions such that benzene emissions are less than 1 tpy.

ATTACHMENT A

GRI-GLYCalc (Version 4.0)© Input Summary Files

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0259	0.622	0.1135
Ethane	0.0095	0.229	0.0418
Propane	0.0059	0.142	0.0258
n-Butane	0.0137	0.329	0.0601
n-Pentane	0.0191	0.458	0.0836
n-Hexane	0.0016	0.039	0.0071
Other Hexanes	0.0025	0.059	0.0108
Heptanes	0.0009	0.021	0.0038
2,2,4-Trimethylpentane	0.0008	0.020	0.0037
Benzene	0.0136	0.328	0.0598
Toluene	0.0125	0.299	0.0546
Ethylbenzene	0.0020	0.049	0.0090
Xylenes	0.0151	0.363	0.0663
Total Emissions	0.1233	2.958	0.5399
Total Hydrocarbon Emissions	0.1233	2.958	0.5399
Total VOC Emissions	0.0878	2.107	0.3846
Total HAP Emissions	0.0458	1.099	0.2005
Total BTEX Emissions	0.0433	1.039	0.1897

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.1000 MMSCF/day
Glycol Losses with Dry Gas: 0.0006 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	2.37e-001
Carbon Dioxide	9.99e-001	4.83e+000
Methane	8.99e+001	1.59e+002
Ethane	5.29e+000	1.75e+001
Propane	1.30e+000	6.30e+000
n-Butane	1.20e+000	7.66e+000
n-Pentane	9.99e-001	7.93e+000
n-Hexane	4.19e-002	3.98e-001
Other Hexanes	8.39e-002	7.95e-001
Heptanes	9.99e-003	1.10e-001
2,2,4-Trimethylpentane	2.00e-002	2.51e-001
Benzene	1.04e-002	8.92e-002
Toluene	5.59e-003	5.67e-002
Ethylbenzene	5.99e-004	7.00e-003
Xylenes	3.40e-003	3.97e-002
Total Components	100.00	2.05e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	1.21e-002
Carbon Dioxide	9.98e-001	4.82e+000
Methane	9.00e+001	1.59e+002
Ethane	5.30e+000	1.75e+001
Propane	1.30e+000	6.29e+000
n-Butane	1.20e+000	7.65e+000
n-Pentane	9.98e-001	7.91e+000
n-Hexane	4.18e-002	3.96e-001
Other Hexanes	8.38e-002	7.93e-001
Heptanes	9.92e-003	1.09e-001
2,2,4-Trimethylpentane	1.99e-002	2.50e-001
Benzene	8.81e-003	7.56e-002
Toluene	4.37e-003	4.42e-002
Ethylbenzene	4.25e-004	4.95e-003
Xylenes	2.10e-003	2.45e-002
Total Components	100.00	2.04e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 2.04e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	1.13e+001
Water	1.50e+000	1.72e-001
Carbon Dioxide	9.88e-012	1.13e-012
Methane	7.59e-018	8.70e-019
Ethane	3.93e-008	4.51e-009
Propane	2.09e-009	2.40e-010
n-Butane	2.97e-009	3.40e-010
n-Pentane	8.36e-004	9.59e-005
n-Hexane	7.15e-005	8.20e-006
Other Hexanes	2.17e-004	2.49e-005
Heptanes	3.78e-005	4.34e-006
2,2,4-Trimethylpentane	1.12e-004	1.28e-005
Benzene	6.26e-003	7.18e-004
Toluene	9.33e-003	1.07e-003
Ethylbenzene	2.07e-003	2.37e-004
Xylenes	1.96e-002	2.24e-003
Total Components	100.00	1.15e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.11e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	1.13e+001
Water	3.36e+000	3.97e-001
Carbon Dioxide	9.58e-002	1.13e-002
Methane	2.19e-001	2.59e-002
Ethane	8.07e-002	9.55e-003
Propane	4.99e-002	5.90e-003
n-Butane	1.16e-001	1.37e-002
n-Pentane	1.62e-001	1.92e-002
n-Hexane	1.39e-002	1.64e-003
Other Hexanes	2.11e-002	2.49e-003
Heptanes	7.34e-003	8.68e-004
2,2,4-Trimethylpentane	7.23e-003	8.56e-004
Benzene	1.21e-001	1.44e-002
Toluene	1.15e-001	1.35e-002
Ethylbenzene	1.93e-002	2.28e-003
Xylenes	1.47e-001	1.74e-002
Total Components	100.00	1.18e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 6.01e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	2.25e-001
Carbon Dioxide	1.63e+000	1.13e-002
Methane	1.02e+001	2.59e-002
Ethane	2.00e+000	9.55e-003
Propane	8.44e-001	5.90e-003
n-Butane	1.49e+000	1.37e-002
n-Pentane	1.67e+000	1.91e-002
n-Hexane	1.20e-001	1.63e-003
Other Hexanes	1.81e-001	2.47e-003
Heptanes	5.44e-002	8.64e-004
2,2,4-Trimethylpentane	4.66e-002	8.43e-004
Benzene	1.10e+000	1.36e-002
Toluene	8.55e-001	1.25e-002
Ethylbenzene	1.22e-001	2.04e-003
Xylenes	9.00e-001	1.51e-002
Total Components	100.00	3.59e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.1 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0011	0.027	0.0049
Ethane	0.0012	0.029	0.0053
Propane	0.0013	0.032	0.0059
n-Butane	0.0048	0.114	0.0209
n-Pentane	0.0079	0.190	0.0346
n-Hexane	0.0009	0.021	0.0039
Other Hexanes	0.0012	0.029	0.0052
Heptanes	0.0006	0.014	0.0026
2,2,4-Trimethylpentane	0.0005	0.011	0.0020
Benzene	0.0132	0.317	0.0578
Toluene	0.0122	0.292	0.0534
Ethylbenzene	0.0020	0.048	0.0088
Xylenes	0.0150	0.359	0.0656
Total Emissions	0.0618	1.484	0.2709

Total Hydrocarbon Emissions	0.0618	1.484	0.2709
Total VOC Emissions	0.0595	1.429	0.2607
Total HAP Emissions	0.0437	1.049	0.1914
Total BTEX Emissions	0.0424	1.017	0.1855

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0248	0.595	0.1086
Ethane	0.0083	0.200	0.0365
Propane	0.0045	0.109	0.0199
n-Butane	0.0089	0.215	0.0392
n-Pentane	0.0112	0.268	0.0489
n-Hexane	0.0007	0.018	0.0033
Other Hexanes	0.0013	0.031	0.0056
Heptanes	0.0003	0.006	0.0012

2,2,4-Trimethylpentane	0.0004	0.009	0.0017
Benzene	0.0005	0.011	0.0020
Toluene	0.0003	0.007	0.0013
Ethylbenzene	<0.0001	0.001	0.0001
Xylenes	0.0002	0.004	0.0007
Total Emissions	0.0614	1.474	0.2690

Total Hydrocarbon Emissions	0.0614	1.474	0.2690
Total VOC Emissions	0.0283	0.679	0.1239
Total HAP Emissions	0.0021	0.050	0.0091
Total BTEX Emissions	0.0009	0.023	0.0041

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages:	1.25
Calculated Dry Gas Dew Point:	2.90 lbs. H2O/MMSCF
Temperature:	90.0 deg. F
Pressure:	700.0 psig
Dry Gas Flow Rate:	0.1000 MMSCF/day
Glycol Losses with Dry Gas:	0.0006 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	2.37e-001
Carbon Dioxide	9.99e-001	4.83e+000
Methane	8.99e+001	1.59e+002
Ethane	5.29e+000	1.75e+001
Propane	1.30e+000	6.30e+000
n-Butane	1.20e+000	7.66e+000
n-Pentane	9.99e-001	7.93e+000
n-Hexane	4.19e-002	3.98e-001
Other Hexanes	8.39e-002	7.95e-001
Heptanes	9.99e-003	1.10e-001
2,2,4-Trimethylpentane	2.00e-002	2.51e-001
Benzene	1.04e-002	8.92e-002
Toluene	5.59e-003	5.67e-002
Ethylbenzene	5.99e-004	7.00e-003
Xylenes	3.40e-003	3.97e-002
Total Components	100.00	2.05e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.17e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	1.21e-002
Carbon Dioxide	9.98e-001	4.82e+000
Methane	9.00e+001	1.59e+002
Ethane	5.30e+000	1.75e+001
Propane	1.30e+000	6.29e+000
n-Butane	1.20e+000	7.65e+000
n-Pentane	9.98e-001	7.91e+000
n-Hexane	4.18e-002	3.96e-001
Other Hexanes	8.38e-002	7.93e-001
Heptanes	9.92e-003	1.09e-001
2,2,4-Trimethylpentane	1.99e-002	2.50e-001
Benzene	8.81e-003	7.56e-002
Toluene	4.37e-003	4.42e-002
Ethylbenzene	4.25e-004	4.95e-003
Xylenes	2.10e-003	2.45e-002
Total Components	100.00	2.04e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 2.04e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	1.13e+001
Water	1.50e+000	1.72e-001
Carbon Dioxide	9.88e-012	1.13e-012
Methane	7.59e-018	8.70e-019
Ethane	3.93e-008	4.51e-009
Propane	2.09e-009	2.40e-010
n-Butane	2.97e-009	3.40e-010
n-Pentane	8.36e-004	9.59e-005
n-Hexane	7.15e-005	8.20e-006
Other Hexanes	2.17e-004	2.49e-005
Heptanes	3.78e-005	4.34e-006
2,2,4-Trimethylpentane	1.12e-004	1.28e-005
Benzene	6.26e-003	7.18e-004
Toluene	9.33e-003	1.07e-003
Ethylbenzene	2.07e-003	2.37e-004
Xylenes	1.96e-002	2.24e-003
Total Components	100.00	1.15e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.11e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	1.13e+001
Water	3.36e+000	3.97e-001
Carbon Dioxide	9.58e-002	1.13e-002
Methane	2.19e-001	2.59e-002
Ethane	8.07e-002	9.55e-003
Propane	4.99e-002	5.90e-003
n-Butane	1.16e-001	1.37e-002
n-Pentane	1.62e-001	1.92e-002
n-Hexane	1.39e-002	1.64e-003
Other Hexanes	2.11e-002	2.49e-003
Heptanes	7.34e-003	8.68e-004
2,2,4-Trimethylpentane	7.23e-003	8.56e-004
Benzene	1.21e-001	1.44e-002
Toluene	1.15e-001	1.35e-002
Ethylbenzene	1.93e-002	2.28e-003
Xylenes	1.47e-001	1.74e-002
Total Components	100.00	1.18e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 9.40e-001 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	4.21e-004
Carbon Dioxide	7.28e+000	7.94e-003
Methane	6.23e+001	2.48e-002
Ethane	1.12e+001	8.34e-003
Propane	4.16e+000	4.55e-003
n-Butane	6.21e+000	8.95e-003
n-Pentane	6.25e+000	1.12e-002
n-Hexane	3.48e-001	7.44e-004
Other Hexanes	6.00e-001	1.28e-003
Heptanes	1.06e-001	2.63e-004
2,2,4-Trimethylpentane	1.36e-001	3.84e-004
Benzene	2.38e-001	4.61e-004
Toluene	1.28e-001	2.93e-004
Ethylbenzene	1.13e-002	2.98e-005
Xylenes	5.98e-002	1.57e-004
Total Components	100.00	6.98e-002

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 2.10e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	1.13e+001
Water	3.37e+000	3.96e-001
Carbon Dioxide	2.89e-002	3.40e-003
Methane	9.52e-003	1.12e-003
Ethane	1.03e-002	1.21e-003
Propane	1.15e-002	1.35e-003
n-Butane	4.06e-002	4.77e-003
n-Pentane	6.81e-002	8.00e-003
n-Hexane	7.63e-003	8.97e-004
Other Hexanes	1.03e-002	1.21e-003
Heptanes	5.14e-003	6.05e-004
2,2,4-Trimethylpentane	4.01e-003	4.72e-004
Benzene	1.18e-001	1.39e-002
Toluene	1.13e-001	1.33e-002
Ethylbenzene	1.91e-002	2.25e-003
Xylenes	1.46e-001	1.72e-002
Total Components	100.00	1.18e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 5.07e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	2.24e-001
Carbon Dioxide	5.78e-001	3.40e-003

Methane	5.23e-001	1.12e-003
Ethane	3.01e-001	1.21e-003
Propane	2.29e-001	1.35e-003
n-Butane	6.14e-001	4.77e-003
n-Pentane	8.20e-001	7.91e-003
n-Hexane	7.72e-002	8.88e-004
Other Hexanes	1.03e-001	1.19e-003
Heptanes	4.48e-002	6.00e-004
2,2,4-Trimethylpentane	3.01e-002	4.59e-004
Benzene	1.26e+000	1.32e-002
Toluene	9.89e-001	1.22e-002
Ethylbenzene	1.42e-001	2.01e-003
Xylenes	1.06e+000	1.50e-002
Total Components	100.00	2.90e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.1 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.1mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.1 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.1 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0518	1.243	0.2269
Ethane	0.0191	0.458	0.0836
Propane	0.0118	0.283	0.0517
n-Butane	0.0274	0.659	0.1202
n-Pentane	0.0382	0.916	0.1671
n-Hexane	0.0033	0.078	0.0143
Other Hexanes	0.0049	0.119	0.0216
Heptanes	0.0017	0.041	0.0076
2,2,4-Trimethylpentane	0.0017	0.040	0.0074
Benzene	0.0273	0.655	0.1196
Toluene	0.0249	0.599	0.1093
Ethylbenzene	0.0041	0.098	0.0179
Xylenes	0.0303	0.726	0.1326
Total Emissions	0.2465	5.916	1.0797
Total Hydrocarbon Emissions	0.2465	5.916	1.0797
Total VOC Emissions	0.1756	4.215	0.7692
Total HAP Emissions	0.0916	2.197	0.4010
Total BTEX Emissions	0.0866	2.078	0.3793

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.2000 MMSCF/day
Glycol Losses with Dry Gas: 0.0012 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.35e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	4.74e-001
Carbon Dioxide	9.99e-001	9.67e+000
Methane	8.99e+001	3.17e+002
Ethane	5.29e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.99e-001	1.59e+001
n-Hexane	4.19e-002	7.95e-001
Other Hexanes	8.39e-002	1.59e+000
Heptanes	9.99e-003	2.20e-001
2,2,4-Trimethylpentane	2.00e-002	5.02e-001
Benzene	1.04e-002	1.78e-001
Toluene	5.59e-003	1.13e-001
Ethylbenzene	5.99e-004	1.40e-002
Xylenes	3.40e-003	7.93e-002
Total Components	100.00	4.10e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.33e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	2.41e-002
Carbon Dioxide	9.98e-001	9.65e+000
Methane	9.00e+001	3.17e+002
Ethane	5.30e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.98e-001	1.58e+001
n-Hexane	4.18e-002	7.92e-001
Other Hexanes	8.38e-002	1.59e+000
Heptanes	9.92e-003	2.18e-001
2,2,4-Trimethylpentane	1.99e-002	5.00e-001
Benzene	8.81e-003	1.51e-001
Toluene	4.37e-003	8.84e-002
Ethylbenzene	4.25e-004	9.91e-003
Xylenes	2.10e-003	4.90e-002
Total Components	100.00	4.09e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 4.07e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	2.26e+001
Water	1.50e+000	3.44e-001
Carbon Dioxide	9.88e-012	2.27e-012
Methane	7.59e-018	1.74e-018
Ethane	3.93e-008	9.01e-009
Propane	2.09e-009	4.80e-010
n-Butane	2.97e-009	6.80e-010
n-Pentane	8.36e-004	1.92e-004
n-Hexane	7.15e-005	1.64e-005
Other Hexanes	2.17e-004	4.99e-005
Heptanes	3.78e-005	8.68e-006
2,2,4-Trimethylpentane	1.12e-004	2.57e-005
Benzene	6.26e-003	1.44e-003
Toluene	9.33e-003	2.14e-003
Ethylbenzene	2.07e-003	4.75e-004
Xylenes	1.96e-002	4.49e-003
Total Components	100.00	2.29e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.22e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	2.26e+001
Water	3.36e+000	7.94e-001
Carbon Dioxide	9.58e-002	2.27e-002
Methane	2.19e-001	5.18e-002
Ethane	8.07e-002	1.91e-002
Propane	4.99e-002	1.18e-002
n-Butane	1.16e-001	2.74e-002
n-Pentane	1.62e-001	3.83e-002
n-Hexane	1.39e-002	3.28e-003
Other Hexanes	2.11e-002	4.99e-003
Heptanes	7.34e-003	1.74e-003
2,2,4-Trimethylpentane	7.23e-003	1.71e-003
Benzene	1.21e-001	2.87e-002
Toluene	1.15e-001	2.71e-002
Ethylbenzene	1.93e-002	4.56e-003
Xylenes	1.47e-001	3.48e-002
Total Components	100.00	2.37e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.20e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	4.49e-001
Carbon Dioxide	1.63e+000	2.27e-002
Methane	1.02e+001	5.18e-002
Ethane	2.00e+000	1.91e-002
Propane	8.44e-001	1.18e-002
n-Butane	1.49e+000	2.74e-002
n-Pentane	1.67e+000	3.82e-002
n-Hexane	1.20e-001	3.26e-003
Other Hexanes	1.81e-001	4.94e-003
Heptanes	5.44e-002	1.73e-003
2,2,4-Trimethylpentane	4.66e-002	1.69e-003
Benzene	1.10e+000	2.73e-002
Toluene	8.55e-001	2.49e-002
Ethylbenzene	1.22e-001	4.09e-003
Xylenes	9.00e-001	3.03e-002
Total Components	100.00	7.19e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.2 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0022	0.054	0.0098
Ethane	0.0024	0.058	0.0106
Propane	0.0027	0.065	0.0118
n-Butane	0.0095	0.229	0.0418
n-Pentane	0.0158	0.380	0.0693
n-Hexane	0.0018	0.043	0.0078
Other Hexanes	0.0024	0.057	0.0104
Heptanes	0.0012	0.029	0.0053
2,2,4-Trimethylpentane	0.0009	0.022	0.0040
Benzene	0.0264	0.633	0.1155
Toluene	0.0244	0.585	0.1067
Ethylbenzene	0.0040	0.097	0.0176
Xylenes	0.0300	0.719	0.1312
Total Emissions	0.1237	2.969	0.5418

Total Hydrocarbon Emissions	0.1237	2.969	0.5418
Total VOC Emissions	0.1190	2.857	0.5214
Total HAP Emissions	0.0874	2.098	0.3829
Total BTEX Emissions	0.0847	2.033	0.3711

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0496	1.190	0.2171
Ethane	0.0167	0.400	0.0730
Propane	0.0091	0.218	0.0398
n-Butane	0.0179	0.430	0.0784
n-Pentane	0.0223	0.536	0.0979
n-Hexane	0.0015	0.036	0.0065
Other Hexanes	0.0026	0.062	0.0112
Heptanes	0.0005	0.013	0.0023

2,2,4-Trimethylpentane	0.0008	0.018	0.0034
Benzene	0.0009	0.022	0.0040
Toluene	0.0006	0.014	0.0026
Ethylbenzene	0.0001	0.001	0.0003
Xylenes	0.0003	0.008	0.0014
Total Emissions	0.1228	2.948	0.5379
Total Hydrocarbon Emissions	0.1228	2.948	0.5379
Total VOC Emissions	0.0566	1.358	0.2478
Total HAP Emissions	0.0041	0.099	0.0181
Total BTEX Emissions	0.0019	0.045	0.0083

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.2000 MMSCF/day
Glycol Losses with Dry Gas: 0.0012 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 8.35e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	4.74e-001
Carbon Dioxide	9.99e-001	9.67e+000
Methane	8.99e+001	3.17e+002
Ethane	5.29e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.99e-001	1.59e+001
n-Hexane	4.19e-002	7.95e-001
Other Hexanes	8.39e-002	1.59e+000
Heptanes	9.99e-003	2.20e-001
2,2,4-Trimethylpentane	2.00e-002	5.02e-001
Benzene	1.04e-002	1.78e-001
Toluene	5.59e-003	1.13e-001
Ethylbenzene	5.99e-004	1.40e-002
Xylenes	3.40e-003	7.93e-002
Total Components	100.00	4.10e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.33e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	2.41e-002
Carbon Dioxide	9.98e-001	9.65e+000
Methane	9.00e+001	3.17e+002
Ethane	5.30e+000	3.50e+001
Propane	1.30e+000	1.26e+001
n-Butane	1.20e+000	1.53e+001
n-Pentane	9.98e-001	1.58e+001
n-Hexane	4.18e-002	7.92e-001
Other Hexanes	8.38e-002	1.59e+000
Heptanes	9.92e-003	2.18e-001
2,2,4-Trimethylpentane	1.99e-002	5.00e-001
Benzene	8.81e-003	1.51e-001
Toluene	4.37e-003	8.84e-002
Ethylbenzene	4.25e-004	9.91e-003
Xylenes	2.10e-003	4.90e-002
Total Components	100.00	4.09e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 4.07e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	2.26e+001
Water	1.50e+000	3.44e-001
Carbon Dioxide	9.88e-012	2.27e-012
Methane	7.59e-018	1.74e-018
Ethane	3.93e-008	9.01e-009
Propane	2.09e-009	4.80e-010
n-Butane	2.97e-009	6.80e-010
n-Pentane	8.36e-004	1.92e-004
n-Hexane	7.15e-005	1.64e-005
Other Hexanes	2.17e-004	4.99e-005
Heptanes	3.78e-005	8.68e-006
2,2,4-Trimethylpentane	1.12e-004	2.57e-005
Benzene	6.26e-003	1.44e-003
Toluene	9.33e-003	2.14e-003
Ethylbenzene	2.07e-003	4.75e-004
Xylenes	1.96e-002	4.49e-003
Total Components	100.00	2.29e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 4.22e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	2.26e+001
Water	3.36e+000	7.94e-001
Carbon Dioxide	9.58e-002	2.27e-002
Methane	2.19e-001	5.18e-002
Ethane	8.07e-002	1.91e-002
Propane	4.99e-002	1.18e-002
n-Butane	1.16e-001	2.74e-002
n-Pentane	1.62e-001	3.83e-002
n-Hexane	1.39e-002	3.28e-003
Other Hexanes	2.11e-002	4.99e-003
Heptanes	7.34e-003	1.74e-003
2,2,4-Trimethylpentane	7.23e-003	1.71e-003
Benzene	1.21e-001	2.87e-002
Toluene	1.15e-001	2.71e-002
Ethylbenzene	1.93e-002	4.56e-003
Xylenes	1.47e-001	3.48e-002
Total Components	100.00	2.37e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 1.88e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	8.41e-004
Carbon Dioxide	7.28e+000	1.59e-002
Methane	6.23e+001	4.96e-002
Ethane	1.12e+001	1.67e-002
Propane	4.16e+000	9.10e-003
n-Butane	6.21e+000	1.79e-002
n-Pentane	6.25e+000	2.23e-002
n-Hexane	3.48e-001	1.49e-003
Other Hexanes	6.00e-001	2.56e-003
Heptanes	1.06e-001	5.27e-004
2,2,4-Trimethylpentane	1.36e-001	7.68e-004
Benzene	2.38e-001	9.23e-004
Toluene	1.28e-001	5.87e-004
Ethylbenzene	1.13e-002	5.95e-005
Xylenes	5.98e-002	3.15e-004
Total Components	100.00	1.40e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 4.19e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	2.26e+001
Water	3.37e+000	7.93e-001
Carbon Dioxide	2.89e-002	6.80e-003
Methane	9.52e-003	2.24e-003
Ethane	1.03e-002	2.41e-003
Propane	1.15e-002	2.70e-003
n-Butane	4.06e-002	9.54e-003
n-Pentane	6.81e-002	1.60e-002
n-Hexane	7.63e-003	1.79e-003
Other Hexanes	1.03e-002	2.43e-003
Heptanes	5.14e-003	1.21e-003
2,2,4-Trimethylpentane	4.01e-003	9.43e-004
Benzene	1.18e-001	2.78e-002
Toluene	1.13e-001	2.65e-002
Ethylbenzene	1.91e-002	4.50e-003
Xylenes	1.46e-001	3.44e-002
Total Components	100.00	2.35e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.01e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	4.49e-001
Carbon Dioxide	5.78e-001	6.80e-003

Methane	5.23e-001	2.24e-003
Ethane	3.01e-001	2.41e-003
Propane	2.29e-001	2.70e-003
n-Butane	6.14e-001	9.54e-003
n-Pentane	8.20e-001	1.58e-002
n-Hexane	7.72e-002	1.78e-003
Other Hexanes	1.03e-001	2.38e-003
Heptanes	4.48e-002	1.20e-003
2,2,4-Trimethylpentane	3.01e-002	9.18e-004
Benzene	1.26e+000	2.64e-002
Toluene	9.89e-001	2.44e-002
Ethylbenzene	1.42e-001	4.03e-003
Xylenes	1.06e+000	3.00e-002
Total Components	100.00	5.79e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.2 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.2mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.2 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.2 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0777	1.865	0.3404
Ethane	0.0286	0.687	0.1254
Propane	0.0177	0.425	0.0775
n-Butane	0.0412	0.988	0.1803
n-Pentane	0.0572	1.374	0.2507
n-Hexane	0.0049	0.117	0.0214
Other Hexanes	0.0074	0.178	0.0325
Heptanes	0.0026	0.062	0.0113
2,2,4-Trimethylpentane	0.0025	0.061	0.0111
Benzene	0.0409	0.983	0.1794
Toluene	0.0374	0.898	0.1639
Ethylbenzene	0.0061	0.147	0.0269
Xylenes	0.0454	1.090	0.1989
Total Emissions	0.3698	8.874	1.6196
Total Hydrocarbon Emissions	0.3698	8.874	1.6196
Total VOC Emissions	0.2634	6.322	1.1537
Total HAP Emissions	0.1373	3.296	0.6015
Total BTEX Emissions	0.1299	3.118	0.5690

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.3000 MMSCF/day
Glycol Losses with Dry Gas: 0.0018 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e-001
Carbon Dioxide	9.99e-001	1.45e+001
Methane	8.99e+001	4.76e+002
Ethane	5.29e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.30e+001
n-Pentane	9.99e-001	2.38e+001
n-Hexane	4.19e-002	1.19e+000
Other Hexanes	8.39e-002	2.39e+000
Heptanes	9.99e-003	3.30e-001
2,2,4-Trimethylpentane	2.00e-002	7.53e-001
Benzene	1.04e-002	2.68e-001
Toluene	5.59e-003	1.70e-001
Ethylbenzene	5.99e-004	2.10e-002
Xylenes	3.40e-003	1.19e-001
Total Components	100.00	6.14e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	3.62e-002
Carbon Dioxide	9.98e-001	1.45e+001
Methane	9.00e+001	4.76e+002
Ethane	5.30e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.29e+001
n-Pentane	9.98e-001	2.37e+001
n-Hexane	4.18e-002	1.19e+000
Other Hexanes	8.38e-002	2.38e+000
Heptanes	9.92e-003	3.28e-001
2,2,4-Trimethylpentane	1.99e-002	7.50e-001
Benzene	8.81e-003	2.27e-001
Toluene	4.37e-003	1.33e-001
Ethylbenzene	4.25e-004	1.49e-002
Xylenes	2.10e-003	7.35e-002
Total Components	100.00	6.13e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 6.11e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	3.39e+001
Water	1.50e+000	5.16e-001
Carbon Dioxide	9.88e-012	3.40e-012
Methane	7.59e-018	2.61e-018
Ethane	3.93e-008	1.35e-008
Propane	2.09e-009	7.20e-010
n-Butane	2.97e-009	1.02e-009
n-Pentane	8.36e-004	2.88e-004
n-Hexane	7.15e-005	2.46e-005
Other Hexanes	2.17e-004	7.48e-005
Heptanes	3.78e-005	1.30e-005
2,2,4-Trimethylpentane	1.12e-004	3.85e-005
Benzene	6.26e-003	2.16e-003
Toluene	9.33e-003	3.21e-003
Ethylbenzene	2.07e-003	7.12e-004
Xylenes	1.96e-002	6.73e-003
Total Components	100.00	3.44e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 6.33e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	3.39e+001
Water	3.36e+000	1.19e+000
Carbon Dioxide	9.58e-002	3.40e-002
Methane	2.19e-001	7.77e-002
Ethane	8.07e-002	2.86e-002
Propane	4.99e-002	1.77e-002
n-Butane	1.16e-001	4.12e-002
n-Pentane	1.62e-001	5.75e-002
n-Hexane	1.39e-002	4.92e-003
Other Hexanes	2.11e-002	7.48e-003
Heptanes	7.34e-003	2.60e-003
2,2,4-Trimethylpentane	7.23e-003	2.57e-003
Benzene	1.21e-001	4.31e-002
Toluene	1.15e-001	4.06e-002
Ethylbenzene	1.93e-002	6.84e-003
Xylenes	1.47e-001	5.21e-002
Total Components	100.00	3.55e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.80e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	6.74e-001
Carbon Dioxide	1.63e+000	3.40e-002
Methane	1.02e+001	7.77e-002
Ethane	2.00e+000	2.86e-002
Propane	8.44e-001	1.77e-002
n-Butane	1.49e+000	4.12e-002
n-Pentane	1.67e+000	5.72e-002
n-Hexane	1.20e-001	4.90e-003
Other Hexanes	1.81e-001	7.41e-003
Heptanes	5.44e-002	2.59e-003
2,2,4-Trimethylpentane	4.66e-002	2.53e-003
Benzene	1.10e+000	4.09e-002
Toluene	8.55e-001	3.74e-002
Ethylbenzene	1.22e-001	6.13e-003
Xylenes	9.00e-001	4.54e-002
Total Components	100.00	1.08e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.3 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0034	0.081	0.0147
Ethane	0.0036	0.087	0.0159
Propane	0.0040	0.097	0.0177
n-Butane	0.0143	0.343	0.0627
n-Pentane	0.0237	0.569	0.1039
n-Hexane	0.0027	0.064	0.0117
Other Hexanes	0.0036	0.086	0.0156
Heptanes	0.0018	0.043	0.0079
2,2,4-Trimethylpentane	0.0014	0.033	0.0060
Benzene	0.0396	0.950	0.1733
Toluene	0.0365	0.877	0.1601
Ethylbenzene	0.0060	0.145	0.0265
Xylenes	0.0449	1.078	0.1968
Total Emissions	0.1855	4.453	0.8127

Total Hydrocarbon Emissions	0.1855	4.453	0.8127
Total VOC Emissions	0.1786	4.286	0.7821
Total HAP Emissions	0.1311	3.147	0.5743
Total BTEX Emissions	0.1271	3.050	0.5566

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0744	1.785	0.3257
Ethane	0.0250	0.600	0.1096
Propane	0.0136	0.327	0.0598
n-Butane	0.0268	0.644	0.1176
n-Pentane	0.0335	0.804	0.1468
n-Hexane	0.0022	0.054	0.0098
Other Hexanes	0.0038	0.092	0.0168
Heptanes	0.0008	0.019	0.0035

2,2,4-Trimethylpentane	0.0012	0.028	0.0050
Benzene	0.0014	0.033	0.0061
Toluene	0.0009	0.021	0.0039
Ethylbenzene	0.0001	0.002	0.0004
Xylenes	0.0005	0.011	0.0021
Total Emissions	0.1842	4.421	0.8069
Total Hydrocarbon Emissions	0.1842	4.421	0.8069
Total VOC Emissions	0.0848	2.036	0.3716
Total HAP Emissions	0.0062	0.149	0.0272
Total BTEX Emissions	0.0028	0.068	0.0124

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.3000 MMSCF/day
Glycol Losses with Dry Gas: 0.0018 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	7.10e-001
Carbon Dioxide	9.99e-001	1.45e+001
Methane	8.99e+001	4.76e+002
Ethane	5.29e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.30e+001
n-Pentane	9.99e-001	2.38e+001
n-Hexane	4.19e-002	1.19e+000
Other Hexanes	8.39e-002	2.39e+000
Heptanes	9.99e-003	3.30e-001
2,2,4-Trimethylpentane	2.00e-002	7.53e-001
Benzene	1.04e-002	2.68e-001
Toluene	5.59e-003	1.70e-001
Ethylbenzene	5.99e-004	2.10e-002
Xylenes	3.40e-003	1.19e-001
Total Components	100.00	6.14e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.25e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	3.62e-002
Carbon Dioxide	9.98e-001	1.45e+001
Methane	9.00e+001	4.76e+002
Ethane	5.30e+000	5.25e+001
Propane	1.30e+000	1.89e+001
n-Butane	1.20e+000	2.29e+001
n-Pentane	9.98e-001	2.37e+001
n-Hexane	4.18e-002	1.19e+000
Other Hexanes	8.38e-002	2.38e+000
Heptanes	9.92e-003	3.28e-001
2,2,4-Trimethylpentane	1.99e-002	7.50e-001
Benzene	8.81e-003	2.27e-001
Toluene	4.37e-003	1.33e-001
Ethylbenzene	4.25e-004	1.49e-002
Xylenes	2.10e-003	7.35e-002
Total Components	100.00	6.13e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 6.11e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	3.39e+001
Water	1.50e+000	5.16e-001
Carbon Dioxide	9.88e-012	3.40e-012
Methane	7.59e-018	2.61e-018
Ethane	3.93e-008	1.35e-008
Propane	2.09e-009	7.20e-010
n-Butane	2.97e-009	1.02e-009
n-Pentane	8.36e-004	2.88e-004
n-Hexane	7.15e-005	2.46e-005
Other Hexanes	2.17e-004	7.48e-005
Heptanes	3.78e-005	1.30e-005
2,2,4-Trimethylpentane	1.12e-004	3.85e-005
Benzene	6.26e-003	2.16e-003
Toluene	9.33e-003	3.21e-003
Ethylbenzene	2.07e-003	7.12e-004
Xylenes	1.96e-002	6.73e-003
Total Components	100.00	3.44e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 6.33e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	3.39e+001
Water	3.36e+000	1.19e+000
Carbon Dioxide	9.58e-002	3.40e-002
Methane	2.19e-001	7.77e-002
Ethane	8.07e-002	2.86e-002
Propane	4.99e-002	1.77e-002
n-Butane	1.16e-001	4.12e-002
n-Pentane	1.62e-001	5.75e-002
n-Hexane	1.39e-002	4.92e-003
Other Hexanes	2.11e-002	7.48e-003
Heptanes	7.34e-003	2.60e-003
2,2,4-Trimethylpentane	7.23e-003	2.57e-003
Benzene	1.21e-001	4.31e-002
Toluene	1.15e-001	4.06e-002
Ethylbenzene	1.93e-002	6.84e-003
Xylenes	1.47e-001	5.21e-002
Total Components	100.00	3.55e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 2.82e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	1.26e-003
Carbon Dioxide	7.28e+000	2.38e-002
Methane	6.23e+001	7.44e-002
Ethane	1.12e+001	2.50e-002
Propane	4.16e+000	1.36e-002
n-Butane	6.21e+000	2.68e-002
n-Pentane	6.25e+000	3.35e-002
n-Hexane	3.48e-001	2.23e-003
Other Hexanes	6.00e-001	3.85e-003
Heptanes	1.06e-001	7.90e-004
2,2,4-Trimethylpentane	1.36e-001	1.15e-003
Benzene	2.38e-001	1.38e-003
Toluene	1.28e-001	8.80e-004
Ethylbenzene	1.13e-002	8.93e-005
Xylenes	5.98e-002	4.72e-004
Total Components	100.00	2.09e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 6.29e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	3.39e+001
Water	3.37e+000	1.19e+000
Carbon Dioxide	2.89e-002	1.02e-002
Methane	9.52e-003	3.36e-003
Ethane	1.03e-002	3.62e-003
Propane	1.15e-002	4.05e-003
n-Butane	4.06e-002	1.43e-002
n-Pentane	6.81e-002	2.40e-002
n-Hexane	7.63e-003	2.69e-003
Other Hexanes	1.03e-002	3.64e-003
Heptanes	5.14e-003	1.81e-003
2,2,4-Trimethylpentane	4.01e-003	1.42e-003
Benzene	1.18e-001	4.17e-002
Toluene	1.13e-001	3.98e-002
Ethylbenzene	1.91e-002	6.75e-003
Xylenes	1.46e-001	5.17e-002
Total Components	100.00	3.53e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.52e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	6.73e-001
Carbon Dioxide	5.78e-001	1.02e-002

Methane	5.23e-001	3.36e-003
Ethane	3.01e-001	3.62e-003
Propane	2.29e-001	4.05e-003
n-Butane	6.14e-001	1.43e-002
n-Pentane	8.20e-001	2.37e-002
n-Hexane	7.72e-002	2.67e-003
Other Hexanes	1.03e-001	3.56e-003
Heptanes	4.48e-002	1.80e-003
2,2,4-Trimethylpentane	3.01e-002	1.38e-003
Benzene	1.26e+000	3.96e-002
Toluene	9.89e-001	3.65e-002
Ethylbenzene	1.42e-001	6.04e-003
Xylenes	1.06e+000	4.49e-002
Total Components	100.00	8.69e-001

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.3 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.3mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.3 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.3 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1036	2.487	0.4539
Ethane	0.0382	0.916	0.1672
Propane	0.0236	0.566	0.1033
n-Butane	0.0549	1.317	0.2404
n-Pentane	0.0763	1.831	0.3342
n-Hexane	0.0065	0.157	0.0286
Other Hexanes	0.0099	0.237	0.0433
Heptanes	0.0035	0.083	0.0151
2,2,4-Trimethylpentane	0.0034	0.081	0.0148
Benzene	0.0546	1.310	0.2391
Toluene	0.0499	1.198	0.2185
Ethylbenzene	0.0082	0.196	0.0358
Xylenes	0.0605	1.453	0.2652
Total Emissions	0.4930	11.832	2.1594
Total Hydrocarbon Emissions	0.4930	11.832	2.1594
Total VOC Emissions	0.3512	8.429	1.5383
Total HAP Emissions	0.1831	4.394	0.8020
Total BTEX Emissions	0.1732	4.157	0.7586

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.4000 MMSCF/day
Glycol Losses with Dry Gas: 0.0024 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	9.47e-001
Carbon Dioxide	9.99e-001	1.93e+001
Methane	8.99e+001	6.34e+002
Ethane	5.29e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.99e-001	3.17e+001
n-Hexane	4.19e-002	1.59e+000
Other Hexanes	8.39e-002	3.18e+000
Heptanes	9.99e-003	4.40e-001
2,2,4-Trimethylpentane	2.00e-002	1.00e+000
Benzene	1.04e-002	3.57e-001
Toluene	5.59e-003	2.27e-001
Ethylbenzene	5.99e-004	2.80e-002
Xylenes	3.40e-003	1.59e-001
Total Components	100.00	8.19e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	4.83e-002
Carbon Dioxide	9.98e-001	1.93e+001
Methane	9.00e+001	6.34e+002
Ethane	5.30e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.98e-001	3.16e+001
n-Hexane	4.18e-002	1.58e+000
Other Hexanes	8.38e-002	3.17e+000
Heptanes	9.92e-003	4.37e-001
2,2,4-Trimethylpentane	1.99e-002	1.00e+000
Benzene	8.81e-003	3.02e-001
Toluene	4.37e-003	1.77e-001
Ethylbenzene	4.25e-004	1.98e-002
Xylenes	2.10e-003	9.81e-002
Total Components	100.00	8.18e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 8.15e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	4.52e+001
Water	1.50e+000	6.88e-001
Carbon Dioxide	9.88e-012	4.53e-012
Methane	7.59e-018	3.48e-018
Ethane	3.93e-008	1.80e-008
Propane	2.09e-009	9.60e-010
n-Butane	2.97e-009	1.36e-009
n-Pentane	8.36e-004	3.83e-004
n-Hexane	7.15e-005	3.28e-005
Other Hexanes	2.17e-004	9.98e-005
Heptanes	3.78e-005	1.74e-005
2,2,4-Trimethylpentane	1.12e-004	5.13e-005
Benzene	6.26e-003	2.87e-003
Toluene	9.33e-003	4.28e-003
Ethylbenzene	2.07e-003	9.50e-004
Xylenes	1.96e-002	8.98e-003
Total Components	100.00	4.59e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.44e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	4.52e+001
Water	3.36e+000	1.59e+000
Carbon Dioxide	9.58e-002	4.53e-002
Methane	2.19e-001	1.04e-001
Ethane	8.07e-002	3.82e-002
Propane	4.99e-002	2.36e-002
n-Butane	1.16e-001	5.49e-002
n-Pentane	1.62e-001	7.67e-002
n-Hexane	1.39e-002	6.56e-003
Other Hexanes	2.11e-002	9.98e-003
Heptanes	7.34e-003	3.47e-003
2,2,4-Trimethylpentane	7.23e-003	3.42e-003
Benzene	1.21e-001	5.75e-002
Toluene	1.15e-001	5.42e-002
Ethylbenzene	1.93e-002	9.12e-003
Xylenes	1.47e-001	6.95e-002
Total Components	100.00	4.73e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.40e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	8.99e-001
Carbon Dioxide	1.63e+000	4.53e-002
Methane	1.02e+001	1.04e-001
Ethane	2.00e+000	3.82e-002
Propane	8.44e-001	2.36e-002
n-Butane	1.49e+000	5.49e-002
n-Pentane	1.67e+000	7.63e-002
n-Hexane	1.20e-001	6.53e-003
Other Hexanes	1.81e-001	9.88e-003
Heptanes	5.44e-002	3.45e-003
2,2,4-Trimethylpentane	4.66e-002	3.37e-003
Benzene	1.10e+000	5.46e-002
Toluene	8.55e-001	4.99e-002
Ethylbenzene	1.22e-001	8.17e-003
Xylenes	9.00e-001	6.05e-002
Total Components	100.00	1.44e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0045	0.108	0.0196
Ethane	0.0048	0.116	0.0212
Propane	0.0054	0.130	0.0237
n-Butane	0.0191	0.458	0.0836
n-Pentane	0.0316	0.759	0.1385
n-Hexane	0.0036	0.085	0.0156
Other Hexanes	0.0048	0.114	0.0208
Heptanes	0.0024	0.058	0.0105
2,2,4-Trimethylpentane	0.0018	0.044	0.0080
Benzene	0.0528	1.266	0.2311
Toluene	0.0487	1.169	0.2134
Ethylbenzene	0.0081	0.193	0.0353
Xylenes	0.0599	1.438	0.2624
Total Emissions	0.2474	5.938	1.0836
Total Hydrocarbon Emissions	0.2474	5.938	1.0836
Total VOC Emissions	0.2381	5.714	1.0428
Total HAP Emissions	0.1748	4.196	0.7657
Total BTEX Emissions	0.1694	4.067	0.7421

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0991	2.379	0.4342
Ethane	0.0334	0.801	0.1461
Propane	0.0182	0.437	0.0797
n-Butane	0.0358	0.859	0.1568
n-Pentane	0.0447	1.072	0.1957
n-Hexane	0.0030	0.071	0.0130
Other Hexanes	0.0051	0.123	0.0225
Heptanes	0.0011	0.025	0.0046

2,2,4-Trimethylpentane	0.0015	0.037	0.0067
Benzene	0.0018	0.044	0.0081
Toluene	0.0012	0.028	0.0051
Ethylbenzene	0.0001	0.003	0.0005
Xylenes	0.0006	0.015	0.0028
Total Emissions	0.2456	5.895	1.0758
Total Hydrocarbon Emissions	0.2456	5.895	1.0758
Total VOC Emissions	0.1131	2.715	0.4955
Total HAP Emissions	0.0083	0.199	0.0363
Total BTEX Emissions	0.0038	0.090	0.0165

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.4000 MMSCF/day
Glycol Losses with Dry Gas: 0.0024 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	9.47e-001
Carbon Dioxide	9.99e-001	1.93e+001
Methane	8.99e+001	6.34e+002
Ethane	5.29e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.99e-001	3.17e+001
n-Hexane	4.19e-002	1.59e+000
Other Hexanes	8.39e-002	3.18e+000
Heptanes	9.99e-003	4.40e-001
2,2,4-Trimethylpentane	2.00e-002	1.00e+000
Benzene	1.04e-002	3.57e-001
Toluene	5.59e-003	2.27e-001
Ethylbenzene	5.99e-004	2.80e-002
Xylenes	3.40e-003	1.59e-001
Total Components	100.00	8.19e+002

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.67e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	4.83e-002
Carbon Dioxide	9.98e-001	1.93e+001
Methane	9.00e+001	6.34e+002
Ethane	5.30e+000	7.00e+001
Propane	1.30e+000	2.52e+001
n-Butane	1.20e+000	3.06e+001
n-Pentane	9.98e-001	3.16e+001
n-Hexane	4.18e-002	1.58e+000
Other Hexanes	8.38e-002	3.17e+000
Heptanes	9.92e-003	4.37e-001
2,2,4-Trimethylpentane	1.99e-002	1.00e+000
Benzene	8.81e-003	3.02e-001
Toluene	4.37e-003	1.77e-001
Ethylbenzene	4.25e-004	1.98e-002
Xylenes	2.10e-003	9.81e-002
Total Components	100.00	8.18e+002

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 8.15e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	4.52e+001
Water	1.50e+000	6.88e-001
Carbon Dioxide	9.88e-012	4.53e-012
Methane	7.59e-018	3.48e-018
Ethane	3.93e-008	1.80e-008
Propane	2.09e-009	9.60e-010
n-Butane	2.97e-009	1.36e-009
n-Pentane	8.36e-004	3.83e-004
n-Hexane	7.15e-005	3.28e-005
Other Hexanes	2.17e-004	9.98e-005
Heptanes	3.78e-005	1.74e-005
2,2,4-Trimethylpentane	1.12e-004	5.13e-005
Benzene	6.26e-003	2.87e-003
Toluene	9.33e-003	4.28e-003
Ethylbenzene	2.07e-003	9.50e-004
Xylenes	1.96e-002	8.98e-003
Total Components	100.00	4.59e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 8.44e-002 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	4.52e+001
Water	3.36e+000	1.59e+000
Carbon Dioxide	9.58e-002	4.53e-002
Methane	2.19e-001	1.04e-001
Ethane	8.07e-002	3.82e-002
Propane	4.99e-002	2.36e-002
n-Butane	1.16e-001	5.49e-002
n-Pentane	1.62e-001	7.67e-002
n-Hexane	1.39e-002	6.56e-003
Other Hexanes	2.11e-002	9.98e-003
Heptanes	7.34e-003	3.47e-003
2,2,4-Trimethylpentane	7.23e-003	3.42e-003
Benzene	1.21e-001	5.75e-002
Toluene	1.15e-001	5.42e-002
Ethylbenzene	1.93e-002	9.12e-003
Xylenes	1.47e-001	6.95e-002
Total Components	100.00	4.73e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 3.76e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	1.68e-003
Carbon Dioxide	7.28e+000	3.17e-002
Methane	6.23e+001	9.91e-002
Ethane	1.12e+001	3.34e-002
Propane	4.16e+000	1.82e-002
n-Butane	6.21e+000	3.58e-002
n-Pentane	6.25e+000	4.47e-002
n-Hexane	3.48e-001	2.97e-003
Other Hexanes	6.00e-001	5.13e-003
Heptanes	1.06e-001	1.05e-003
2,2,4-Trimethylpentane	1.36e-001	1.54e-003
Benzene	2.38e-001	1.85e-003
Toluene	1.28e-001	1.17e-003
Ethylbenzene	1.13e-002	1.19e-004
Xylenes	5.98e-002	6.30e-004
Total Components	100.00	2.79e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 8.38e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	4.52e+001
Water	3.37e+000	1.59e+000
Carbon Dioxide	2.89e-002	1.36e-002
Methane	9.52e-003	4.48e-003
Ethane	1.03e-002	4.83e-003
Propane	1.15e-002	5.40e-003
n-Butane	4.06e-002	1.91e-002
n-Pentane	6.81e-002	3.20e-002
n-Hexane	7.63e-003	3.59e-003
Other Hexanes	1.03e-002	4.85e-003
Heptanes	5.14e-003	2.42e-003
2,2,4-Trimethylpentane	4.01e-003	1.89e-003
Benzene	1.18e-001	5.56e-002
Toluene	1.13e-001	5.30e-002
Ethylbenzene	1.91e-002	9.00e-003
Xylenes	1.46e-001	6.89e-002
Total Components	100.00	4.70e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.03e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	8.97e-001
Carbon Dioxide	5.78e-001	1.36e-002

Methane	5.23e-001	4.48e-003
Ethane	3.01e-001	4.83e-003
Propane	2.29e-001	5.40e-003
n-Butane	6.14e-001	1.91e-002
n-Pentane	8.20e-001	3.16e-002
n-Hexane	7.72e-002	3.55e-003
Other Hexanes	1.03e-001	4.75e-003
Heptanes	4.48e-002	2.40e-003
2,2,4-Trimethylpentane	3.01e-002	1.84e-003
Benzene	1.26e+000	5.28e-002
Toluene	9.89e-001	4.87e-002
Ethylbenzene	1.42e-001	8.06e-003
Xylenes	1.06e+000	5.99e-002
Total Components	100.00	1.16e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.4 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.4mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a 0.4 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1295	3.109	0.5673
Ethane	0.0477	1.146	0.2091
Propane	0.0295	0.708	0.1292
n-Butane	0.0686	1.646	0.3004
n-Pentane	0.0954	2.289	0.4178
n-Hexane	0.0082	0.196	0.0357
Other Hexanes	0.0123	0.296	0.0541
Heptanes	0.0043	0.104	0.0189
2,2,4-Trimethylpentane	0.0042	0.101	0.0185
Benzene	0.0682	1.638	0.2989
Toluene	0.0624	1.497	0.2732
Ethylbenzene	0.0102	0.245	0.0448
Xylenes	0.0757	1.816	0.3314
Total Emissions	0.6163	14.791	2.6993

Total Hydrocarbon Emissions	0.6163	14.791	2.6993
Total VOC Emissions	0.4390	10.536	1.9229
Total HAP Emissions	0.2289	5.493	1.0025
Total BTEX Emissions	0.2165	5.196	0.9483

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.5000 MMSCF/day
Glycol Losses with Dry Gas: 0.0030 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.09e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.18e+000
Carbon Dioxide	9.99e-001	2.42e+001
Methane	8.99e+001	7.93e+002
Ethane	5.29e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.83e+001
n-Pentane	9.99e-001	3.96e+001
n-Hexane	4.19e-002	1.99e+000
Other Hexanes	8.39e-002	3.98e+000
Heptanes	9.99e-003	5.50e-001
2,2,4-Trimethylpentane	2.00e-002	1.25e+000
Benzene	1.04e-002	4.46e-001
Toluene	5.59e-003	2.83e-001
Ethylbenzene	5.99e-004	3.50e-002
Xylenes	3.40e-003	1.98e-001
Total Components	100.00	1.02e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.08e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	6.03e-002
Carbon Dioxide	9.98e-001	2.41e+001
Methane	9.00e+001	7.93e+002
Ethane	5.30e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.82e+001
n-Pentane	9.98e-001	3.95e+001
n-Hexane	4.18e-002	1.98e+000
Other Hexanes	8.38e-002	3.96e+000
Heptanes	9.92e-003	5.46e-001
2,2,4-Trimethylpentane	1.99e-002	1.25e+000
Benzene	8.81e-003	3.78e-001
Toluene	4.37e-003	2.21e-001
Ethylbenzene	4.25e-004	2.48e-002
Xylenes	2.10e-003	1.23e-001
Total Components	100.00	1.02e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.02e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	5.65e+001
Water	1.50e+000	8.60e-001
Carbon Dioxide	9.88e-012	5.67e-012
Methane	7.59e-018	4.35e-018
Ethane	3.93e-008	2.25e-008
Propane	2.09e-009	1.20e-009
n-Butane	2.97e-009	1.70e-009
n-Pentane	8.36e-004	4.79e-004
n-Hexane	7.15e-005	4.10e-005
Other Hexanes	2.17e-004	1.25e-004
Heptanes	3.78e-005	2.17e-005
2,2,4-Trimethylpentane	1.12e-004	6.42e-005
Benzene	6.26e-003	3.59e-003
Toluene	9.33e-003	5.35e-003
Ethylbenzene	2.07e-003	1.19e-003
Xylenes	1.96e-002	1.12e-002
Total Components	100.00	5.74e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.06e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	5.65e+001
Water	3.36e+000	1.98e+000
Carbon Dioxide	9.58e-002	5.67e-002
Methane	2.19e-001	1.30e-001
Ethane	8.07e-002	4.77e-002
Propane	4.99e-002	2.95e-002
n-Butane	1.16e-001	6.86e-002
n-Pentane	1.62e-001	9.59e-002
n-Hexane	1.39e-002	8.20e-003
Other Hexanes	2.11e-002	1.25e-002
Heptanes	7.34e-003	4.34e-003
2,2,4-Trimethylpentane	7.23e-003	4.28e-003
Benzene	1.21e-001	7.18e-002
Toluene	1.15e-001	6.77e-002
Ethylbenzene	1.93e-002	1.14e-002
Xylenes	1.47e-001	8.69e-002
Total Components	100.00	5.91e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.00e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.12e+000
Carbon Dioxide	1.63e+000	5.67e-002
Methane	1.02e+001	1.30e-001
Ethane	2.00e+000	4.77e-002
Propane	8.44e-001	2.95e-002
n-Butane	1.49e+000	6.86e-002
n-Pentane	1.67e+000	9.54e-002
n-Hexane	1.20e-001	8.16e-003
Other Hexanes	1.81e-001	1.23e-002
Heptanes	5.44e-002	4.32e-003
2,2,4-Trimethylpentane	4.66e-002	4.21e-003
Benzene	1.10e+000	6.82e-002
Toluene	8.55e-001	6.24e-002
Ethylbenzene	1.22e-001	1.02e-002
Xylenes	9.00e-001	7.57e-002
Total Components	100.00	1.80e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.5 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0056	0.134	0.0245
Ethane	0.0060	0.145	0.0264
Propane	0.0067	0.162	0.0296
n-Butane	0.0239	0.572	0.1045
n-Pentane	0.0395	0.949	0.1732
n-Hexane	0.0044	0.107	0.0195
Other Hexanes	0.0059	0.143	0.0260
Heptanes	0.0030	0.072	0.0131
2,2,4-Trimethylpentane	0.0023	0.055	0.0100
Benzene	0.0659	1.583	0.2888
Toluene	0.0609	1.462	0.2668
Ethylbenzene	0.0101	0.242	0.0441
Xylenes	0.0749	1.797	0.3280
Total Emissions	0.3092	7.422	1.3545
Total Hydrocarbon Emissions	0.3092	7.422	1.3545
Total VOC Emissions	0.2976	7.143	1.3035
Total HAP Emissions	0.2185	5.245	0.9572
Total BTEX Emissions	0.2118	5.083	0.9277

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1239	2.974	0.5428
Ethane	0.0417	1.001	0.1826
Propane	0.0227	0.546	0.0996
n-Butane	0.0447	1.074	0.1960
n-Pentane	0.0559	1.340	0.2446
n-Hexane	0.0037	0.089	0.0163
Other Hexanes	0.0064	0.154	0.0281
Heptanes	0.0013	0.032	0.0058

2,2,4-Trimethylpentane	0.0019	0.046	0.0084
Benzene	0.0023	0.055	0.0101
Toluene	0.0015	0.035	0.0064
Ethylbenzene	0.0001	0.004	0.0007
Xylenes	0.0008	0.019	0.0034
Total Emissions	0.3070	7.369	1.3448
Total Hydrocarbon Emissions	0.3070	7.369	1.3448
Total VOC Emissions	0.1414	3.394	0.6194
Total HAP Emissions	0.0103	0.248	0.0453
Total BTEX Emissions	0.0047	0.113	0.0206

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.5000 MMSCF/day
Glycol Losses with Dry Gas: 0.0030 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 2.09e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.18e+000
Carbon Dioxide	9.99e-001	2.42e+001
Methane	8.99e+001	7.93e+002
Ethane	5.29e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.83e+001
n-Pentane	9.99e-001	3.96e+001
n-Hexane	4.19e-002	1.99e+000
Other Hexanes	8.39e-002	3.98e+000
Heptanes	9.99e-003	5.50e-001
2,2,4-Trimethylpentane	2.00e-002	1.25e+000
Benzene	1.04e-002	4.46e-001
Toluene	5.59e-003	2.83e-001
Ethylbenzene	5.99e-004	3.50e-002
Xylenes	3.40e-003	1.98e-001
Total Components	100.00	1.02e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.08e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	6.03e-002
Carbon Dioxide	9.98e-001	2.41e+001
Methane	9.00e+001	7.93e+002
Ethane	5.30e+000	8.75e+001
Propane	1.30e+000	3.15e+001
n-Butane	1.20e+000	3.82e+001
n-Pentane	9.98e-001	3.95e+001
n-Hexane	4.18e-002	1.98e+000
Other Hexanes	8.38e-002	3.96e+000
Heptanes	9.92e-003	5.46e-001
2,2,4-Trimethylpentane	1.99e-002	1.25e+000
Benzene	8.81e-003	3.78e-001
Toluene	4.37e-003	2.21e-001
Ethylbenzene	4.25e-004	2.48e-002
Xylenes	2.10e-003	1.23e-001
Total Components	100.00	1.02e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.02e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	5.65e+001
Water	1.50e+000	8.60e-001
Carbon Dioxide	9.88e-012	5.67e-012
Methane	7.59e-018	4.35e-018
Ethane	3.93e-008	2.25e-008
Propane	2.09e-009	1.20e-009
n-Butane	2.97e-009	1.70e-009
n-Pentane	8.36e-004	4.79e-004
n-Hexane	7.15e-005	4.10e-005
Other Hexanes	2.17e-004	1.25e-004
Heptanes	3.78e-005	2.17e-005
2,2,4-Trimethylpentane	1.12e-004	6.42e-005
Benzene	6.26e-003	3.59e-003
Toluene	9.33e-003	5.35e-003
Ethylbenzene	2.07e-003	1.19e-003
Xylenes	1.96e-002	1.12e-002
Total Components	100.00	5.74e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.06e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	5.65e+001
Water	3.36e+000	1.98e+000
Carbon Dioxide	9.58e-002	5.67e-002
Methane	2.19e-001	1.30e-001
Ethane	8.07e-002	4.77e-002
Propane	4.99e-002	2.95e-002
n-Butane	1.16e-001	6.86e-002
n-Pentane	1.62e-001	9.59e-002
n-Hexane	1.39e-002	8.20e-003
Other Hexanes	2.11e-002	1.25e-002
Heptanes	7.34e-003	4.34e-003
2,2,4-Trimethylpentane	7.23e-003	4.28e-003
Benzene	1.21e-001	7.18e-002
Toluene	1.15e-001	6.77e-002
Ethylbenzene	1.93e-002	1.14e-002
Xylenes	1.47e-001	8.69e-002
Total Components	100.00	5.91e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 4.70e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	2.10e-003
Carbon Dioxide	7.28e+000	3.97e-002
Methane	6.23e+001	1.24e-001
Ethane	1.12e+001	4.17e-002
Propane	4.16e+000	2.27e-002
n-Butane	6.21e+000	4.47e-002
n-Pentane	6.25e+000	5.59e-002
n-Hexane	3.48e-001	3.72e-003
Other Hexanes	6.00e-001	6.41e-003
Heptanes	1.06e-001	1.32e-003
2,2,4-Trimethylpentane	1.36e-001	1.92e-003
Benzene	2.38e-001	2.31e-003
Toluene	1.28e-001	1.47e-003
Ethylbenzene	1.13e-002	1.49e-004
Xylenes	5.98e-002	7.87e-004
Total Components	100.00	3.49e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.05e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	5.65e+001
Water	3.37e+000	1.98e+000
Carbon Dioxide	2.89e-002	1.70e-002
Methane	9.52e-003	5.60e-003
Ethane	1.03e-002	6.04e-003
Propane	1.15e-002	6.75e-003
n-Butane	4.06e-002	2.39e-002
n-Pentane	6.81e-002	4.00e-002
n-Hexane	7.63e-003	4.48e-003
Other Hexanes	1.03e-002	6.06e-003
Heptanes	5.14e-003	3.02e-003
2,2,4-Trimethylpentane	4.01e-003	2.36e-003
Benzene	1.18e-001	6.95e-002
Toluene	1.13e-001	6.63e-002
Ethylbenzene	1.91e-002	1.13e-002
Xylenes	1.46e-001	8.61e-002
Total Components	100.00	5.88e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.53e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.12e+000
Carbon Dioxide	5.78e-001	1.70e-002

Methane	5.23e-001	5.60e-003
Ethane	3.01e-001	6.04e-003
Propane	2.29e-001	6.75e-003
n-Butane	6.14e-001	2.39e-002
n-Pentane	8.20e-001	3.95e-002
n-Hexane	7.72e-002	4.44e-003
Other Hexanes	1.03e-001	5.94e-003
Heptanes	4.48e-002	3.00e-003
2,2,4-Trimethylpentane	3.01e-002	2.29e-003
Benzene	1.26e+000	6.59e-002
Toluene	9.89e-001	6.09e-002
Ethylbenzene	1.42e-001	1.01e-002
Xylenes	1.06e+000	7.49e-002
Total Components	100.00	1.45e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .5 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.5mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .5 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.5 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1554	3.730	0.6808
Ethane	0.0573	1.375	0.2509
Propane	0.0354	0.849	0.1550
n-Butane	0.0823	1.976	0.3605
n-Pentane	0.1145	2.747	0.5014
n-Hexane	0.0098	0.235	0.0429
Other Hexanes	0.0148	0.356	0.0649
Heptanes	0.0052	0.124	0.0227
2,2,4-Trimethylpentane	0.0051	0.121	0.0221
Benzene	0.0819	1.965	0.3587
Toluene	0.0748	1.796	0.3278
Ethylbenzene	0.0123	0.294	0.0537
Xylenes	0.0908	2.179	0.3977
Total Emissions	0.7395	17.749	3.2391
Total Hydrocarbon Emissions	0.7395	17.749	3.2391
Total VOC Emissions	0.5268	12.644	2.3075
Total HAP Emissions	0.2747	6.592	1.2030
Total BTEX Emissions	0.2598	6.235	1.1380

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.6000 MMSCF/day
Glycol Losses with Dry Gas: 0.0036 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.42e+000
Carbon Dioxide	9.99e-001	2.90e+001
Methane	8.99e+001	9.52e+002
Ethane	5.29e+000	1.05e+002
Propane	1.30e+000	3.78e+001
n-Butane	1.20e+000	4.60e+001
n-Pentane	9.99e-001	4.76e+001
n-Hexane	4.19e-002	2.39e+000
Other Hexanes	8.39e-002	4.77e+000
Heptanes	9.99e-003	6.60e-001
2,2,4-Trimethylpentane	2.00e-002	1.51e+000
Benzene	1.04e-002	5.35e-001
Toluene	5.59e-003	3.40e-001
Ethylbenzene	5.99e-004	4.20e-002
Xylenes	3.40e-003	2.38e-001
Total Components	100.00	1.23e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	7.24e-002
Carbon Dioxide	9.98e-001	2.89e+001
Methane	9.00e+001	9.52e+002
Ethane	5.30e+000	1.05e+002
Propane	1.30e+000	3.77e+001
n-Butane	1.20e+000	4.59e+001
n-Pentane	9.98e-001	4.74e+001
n-Hexane	4.18e-002	2.38e+000
Other Hexanes	8.38e-002	4.76e+000
Heptanes	9.92e-003	6.55e-001
2,2,4-Trimethylpentane	1.99e-002	1.50e+000
Benzene	8.81e-003	4.53e-001
Toluene	4.37e-003	2.65e-001
Ethylbenzene	4.25e-004	2.97e-002
Xylenes	2.10e-003	1.47e-001
Total Components	100.00	1.23e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.22e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	6.78e+001
Water	1.50e+000	1.03e+000
Carbon Dioxide	9.88e-012	6.80e-012
Methane	7.59e-018	5.22e-018
Ethane	3.93e-008	2.70e-008
Propane	2.09e-009	1.44e-009
n-Butane	2.97e-009	2.04e-009
n-Pentane	8.36e-004	5.75e-004
n-Hexane	7.15e-005	4.92e-005
Other Hexanes	2.17e-004	1.50e-004
Heptanes	3.78e-005	2.60e-005
2,2,4-Trimethylpentane	1.12e-004	7.70e-005
Benzene	6.26e-003	4.31e-003
Toluene	9.33e-003	6.42e-003
Ethylbenzene	2.07e-003	1.42e-003
Xylenes	1.96e-002	1.35e-002
Total Components	100.00	6.88e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.27e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	6.77e+001
Water	3.36e+000	2.38e+000
Carbon Dioxide	9.58e-002	6.80e-002
Methane	2.19e-001	1.55e-001
Ethane	8.07e-002	5.73e-002
Propane	4.99e-002	3.54e-002
n-Butane	1.16e-001	8.23e-002
n-Pentane	1.62e-001	1.15e-001
n-Hexane	1.39e-002	9.84e-003
Other Hexanes	2.11e-002	1.50e-002
Heptanes	7.34e-003	5.21e-003
2,2,4-Trimethylpentane	7.23e-003	5.13e-003
Benzene	1.21e-001	8.62e-002
Toluene	1.15e-001	8.13e-002
Ethylbenzene	1.93e-002	1.37e-002
Xylenes	1.47e-001	1.04e-001
Total Components	100.00	7.10e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.61e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.35e+000
Carbon Dioxide	1.63e+000	6.80e-002
Methane	1.02e+001	1.55e-001
Ethane	2.00e+000	5.73e-002
Propane	8.44e-001	3.54e-002
n-Butane	1.49e+000	8.23e-002
n-Pentane	1.67e+000	1.14e-001
n-Hexane	1.20e-001	9.79e-003
Other Hexanes	1.81e-001	1.48e-002
Heptanes	5.44e-002	5.18e-003
2,2,4-Trimethylpentane	4.66e-002	5.06e-003
Benzene	1.10e+000	8.19e-002
Toluene	8.55e-001	7.48e-002
Ethylbenzene	1.22e-001	1.23e-002
Xylenes	9.00e-001	9.08e-002
Total Components	100.00	2.16e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.6 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0067	0.161	0.0294
Ethane	0.0072	0.174	0.0317
Propane	0.0081	0.194	0.0355
n-Butane	0.0286	0.687	0.1254
n-Pentane	0.0474	1.139	0.2078
n-Hexane	0.0053	0.128	0.0233
Other Hexanes	0.0071	0.171	0.0312
Heptanes	0.0036	0.086	0.0158
2,2,4-Trimethylpentane	0.0028	0.066	0.0121
Benzene	0.0791	1.899	0.3466
Toluene	0.0731	1.754	0.3201
Ethylbenzene	0.0121	0.290	0.0529
Xylenes	0.0899	2.157	0.3936
Total Emissions	0.3711	8.906	1.6254

Total Hydrocarbon Emissions	0.3711	8.906	1.6254
Total VOC Emissions	0.3571	8.571	1.5642
Total HAP Emissions	0.2622	6.294	1.1486
Total BTEX Emissions	0.2542	6.100	1.1132

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1487	3.569	0.6514
Ethane	0.0500	1.201	0.2191
Propane	0.0273	0.655	0.1195
n-Butane	0.0537	1.289	0.2352
n-Pentane	0.0670	1.609	0.2936
n-Hexane	0.0045	0.107	0.0195
Other Hexanes	0.0077	0.185	0.0337
Heptanes	0.0016	0.038	0.0069

2,2,4-Trimethylpentane	0.0023	0.055	0.0101
Benzene	0.0028	0.066	0.0121
Toluene	0.0018	0.042	0.0077
Ethylbenzene	0.0002	0.004	0.0008
Xylenes	0.0009	0.023	0.0041
Total Emissions	0.3684	8.843	1.6138
Total Hydrocarbon Emissions	0.3684	8.843	1.6138
Total VOC Emissions	0.1697	4.073	0.7433
Total HAP Emissions	0.0124	0.298	0.0544
Total BTEX Emissions	0.0057	0.136	0.0248

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.6000 MMSCF/day
Glycol Losses with Dry Gas: 0.0036 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.42e+000
Carbon Dioxide	9.99e-001	2.90e+001
Methane	8.99e+001	9.52e+002
Ethane	5.29e+000	1.05e+002
Propane	1.30e+000	3.78e+001
n-Butane	1.20e+000	4.60e+001
n-Pentane	9.99e-001	4.76e+001
n-Hexane	4.19e-002	2.39e+000
Other Hexanes	8.39e-002	4.77e+000
Heptanes	9.99e-003	6.60e-001
2,2,4-Trimethylpentane	2.00e-002	1.51e+000
Benzene	1.04e-002	5.35e-001
Toluene	5.59e-003	3.40e-001
Ethylbenzene	5.99e-004	4.20e-002
Xylenes	3.40e-003	2.38e-001
Total Components	100.00	1.23e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.50e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	7.24e-002
Carbon Dioxide	9.98e-001	2.89e+001
Methane	9.00e+001	9.52e+002
Ethane	5.30e+000	1.05e+002
Propane	1.30e+000	3.77e+001
n-Butane	1.20e+000	4.59e+001
n-Pentane	9.98e-001	4.74e+001
n-Hexane	4.18e-002	2.38e+000
Other Hexanes	8.38e-002	4.76e+000
Heptanes	9.92e-003	6.55e-001
2,2,4-Trimethylpentane	1.99e-002	1.50e+000
Benzene	8.81e-003	4.53e-001
Toluene	4.37e-003	2.65e-001
Ethylbenzene	4.25e-004	2.97e-002
Xylenes	2.10e-003	1.47e-001
Total Components	100.00	1.23e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.22e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	6.78e+001
Water	1.50e+000	1.03e+000
Carbon Dioxide	9.88e-012	6.80e-012
Methane	7.59e-018	5.22e-018
Ethane	3.93e-008	2.70e-008
Propane	2.09e-009	1.44e-009
n-Butane	2.97e-009	2.04e-009
n-Pentane	8.36e-004	5.75e-004
n-Hexane	7.15e-005	4.92e-005
Other Hexanes	2.17e-004	1.50e-004
Heptanes	3.78e-005	2.60e-005
2,2,4-Trimethylpentane	1.12e-004	7.70e-005
Benzene	6.26e-003	4.31e-003
Toluene	9.33e-003	6.42e-003
Ethylbenzene	2.07e-003	1.42e-003
Xylenes	1.96e-002	1.35e-002
Total Components	100.00	6.88e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.27e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	6.77e+001
Water	3.36e+000	2.38e+000
Carbon Dioxide	9.58e-002	6.80e-002
Methane	2.19e-001	1.55e-001
Ethane	8.07e-002	5.73e-002
Propane	4.99e-002	3.54e-002
n-Butane	1.16e-001	8.23e-002
n-Pentane	1.62e-001	1.15e-001
n-Hexane	1.39e-002	9.84e-003
Other Hexanes	2.11e-002	1.50e-002
Heptanes	7.34e-003	5.21e-003
2,2,4-Trimethylpentane	7.23e-003	5.13e-003
Benzene	1.21e-001	8.62e-002
Toluene	1.15e-001	8.13e-002
Ethylbenzene	1.93e-002	1.37e-002
Xylenes	1.47e-001	1.04e-001
Total Components	100.00	7.10e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 5.64e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	2.52e-003
Carbon Dioxide	7.28e+000	4.76e-002
Methane	6.23e+001	1.49e-001
Ethane	1.12e+001	5.00e-002
Propane	4.16e+000	2.73e-002
n-Butane	6.21e+000	5.37e-002
n-Pentane	6.25e+000	6.70e-002
n-Hexane	3.48e-001	4.46e-003
Other Hexanes	6.00e-001	7.69e-003
Heptanes	1.06e-001	1.58e-003
2,2,4-Trimethylpentane	1.36e-001	2.30e-003
Benzene	2.38e-001	2.77e-003
Toluene	1.28e-001	1.76e-003
Ethylbenzene	1.13e-002	1.79e-004
Xylenes	5.98e-002	9.45e-004
Total Components	100.00	4.19e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.26e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	6.77e+001
Water	3.37e+000	2.38e+000
Carbon Dioxide	2.89e-002	2.04e-002
Methane	9.52e-003	6.72e-003
Ethane	1.03e-002	7.24e-003
Propane	1.15e-002	8.10e-003
n-Butane	4.06e-002	2.86e-002
n-Pentane	6.81e-002	4.80e-002
n-Hexane	7.63e-003	5.38e-003
Other Hexanes	1.03e-002	7.28e-003
Heptanes	5.14e-003	3.63e-003
2,2,4-Trimethylpentane	4.01e-003	2.83e-003
Benzene	1.18e-001	8.34e-002
Toluene	1.13e-001	7.95e-002
Ethylbenzene	1.91e-002	1.35e-002
Xylenes	1.46e-001	1.03e-001
Total Components	100.00	7.05e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.04e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.35e+000
Carbon Dioxide	5.78e-001	2.04e-002

Methane	5.23e-001	6.72e-003
Ethane	3.01e-001	7.24e-003
Propane	2.29e-001	8.10e-003
n-Butane	6.14e-001	2.86e-002
n-Pentane	8.20e-001	4.74e-002
n-Hexane	7.72e-002	5.33e-003
Other Hexanes	1.03e-001	7.13e-003
Heptanes	4.48e-002	3.60e-003
2,2,4-Trimethylpentane	3.01e-002	2.75e-003
Benzene	1.26e+000	7.91e-002
Toluene	9.89e-001	7.31e-002
Ethylbenzene	1.42e-001	1.21e-002
Xylenes	1.06e+000	8.99e-002
Total Components	100.00	1.74e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .6 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.6mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .6 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.6 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1813	4.352	0.7943
Ethane	0.0668	1.604	0.2927
Propane	0.0413	0.991	0.1808
n-Butane	0.0960	2.305	0.4206
n-Pentane	0.1335	3.205	0.5849
n-Hexane	0.0114	0.274	0.0500
Other Hexanes	0.0173	0.415	0.0757
Heptanes	0.0060	0.145	0.0265
2,2,4-Trimethylpentane	0.0059	0.142	0.0258
Benzene	0.0955	2.293	0.4185
Toluene	0.0873	2.096	0.3825
Ethylbenzene	0.0143	0.343	0.0627
Xylenes	0.1059	2.543	0.4640
Total Emissions	0.8628	20.707	3.7790
Total Hydrocarbon Emissions	0.8628	20.707	3.7790
Total VOC Emissions	0.6146	14.751	2.6921
Total HAP Emissions	0.3204	7.690	1.4035
Total BTEX Emissions	0.3031	7.275	1.3276

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.7000 MMSCF/day
Glycol Losses with Dry Gas: 0.0042 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.66e+000
Carbon Dioxide	9.99e-001	3.38e+001
Methane	8.99e+001	1.11e+003
Ethane	5.29e+000	1.23e+002
Propane	1.30e+000	4.41e+001
n-Butane	1.20e+000	5.36e+001
n-Pentane	9.99e-001	5.55e+001
n-Hexane	4.19e-002	2.78e+000
Other Hexanes	8.39e-002	5.57e+000
Heptanes	9.99e-003	7.71e-001
2,2,4-Trimethylpentane	2.00e-002	1.76e+000
Benzene	1.04e-002	6.25e-001
Toluene	5.59e-003	3.97e-001
Ethylbenzene	5.99e-004	4.90e-002
Xylenes	3.40e-003	2.78e-001
Total Components	100.00	1.43e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	8.44e-002
Carbon Dioxide	9.98e-001	3.38e+001
Methane	9.00e+001	1.11e+003
Ethane	5.30e+000	1.22e+002
Propane	1.30e+000	4.40e+001
n-Butane	1.20e+000	5.35e+001
n-Pentane	9.98e-001	5.53e+001
n-Hexane	4.18e-002	2.77e+000
Other Hexanes	8.38e-002	5.55e+000
Heptanes	9.92e-003	7.64e-001
2,2,4-Trimethylpentane	1.99e-002	1.75e+000
Benzene	8.81e-003	5.29e-001
Toluene	4.37e-003	3.09e-001
Ethylbenzene	4.25e-004	3.47e-002
Xylenes	2.10e-003	1.72e-001
Total Components	100.00	1.43e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.43e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	7.91e+001
Water	1.50e+000	1.20e+000
Carbon Dioxide	9.88e-012	7.93e-012
Methane	7.59e-018	6.09e-018
Ethane	3.93e-008	3.15e-008
Propane	2.09e-009	1.68e-009
n-Butane	2.97e-009	2.38e-009
n-Pentane	8.36e-004	6.71e-004
n-Hexane	7.15e-005	5.74e-005
Other Hexanes	2.17e-004	1.75e-004
Heptanes	3.78e-005	3.04e-005
2,2,4-Trimethylpentane	1.12e-004	8.98e-005
Benzene	6.26e-003	5.03e-003
Toluene	9.33e-003	7.49e-003
Ethylbenzene	2.07e-003	1.66e-003
Xylenes	1.96e-002	1.57e-002
Total Components	100.00	8.03e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.48e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	7.90e+001
Water	3.36e+000	2.78e+000
Carbon Dioxide	9.58e-002	7.94e-002
Methane	2.19e-001	1.81e-001
Ethane	8.07e-002	6.68e-002
Propane	4.99e-002	4.13e-002
n-Butane	1.16e-001	9.60e-002
n-Pentane	1.62e-001	1.34e-001
n-Hexane	1.39e-002	1.15e-002
Other Hexanes	2.11e-002	1.75e-002
Heptanes	7.34e-003	6.08e-003
2,2,4-Trimethylpentane	7.23e-003	5.99e-003
Benzene	1.21e-001	1.01e-001
Toluene	1.15e-001	9.48e-002
Ethylbenzene	1.93e-002	1.60e-002
Xylenes	1.47e-001	1.22e-001
Total Components	100.00	8.28e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 4.21e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.57e+000
Carbon Dioxide	1.63e+000	7.94e-002
Methane	1.02e+001	1.81e-001
Ethane	2.00e+000	6.68e-002
Propane	8.44e-001	4.13e-002
n-Butane	1.49e+000	9.60e-002
n-Pentane	1.67e+000	1.34e-001
n-Hexane	1.20e-001	1.14e-002
Other Hexanes	1.81e-001	1.73e-002
Heptanes	5.44e-002	6.05e-003
2,2,4-Trimethylpentane	4.66e-002	5.90e-003
Benzene	1.10e+000	9.55e-002
Toluene	8.55e-001	8.73e-002
Ethylbenzene	1.22e-001	1.43e-002
Xylenes	9.00e-001	1.06e-001
Total Components	100.00	2.52e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.7 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0078	0.188	0.0343
Ethane	0.0085	0.203	0.0370
Propane	0.0094	0.227	0.0414
n-Butane	0.0334	0.801	0.1463
n-Pentane	0.0553	1.328	0.2424
n-Hexane	0.0062	0.149	0.0272
Other Hexanes	0.0083	0.200	0.0364
Heptanes	0.0042	0.101	0.0184
2,2,4-Trimethylpentane	0.0032	0.077	0.0141
Benzene	0.0923	2.216	0.4043
Toluene	0.0853	2.046	0.3735
Ethylbenzene	0.0141	0.338	0.0617
Xylenes	0.1048	2.516	0.4592
Total Emissions	0.4329	10.391	1.8963

Total Hydrocarbon Emissions	0.4329	10.391	1.8963
Total VOC Emissions	0.4167	10.000	1.8249
Total HAP Emissions	0.3059	7.343	1.3400
Total BTEX Emissions	0.2965	7.116	1.2987

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1735	4.164	0.7599
Ethane	0.0584	1.401	0.2557
Propane	0.0318	0.764	0.1394
n-Butane	0.0626	1.503	0.2744
n-Pentane	0.0782	1.877	0.3425
n-Hexane	0.0052	0.125	0.0228
Other Hexanes	0.0090	0.215	0.0393
Heptanes	0.0018	0.044	0.0081

2,2,4-Trimethylpentane	0.0027	0.065	0.0118
Benzene	0.0032	0.077	0.0141
Toluene	0.0021	0.049	0.0090
Ethylbenzene	0.0002	0.005	0.0009
Xylenes	0.0011	0.026	0.0048
Total Emissions	0.4298	10.316	1.8827
Total Hydrocarbon Emissions	0.4298	10.316	1.8827
Total VOC Emissions	0.1980	4.751	0.8671
Total HAP Emissions	0.0145	0.348	0.0634
Total BTEX Emissions	0.0066	0.158	0.0289

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.7000 MMSCF/day
Glycol Losses with Dry Gas: 0.0042 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.66e+000
Carbon Dioxide	9.99e-001	3.38e+001
Methane	8.99e+001	1.11e+003
Ethane	5.29e+000	1.23e+002
Propane	1.30e+000	4.41e+001
n-Butane	1.20e+000	5.36e+001
n-Pentane	9.99e-001	5.55e+001
n-Hexane	4.19e-002	2.78e+000
Other Hexanes	8.39e-002	5.57e+000
Heptanes	9.99e-003	7.71e-001
2,2,4-Trimethylpentane	2.00e-002	1.76e+000
Benzene	1.04e-002	6.25e-001
Toluene	5.59e-003	3.97e-001
Ethylbenzene	5.99e-004	4.90e-002
Xylenes	3.40e-003	2.78e-001
Total Components	100.00	1.43e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 2.92e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	8.44e-002
Carbon Dioxide	9.98e-001	3.38e+001
Methane	9.00e+001	1.11e+003
Ethane	5.30e+000	1.22e+002
Propane	1.30e+000	4.40e+001
n-Butane	1.20e+000	5.35e+001
n-Pentane	9.98e-001	5.53e+001
n-Hexane	4.18e-002	2.77e+000
Other Hexanes	8.38e-002	5.55e+000
Heptanes	9.92e-003	7.64e-001
2,2,4-Trimethylpentane	1.99e-002	1.75e+000
Benzene	8.81e-003	5.29e-001
Toluene	4.37e-003	3.09e-001
Ethylbenzene	4.25e-004	3.47e-002
Xylenes	2.10e-003	1.72e-001
Total Components	100.00	1.43e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.43e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	7.91e+001
Water	1.50e+000	1.20e+000
Carbon Dioxide	9.88e-012	7.93e-012
Methane	7.59e-018	6.09e-018
Ethane	3.93e-008	3.15e-008
Propane	2.09e-009	1.68e-009
n-Butane	2.97e-009	2.38e-009
n-Pentane	8.36e-004	6.71e-004
n-Hexane	7.15e-005	5.74e-005
Other Hexanes	2.17e-004	1.75e-004
Heptanes	3.78e-005	3.04e-005
2,2,4-Trimethylpentane	1.12e-004	8.98e-005
Benzene	6.26e-003	5.03e-003
Toluene	9.33e-003	7.49e-003
Ethylbenzene	2.07e-003	1.66e-003
Xylenes	1.96e-002	1.57e-002
Total Components	100.00	8.03e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.48e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	7.90e+001
Water	3.36e+000	2.78e+000
Carbon Dioxide	9.58e-002	7.94e-002
Methane	2.19e-001	1.81e-001
Ethane	8.07e-002	6.68e-002
Propane	4.99e-002	4.13e-002
n-Butane	1.16e-001	9.60e-002
n-Pentane	1.62e-001	1.34e-001
n-Hexane	1.39e-002	1.15e-002
Other Hexanes	2.11e-002	1.75e-002
Heptanes	7.34e-003	6.08e-003
2,2,4-Trimethylpentane	7.23e-003	5.99e-003
Benzene	1.21e-001	1.01e-001
Toluene	1.15e-001	9.48e-002
Ethylbenzene	1.93e-002	1.60e-002
Xylenes	1.47e-001	1.22e-001
Total Components	100.00	8.28e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 6.58e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	2.94e-003
Carbon Dioxide	7.28e+000	5.55e-002
Methane	6.23e+001	1.74e-001
Ethane	1.12e+001	5.84e-002
Propane	4.16e+000	3.18e-002
n-Butane	6.21e+000	6.26e-002
n-Pentane	6.25e+000	7.82e-002
n-Hexane	3.48e-001	5.21e-003
Other Hexanes	6.00e-001	8.97e-003
Heptanes	1.06e-001	1.84e-003
2,2,4-Trimethylpentane	1.36e-001	2.69e-003
Benzene	2.38e-001	3.23e-003
Toluene	1.28e-001	2.05e-003
Ethylbenzene	1.13e-002	2.08e-004
Xylenes	5.98e-002	1.10e-003
Total Components	100.00	4.88e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.47e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	7.90e+001
Water	3.37e+000	2.77e+000
Carbon Dioxide	2.89e-002	2.38e-002
Methane	9.52e-003	7.84e-003
Ethane	1.03e-002	8.45e-003
Propane	1.15e-002	9.45e-003
n-Butane	4.06e-002	3.34e-002
n-Pentane	6.81e-002	5.60e-002
n-Hexane	7.63e-003	6.28e-003
Other Hexanes	1.03e-002	8.49e-003
Heptanes	5.14e-003	4.23e-003
2,2,4-Trimethylpentane	4.01e-003	3.30e-003
Benzene	1.18e-001	9.73e-002
Toluene	1.13e-001	9.28e-002
Ethylbenzene	1.91e-002	1.58e-002
Xylenes	1.46e-001	1.21e-001
Total Components	100.00	8.23e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 3.55e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.57e+000
Carbon Dioxide	5.78e-001	2.38e-002

Methane	5.23e-001	7.84e-003
Ethane	3.01e-001	8.45e-003
Propane	2.29e-001	9.45e-003
n-Butane	6.14e-001	3.34e-002
n-Pentane	8.20e-001	5.53e-002
n-Hexane	7.72e-002	6.22e-003
Other Hexanes	1.03e-001	8.31e-003
Heptanes	4.48e-002	4.20e-003
2,2,4-Trimethylpentane	3.01e-002	3.21e-003
Benzene	1.26e+000	9.23e-002
Toluene	9.89e-001	8.53e-002
Ethylbenzene	1.42e-001	1.41e-002
Xylenes	1.06e+000	1.05e-001
Total Components	100.00	2.03e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .7 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.7mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .7 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.7 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: 0.8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2072	4.974	0.9077
Ethane	0.0764	1.833	0.3345
Propane	0.0472	1.132	0.2067
n-Butane	0.1098	2.634	0.4807
n-Pentane	0.1526	3.663	0.6685
n-Hexane	0.0131	0.313	0.0572
Other Hexanes	0.0198	0.474	0.0865
Heptanes	0.0069	0.166	0.0303
2,2,4-Trimethylpentane	0.0067	0.162	0.0295
Benzene	0.1092	2.621	0.4783
Toluene	0.0998	2.395	0.4371
Ethylbenzene	0.0163	0.392	0.0716
Xylenes	0.1211	2.906	0.5303
Total Emissions	0.9860	23.665	4.3188
Total Hydrocarbon Emissions	0.9860	23.665	4.3188
Total VOC Emissions	0.7024	16.858	3.0766
Total HAP Emissions	0.3662	8.789	1.6040
Total BTEX Emissions	0.3464	8.314	1.5173

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.8000 MMSCF/day
Glycol Losses with Dry Gas: 0.0048 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.34e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.89e+000
Carbon Dioxide	9.99e-001	3.87e+001
Methane	8.99e+001	1.27e+003
Ethane	5.29e+000	1.40e+002
Propane	1.30e+000	5.04e+001
n-Butane	1.20e+000	6.13e+001
n-Pentane	9.99e-001	6.34e+001
n-Hexane	4.19e-002	3.18e+000
Other Hexanes	8.39e-002	6.36e+000
Heptanes	9.99e-003	8.81e-001
2,2,4-Trimethylpentane	2.00e-002	2.01e+000
Benzene	1.04e-002	7.14e-001
Toluene	5.59e-003	4.53e-001
Ethylbenzene	5.99e-004	5.60e-002
Xylenes	3.40e-003	3.17e-001
Total Components	100.00	1.64e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.33e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	9.65e-002
Carbon Dioxide	9.98e-001	3.86e+001
Methane	9.00e+001	1.27e+003
Ethane	5.30e+000	1.40e+002
Propane	1.30e+000	5.03e+001
n-Butane	1.20e+000	6.12e+001
n-Pentane	9.98e-001	6.32e+001
n-Hexane	4.18e-002	3.17e+000
Other Hexanes	8.38e-002	6.34e+000
Heptanes	9.92e-003	8.74e-001
2,2,4-Trimethylpentane	1.99e-002	2.00e+000
Benzene	8.81e-003	6.05e-001
Toluene	4.37e-003	3.54e-001
Ethylbenzene	4.25e-004	3.96e-002
Xylenes	2.10e-003	1.96e-001
Total Components	100.00	1.64e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.63e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.85e+001	9.04e+001
Water	1.50e+000	1.38e+000
Carbon Dioxide	9.88e-012	9.07e-012
Methane	7.59e-018	6.96e-018
Ethane	3.93e-008	3.60e-008
Propane	2.09e-009	1.92e-009
n-Butane	2.97e-009	2.72e-009
n-Pentane	8.36e-004	7.67e-004
n-Hexane	7.15e-005	6.56e-005
Other Hexanes	2.17e-004	2.00e-004
Heptanes	3.78e-005	3.47e-005
2,2,4-Trimethylpentane	1.12e-004	1.03e-004
Benzene	6.26e-003	5.75e-003
Toluene	9.33e-003	8.56e-003
Ethylbenzene	2.07e-003	1.90e-003
Xylenes	1.96e-002	1.80e-002
Total Components	100.00	9.18e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.69e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	9.03e+001
Water	3.36e+000	3.17e+000
Carbon Dioxide	9.58e-002	9.07e-002
Methane	2.19e-001	2.07e-001
Ethane	8.07e-002	7.64e-002
Propane	4.99e-002	4.72e-002
n-Butane	1.16e-001	1.10e-001
n-Pentane	1.62e-001	1.53e-001
n-Hexane	1.39e-002	1.31e-002
Other Hexanes	2.11e-002	2.00e-002
Heptanes	7.34e-003	6.94e-003
2,2,4-Trimethylpentane	7.23e-003	6.84e-003
Benzene	1.21e-001	1.15e-001
Toluene	1.15e-001	1.08e-001
Ethylbenzene	1.93e-002	1.82e-002
Xylenes	1.47e-001	1.39e-001
Total Components	100.00	9.46e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 4.81e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	7.88e+001	1.80e+000
Carbon Dioxide	1.63e+000	9.07e-002
Methane	1.02e+001	2.07e-001
Ethane	2.00e+000	7.64e-002
Propane	8.44e-001	4.72e-002
n-Butane	1.49e+000	1.10e-001
n-Pentane	1.67e+000	1.53e-001
n-Hexane	1.20e-001	1.31e-002
Other Hexanes	1.81e-001	1.98e-002
Heptanes	5.44e-002	6.91e-003
2,2,4-Trimethylpentane	4.66e-002	6.74e-003
Benzene	1.10e+000	1.09e-001
Toluene	8.55e-001	9.98e-002
Ethylbenzene	1.22e-001	1.63e-002
Xylenes	9.00e-001	1.21e-001
Total Components	100.00	2.87e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: 0.8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.8 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0090	0.215	0.0392
Ethane	0.0097	0.232	0.0423
Propane	0.0108	0.259	0.0473
n-Butane	0.0382	0.916	0.1672
n-Pentane	0.0633	1.518	0.2771
n-Hexane	0.0071	0.171	0.0311
Other Hexanes	0.0095	0.228	0.0416
Heptanes	0.0048	0.115	0.0210
2,2,4-Trimethylpentane	0.0037	0.088	0.0161
Benzene	0.1055	2.532	0.4621
Toluene	0.0974	2.339	0.4268
Ethylbenzene	0.0161	0.387	0.0706
Xylenes	0.1198	2.876	0.5248
Total Emissions	0.4948	11.875	2.1672
Total Hydrocarbon Emissions	0.4948	11.875	2.1672
Total VOC Emissions	0.4762	11.428	2.0856
Total HAP Emissions	0.3497	8.392	1.5315
Total BTEX Emissions	0.3389	8.133	1.4843

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1983	4.759	0.8685
Ethane	0.0667	1.601	0.2922
Propane	0.0364	0.873	0.1594
n-Butane	0.0716	1.718	0.3136
n-Pentane	0.0894	2.145	0.3914
n-Hexane	0.0059	0.143	0.0261
Other Hexanes	0.0103	0.246	0.0449
Heptanes	0.0021	0.051	0.0092

2,2,4-Trimethylpentane	0.0031	0.074	0.0135
Benzene	0.0037	0.089	0.0162
Toluene	0.0023	0.056	0.0103
Ethylbenzene	0.0002	0.006	0.0010
Xylenes	0.0013	0.030	0.0055
Total Emissions	0.4913	11.790	2.1517
Total Hydrocarbon Emissions	0.4913	11.790	2.1517
Total VOC Emissions	0.2263	5.430	0.9910
Total HAP Emissions	0.0166	0.397	0.0725
Total BTEX Emissions	0.0075	0.181	0.0330

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.8000 MMSCF/day
Glycol Losses with Dry Gas: 0.0048 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

FLASH TANK

Flash Control: Vented to atmosphere
Flash Temperature: 160.0 deg. F
Flash Pressure: 28.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.89%	0.11%
Carbon Dioxide	30.00%	70.00%
Methane	4.32%	95.68%
Ethane	12.65%	87.35%
Propane	22.89%	77.11%
n-Butane	34.77%	65.23%
n-Pentane	41.74%	58.26%
n-Hexane	54.66%	45.34%
Other Hexanes	48.61%	51.39%
Heptanes	69.65%	30.35%
2,2,4-Trimethylpentane	55.13%	44.87%
Benzene	96.79%	3.21%
Toluene	97.83%	2.17%
Ethylbenzene	98.70%	1.30%
Xylenes	99.09%	0.91%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.41%	56.59%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	1.20%	98.80%
n-Hexane	0.91%	99.09%
Other Hexanes	2.06%	97.94%
Heptanes	0.72%	99.28%
2,2,4-Trimethylpentane	2.72%	97.28%
Benzene	5.17%	94.83%
Toluene	8.08%	91.92%
Ethylbenzene	10.54%	89.46%
Xylenes	13.03%	86.97%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia

Flow Rate: 3.34e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.20e-001	1.89e+000
Carbon Dioxide	9.99e-001	3.87e+001
Methane	8.99e+001	1.27e+003
Ethane	5.29e+000	1.40e+002
Propane	1.30e+000	5.04e+001
n-Butane	1.20e+000	6.13e+001
n-Pentane	9.99e-001	6.34e+001
n-Hexane	4.19e-002	3.18e+000
Other Hexanes	8.39e-002	6.36e+000
Heptanes	9.99e-003	8.81e-001
2,2,4-Trimethylpentane	2.00e-002	2.01e+000
Benzene	1.04e-002	7.14e-001
Toluene	5.59e-003	4.53e-001
Ethylbenzene	5.99e-004	5.60e-002
Xylenes	3.40e-003	3.17e-001
Total Components	100.00	1.64e+003

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 3.33e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	6.10e-003	9.65e-002
Carbon Dioxide	9.98e-001	3.86e+001
Methane	9.00e+001	1.27e+003
Ethane	5.30e+000	1.40e+002
Propane	1.30e+000	5.03e+001
n-Butane	1.20e+000	6.12e+001
n-Pentane	9.98e-001	6.32e+001
n-Hexane	4.18e-002	3.17e+000
Other Hexanes	8.38e-002	6.34e+000
Heptanes	9.92e-003	8.74e-001
2,2,4-Trimethylpentane	1.99e-002	2.00e+000
Benzene	8.81e-003	6.05e-001
Toluene	4.37e-003	3.54e-001
Ethylbenzene	4.25e-004	3.96e-002
Xylenes	2.10e-003	1.96e-001
Total Components	100.00	1.64e+003

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.63e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)

TEG	9.85e+001	9.04e+001
Water	1.50e+000	1.38e+000
Carbon Dioxide	9.88e-012	9.07e-012
Methane	7.59e-018	6.96e-018
Ethane	3.93e-008	3.60e-008
Propane	2.09e-009	1.92e-009
n-Butane	2.97e-009	2.72e-009
n-Pentane	8.36e-004	7.67e-004
n-Hexane	7.15e-005	6.56e-005
Other Hexanes	2.17e-004	2.00e-004
Heptanes	3.78e-005	3.47e-005
2,2,4-Trimethylpentane	1.12e-004	1.03e-004
Benzene	6.26e-003	5.75e-003
Toluene	9.33e-003	8.56e-003
Ethylbenzene	2.07e-003	1.90e-003
Xylenes	1.96e-002	1.80e-002
Total Components	100.00	9.18e+001

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 714.70 psia
Flow Rate: 1.69e-001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.55e+001	9.03e+001
Water	3.36e+000	3.17e+000
Carbon Dioxide	9.58e-002	9.07e-002
Methane	2.19e-001	2.07e-001
Ethane	8.07e-002	7.64e-002
Propane	4.99e-002	4.72e-002
n-Butane	1.16e-001	1.10e-001
n-Pentane	1.62e-001	1.53e-001
n-Hexane	1.39e-002	1.31e-002
Other Hexanes	2.11e-002	2.00e-002
Heptanes	7.34e-003	6.94e-003
2,2,4-Trimethylpentane	7.23e-003	6.84e-003
Benzene	1.21e-001	1.15e-001
Toluene	1.15e-001	1.08e-001
Ethylbenzene	1.93e-002	1.82e-002
Xylenes	1.47e-001	1.39e-001
Total Components	100.00	9.46e+001

FLASH TANK OFF GAS STREAM

Temperature: 160.00 deg. F
Pressure: 42.70 psia
Flow Rate: 7.52e+000 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	9.42e-001	3.37e-003
Carbon Dioxide	7.28e+000	6.35e-002
Methane	6.23e+001	1.98e-001
Ethane	1.12e+001	6.67e-002
Propane	4.16e+000	3.64e-002
n-Butane	6.21e+000	7.16e-002
n-Pentane	6.25e+000	8.94e-002
n-Hexane	3.48e-001	5.95e-003
Other Hexanes	6.00e-001	1.03e-002
Heptanes	1.06e-001	2.11e-003
2,2,4-Trimethylpentane	1.36e-001	3.07e-003
Benzene	2.38e-001	3.69e-003
Toluene	1.28e-001	2.35e-003
Ethylbenzene	1.13e-002	2.38e-004
Xylenes	5.98e-002	1.26e-003
Total Components	100.00	5.58e-001

FLASH TANK GLYCOL STREAM

Temperature: 160.00 deg. F
Flow Rate: 1.68e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.60e+001	9.03e+001
Water	3.37e+000	3.17e+000
Carbon Dioxide	2.89e-002	2.72e-002
Methane	9.52e-003	8.96e-003
Ethane	1.03e-002	9.66e-003
Propane	1.15e-002	1.08e-002
n-Butane	4.06e-002	3.82e-002
n-Pentane	6.81e-002	6.40e-002
n-Hexane	7.63e-003	7.17e-003
Other Hexanes	1.03e-002	9.70e-003
Heptanes	5.14e-003	4.84e-003
2,2,4-Trimethylpentane	4.01e-003	3.77e-003
Benzene	1.18e-001	1.11e-001
Toluene	1.13e-001	1.06e-001
Ethylbenzene	1.91e-002	1.80e-002
Xylenes	1.46e-001	1.38e-001
Total Components	100.00	9.41e+001

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 4.06e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.32e+001	1.79e+000
Carbon Dioxide	5.78e-001	2.72e-002

Methane	5.23e-001	8.96e-003
Ethane	3.01e-001	9.66e-003
Propane	2.29e-001	1.08e-002
n-Butane	6.14e-001	3.82e-002
n-Pentane	8.20e-001	6.33e-002
n-Hexane	7.72e-002	7.11e-003
Other Hexanes	1.03e-001	9.50e-003
Heptanes	4.48e-002	4.80e-003
2,2,4-Trimethylpentane	3.01e-002	3.67e-003
Benzene	1.26e+000	1.06e-001
Toluene	9.89e-001	9.74e-002
Ethylbenzene	1.42e-001	1.61e-002
Xylenes	1.06e+000	1.20e-001
Total Components	100.00	2.32e+000

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: .8 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.8mmscf per day flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .8 mmscf/d actual throughput
BTEX content = 200ppmv
Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 90.00 deg. F
Pressure: 700.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	1.0000
Methane	90.0240
Ethane	5.3000
Propane	1.3000
n-Butane	1.2000
n-Pentane	1.0000
n-Hexane	0.0420
Other Hexanes	0.0840
Heptanes	0.0100
2,2,4-Trimethylpentane	0.0200
Benzene	0.0104
Toluene	0.0056
Ethylbenzene	0.0006
Xylenes	0.0034

DRY GAS:

Flow Rate: 0.8 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 5.9 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Vented to atmosphere
Temperature: 160.0 deg. F
Pressure: 28.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: .9 mmscf/d Dehy
File Name: D:\My Documents\Oil and Gas\number of area sources\GRI Runs\actual throughput\0.9mmscf per day no flash tank.ddf
Date: November 08, 2004

DESCRIPTION:

Description: Dehydration unit with a .9 mmscf/d actual throughput
BTEX content = 200ppmv
No Flash Tank
Production Unit

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2331	5.596	1.0212
Ethane	0.0859	2.062	0.3763
Propane	0.0531	1.274	0.2325
n-Butane	0.1235	2.963	0.5408
n-Pentane	0.1717	4.121	0.7520
n-Hexane	0.0147	0.352	0.0643
Other Hexanes	0.0222	0.533	0.0974
Heptanes	0.0078	0.187	0.0340
2,2,4-Trimethylpentane	0.0076	0.182	0.0332
Benzene	0.1228	2.948	0.5381
Toluene	0.1123	2.694	0.4917
Ethylbenzene	0.0184	0.441	0.0806
Xylenes	0.1362	3.269	0.5966
Total Emissions	1.1093	26.623	4.8587
Total Hydrocarbon Emissions	1.1093	26.623	4.8587
Total VOC Emissions	0.7902	18.966	3.4612
Total HAP Emissions	0.4120	9.888	1.8045
Total BTEX Emissions	0.3897	9.353	1.7069

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 2.90 lbs. H2O/MMSCF

Temperature: 90.0 deg. F
Pressure: 700.0 psig
Dry Gas Flow Rate: 0.9000 MMSCF/day
Glycol Losses with Dry Gas: 0.0054 lb/hr
Wet Gas Water Content: Saturated
Calculated Wet Gas Water Content: 56.75 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio: 5.90 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.09%	94.91%
Carbon Dioxide	99.77%	0.23%
Methane	99.98%	0.02%
Ethane	99.95%	0.05%
Propane	99.91%	0.09%
n-Butane	99.82%	0.18%
n-Pentane	99.76%	0.24%
n-Hexane	99.59%	0.41%
Other Hexanes	99.69%	0.31%
Heptanes	99.22%	0.78%
2,2,4-Trimethylpentane	99.66%	0.34%
Benzene	84.70%	15.30%
Toluene	77.99%	22.01%
Ethylbenzene	70.79%	29.21%
Xylenes	61.83%	38.17%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	43.37%	56.63%
Carbon Dioxide	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
n-Butane	0.00%	100.00%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Other Hexanes	1.00%	99.00%
Heptanes	0.50%	99.50%
2,2,4-Trimethylpentane	1.50%	98.50%
Benzene	5.00%	95.00%
Toluene	7.90%	92.10%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%

STREAM REPORTS:

MEMORANDUM

DATE: December 21, 2006

SUBJECT: Impacts of the Final Standards for Oil and Natural Gas Production Area Sources

FROM: Heather P. Brown, P.E.

TO: Greg Nizich, EPA/OAQPS/SPPD/CCG

I. INTRODUCTION AND BACKGROUND

On July 8, 2005, (70 FR 39441), the United States Environmental Protection Agency (EPA) issued a supplemental proposal to the February 6, 1998 (63 FR 6288), proposed standards for oil and natural gas production area sources. Impacts were developed for the July 2005 supplemental proposed action based on regulating area sources on a nationwide basis.[1] For the final rule, EPA has created three subcategories of sources: (1) triethylene glycol (TEG) dehydration units with either an annual average natural gas flow rate less than 3 million standard cubic feet per day (MMSCF/D) or benzene emissions less than 1 ton per year (tpy); (2) TEG dehydration units with an annual average natural gas flow rate equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1 tpy and located within areas of higher population densities with 10,000 people or more; and (3) TEG dehydration units with an annual average natural gas flow rate equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1 tpy and located outside areas of higher population densities with 10,000 people or more.

The purpose of this memorandum is to present the regulatory alternatives considered, as well as the impacts for the final standards for oil and natural gas production. The impacts presented include primary air impacts, secondary environmental impacts (air pollution, water, and solid waste impacts), energy impacts, and cost impacts.

II. REGULATORY ALTERNATIVES

The oil and natural gas production source category is unique compared to many source categories since the location of the facilities is dictated by the location of the natural resources, rather than a need to serve a particular population center. For this reason, many sources are located in remote or rural areas. Further, these sources do not require on-site operators and are usually not manned by large staff, if manned at all. Finally, the operation of these sources is not

[1] Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., US Environmental Protection Agency. Revised Impacts for Area Sources in the Oil and Natural Gas Production Source Category. June 25, 2005. Docket No. EPA-HQ-OAR-2004-0238-0002, 0003.

dependant on being close to populated areas. Based on these factors, EPA explored two regulatory alternatives for applying add-on controls to TEG dehydration units in the two subcategories of sources with an annual average natural gas flow rate equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1 tpy. The first alternative was to apply add-on control requirements to TEG dehydration units nationwide. The second alternative was to apply add-on control requirements to units located in areas of high population densities.

A. Regulatory Alternative 1: Apply Add-on Control Requirements Nationwide

Under this regulatory alternative, each subject TEG dehydration unit at an area source is required to: (1) reduce hazardous air pollutant (HAP) emissions by 95 percent or more; (2) reduce HAP emissions to an outlet concentration of 20 parts per million by volume (ppmv); or (3) reduce benzene emissions to a level less than 1.0 tpy. For the purposes of this memorandum, an emission reduction of 77.5 percent was assumed.

In the July 2005 supplemental proposal, EPA estimated that there are potentially 38,067 area source TEG dehydration units in the United States. Of the 38,067 potential TEG dehydration units, EPA estimates that 2,222 have actual annual average natural gas throughputs greater than 3 MMSCF/D and benzene emission greater than 1.0 tpy. Baseline HAP emissions of 49,635 tpy (14,803 tpy benzene) were estimated using GRI-GLYCalc© (version 4.0).[2] Reducing emissions by 77.5 percent resulted in an emission reduction of 13,377 tpy HAP (3,989 tpy benzene).

Using an approach consistent with that used in the July 2005 proposal (70 FR 39446), EPA evaluated the affected TEG dehydration units relative to the populations contained in the top 13 natural gas producing States (Alabama, Alaska, California, Colorado, Kansas, Louisiana, Michigan, Mississippi, New Mexico, Oklahoma, Texas, Utah, and Wyoming). EPA estimated that these 2,222 TEG dehydration units were located in States with a combined population of 92 million people.[3] The annual cost for this option was estimated to be $39 million.[4]

B. Regulatory Alternative 2: Apply Add-on Control Requirements to Units Located in Areas of High Population Densities

Under this regulatory alternative, TEG units located in areas of higher population densities with 10,000 people or more would be required to apply add-on controls (see Regulatory Alternative 1). EPA defines areas of higher population densities with 10,000 people or more as including the area occupied by each urban cluster[5] (UC) with 10,000 or more (referred to as UC

[2] See footnote 1.
[3] Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., US Environmental Protection Agency. Evaluation of Number of Sources Potentially Affected within Census Designated Geographies for 13 States Responsible for the Highest Oil and Natural Gas Production. June 29, 2006. Docket No. . EPA-HQ-OAR-2004-0238-0013.
[4] See footnote 1.
[5] An Urban Cluster refers to o Census 2000 Urban Cluster, which is defined in the *Urban Area Criteria for Census 2000,* 67 FR 11667 (March 15, 2002). Essentially, an UC consists of densely settled territory with at least 2,500 people but fewer than 50,000 people.

NMED Exhibit 79 - 0002

≥ 10,000) and each urbanized area[6] (UA) plus the area located two miles or less from each UA boundary,[7] referred to by the phrase "UA plus offset." Based on this definition, EPA estimates that 50 TEG dehydration units would be required to apply add-on controls.[8] Baseline emissions from a single TEG dehydration unit are presented in another memorandum.[9] Table 1 presents baseline emissions from the 50 TEG dehydration units located within UC ≥ 10,000 and UA plus offset boundaries as well as emissions after reducing benzene emissions by 77.5 percent tpy by applying add-on controls. Emission reductions were estimated to be 301 tpy HAP (90 tpy of benzene).

EPA estimated that these 50 units are located in urban areas with a combined population of 76 million people.[10] Annual costs for a single unit without a flash tank were estimated to be $17,700 per year and for those with a flash tank annual costs were estimated to be $17,280 per year.[11] Assuming that 45 units do not have a flash tank and 5 units have a flash tank,[12] the annual costs for the 50 TEG dehydration units located within UC ≥ 10,000 and UA plus offset boundaries were estimated to be approximately $880 thousand per year.

C. Results of Regulatory Alternative Evaluation

Table 2 presents a cost comparison of Regulatory Alternatives 1 and 2. As shown in Table 2, extending the add-on control requirement to sources outside UC ≥ 10,000 and UA plus offset boundaries would result in an additional annual cost exceeding $38 million per year in an area with a combined population of 16 million people. This analysis shows that the overall cost of controlling units outside UC ≥ 10,000 and UA plus offset boundaries was much higher for a lower total population. Therefore, impacts were developed for Regulatory Alternative 2: apply the add-on control requirement to those TEG dehydration units located within UC ≥ 10,000 and UA plus offset boundaries.

III. PRIMARY AIR IMPACTS

This purpose of this section is to present the primary air pollution impacts (i.e., the reduction of HAP emissions) associated with the area source standards for existing and new sources.

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[6] An Urbanized Area refers to Census 2000 Urbanized Area, which is defined in the *Urban Area Criteria for Census 2000*, 67 FR 11663, 11667 (March 15, 2002). Essentially, an UA consists of densely settled territory with a population of at least 50,000 people.

[7] Memorandum from Brown, H., EC/R Incorporated, to Nizich, G., US Environmental Protection Agency. Estimation of Land Area and Population Associated with Urbanized Area/Urban Cluster plus Offset Boundaries. December 21, 2006.

[8] See footnote 7.

[9] See footnote 1.

[10] See footnote 7.

[11] See footnote 1.

[12] See footnote 1.

NMED Exhibit 79 - 0003

Table 1. Nationwide Baseline Emissions Using UC ≥ 10,000 and UA Plus Offset Definition

Throughput (MMSCF/D)[1]	Number of TEG Dehydration Units	Number Without Flash Tank	Number With Flash Tank[2]	Nationwide						Emissions after control					
				No Flash Tank			Flash Tank			No Flash Tank			Flash Tank		
				Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)	Total HAP emissions (tpy)	Total VOC Emissions (tpy)	Benzene Emissions (tpy)
3	20	18	2	108	206	32	12	23	4	24	46	7	3	5	1
4	16	14	2	116	223	35	16	31	5	26	50	8	4	7	1
5	14	13	1	127	243	38	10	19	3	28	55	8	2	4	1
	50	45	5	350	672	104	38	73	11	79	151	24	9	16	3

[1] Throughput used as an input to GLYCalc. See footnote 1.

[2] Approximately 10 percent of units are assumed to have a flash tank. See footnote 1.

Table 2. Comparison of Regulatory Alternatives 1 and 2

Factor	Regulatory Alternative 1	Regulatory Alternative 2
Number of Sources	2,222	50
HAP Emission Reductions (tpy)	13,377	301
Affected Population in 13 States (million)	92	76
Annual Cost ($million)	39	0.880

NMED Exhibit 79 - 0005

Existing Sources

As previously stated, EPA has estimated that there are potentially 38,067 existing area source TEG dehydration units in the U.S. Of these, EPA has identified 35,845 TEG dehydration units that fall within the subcategory of sources with either an annual average natural gas flow rate less than 3 MMSCF/D or benzene emissions less than 1.0 tpy. Baseline emissions for these units were estimated to be 32,375 tpy. [13] For this subcategory, EPA has determined that GACT is no control.

There are 2,222 TEG dehydration units with annual average natural gas flow rates equal to or greater than 3 MMSCF/D and benzene emissions equal to or greater than 1.0 tpy and are subject to emission reduction requirements. There are two subcategories within this group of sources. One subcategory consists of the 50 TEG dehydration units identified as being located within UC $\geq$ 10,000 and UA plus offset boundaries. EPA determined that these sources are subject to the add-on controls requirements of Regulatory Alternative 2.

The remaining 2,172 TEG dehydration units fall within the subcategory of sources located outside of UC $\geq$ 10,000 and UA plus offset boundaries. These units would be required to implement management practices by reducing their glycol circulation rate to an optimum rate. Impacts of implementing management practices for a single unit were developed in a separate memorandum.[14] It was determined that reducing the glycol circulation rate to an optimum level would result in a HAP emission reduction of 45 percent (47 percent for benzene). To estimate national impacts, the same relative distribution used to estimate impacts at proposal[15] was used to determine how many TEG units fall within each throughput category (3, 4, and 5 MMSCF/D). Tables 3 and 4 present the HAP and benzene air emission impacts, respectively, associated with applying Regulatory Alternative 2 plus implementing management practices. The overall emission reduction was estimated to be 7,909 tpy HAP (2,455 tpy benzene).

New Sources

EPA has estimated that there will be 423 new TEG dehydration units (141 each year) that will come into service during the first three years after promulgation (from 2007 to 2009).[16] Assuming the same location distribution of existing sources, it was estimated that 3 new TEG dehydration units (2.2 percent of 141) would be located within UC $\geq$ 10,000 and UA plus offset boundaries, and would be subject to add-on control requirements. Additionally, it was estimated that 138 new TEG dehydration units would be required to implement management practices.

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[13] Memorandum from Brown. H., EC/R Incorporated, to Nizich, G., United States Environmental Protection Agency. Methodology for Estimating the Number of Area Sources in the Oil and Natural Gas Production Source Category. June 15, 2005. Docket No. EPA-HQ-OAR-2004-0238-0005.

[14] Memorandum from Brown, H., EC/R Incorporated to Nizich, G., United States Environmental Protection Agency. Impacts of Applying Management Practices to a Single Oil and Natural Gas Production Area Source Facility. December 21, 2006.

[15] See footnote 1.

[16] Memorandum from Brown. H., EC/R Incorporated, to Nizich, G., United States Environmental Protection Agency. Estimation of the Number of New Area Source Triethylene Glycol Dehydration Units in the Oil and Natural Gas Production Source Category. December 21, 2006.

NMED Exhibit 79 - 0006

Table 3. HAP Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to Existing Sources

Throughput Category (MMscf/d)	Number of Units	Total HAP Emissions (tpy)	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Management Practices (tpy)**	Total HAP Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	35,845	32,375	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	884	5,317	20	93	864	2,343	2,437
>3 and ≤4	732	5,871	16	99	716	2,589	2,689
>4 and ≤5	606	6,072	14	109	592	2,675	2,784
Total	2,222	17,260	50	301	2,172	7,607	7,909

* Emission reduction of 77.5%

** Emission reductions of 45% (see footnote 13).

NMED Exhibit 79 - 0007

Table 4. Benzene Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to Existing Sources

Throughput Category (MMscf/d)	Number of Units	Total Benzene Emissions (tpy)	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Management Practices (tpy)**	Total Benzene Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	35,845	9,655	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	884	1,585	20	28	864	728	756
>3 and ≤4	732	1,750	16	30	716	805	834
>4 and ≤5	606	1,811	14	32	592	832	864
Total	2,222	5,147	50	90	2,172	2,365	2,455

* Emission reduction of 77.5%

** Emission reductions of 47% (see footnote 13).

NMED Exhibit 79 - 0008

Tables 5 and 6 present the HAP and benzene air emission impacts, respectively, for new sources. The overall emission reduction associated with the regulation of new sources was estimated to be 501 tpy HAP (155 tpy benzene).

IV. SECONDARY ENVIRONMENTAL IMPACTS

Although the intent of the area source standards is to reduce HAP emissions, the application of control technologies can lead to other secondary environmental impacts. These secondary impacts can have a positive environmental impact, such as the reduction of volatile organic compounds (VOC) emissions, or a negative impact. Negative impacts may result from air pollutants emitted as a result of combustion sources (e.g., flares) or generation of a solid or liquid waste stream. The secondary impacts on air pollution and water and solid waste are discussed in this section.

A. Air Pollution Impacts

The primary method of HAP control from area source TEG dehydration units located within UC $\geq$ 10,000 and UA plus offset boundaries is the installation of a condenser and, if not present, a gas condensate glycol separator (GCG separator or flash tank). The secondary air pollution impacts associated with the application of this type of control are the decreased VOC emissions resulting from capture and control of HAP emissions. For TEG dehydration units located outside of UC $\geq$ 10,000 and UA plus offset boundaries, reducing the glycol circulation rate to the optimum level also decreases VOC emissions. Table 7 presents the total VOC emissions reduction (approximately 16,004 tpy) for existing area sources. Table 8 presents the VOC emissions reduction (approximately 1,013 tpy) for new sources.

Other secondary air pollution impacts are those associated with the operation of certain air emission control devices (i.e., flares). For facilities located within UC $\geq$ 10,000 and UA plus offset areas EPA assumed that 90 percent of the facilities would install condensers. Of these, EPA estimated that 45 percent of impacted facilities would be able to recycle the non-condensable vapors into a low pressure header system for combination with other hydrocarbon streams handled at the facilities and 45 percent of impacted facilities would use the non-condensable portion of the emission stream as a supplemental fuel for the glycol reboiler.[17] Therefore, for 90 percent of the impacted facilities there is no net change in energy use associated with the application of this control technology for facilities that incorporate this design and no net change in combustion-related emissions. In some cases, a facility does not have the ability to handle the collected vapor for use as a fuel or recycle the collected vapor back into the process. In such cases, the collected vapors may be directed to an on-site flare. EPA estimated that 10 percent of the facilities required to install add-on controls would direct all collected non-condensable vapors to an on-site flare.[18] The adverse secondary air impacts resulting from the use of a flare would be minimal in comparison to the primary HAP reduction

[17] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. National Emission Standards for Hazardous Air Pollutants for Source Categories: Oil and Natural Gas Production and Natural Gas Transmission and Storage. Background Information Document for Proposed Standards. EPA-453/R-94-079a. page 5-2.

[18] See footnote 17.

NMED Exhibit 79 - 0009

Table 5. HAP Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to New Sources

Throughput Category (MMscf/d)	Number of Units	Total HAP Emissions (tpy)	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	HAP Emission Reduction due to Management Practices (tpy)**	Total HAP Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	2,269	2,050	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	56	337	1	5	55	149	154
>3 and ≤4	46	372	1	6	45	164	170
>4 and ≤5	38	385	1	8	37	169	177
Total	141	1,093	3	19	138	482	501

* Emission reduction of 77.5%

** Emission reductions of 45% (see footnote 13).

NMED Exhibit 79 - 0010

Table 6. Benzene Air Emission Impacts Associated with Applying Add-on Controls and Management Practices to New Sources

Throughput Category (MMscf/d)	Number of Units	Total Benzene Emissions (tpy)	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	Benzene Emission Reduction due to Management Practices (tpy)**	Total Benzene Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	2,269	611	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	56	100	1	1	55	46	48
>3 and ≤4	46	111	1	2	45	51	53
>4 and ≤5	38	115	1	2	37	52	55
Total	141	326	3	6	138	150	155

* Emission reduction of 77.5%

** Emission reductions of 47% (see footnote 13).

NMED Exhibit 79 - 0011

Table 7. Secondary VOC Air Pollution Impacts Associated with Applying Add-on Controls and Management Practices to Existing Sources

Throughput Category (MMscf/d)	Number of Units	Total VOC Emissions (tpy)	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Management Practices (tpy)**	Total VOC Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	35,845	62,098	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	884	10,199	20	179	864	4,751	4,930
>3 and ≤4	732	11,261	16	191	716	5,249	5,440
>4 and ≤5	606	11,653	14	209	592	5,425	5,634
Total	2,222	33,112	50	578	2,172	15,426	16,004

* Emission reduction of 77.5%

** Emission reductions of 48% (see footnote 13).

NMED Exhibit 79 - 0012

Table 8. Secondary VOC Air Pollution Impacts Associated with Applying Add-on Controls and Management Practices to New Sources

Throughput Category (MMscf/d)	Number of Units	Total VOC Emissions (tpy)	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Add-on Controls (tpy)*	Number of Units Subject to Emission Reduction	VOC Emission Reduction due to Management Practices (tpy)**	Total VOC Emission Reduction (tpy)
Not Subject to Emission Reduction Requirements							
≤ 2	2,269	3,931	0	0	0	0	0
Subject to Emission Reduction Requirements							
>2 and ≤3	56	646	1	9	55	302	311
>3 and ≤4	46	713	1	12	45	332	344
>4 and ≤5	38	738	1	15	37	342	357
Total	141	2,096	3	36	138	977	1,013

* Emission reduction of 77.5%

** Emission reductions of 48% (see footnote 13).

NMED Exhibit 79 - 0013

benefits from implementing the proposed control options for area sources. The secondary air impacts due to the use of flares are presented in Table 9 for existing area sources and Table 10 for new sources.

B. Water and Solid Waste Impacts

The water impacts associated the installation of a condenser system for the TEG dehydration unit reboiler vent would be minimal. The condensed water collected with the hydrocarbon condensate can be directed back into the system for reprocessing with the hydrocarbon condensate or, if separated, combined with produced water for disposal by reinjection.[19]

There is no solid waste generated from the control of HAP emissions using a condenser. Therefore, we do not anticipate any adverse solid waste impacts from the implementation of the area source standards.

V. ENERGY IMPACTS

Energy impacts are those energy requirements associated with the operation of emission control devices. There would be no national energy demand increase from the operation of any of the control options analyzed under the oil and natural gas production standards for area sources. The area source standards (1) encourage the use of emission controls that recover hydrocarbon products, such as methane and condensate, which can be used on-site as fuel or reprocessed within the production process and sold and (2) require management practices that result in a natural gas savings. Thus, the standards have a positive impact associated with the recovery of non-renewable energy resources.

VI. COST IMPACTS

The cost impacts due to the final area source standards include the cost of equipment that must be purchased, along with the cost of the installation of the equipment. There are also costs for the operation and maintenance of the equipment. Finally, there are costs associated with the required monitoring, inspection, recordkeeping, and reporting (MIRR). This section presents the estimated costs associated with compliance with the area source standards.

Existing Sources

The total capital investment and total annual costs associated with the installation of add-on controls for a single unit were estimated during the development of the July 2005 proposal and are summarized in Table 11.[20] Table 11 also presents the nationwide impacts for total capital investment ($847 thousand) and total annual cost ($883 thousand) for the 50 existing sources located within UC $\geq$ 10,000 and UA plus offset boundaries.

[19] See footnote 18, page 5-6.
[20] See footnote 14.

NMED Exhibit 79 - 0014

Table 9. Secondary Air Pollution Impacts Due to the Use of a Flare for Existing Area Sources in the Oil and Natural Gas Production Source Category

Pollutant	Estimated Emissions per Flare (lb/yr)*	Estimated Number of Units Installing a Flare	Nationwide Emissions (tpy)
SO_x	2.20	5	0.01
NO_x	106	5	0.26
CO	22	5	0.06

* See footnote 17, page 5-7.

NMED Exhibit 79 - 0015

Table 10. Secondary Air Pollution Impacts Due to the Use of a Flare for New Area Sources in the Oil and Natural Gas Production Source Category

Pollutant	Estimated Emissions per Flare (lb/yr)*	Estimated Number of Units Installing a Flare	Nationwide Emissions (tpy)
SO_x	22.05	1	0.01
NO_x	22	1	0.01
CO	5	1	0.00

* See footnote 17, page 5-7.

NMED Exhibit 79 - 0016

Table 11. Cost Impacts Associated with Add-on Controls for Existing Area Sources

	UC ≥ 10,000 and UA Plus Offset Revised Costs(a,b)	
Cost Parameter	**TEG-A (without flash tank)**	**TEG-A' (with flash tank)**
Capital Costs	17,220	14,410
Annualized Capital Costs	1,891	1,582
O&M	8,816	8,816
Other Annual Costs (Admin., taxes, ins.)	4,940	4,828
Product Recovery	(141)	(141)
MIRR (c)	2,193	2,193
Cost Impact Summary for one Unit		
Total Capital Investment	17,220	14,410
Total Annual Cost	17,699	17,278
Nationwide Impacts		
Estimated Number of Impacted Units (d)	45	5
Total Capital Investment	774,902	72,050
Total Annual Cost	796,456	86,390
Nationwide Total Capital Investment =		846,952
Nationwide Total Annual Cost =		882,846

a- Costs for the proposed rule are in July 1993 dollars

b- Revised costs are in April 2004 dollars

c- Labor cost for MIRR was updated based on March 2004 data from the BLS

d- Ten percent of TEG dehydration units are equipped with flash tanks

NMED Exhibit 79 - 0017

Table 12. Cost Impacts Associated with Implementing Management Practices for Existing Sources

Cost Parameter	Single Unit	Number of Impacted Units	Nationwide Cost Impacts
Total Capital Investment			
TEG dehydration units required to install a new pump	$ 1,539	1,086	$ 1,671,409
TEG dehydration units not required to install a new pump	$ -	1,086	$ -
Total	na	**2,172**	**$ 1,671,409**
Total Annual Costs			
TEG dehydration units required to install a new pump	$ 6,717	1,086	$ 7,294,187
TEG dehydration units not required to install a new pump	$ 6,405	1,086	$ 6,955,316
Total	na	**2,172**	**$ 14,249,503**
Total Gas Savings (all TEG dehydration units)	$ (5,802)	2,172	$ (12,602,957)
Total	na	**2,172**	**$ 1,646,546**

Table 13. Cost Impacts for Existing Sources and New Sources

Cost Parameter	Existing Sources	New Sources
Total Capital Investment		
Add-On Controls	$846,952	$37,590
Management Practices	$1,671,409	$106,195
Total	$2,518,361	$143,785
Total Annual Cost		
Add-On Controls	$882,846	$50,989
Management Practices	$14,249,503	$905,355
Gas Savings (Due to management practices)	($12,602,957)	($800,740)
Total	$2,529,392	$155,604

The total capital investment and total annual costs, as well as the gas savings, associated with the implementation of management practices for a single unit are presented in another memorandum.[21] Table 12 presents a summary of these impacts for the 2,172 existing sources estimated to be located outside of UC $\geq$ 10,000 and UA plus offset boundaries. It was assumed that 50 percent of these existing sources (1,086) would be required to install a new pump.

Table 13 presents the combined impacts for existing sources associated with the application of add-on controls and the implementation of management practices.

New Sources

To estimate the impacts of the area source standards on new sources, it was assumed that no new sources would be constructed without flash tanks. Therefore, total capital investment and total annual cost associated with applying add-on controls to new sources was calculated only for those already with flash tanks for the 3 new sources assumed to be located within UC $\geq$ 10,000 and UA plus offset boundaries. A summary of the cost impact calculations associated with the installation of add-on controls is presented in Table 14. A retrofit factor of 15 percent was assumed for existing sources.[22] Therefore, the new source capital investment values are 1.15 times lower than those presented in Table 11. The annual costs were calculated using the same methodology as used to estimate existing source annual costs.[23]

To estimate the cost impacts of applying management practices to new sources, the total capital investment and total annual cost associated with the reduction of the glycol circulation rate are the same as for existing sources.[24] Table 15 presents a summary of these impacts. The national impacts presented in Table 15 were estimated for the 138 new sources determined to be located outside of UC $\geq$ 10,000 and UA plus offset boundaries. Of these, 69 (50 percent of 138) were assumed to require the installation of a new pump and the remaining 69 were assumed to be able to design the TEG dehydration unit to achieve the optimum glycol circulation rate.

Table 13 also presents the combined impacts for new sources associated with the application of add-on controls and the implementation of management practices.

[21] See footnote 14.
[22] See footnote 1. Table 8.
[23] See footnote 1. Table 9.
[24] See footnote 14.

NMED Exhibit 79 - 0020

Table 14. Cost Impacts Associated with Add-on Controls for New Area Sources

	New Sources UC > 10,000 and UA Plus Offset Revised Costs(a,b)	
Cost Parameter	**TEG-A (without flash tank)**	**TEG-A' (with flash tank)**
Capital Costs	0	12,530
Annualized Capital Costs	0	1,376
O&M	0	8,816
Other Annual Costs (Admin., taxes, ins.)	0	4,752
Product Recovery	0	(141)
MIRR (c)	0	2,193
Cost Impact Summary for one Unit		
Total Capital Investment	0	12,530
Total Annual Cost	0	16,996
Nationwide Impacts		
Estimated Number of Impacted Units	0	3
Total Capital Investment	0	37,590
Total Annual Cost	0	50,989
Nationwide Total Capital Investment =		37,590
Nationwide Total Annual Cost =		50,989

a- Costs for the proposed rule are in July 1993 dollars

b- Revised costs are in April 2004 dollars

c- Labor cost for MIRR was updated based on March 2004 data from the BLS

NMED Exhibit 79 - 0021

Table 15. Cost Impacts Associated with Implementing Management Practices for New Sources

Cost Parameter	Single Unit	Number of Impacted Units	Nationwide Cost Impacts
Total Capital Investment			
TEG dehydration units required to install a new pump	$ 1,539	69	$ 106,195
TEG dehydration units not required to install a new pump	$ -	69	$ -
Total	na	**138**	**$ 106,195**
Total Annual Costs (not including gas savings)			
TEG dehydration units required to install a new pump	$ 6,717	69	$ 463,443
TEG dehydration units not required to install a new pump	$ 6,405	69	$ 441,912
Total	na	**138**	**$ 905,355**
Total Gas Savings (all TEG dehydration units)	$ (5,802)	138	$ (800,740)
Total Annual Cost (including gas savings)	na	**138**	**$ 104,615**

NMED Exhibit 79 - 0022

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Part V

Environmental Protection Agency

40 CFR Part 63
National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2002–0058; FRL–9676–8]

RIN 2060–AR13

National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; notice of final action on reconsideration.

SUMMARY: In this action the EPA is taking final action on its reconsideration of certain issues in the emission standards for the control of hazardous air pollutants from new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants, which were issued under section 112 of the Clean Air Act. As part of this action, the EPA is making technical corrections to the final rule to clarify definitions, references, applicability and compliance issues raised by petitioners and other stakeholders affected by this rule. On March 21, 2011, the EPA promulgated national emission standards for this source category. On that same day, the EPA also published a notice announcing its intent to reconsider certain provisions of the final rule. Following these actions, the Administrator received several petitions for reconsideration. After consideration of the petitions received, on December 23, 2011, the EPA proposed revisions to certain provisions of the March 21, 2011, final rule, and requested public comment on several provisions of the final rule. The EPA is now taking final action on the proposed reconsideration.

DATES: The May 18, 2011 (76 FR28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted January 31, 2013. The amendments in this rule to 40 CFR part 63, subpart DDDDD are effective as of April 1, 2013.

ADDRESSES: The EPA established a single docket under Docket ID No. EPA–HQ–OAR–2002–0058 for this action. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Jim Eddinger, Energy Strategies Group, Sector Policies and Programs Division, (D243–01), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; Telephone number: (919) 541–5426; Fax number (919) 541–5450; Email address: *eddinger.jim@epa.gov*.

SUPPLEMENTARY INFORMATION:

Executive Summary

Purpose of This Regulatory Action

The EPA is taking final action on its proposed reconsideration of certain provisions of its March 21, 2011, final rule that established standards for new and existing industrial, commercial, and institutional boilers and process heaters at major sources of hazardous air pollutants. Section 112(d) of the CAA requires the EPA to regulate HAP from major stationary sources based on the performance of MACT. Section 112(h) of the CAA allows the EPA to establish work practice standards in lieu of numerical emission limits only in cases where the agency determines that it is not feasible to prescribe or enforce an emission standard, including circumstances in which the agency determines that the application of measurement methodology is not practicable due to technological and economic limitations. The EPA is revising certain MACT standards established in March 2011 for boilers and process heaters, including standards for CO—as a surrogate for organic HAP; HCl—as a surrogate for acid gas HAP; Hg; TSM or filterable PM—as a surrogate for non-Hg metallic HAP; and dioxin/furan.

This final rule amends certain provisions of the final rule issued by the EPA on March 21, 2011. The EPA delayed the effective date of the 2011 rule in a May 18, 2011, notice, but that delay notice was vacated by the U.S. District Court for the District of Columbia on January 9, 2012, and the March 2011 final rule was, therefore, in effect until publication of this action.

Summary of Major Reconsideration Provisions

In general, this final rule requires facilities classified as major sources of HAP with affected boilers or process heaters to reduce emissions of harmful toxic air emissions from these combustion sources. This will improve air quality and protect public health in communities where these facilities are located.

Recognizing the diversity of this source category and the multiple sectors of the economy this final rule effects, the EPA is revising certain subcategories for boilers and process heaters in this action that were established in the March 2011 final rule, based on the design of the combustion equipment. These revisions result in 19 subcategories for the boilers and process heaters source category. Numerical emission limits are established for most of the subcategories for five pollutants, CO, HCl, Hg, and PM or TSM. The review of existing data and consideration of new data have resulted in changes to some of the emission limits contained in the March 2011 final rule. Overall, for both new and existing affected units, about 30 percent of the emission limits are more stringent, half are less stringent, and 20 percent unchanged as compared to the March 2011 final rule. Also, based on its review and analysis of new data submissions, the EPA is establishing an alternative emission standard for CO, based on CEMS data for several subcategories with CO CEMS data available. This alternative standard is based on a 30-day rolling average for subcategories for which sufficient CEMS data were available for more than a 30-day period, or a 10-day rolling average for subcategories for which CEMS data were available for less than a 30-day period, and provides additional compliance flexibility to sources. All of the subcategories are subject to periodic tune-up work practices for dioxin/furan emissions.

The compliance dates for the rule are January 31, 2016, for existing sources and, January 31, 2013, or upon startup, whichever is later, for new sources. New sources are defined as sources that began operation on or after June 4, 2010.

Costs and Benefits

The final rule affects 1,700 existing major source facilities with an estimated 14,136 boilers and process heaters and the EPA projects an additional 1,844 new boilers and process heaters to be subject to this final rule over the next 3

years. This final rule affects multiple sectors of the economy including small entities. Table 1 summarizes the costs and benefits associated with this final rule. A more detailed discussion of the costs and benefits of this final rule is provided in section VI of this preamble.

TABLE 1—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$25,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,000 to $59,000.
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of Hg and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.

[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the ''social cost of carbon,'' which is discussed further in the RIA.

[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

ACC American Chemistry Council
ACCCI American Coke and Coal Chemicals Institute
AF&PA American Forest and Paper Association
AHFA American Home Furnishings Alliance
AISI American Iron and Steel Institute
AMP American Municipal Power Inc.
AIE Alliance for Industrial Efficiency
APCD air pollution control devices
API American Petroleum Institute
AIF Auto Industry Forum
BFG Blast furnace gas
BLDS Bag leak detection system
BCSE The Business Council for Sustainable Energy
CIBO Council of Industrial Boiler Owners
CO Carbon monoxide
CO_2 Carbon dioxide
CEMS Continuous emissions monitoring system
CEG Citizens Energy Group
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous parameter monitoring system
CMI CraftMaster Manufacturing Inc.
ERT Electronic Reporting Tool
ESP Electrostatic precipitator
EPA Environmental Protection Agency
FBC Fluidized bed combustion
FR Federal Register
FSI Florida Sugar Industry
GPSP Great Plains Synfuels Plant
HAP Hazardous air pollutants
HBES Health-based emissions standard
HF Hydrogen fluoride
Hg Mercury
HCl Hydrogen chloride
kWh Kilowatt hours
ISO International Standards Organization
lb Pounds
LFG Landfill gas
MACT Maximum achievable control technology
MATS Mercury Air Toxics Standards
MSU Michigan State University
MMBtu Million British thermal units
NESHAP National Emission Standards for Hazardous Air Pollutants
NPRA National Petrochemical and Refiners Association
NTTAA National Technology Transfer and Advancement Act
NAICS North American Industry Classification System
NO_X Nitrogen oxide
NSR New Source Review
OMB Office of Management and Budget
PM Particulate matter
PSU Penn State University
PS Performance Specification
ppm Parts per million
QA Quality assurance
QC Quality control
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
RPU Rochester Public Utilities
RTC Response to comment
SCR Selective catalytic reduction
SNCR Selective non-catalytic reduction
SO_2 Sulfur dioxide
TBtu/yr Trillion British thermal units per year
THC Total hydrocarbon
TSM Total selected metals
TTN Technology Transfer Network
tpy Tons per year
UMRA Unfunded Mandates Reform Act of 1995
U.S. United States
USCHPA US Clean Heat Power Association
US Sugar United States Sugar Corporation
UPL Upper prediction limit
UARG Utility Air Regulatory Group
VCS Voluntary Consensus Standards
VOC Volatile organic compounds
WM Waste Management Inc.
WEPCO Wisconsin Electric Power Company
WWW Worldwide Web

Organization of this Document. The information presented in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document?
C. Judicial Review
II. Background Information
A. Chronological History of Related Actions
III. Summary of This Final Rule
A. What is an affected source?
B. What are the subcategories of boilers and process heaters?
C. What emission limits and work practice standards are being finalized?
D. What are the requirements during periods of startup and shutdown?
E. What are the testing and initial compliance requirements?
F. What are the continuous compliance requirements?

G. What are the compliance dates?
IV. Summary of Significant Changes Since Proposal
A. Applicability
B. Subcategories
C. Performance Test Requirements
D. Emission Limits
E. Work Practice Requirement
F. Averaging Times Definitions
G. Energy Assessment
H. Startup and Shutdown Definitions
I. Fuel Sampling Frequency
J. Affirmative Defense
V. Other Actions We Are Taking
VI. Impacts of This Final Rule
A. What are the incremental air impacts?
B. What are the incremental water and solid waste impacts?
C. What are the incremental energy impacts?
D. What are the incremental cost impacts?
E. What are the economic impacts?
F. What are the benefits of this final rule?
G. What are the incremental secondary air impacts?
VII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. General Information

A. Does this action apply to me?

The regulated categories and entities potentially affected by this action include:

TABLE 2—POTENTIAL REGULATED CATEGORIES AND ENTITIES AFFECTED

Category	NAICS code[1]	Examples of potentially regulated entities
Any industry using a boiler or process heater as defined in the final rule	211	Extractors of crude petroleum and natural gas.
	321	Manufacturers of lumber and wood products.
	322	Pulp and paper mills.
	325	Chemical manufacturers.
	324	Petroleum refineries, and manufacturers of coal products.
	316, 326, 339	Manufacturers of rubber and miscellaneous plastic products.
	331	Steel works, blast furnaces.
	332	Electroplating, plating, polishing, anodizing, and coloring.
	336	Manufacturers of motor vehicle parts and accessories.
	221	Electric, gas, and sanitary services.
	622	Health services.
	611	Educational services.

[1] North American Industry Classification System.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this reconsideration action. To determine whether your facility may be affected by this reconsideration action, you should examine the applicability criteria in 40 CFR 63.7485 of subpart DDDDD (National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial, Commercial, and Institutional Boilers and Process Heaters). If you have any questions regarding the applicability of this final rule to a particular entity, consult either the air permitting authority for the entity or your EPA regional representative, as listed in 40 CFR 63.13 of subpart A (General Provisions).

B. Where can I get a copy of this document?

In addition to being available in the docket, an electronic copy of this action will also be available on the WWW through the TTN. Following signature, a copy of the action will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

C. Judicial Review

Under the CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by April 1, 2013. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

II. Background Information

A. Chronological History of Related Actions

On March 21, 2011, the EPA issued final standards for new and existing industrial, commercial, and institutional boilers and process heaters, pursuant to its authority under section 112 of the CAA. On the same day as the final rule was issued, the EPA stated in a separate notice that it planned to initiate a reconsideration of several provisions of the final rule. This reconsideration notice identified several provisions of the March 2011 final rule where additional public comment was appropriate. This notice also identified several issues of central relevance to the rulemaking where reconsideration was appropriate under CAA section 307(d).

On May 18, 2011, the EPA issued a notice to postpone the effective date of the March 21, 2011 final rule. Following promulgation of the final rule, the EPA received petitions for reconsideration from the following organizations

(''Petitioners''): AIE, USCHPA, Alyeska Pipeline, ACC, AHFA, AISI, ACCCI, AMP, API, NPRA, AIF, Citizens Energy Group (CEG), CIBO, CMI, District Energy St. Paul, FSI, GPSP, Hovensa L.L.C., Tesoro Hawaii Corp., Industry Coalition (AF&PA *et al.*), JELD–WEN Inc., MSU, PSU, Purdue University, Renovar Energy Corp., RPU, Sierra Club, Southeastern Lumber Manufacturers Association, State of Washington Department of Ecology, BCSE, UARG, US Sugar, WM and WEPCO. Copies of these petitions are provided in the docket (see Docket ID No. EPA–HQ–OAR–2002–0058). Petitioners, pursuant to CAA section 307(d)(7)(B), requested that the EPA reconsider numerous provisions in the rule. On December 23, 2011, the EPA granted the petitions for reconsideration on certain issues, and proposed certain revisions to the final rule in response to the reconsideration petitions and to address the issues that the EPA previously identified as warranting reconsideration. That proposal solicited comment on several specific aspects of the rule, including:

- Revising the proposed subcategories.
- Solicitation of new data or corrections to existing data to revise emission standards calculations.
- Establishing an alternative TSM limit.
- Appropriateness of an alternative TSM limit for the liquid subcategories.
- Establishing work practice standards for dioxin/furan emissions.
- Revising the efficiency assumptions for the alternative output-based emission standards.
- Accommodating emissions averaging provisions in the alternative output-based emission standards.
- Establishing a mercury fuel specification through which gas-fired boilers that use a fuel other than natural gas or refinery gas may be considered Gas 1 units.
- Establishing a work practice standard for limited use units.
- Providing an affirmative defense for malfunction events.
- Revisions to the monitoring requirements for oxygen in the March 2011 final rule.
- Establishing a full-load stack test requirement for carbon monoxide coupled with continuous oxygen (oxygen trim) monitoring.
- Revising PM monitoring requirements from CEMS to CPMS and exempting biomass units from PM CPMS requirements.
- Revising mercury monitoring requirements to allow for an alternative mercury CEMS.
- Considering use of SO_2 CEMS to demonstrate compliance with HCl limits.
- Minimum data availability provisions.
- Averaging times for monitored parameters and pollutants.
- Revised methods for computing minimum detection levels.
- Providing an alternative CO emission limit based on CO CEMS data.
- Soliciting additional data to set MACT floor emission limits for non-continental liquid units.
- Selecting a 99 percent confidence interval for setting the CO emission limit.
- Tune-up frequencies, timing of initial tune-ups and adjusted tune-up requirements for shutdown units.
- Scope and duration of the energy assessment and deadline for completing the assessment.
- Revising work practices during startup and shutdown.
- Revisions to certain exemptions, including units serving as control devices, waste heat process heaters, units firing comparable fuels and residential units.
- Revisions to reduced testing frequency for emission limits that are established at minimum detection levels.
- Removing fuel analysis requirements for gas 1 fuels at co-fired units.
- Revisions to automating techniques for coal sampling.
- Revisions to emissions averaging across subcategories when units opt to switch to natural gas.
- Consideration of a new subcategory for units installed and used in place of flares.

In this action, the EPA is finalizing multiple changes to the March 2011 final rule after considering public comments on the items under reconsideration.

III. Summary of This Final Rule

As stated above, the December 23, 2011 proposed rule addressed specific issues and provisions the EPA identified for reconsideration. This summary of the final rule reflects the changes to 40 CFR part 63, subpart DDDDD (March 21, 2011 final rule) in regards to those provisions identified for reconsideration and on other discrete matters identified in response to comments or data received during the comment period. Information on other provisions and issues not proposed for reconsideration is contained in the notice and record for the 2011 final rule. [See 76 FR 15608]

This section summarizes the requirements of this action. Section IV below provides a summary of the significant changes to the March 21, 2011 final rule.

A. What is an affected source?

This final rule revises the list of exemptions in § 63.7491 to include residential boilers that may be located at an industrial, commercial or institutional major source. The exemption for boilers or process heaters used specifically for research and development has been revised to include boilers used for certain testing purposes.

B. What are the subcategories of boilers and process heaters?

In this final rule, we are finalizing separate subcategories for heavy liquid-fired, light liquid-fired and liquid-fired units in non-continental locations for PM and CO, pollutants that are dependent on combustor design. In addition, a new subcategory for coal-fired fluidized bed boilers with integrated fluidized bed heat exchangers has been included in the final rule for CO which is dependent on boiler design. Finally, we are finalizing the subcategory for PM at coal/fossil solid units across all coal combustor designs.

C. What emission limits and work practice standards are being finalized?

You must meet the emission limits presented in Table 3 of this preamble for each subcategory of units listed in the table. This final rule includes 19 subcategories, which are based on unit design. New and existing units in three of the subcategories are subject to work practices standards in lieu of emission limits for all pollutants. Numeric emission limits are finalized for new and existing sources in each of the other 16 subcategories.

The changes associated with the emission limits are due to new data, corrections to old data, and inventory changes. In summary, for existing subcategories, for the HCl emission limits, 10 are more stringent, 3 are less stringent and 1 remained the same from the March 21, 2011 final rule; for the mercury emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule; for the PM emission limits, 2 are more stringent, 7 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 4 are more stringent and 10 are less stringent from the March 21, 2011 final rule. For new subcategories, for the HCl emission limits, 13 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the mercury emission limits, 11 are more

stringent, 2 are less stringent and 1 is unchanged from the March 21, 2011 final rule; for the PM emission limits, 9 are less stringent and 5 are unchanged from the March 21, 2011 final rule; and for the CO emission limits, 3 are more stringent and 11 are less stringent from the March 21, 2011 final rule.

TABLE 3—EMISSION LIMITS FOR BOILERS AND PROCESS HEATERS

[lb/MMBtu heat input basis unless noted; alternative output based limits are not shown in the summary table below]

Subcategory	Filterable PM (or total selected metals) (lb per MMBtu of heat input) [a]	HCl (lb per MMBtu of heat input) [a]	Mercury (lb per MMBtu of heat input) [a]	CO (ppm @3% oxygen) [a]	Alternate CO CEMS limit, (ppm @3% oxygen) [b]
Existing—Coal Stoker	0.040 (5.3E–05)	0.022	5.7E–06	160	340
Existing—Coal Fluidized Bed	0.040 (5.3E–05)	0.022	5.7E–06	130	230
Existing—Coal Fluidized Bed with FB heat exchanger	0.040 (5.3E–05)	0.022	5.7E–06	140	150
Existing—Coal-Burning Pulverized Coal	0.040 (5.3E–05)	0.022	5.7E–06	130	320
Existing—Biomass Wet Stoker/Sloped Grate/Other	0.037 (2.4E–04)	0.022	5.7E–06	1,500	720
Existing—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.32 (4.0E–03)	0.022	5.7E–06	460	ND
Existing—Biomass Fluidized Bed	0.11 (1.2E–03)	0.022	5.7E–06	470	310
Existing—Biomass Suspension Burner	0.051 (6.5E–03)	0.022	5.7E–06	2,400	[c] 2,000
Existing—Biomass Dutch Ovens/Pile Burners	0.28 (2.0E–03)	0.022	5.7E–06	770	[c] 520
Existing—Biomass Fuel Cells	0.020 (5.8E–03)	0.022	5.7E–06	1,100	ND
Existing—Biomass Hybrid Suspension Grate	0.44(4.5E–04)	0.022	5.7E–06	2,800	900
Existing—Heavy Liquid	0.062 (2.0E–04)	0.0011	2.0E–06	130	ND
Existing—Light Liquid	0.0079 (6.2E–05)	0.0011	2.0E–06	130	ND
Existing—non-Continental Liquid	0.27 (8.6E–04)	0.0011	2.0E–06	130	ND
Existing—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND
New—Coal Stoker	0.0011 (2.3E–05)	0.022	8.0E–07	130	340
New—Coal Fluidized Bed	0.0011 (2.3E–05)	0.022	8.0E–07	130	230
New—Coal Fluidized Bed with FB Heat Exchanger	0.0011 (2.3E–05)	0.022	8.0E–07	140	150
New—Coal-Burning Pulverized Coal	0.0011 (2.3E–05)	0.022	8.0E–07	130	320
New—Biomass Wet Stoker/Sloped Grate/Other	0.030 (2.6E–05)	0.022	8.0E–07	620	390
New—Biomass Kiln-Dried Stoker/Sloped Grate/Other	0.030 (4.0E–03)	0.022	8.0E–07	460	ND
New—Biomass Fluidized Bed	0.0098 (8.3E–05)	0.022	8.0E–07	230	310
New—Biomass Suspension Burner	0.030 (6.5E–03)	0.022	8.0E–07	2,400	[c] 2,000
New—Biomass Dutch Ovens/Pile Burners	0.0032 (3.9E–05)	0.022	8.0E–07	330	[c] 520
New—Biomass Fuel Cells	0.020 (2.9E–05)	0.022	8.0E–07	910	ND
New—Biomass Hybrid Suspension Grate	0.026 (4.4E–04)	0.022	8.0E–07	1,100	900
New—Heavy Liquid	0.013 (7.5E–05)	4.4E–04	4.8E–07	130	ND
New—Light Liquid	0.0011 (2.9E–05)	4.4E–04	4.8E–07	130	ND
New—Non-Continental Liquid	0.023 (8.6E–04)	4.4E–04	4.8E–07	130	ND
New—Gas 2 (Other Process Gases)	0.0067 (2.1E–04)	0.0017	7.9E–06	130	ND

NA-Not applicable; ND-No data available
[a] 3-run average, unless otherwise noted.
[b] 30-day rolling average, unless otherwise noted.
[c] 10-day rolling average.

We also are finalizing a work practice standard for dioxin/furan emissions from all subcategories.

D. What are the requirements during periods of startup and shutdown?

We are finalizing revised work practice standards for periods of startup and shutdown to better reflect the maximum achievable control technology during those periods. In addition, we are finalizing definitions of startup and shutdown. We are defining startup as the period between the state of first-firing of fuel in the unit after a shutdown to the period where the unit first supplies steam. We are defining shutdown as the period that begins when no more steam is supplied or at the point of no fuel being fired in the unit. For periods of startup and shutdown, we are finalizing the following work practice standard: You must operate all continuous monitoring systems during startup and shutdown. For startup, you must use one or a combination of the listed clean fuels. Once you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must engage all of the applicable control devices except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems as expeditiously as possible. During shutdown while firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR. You must comply with all applicable emissions and operating limits at all times the unit is in operation except for periods that meet the definitions of startup and shutdown in this subpart, during which times you must comply with these work practices. You must keep records during periods of startup or shutdown. You must keep records concerning the date, duration, and fuel usage during startup and shutdown.

E. What are the testing and initial compliance requirements?

We are requiring that the owner or operator of a new or existing boiler or process heater conduct performance tests to demonstrate compliance with all applicable emission limits. This final rule adds the requirement to conduct initial and annual stack tests to determine compliance with the TSM emission limits using EPA Method 29 for those subcategories with alternate TSM limits.

F. What are the continuous compliance requirements?

This final rule removes the requirement for units combusting biomass with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain and operate a CEMS measuring PM emissions. This final rule requires units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater to install, certify, maintain, and operate PM CPMS. Moreover, owners or operators of units combusting solid fossil fuel or heavy liquid with heat input capacities of 250 MMBtu/hr or greater are allowed to install, certify, maintain and operate PM CEMS as an alternative to the use of PM CPMS, consistent with regulations for similarly-sized commercial and industrial solid waste incinerators units and EGUs subject to the MATS. Just as units using PM CPMS will not be required to conduct parameter monitoring for PM, units using PM CEMS will not be required to conduct parameter monitoring for PM.

This final rule also includes an alternative method of demonstrating continuous compliance with the HCl emission limit. This method allows using SO_2 emissions as an alternate operating limit. This method of demonstrating continuous compliance will be allowed only on a unit that utilizes a SO_2 CEMS and an acid-gas control technology including wet scrubber, dry scrubbers and duct sorbent injection. Boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS would be required to maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

G. What are the compliance dates?

For existing sources, the EPA is establishing a compliance date of January 31, 2016. New sources must comply by January 31, 2013, or upon startup, whichever is later. New sources are defined as sources which commenced construction or reconstruction on or after June 4, 2010 pursuant to section 112(a)(4).

Commenters have argued that the 3-year compliance deadline the EPA is establishing for existing sources to meet the standards does not provide them with sufficient time to meet the standards in view of the large number of sources that will be competing for the needed resources and materials from engineering consultants, permitting authorities, equipment vendors, construction contractors, financial institutions, and other critical suppliers.

As an initial matter, we note that many sources subject to the emission standards in the final rule should be able to meet the standards within three years, even those that need to install pollution control technologies to do so. In addition, many sources subject to the rule are gas fired units or small boilers (less than 10 MMBtu/hr) and will not need to install controls in order to demonstrate compliance, as these sources are subject to work practice standards. For these sources, the 3-year compliance deadline is highly unlikely to be problematic either in general, or with respect to the claims commenters have made about the possibility that the demand for resources related to control technology will exceed the supply.

At the same time, the CAA allows title V permitting authorities to grant sources, on a case-by-case basis, extensions to the compliance time of up to one year if such time is needed for the installation of controls. *See* CAA section 112(i)(4)(i)(A). Permitting authorities are already familiar with, and in many cases have experience with, applying the 1-year extension authority under section 112(i)(4)(A) since the provision applies to all NESHAP. We believe that should the range of circumstances that commenters have cited as impeding sources' ability to install controls within three years materialize, then it is reasonable for permitting authorities to take those circumstances into consideration when evaluating a source's request for a 1-year extension, and where such applications prove to be well-founded, it is also reasonable for permitting authorities to make the 1-year extension available to applicants.

In making a determination as to whether an extension is appropriate, we believe it is also reasonable for permitting authorities to consider the large number of pollution control retrofit projects being undertaken for purposes of complying either with the standards in this rule or with those of other rules such as MATS for the power sector that may be competing for similar resources.

Further, commenters have pointed out that in some cases operators of existing sources that are subject to these standards and that generate energy may opt to meet the standards by terminating operations at these sources and building new sources to replace the energy generation at the shut-down sources. While the ultimate discretion to provide a 1-year extension lies with the permitting authority, the EPA believes that it is reasonable for permitting authorities to allow the fourth year extension for the installation of replacement sources of energy generation at the site of a facility applying for an extension for that purpose. Specifically, the EPA believes where an applicant demonstrates that it is building replacement sources of energy generation for purposes of meeting the requirements of these standards such a replacement project could be deemed to constitute the ''installation of controls'' under section 112(i)(3)(B).

In a case where pollution controls are being installed or onsite replacement energy generation is being constructed to allow for retirement of older, under-controlled energy generation units, a determination that an extra year is necessary for compliance should be relatively straightforward. In order to install controls, companies are likely to undertake a number of steps relatively soon after the effective date of the rule, including obtaining necessary building and environmental permits and hiring contractors to perform the construction of the emission controls or replacement energy generation units. This should provide sufficient information for a permitting authority to determine that emission controls are being installed or that replacement energy generation is being constructed. As a result, a permitting authority will be in a position to make a determination as to whether a source's compliance schedule will exceed 3 years and to quickly make a determination as to when an extension is appropriate.

In sum, the EPA believes that although most, if not all, units will be able to fully comply with the standards within 3 years, the fourth year that permitting authorities are allowed to grant for installation of controls is an important flexibility that will address situations where an extra year is necessary. Of course in situations where EPA is the permitting authority, we would also consider the above circumstances when acting on a permit application.

IV. Summary of Significant Changes Since Proposal

The EPA has made numerous changes in this final rule from the proposal after consideration of the public comments received. Most are changes to clarify applicability and implementation issues raised by the commenters. The public comments received on the proposed changes and the responses to them can be viewed in the memorandum ''Response to Comments for Industrial, Commercial, and Institutional Boilers

and Process Heaters National Emission Standards for Hazardous Air Pollutants'' located in the docket.

A. Applicability

Since proposal, the EPA has made certain changes to the applicability of this final rule. We have clarified that the exemption for boilers and process heaters used for research and development includes boilers used for testing the propulsion systems on military vessels. This is consistent with the intent of the exemption in that these test boilers do not provide steam for heating, to a process, or other non-propulsion related uses but are used exclusively to test the propulsion systems of nuclear-powered aircraft carriers that are undergoing repair, overhaul, or installation.

B. Subcategories

As described in the preamble to the proposed reconsideration rule, within the basic unit types of boilers and process heaters there are different designs and combustion systems that, while having a minor effect on fuel-dependent HAP emissions, have a much larger effect on pollutants whose emissions depend on the combustion conditions in a boiler or process heater. In the case of boilers and process heaters, the combustion-related pollutants are the organic HAP. In the proposed rule, we identified the following 17 subcategories for organic HAP: (1) Pulverized coal units; (2) stokers designed to burn coal; (3) fluidized bed units designed to burn coal; (4) stokers designed to burn wet biomass; (5) stokers designed to burn kiln-dried biomass; (6) fluidized bed units designed to burn biomass; (7) suspension burners designed to burn biomass; (8) dutch ovens/pile burners designed to burn biomass; (9) fuel cells designed to burn biomass; (10) hybrid suspension grate units designed to burn biomass; (11) units designed to burn heavy liquid fuel; (12) units designed to burn light liquid fuel; (13) non-continental liquid units; (14) units designed to burn natural gas/refinery gas; (15) units designed to burn other gases; (16) metal process furnaces; and (17) limited-use units.

In this final rule, we are also adding a separate subcategory for fluidized bed units with a fluidized bed heat exchanger designed to burn coal and adjusted the definition of the limited use subcategory.

Fluidized bed boilers are designed to combust fuel with relatively low heating value and high ash compared to other combustor designs. Two fuel properties of coal are heating values and ash content. As the heating value of the coal decreases, ash content increases. Fluidized bed boilers are designed to have large tube surface areas to transfer heat from the fuel through the process of conduction and convection, but in some cases the amount of tube surface area in the furnace for heat transfer is insufficient. In order to overcome insufficient heat exchange, certain fluidized bed boilers adopt a fluidized bed heat exchanger design to achieve heat transfer. The fluidized bed heat exchanger is located at the exit of the cyclone section of the unit. This design allows the boiler to combust coal with a lower heating value than a coal-fired fluidized bed boiler without a fluidized bed heat exchanger. Therefore, because this boiler design does have different combustion-related HAP emission characteristics, a new subcategory of coal fluidized bed with integrated heat exchanger was added to the final rule.

The EPA is also revising the definition of the limited use subcategory. Many affected units operate on standby mode or low loads for periods longer than the proposed definition for limited use units, which limited operation to 876 hours per year. By converting to a capacity-factor approach, we are allowing more flexibility on unit operations without increasing emissions or harm to human health and the environment. For example, units operating at 10 percent load for 8,760 hours per year would emit the same amount of emissions as units operating at full load for 876 hours per year. Further, it is technically infeasible to schedule stack testing for these limited use units since these units serve as back up energy sources and their operating schedules can be intermittent and unpredictable. The limited use subcategory was adjusted to be based on units with a federally enforceable operating limit of less than or equal to 10 percent of an average annual capacity factor.

C. Performance Test Requirements

Table 5 of this final rule has been revised to add performance test procedures for conducting performance stack tests for demonstrating compliance with the alternate TSM emission limits. In the reconsideration proposal, we proposed emissions limits for TSM (i.e., arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium) as an alternative to the proposed PM emission limits for many of the subcategories. In the preamble to the proposed rule, we added procedures in Table 6 of the rule for conducting fuel analysis for total selected metals but we inadvertently failed to add performance test requirements for stack sampling of TSM emissions in Table 5 of the rule.

D. Emission Limits

One significant change since proposal is related to the PM emission limits for the coal subcategories. Several petitioners disagreed with EPA's position to set different PM limits for subcategories of boilers and process heaters based on the fuel used, and instead offered information to support the position that PM should be considered a combustion-based pollutant. The differences in PM particle size, fouling characteristics and feasibility of certain control technologies on certain unit designs suggested that PM is more appropriately classified as a combustion-based pollutant, but only for the coal subcategories. After assessing the points raised by the petitioners, the EPA agreed that PM emissions are influenced by unit design, and fuel type, and proposed to create combustion-based pollutant subcategories for coal and solid fuels and create fuel-based subcategories for liquid and biomass fuel units. The EPA is finalizing a single PM limit for all coal/solid fossil fuel subcategories, and is also finalizing emissions limits based on PM as a combustion-based pollutant for the biomass and liquid fuel subcategories.

Another change from proposal is that the alternative TSM emission limits are now applicable to the three liquid fuel subcategories. Several commenters provided data and comments supporting these alternative emission standards for non-mercury metallic HAP. After assessing the revised data and the points made by the commenters, the EPA agrees that the limited data available for liquid fuel units are not unique to this subcategory. Based on the EPA agreeing with the commenters, the EPA re-calculated the TSM emission limits for the liquid fuel subcategories and included them in the final rule.

The CO emission limit for several subcategories, both new and existing, have been revised to reflect a CO level that is consistent with MACT for organic HAP reduction. Several commenters recommended that the EPA evaluate a minimum CO standard (i.e., 100 ppm corrected to 7 percent oxygen) to serve as a lower bound surrogate for organic HAP. Commenters also provided data and information to support such a standard, and noted that the EPA has taken a similar approach in other emission standards under section 112.

The EPA evaluated whether there is a minimum CO level for boilers and

process heaters below which there is no further benefit in organic HAP reduction/destruction. Specifically, we evaluated the relationship between CO and formaldehyde using the available data obtained during the rulemaking. Formaldehyde was selected as the basis of the organic HAP comparison because it is the most prevalent organic HAP in the emission database and a large number of paired tests existed for boilers and process heaters for CO and formaldehyde. The paired data show decreasing formaldehyde emissions with decreasing CO emissions down to CO levels around 300 ppm, supporting the selection of CO as a surrogate for organic HAP emissions. A slight increase in formaldehyde emissions is observed at CO levels below around 200 ppm, suggesting a breakdown in the CO-formaldehyde relationship at low CO levels. At levels lower than 150 ppm, the mean levels of formaldehyde appear to increase, as does the overall maximum value of and variability in formaldehyde emissions. However, we are aware of no reason why CO concentrations would continue to decrease and formaldehyde concentrations would increase as combustion conditions improve. It is possible that imprecise formaldehyde measurements at low concentrations (i.e., 1–2 ppm) may account for this slight increase in formaldehyde emissions observed at CO levels below 100 ppm corrected to 7 percent oxygen. Based on this, we do not believe that such measurements are sufficiently reliable to use as a basis for establishing an emissions limit.

Therefore, based on the above analysis, we are promulgating a minimum MACT floor level for CO of 130 ppm corrected to 3 percent oxygen (which is equivalent to 100 ppm corrected to 7 percent oxygen). We note this is the same approach used to establish the CO emission limit of 100 ppm corrected to 7 percent oxygen for the Burning of Hazardous Waste in Boilers and Industrial Furnaces rule. Additional discussion of the rationale for this approach can be found in the memorandum ''Revised MACT Floor Analysis (August 2012) for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source.''

Subcategories where the initial MACT floor 99 percent UPL calculations for CO were less than 100 ppm corrected to 7 percent oxygen (or equivalently 130 ppm corrected to 3 percent oxygen) are as follows:

- New and Existing Subcategories: Coal-FB, Coal-PC, Heavy Liquid, Light Liquid, Non-Continental Liquid, Process Gas
- New Subcategories: Coal-Stoker

We believe a CO level of 130 ppm corrected to 3 percent oxygen is an appropriate minimum MACT floor level. Although some measurements show CO levels below 130 ppm corrected to 3 percent oxygen, it is not appropriate to establish a lower floor level because CO is a conservative surrogate for organic HAP. In other words, organic HAP emissions are extremely low when sources operate under the good combustion conditions required to achieve CO levels in the range of zero to 100 ppm. As such, lowering the CO floor below 100 ppm will not provide reductions in organic HAP emissions. There are myriad factors that affect combustion efficiency and, as a function of combustion efficiency, CO emissions. As combustion conditions improve and hydrocarbon levels decrease, the larger and easier to combust compounds are oxidized to form smaller compounds that are, in turn, oxidized to form CO and water. As combustion continues, CO is then oxidized to form carbon dioxide and water. Because CO is a difficult to destroy refractory compound (*i.e.,* oxidation of CO to carbon dioxide is the slowest and last step in the oxidation of hydrocarbons), it is a conservative surrogate for destruction of hydrocarbons, including organic HAP.

The conservative nature of CO as an indicator of good combustion practices is supported by our data. At CO levels less than 100 ppm corrected to 7 percent oxygen, our data indicate that there is no apparent relationship between CO and organic HAP (i.e., formaldehyde). For example, a source with a CO level of 20 ppm may have the same measured formaldehyde as a source achieving a CO emission level of 100 ppm corrected to 7 percent oxygen. Sources are required to establish operating requirements based on operating levels that were demonstrated during the test. Sources must comply with these operating requirements on a continuous basis. Compliance with these requirements adequately assures sources will be controlling organic HAP emissions to MACT levels.

As detailed in the docketed memorandum ''Beyond the Floor Technology Analysis for Major Source Boilers and Process Heaters (Revised August 2012),'' we reviewed the emission limits that are becoming less stringent since the March 2011 final rule in order to assess whether a beyond the floor option was technically achievable and cost effective. As a result of this review, the PM emission limits for several new biomass subcategories have been changed to reflect a beyond the floor limit of 0.03 lb/MMBtu, based on the limit for new biomass boilers in 40 CFR part 60 subparts Db and Dc. Due to the low mercury emission limits for new solid fuel boilers, these new biomass units are expected to install a fabric filter level of control in order to meet the new source mercury limits for the solid fuel subcategory. This mercury control has the co-benefit of reducing PM emissions down to levels of 0.03 lb/MMBtu so there is no incremental cost to achieve these additional reductions in PM for the biomass units that have a design heat input capacity between 10 and 30 MMBtu/hr. For units with a design heat input capacity of 30 MMBtu/hr or greater, these units are already subject to a PM limit of 0.03 lb/MMBtu and adjusting these new source limits to this level of control makes the limits consistent between both rules, without adding additional costs. We did not identify any beyond the floor options for existing source PM limits or new and existing limits for other pollutants as technically feasible or cost effective.

The other changes associated with the other emission limits are due to new data, corrections to old data, and inventory changes. In summary, compared to the December 23, 2011 proposed limits for existing units, the final HCl emission limits remained the same; for the final mercury emission limits, 3 are more stringent, 10 are less stringent and 1 is unchanged; for the final PM emission limits, 3 are more stringent, 5 are less stringent and 6 are unchanged; and for the final CO emission limits, 3 are more stringent and 11 are less stringent. For new units, compared to the proposed emission limits, 3 of the final HCl emission limits are more stringent and 11 remained the same; for the final mercury emission limits, 10 are more stringent and 4 are unchanged; for the final PM emission limits, 5 are more stringent, 2 are less stringent and 7 are unchanged; and for the final CO emission limits, 2 are more stringent, 11 are less stringent and 1 is unchanged.

E. Work Practice Requirement

In this final rule several changes have been made to the work practice requirement to conduct a tune-up. First, the requirement to inspect the burner has been revised to allow units that sell electricity to schedule the burner inspection, as well as the air-to-fuel system inspection, at the time of the first outage but not to exceed 36 months from the previous inspection. This

change is being made to this final rule because commenters stated that large boilers that serve electricity for sale may not require annual outages and would, therefore, need to be taken off-line for the sole purpose of an annual tune-up. This frequency is consistent with the requirements of the NESHAP for electric utility boilers (40 CFR part 63, subpart UUUUU).

Also, for units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or into process equipment. Commenters indicated that some process heaters are installed inside tanks and entry into the tank to access the heater may not occur within a 5 year period.

The requirement to optimize total emissions of CO has been revised to require that this optimization not only be consistent with the manufacturer's specifications but also with any NO_X emission requirement to which the unit is subject. Some commenters indicated that many boilers need different tune-up criteria due to their requirement to also comply with low NO_X emission limits. We are also aware that several states have boiler tune-up requirements to minimize NO_X emissions first and then optimize CO emissions.

We have added boilers or process heaters that have a continuous oxygen trim system to the types of boilers or process heaters that must conduct a tune-up every 5 years. These units do not need to be tuned as frequently because the trim system is designed to continuously measure and maintain an optimum air to fuel ratio which is the purpose of a tune-up.

F. Averaging Times Definitions

We revised the definitions of ''30-day rolling average'' and ''daily block average'' to exclude periods of startup and shutdown or downtime from the arithmetic mean. Commenters requested that the EPA specify how a 30-day rolling average is calculated and whether it includes the previous 720 hours of valid operating data and that the valid data exclude hours during startup and shutdown as well as unit down time. We agree with the commenters that the definitions need clarification and that these periods should not be included in calculating the 30-day rolling average. Therefore, we have revised the definitions accordingly.

We have also included in the final rule a definition of ''10-day rolling average'' that is consistent with the revised definition of ''30-day rolling average.''

G. Energy Assessment

In this final rule, we have revised the definition of energy assessment per the requirements of Table 3 of this final rule by providing duration for performing the energy assessment for large fuel use facilities. In numbered paragraph (3) in the definition of ''Energy assessment'' in § 63.7575, which is for facilities with units having a combined heat input capacity greater than 1 TBtu/yr, we added time duration/size ratio and included a cap to the maximum number of on-site technical hours that should be used in the energy assessment. This addition of a duration for large fuel use facilities is being made to be consistent with durations specified for small [paragraph (1) in the definition of ''Energy assessment''] and medium [paragraph (2) in the definition of ''Energy assessment''] fuel use facilities. The energy assessment for facilities with affected boilers and process heaters having a combined heat input capacity greater than 1.0 TBtu/yr will be up to 24 on-site technical labor hours for the first TBtu/yr plus 8 technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 technical hours, but may be longer at the discretion of the owner or operator.

The revised definition of energy assessment also clarifies our intentions that the scope of assessment is based on energy use by discrete segments of a facility and not by a total aggregation of all individual energy using elements of a facility. The applicable discrete segments of a facility could vary significantly depending on the site and its complexity. We have added the following paragraph (4), to the energy assessment definition to help resolve current problems in identifying the scope of the various energy use systems in a large industrial complex and allow for more streamlined assessments:

''(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy output in (1), (2) and (3) above may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).''

We have also revised paragraph 4 of Table 3 of the final rule to allow a source that is operating under an energy management program established through energy management systems compatible with ISO 50001, which includes the affected units, to satisfy the energy assessment requirement. We consider these energy management programs to be equivalent to the one-time energy assessment because facilities having these programs operate under a set of practices and procedures designed to manage energy use on an ongoing basis. These programs contain energy performance measurements and tracking plans with periodic reviews.

The definition of ''Energy use system'' has also been revised in this final rule to clarify that energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

H. Startup and Shutdown Definitions

A number of commenters indicated that the proposed load specifications (i.e., 25 percent load) within the definitions of ''startup'' and ''shutdown'' were inconsistent with either safe or normal (proper) operation of the various types of boilers and process heaters encountered within the source category. As the basis for defining periods of startup and shutdown, a number of commenters suggested alternative load specifications based on the specific considerations of their boilers; other commenters suggested the achievement of various steady-state conditions.

We have reviewed these comments and believe adjustments are appropriate in the definition of ''startup'' and ''shutdown.'' These adjustments are tailored for industrial boilers and are consistent with the definitions of ''startup'' and ''shutdown'' contained in the 40 CFR part 63, subpart A General Provisions. We believe these revised definitions address the comments and are rational based on the fact that industrial boilers function to provide steam or, in the case of cogeneration units, electricity; therefore, industrial boilers should be considered to be operating normally at all times steam of the proper pressure, temperature, and flow rate is being supplied to a common header system or energy user(s) for use as either process steam or for the cogeneration of electricity. The definitions of ''startup'' and ''shutdown'' have been revised in the final rule as follows:

''*Startup* means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler or process heater after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose.''

''*Shutdown* means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam and heat from the boiler or process heater is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is both no steam or heat being supplied and no fuel being fired in the boiler or process heater.''

The EPA is requiring sources to vent emissions to the main stack(s) and operate all control devices necessary to meet the normal operating standards under this final rule (with the exception of limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR) when firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel or gas 2 (other) gases in the boiler or process heater during startup or shutdown. It is the responsibility of the operators of affected boilers and process heaters to start their limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR and SCR systems appropriately to comply with relevant standards applicable during normal operation. Startup ends and normal operating standards apply when heat or steam is supplied for any purpose.

The EPA carefully considered fuels and potential operational constraints of APCD when designing its work practices for periods of startup and shutdown. The EPA notes that there is no technical barrier to burning clean fuels (e.g., natural gas, distillate oil) for longer portions of startup or shutdown periods at a boiler and the HAP emission reduction benefits warrant additional utilization of such fuels until the temperature and stack emissions pressure is sufficient to engage the APCD. The EPA is aware that SNCR and SCR systems with ammonia injection need to be operated within a prescribed and relatively narrow temperature window to provide NO_X reductions. Further, the EPA is aware that dry scrubbers also need to be operated close to flue gas saturation temperature, and that fabric filters need to be operated at temperatures above the acid dew point. Because these devices have specific temperature requirements for proper operation, the EPA notes in its work practices that it is the responsibility of the operators of affected boilers and process heaters to start their SNCR, SCR, fabric filter and dry scrubber systems appropriately to comply with relevant standards applicable during normal operation.

I. Fuel Sampling Frequency

The sampling frequency for gaseous fuel-fired units that elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory has been revised in this final rule. If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification, no further sampling is required. If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification, only semi-annual sampling need to be conducted. If the initial mercury constituents are greater than 75 percent of the mercury specification, monthly sampling is required.

J. Affirmative Defense

In the proposal, we used terms such as ''exceedance'' or ''excess emissions'' in § 63.7501, which created unnecessary confusion as to when the affirmative defense could be used. In the final amended rule, we have eliminated those terms and used the word ''violation'' to make clear that the affirmative defense to civil penalties is available only where an event that causes a violation of the emissions standard meets the definition of malfunction under § 63.2.

We have also eliminated the 2-day notification requirement that was included in 40 CFR 63.7501(b) at proposal because we expect to receive sufficient notification of malfunction events that result in violations in other required compliance reports, such as the malfunction report required under 40 CFR 63.7550(c). In addition, we have revised the 45-day affirmative defense reporting requirement that was included in 40 CFR 63.7501(b) at proposal to require sources to include the report in the first compliance, deviation or excess emission report due after the initial occurrence of the violation, unless the compliance, deviation or excess emission report is due less than 45 days after the violation. In that case, the affirmative defense report may be included in the second compliance, deviation or excess emission report due after the initial occurrence of the violation. Because the affirmative defense report is now included in a subsequent compliance, deviation or excess emission report, there is no longer a need for the proposed 30-day extension for submitting a stand-alone affirmative defense report. Consequently, we are not including this provision in the final amended rule. We have also re-evaluated the language concerning the use of off-shift and overtime labor to the extent practicable and believe that the language is not necessary. Thus, we have deleted that phrase from section 63.7501(a)(2).

V. Other Actions We Are Taking

Section 307(d)(7)(B) of the CAA states that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States court of appeals for the appropriate circuit (as provided in subsection (b)).''

As to the first procedural criterion for reconsideration, a petitioner must show why the issue could not have been presented during the comment period, either because it was impracticable to raise the issue during that time or because the grounds for the issue arose after the period for public comment (but within 60 days of publication of the final action). The EPA is denying the petitions for reconsideration on a number of issues because this criterion has not been met. In many cases, the petitions reiterate comments made on the proposed June 2011 rule during the public comment period for that rule. On those issues, the EPA responded to those comments in the final rule and made appropriate revisions to the proposed rule after consideration of public comments received. It is well-established that an agency may refine its proposed approach without providing an additional opportunity for public comment. See *Community Nutrition Institute* v. *Block,* 749 F.2d at 58 and *International Fabricare Institute* v. *EPA,* 972 F.2d 384, 399 (D.C. Cir. 1992) (notice and comment is not intended to result in ''interminable back-and-forth[,]'' nor is agency required to provide additional opportunity to comment on its response to comments) and *Small Refiner Lead Phase-Down Task Force* v. *EPA,* 705 F.2d 506, 547 (D.C. Cir. 1983) (''notice requirement

should not force an agency endlessly to repropose a rule because of minor changes'')

In the EPA's view, an objection is of central relevance to the outcome of the rule only if it provides substantial support for the argument that the promulgated regulation should be revised. See *Union Oil* v. *EPA,* 821 F.2d 768, 683 (D.C. Cir. 1987) (court declined to remand rule because petitioners failed to show substantial likelihood that final rule would have been changed based on information in petition). See also the EPA's *Denial of the Petitions to Reconsider the Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202 of the Clean Air Act,* 75 FR at 49556, 49561 (August 13, 2010). See also, 75 FR at 49556, 49560–49563 (August 13, 2010) and 76 FR at 4780, 4786–4788 (January 26, 2011) for additional discussion of the standard for reconsideration under CAA section 307(d)(7)(B).

We are denying reconsideration on the following 57 issues contained in the petitions for reconsideration because they failed to meet the standard described above for reconsideration under CAA section 307(d)(7)(B). Specifically, on these issues, the petitioner has failed to show the following: that it was impracticable to raise their objections during the comment period or that the grounds for their objections arose after the close of the comment period; and/or that their concern is of central relevance to the outcome of the rule. Therefore, the EPA is denying the petitions for reconsideration on the issues for the reasons described below.

Issue: Delist gas units.

The petitioners (API, NPRA) requested that the EPA remove gas-fired units from the section 112(c) list of source categories for which the EPA is required to establish emissions standards under section 112(d). The EPA is denying the petition for reconsideration for the following reasons. First, the issue is outside the scope of this rulemaking, which establishes emissions standards for new and existing units within the major source boilers and process heaters source category. The EPA did not solicit comment in the proposed rule regarding the scope of the subcategory. Further, petitioners provide no information to support delisting gas units under section 112(c)(9), which requires the EPA to make certain findings before delisting any sources. In addition, the petition does not address the D.C. Circuit's decision in *NRDC* v. *EPA,* 489 F.3d 1364 (2007), regarding the EPA's ability to delist subcategories of a source category pursuant to section 112(c)(9). For these reasons, the petitions do not provide support for the argument that the regulation should be changed. For this reason, the petition does not demonstrate that the issue is of central relevance to the outcome of the final rule and the EPA is denying the request for reconsideration.

Issue: Exempt natural gas hot water heaters with tanks greater than 120 gallons.

The petitioner (AIF) requested that the EPA exempt natural gas hot water heaters with tanks greater than 120 gallons. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed work practice standards for such units in its June 2010 proposal, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt natural gas and distillate oil-fired circulating hot water systems with a design capacity of 10 MMBtu/hr or less.

The petitioner (CIBO) requested that the EPA exempt natural gas and distillate oil-fired circulation hot water systems that are not greater than 10 MMBtu/hr. While the EPA disagrees with the petitioner regarding whether such units should be subject to the emissions standards in this rule, the petitioner has not demonstrated that it lacked the opportunity to comment on whether such units should be required to meet emissions standards. The EPA proposed emissions standards for such units, and the petitioner had the opportunity to comment on whether such standards should be applied to such units at all. In addition, the petition does not provide any information to demonstrate that these units should be delisted pursuant to section 112(c)(9). Therefore, the EPA is denying the request for reconsideration.

Issue: Confirm in definitions that open flame heaters (e.g., asphalt tank heaters) are not process heaters.

The petitioners (API, NPRA) requested that the EPA clarify in the definition of ''process heater'' that open flame heaters do not meet the definition. While the EPA disagrees with the petitioners whether clarification is needed in regards to open flame heaters, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed definition. The definition that the EPA proposed clearly states that process heaters are enclosed devices in which the combustion gases do not come into contact with process materials, and as such, does not include open flame heaters. Therefore, the EPA is denying reconsideration.

Issue: For blast furnace fuel-fired boiler exemption, compute the 90 percent BFG by volume threshold to exclude periods of BFG curtailment.

The petitioners (AISI, ACCCI) requested that the EPA revise the exemption for BFG fuel-fired boilers to exclude periods of BFG curtailment. While the EPA disagrees with the petitioners regarding revising the exemption, the petitioners have not demonstrated that it lacked the opportunity to comment on the proposed exemption for BFG fuel-fired boilers. The EPA proposed the exemption for these boilers, and petitioners therefore had the opportunity to comment on whether the exemption should apply to periods of BFG curtailment. Therefore, the EPA is denying the request for reconsideration.

Issue: Exempt boilers whose flue gases are used in direct-fired process heaters subject to other NESHAP.

The petitioner (CMI) requested that the EPA exempt from the rule boilers whose flue gases are used in direct-fired process heaters that are subject to other NESHAP. The final rule does not apply to such units if they are subject to another NESHAP. The EPA does not see a need for further clarification. Since the final rule does in fact exempt these units, the EPA is denying the request for reconsideration.

Issue: Work practice standards do not meet EPA obligations under 112(c)(6).

The petitioner (Sierra Club) requested that the EPA establish numeric emissions limits for Gas 1 units rather than work practice standards. Specifically, the petitioner alleges that the work practice standards do not meet the EPA's obligations under section 112(c)(6) of the CAA, and that it was not the case that data were below the detection level for all HAP emitted from these units. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's arguments regarding the legal authority to establish work practice standards for Gas 1 units and the basis for such standards, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for Gas 1 units and explained in the proposal its rationale for such standards, including the fact that a significant portion of the

emissions data were below the detection level. 75 *FR* at 32024–25. Therefore, the petitioner had the opportunity to comment on this issue, and did in fact submit comments regarding the EPA's legal authority to establish work practice standards for Gas 1 units. Therefore, the EPA is denying reconsideration on this issue.

Issue: Work practices for small units are not justified by 112(h) since small units were not given their own subcategory.

The petitioner (Sierra Club) requested that the EPA require small units, those having a heat input capacity of less than 10 MMBtu/hr, to meet numeric emissions limits rather than work practice standards. The EPA is denying the request for reconsideration on this issue because the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed work practice standards for these units and explained in the proposal its rationale for such standards. 75 *FR* at 32024–25. The EPA did in fact receive comments regarding the proposed standards, to which it responded in the final rule. 76 *FR* at 15640. Moreover, the EPA notes that nothing in section 112(h) limits the EPA's discretion to establish work practice standards to the establishment of such standards for an entire category or subcategory. Therefore, the EPA is denying the request for reconsideration.

Issue: PM is not an adequate surrogate for non-mercury metallic HAP.

The petitioner (Sierra Club) requested that the EPA remove the PM standard as a surrogate for non-mercury metallic HAP and instead adopt a numeric limit for non-mercury metallic HAP because PM is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of PM as a surrogate for non-mercury metallic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed PM standards as a surrogate for non-mercury metallic HAP and explained in the proposal the agency's basis for concluding that PM was an appropriate surrogate. 75 *FR* at 32018. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish direct limits on organics or select a surrogate besides CO.

The petitioner (Sierra Club) requested that the EPA remove the CO standard as a surrogate for organic HAP and instead adopt a numeric limit for these HAP, because CO is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of CO as a surrogate for organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed CO standards as a surrogate for organic HAP and explained in the proposal the agency's basis for concluding that CO was an appropriate surrogate. 75 *FR* at 32018. The EPA received comments on this issue, including comments stating that CO is not an appropriate surrogate for organic HAP. Therefore, the EPA is denying the request for reconsideration.

Issue: Adopt an alternative THC emission standard.

The petitioner (CIBO) requested that the EPA adopt a THC emissions standard as an alternative to the CO standard. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding whether a THC alternative standard is appropriate as a surrogate for non-dioxin organic HAP, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA raised in the proposal the possibility of THC as a surrogate for non-dioxin organic HAP, and explained why the use of CO as a surrogate was preferable. 75 *FR* at 32018. In addition, the EPA did not receive any comments or data during the public comment period on the proposed rule that would have enabled the agency to establish a THC alternative standard, including THC emissions data, nor did the petitioner provide any such data. Therefore, the petition does not provide substantial support for its argument that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration on this issue.

Issue: Regulation of Total dioxin/furans exceeds statutory authority as only 2 compounds are in 112(b)(1).

The petitioners (AISI, ACCCI, AF&PA) alleged that the EPA lacks statutory authority to regulate total dioxin/furans under CAA section 112, and that the EPA's response in the final rule explaining why it is issuing a total dioxin/furan standard was not a logical outgrowth of the proposed rule. The EPA is denying the request for reconsideration on this issue. First, the EPA disagrees that the final rule is not a logical outgrowth of the proposal. The EPA proposed emissions standards for total dioxin/furans and adopted a final emissions standard for the same pollutant. Therefore, the commenter had the opportunity to provide its views during the public comment period regarding the EPA's proposed emissions standard, including its views regarding the EPA's authority to regulate the pollutant at issue. The fact that the EPA responded to those comments does not mean that the petitioner lacked the opportunity to comment—in fact, the petitioner did provide such comments. 76 *FR* at 15640. For this reason, the EPA is denying the petition for reconsideration.

Issue: HCl is an inadequate surrogate for all acid gases.

The petitioner (Sierra Club) requested that the EPA remove the HCl standard as a surrogate for acid gases and instead adopt a numeric limit for these HAP, because HCl is not an appropriate surrogate. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees with the petitioner's argument regarding the suitability of HCl as a surrogate for acid gases, the petitioner has not demonstrated that it lacked the opportunity to comment on this issue. The EPA proposed HCl standards as a surrogate for acid gases and explained in the proposal the agency's basis for concluding that HCl was an appropriate surrogate. 75 *FR* at 32018. While the EPA had emission data for HCl from hundreds of affected units upon which to establish standards, the EPA did not have sufficient data on the other acid gases to do so (hydrogen fluoride, hydrogen cyanide and chlorine). The petitioner did not refer to any such data and, therefore, the issue is not of central relevance to the outcome of the final rule. Therefore, the EPA is denying the request for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO as a surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA adopt a work practice standard for organic HAP rather than a numeric emissions limit based on CO as a surrogate for organic HAP. The EPA is denying the request for reconsideration on this issue. While the EPA disagrees that a work practice standard is appropriate for such HAP for the subcategories for which the EPA adopted a numeric CO limit in the final rule, the petitioners have not demonstrated that they lacked the opportunity to comment on this issue. The EPA proposed numeric CO limits rather than a work practice, and the petitioners had the opportunity to provide their views during the public comment period on the proposed rule regarding why it believed a work practice standard should instead be

finalized. Therefore, the EPA is denying the petition for reconsideration.

Issue: Allow health based compliance alternatives for HCl, other acid gases and manganese.

The petitioners (AMP, AF&PA, AHFA, AISI, ACCCI, RPU, CIBO) requested that the EPA adopt a HBES for HCl and other acid gases as well as for manganese, pursuant to section 112(d)(4). The petitioners also requested that the EPA grant reconsideration on this issue to better address the comments and data submitted during the public comment period for the proposed rule. The EPA is denying the request for reconsideration of this issue. The EPA did not propose a HBES for any pollutants, but did solicit public comment on such standards, explaining its concerns regarding health-based standards, including the lack of available data on which to base such standards. 75 *FR* at 32030. The EPA received comments addressing those concerns and responded to them in the final rule. 76 *FR* at 15642. Therefore, the petitioners have not demonstrated that it lacked the opportunity to comment on this issue. Further, the EPA received no data during the public comment period for the proposed rule on which it could base a HBES for HCl, other acid gases or manganese. Therefore, the petitions do not provide substantial support to demonstrate that the final rule should be changed. For these reasons, the EPA is denying the petition for reconsideration.

Issue: Provide additional compliance alternatives according to Executive Order 13563 (additional subcategories and HBES).

The petitioner (AHFA) requested that the EPA provide additional compliance alternatives in the final rule pursuant to Executive Order 13563 (Improving Regulation and Regulatory Review), including HBES. The EPA is denying the request for reconsideration on this issue because it is not of central relevance. First, nothing in Executive Order 13563 affects the EPA's discretion to establish HBES under the CAA. Additionally, the petition does not provide any information to address our concerns regarding HBES or data to establish such standards.

Issue: Remove energy assessment requirements.

The petitioners (AHFA, AISI, ACCCI, API, NPRA, AIF, CIBO, AF&PA, U.S. Sugar) requested that the EPA remove from the final rule the requirement that existing sources conduct an energy assessment. The EPA is denying the request for reconsideration on this issue. The EPA proposed an energy assessment requirement as a beyond-the-floor standard, and petitioners commented on that proposal. The EPA addressed those comments in the final rule, and petitioners have not demonstrated that they lacked the opportunity to comment on whether the EPA should require an energy assessment, including the EPA's legal authority to do so. 76 *FR* at 15631. Therefore, the EPA is denying the petition for reconsideration. The EPA continues to believe that an energy assessment is not only authorized by the CAA but required as a cost-effective beyond-the-floor standard in accordance with section 112(d)(2).

Issue: Require energy assessment to be conducted every 5 years.

The petitioner (Washington Dept. of Ecology) requested that the EPA require more frequent energy assessments. The EPA proposed a one-time assessment (75 *FR* at p. 32036) and the petitioner has not demonstrated it lacked the opportunity to comment on the frequency of the assessment requirement. Therefore, the EPA is denying the petition.

Issue: Modify cost analysis to include potential fuel savings from implementing assessment findings.

The petitioners (AIE, USCHPA) requested that the EPA modify its cost impacts analysis to include potential fuel savings from implementing energy assessment findings. The EPA is denying the petition. The impacts analysis, including specific mention of how cost savings for energy assessments were handled quantitatively, was explained in the proposal (see 75 FR 32026), and the petitioner therefore had the opportunity to comment on this issue. For this reason, the EPA is denying the petition for reconsideration on this issue.

Issue: Reconsider definition of ''cost effective.''

The petitioners (AIE, USCHPA) requested that the EPA reconsider the definition of ''cost-effective'' in the final rule. The EPA is denying the request for reconsideration on this issue. The EPA proposed to define cost-effective energy conservation measures as any measure with return of investment period of two years or less. 75 *FR* at 32036. The petitioners have not demonstrated it lacked the opportunity to comment on the proposed definition. Therefore, the EPA is denying the petition for reconsideration.

Issue: Establish work practice for other organic HAP instead of using CO surrogate.

The petitioners (AMP, JELD–WEN) requested that the EPA establish work practice standards for controlling organic HAP instead of using CO as a surrogate for organic HAP and establishing CO emission limits. The EPA is denying the request for reconsideration on this issue. Use of CO as a surrogate for organic HAP was subject to notice and comment. (75 FR 32018, 75 FR 32041). Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section ''Choice of Regulated Pollutants: THC vs. CO vs. Other Organic HAP''.

Issue: Provide alternative format for units of measure for CO emission limits to allow sources to use their existing monitoring equipment.

The petitioners (UARG, CIBO) requested that the EPA provide an alternative format (ppm at X percent CO_2) for units of measure for CO emissions in addition to ppm at 3 percent oxygen. The EPA is denying the petition because the petitioners do not demonstrate that it was impracticable to comment on this issue. The format for units of measure for the limits was provided in the proposed rule, and petitioners could have commented on whether the proposed units were appropriate.

Issue: New source emission limits are unachievable and the EPA should collect additional fuel variability data from top performing units to adjust the limits.

The petitioner (AF&PA) requested that the EPA adjust the emissions limits for new sources by collecting additional data from the best performing units that they believed would result in increased variability. The petitioners have not demonstrated that they lacked the opportunity to comment. We proposed standards based on the data we had, including data collected during the ICR process in which petitioners participated, and that data were available for public review. Therefore, petitioners could have commented on this issue. Second, the CAA requires that we base the standards on the sources for which we have emissions information. Petitioners are always free to provide more information to us and the EPA specifically requested new data at each stage of the rulemaking to support the development of emission limits for each subcategory. (75 FR 32041, 76 FR 28663, 76 FR 80612). The EPA has incorporated revised data corrections or new data submittals in its analysis for the final rule. The EPA is denying the request for reconsideration.

Issue: Adjust the methodology for computing MACT floors to address statistical errors and variability concerns.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA adjust the

methodology for computing MACT floors to address statistical errors and variability concerns, including: (1) Dataset reflects the ''best of the best'' units; (2) misapplication of statistical formulae to address distribution, confidence limits, and variability; and (3) failure to address variability in emissions from one unit over time. The methods used to compute the MACT floors were subject to notice and comment. Where new data or data corrections have been submitted that might alter data distributions, identifying best performers or application of fuel variability factors, these changes have been made in the final rule, but the general methodology remains the same. See *Solite Corp.* v. *EPA,* 952 F.2d 473, 485 (D.C. Cir. 1991) (public had sufficient notice of final rule threshold calculations where methodology did not change significantly from proposed rule). The EPA explained the MACT floor methodology in the proposed rule, and addressed comments received on the proposed methodology in the final rule (75 FR 32019–26, 32027–29, 76 15621–30, 76 FR 80614). Therefore, the EPA is denying the request for reconsideration.

Issue: Modify the basis for ranking the top performing units.

The petitioner (WEPCO) requested that the EPA modify the basis for ranking the top performing units, especially for new units, according to the average performance of the unit. The EPA is denying the petition. The methods used to rank units to establish the MACT floors were subject to notice and comment. The EPA explained its methodology in the proposed rule and addressed comments received on the ranking of data for computing the MACT floor in the final rule (75 FR 32019–26, 32027–29, 76 FR 15627).

Issue: Do not use a pollutant-by-pollutant approach to establish MACT floors.

The petitioners (AISI, ACCCI, AF&PA) requested that the EPA not use a pollutant-by-pollutant approach to establish MACT floors. The petitioners stated that this method is not a reasonable interpretation of Section 112(d)(3) of the CAA and that MACT floors should reflect levels achieved in practice, not aspirational controls. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed MACT floors based on the pollutant-by-pollutant methodology, and therefore petitioners could, and in fact did, provide comments opposing this approach. See 75 FR 32021, 32029. The EPA addressed comments received on this approach in the final rule (76 FR 15621–23). Therefore, the EPA is denying the petition.

Issue: Revise approach to establish MACT floors where there is non-detect data.

The petitioner (Sierra Club) requested that the EPA not use the approach it used in the final rule based on the representative detection level (RDL) to establish MACT floors because it does not reflect actual emissions of any source within the subcategory. Further, the petitioner questioned the basis of the selected detection level, and whether or not other variability adjustments (e.g., UPL analysis) sufficiently account for measurement imprecision. The EPA is denying the petition. The three times representative detection level approach was subject to notice and comment. The EPA explained its rationale for this approach in the proposed rule (75 FR 32021) and responded to comments received in the final rule (76 FR 15623, 76 FR 80611).

Issue: The approach used to set MACT floor limits for dioxin/furan emissions is flawed and the EPA should establish an isomer-specific approach.

The petitioner (WEPCO) requested that the EPA establish an isomer-specific approach for dioxin/furan emissions because the three times detection level approach for dioxin/furan emissions is flawed. The EPA is denying the petition. This approach was subject to notice and comment. Rationale and responses to comments on this approach were provided at (75 FR 32021, 32041, 76 FR 15623). Further, the methods for establishing a representative detection level for dioxin/furan have been revised to account for the sensitivity of individual isomers, see rationale provided at (76 FR 80606).

Issue: Incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units.

The petitioners (WEPCO, CIBO) requested that the EPA incorporate a fuel variability factor for PM based on the ash content of the fuel used by best performing units. The MACT floor methodology was explained in the June 4, 2010 proposal which included fuel variability factors that did not reflect the ash content of the fuel. Therefore, the petitioner could have commented recommending that the EPA do so, and, in fact, comments were provided on this issue. The EPA is denying the petition for reconsideration on this issue because it does not demonstrate that it was impracticable to comment on the issue. Responses to comment on this topic were provided in RTC document, Volume 1, EPA–HQ–OAR–2002–0058–3289, see section ''MACT Floor Methodology: Fuel Analysis Variability''.

Issue: Allow energy assessors to determine the time needed to conduct assessment.

The petitioner (Washington Dept. of Ecology) requested that the EPA allow the energy assessor to determine the time needed to conduct the energy assessment. The EPA is denying the petition. The duration of energy assessments was subject to notice and comment and the duration remains up to the affected source. Specific concerns with maximum duration requirements included in the March 21, 2011 final rule were clarified in the December 23, 2011 proposed notice of reconsideration. (76 FR 80615)

Issue: The unit designed to burn gas 1 subcategory should allow for limited use of liquid fuels.

The petitioners (ACC, CEG, API, NPRA) requested that the EPA allow units in the Gas 1 subcategory for limited use of liquid fuels; for example, units with a federally enforceable permit on back up fuels or units burning 10 percent or less of its heat input from liquid fuels should qualify as gas 1 units. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on the issue. The EPA proposed definitions of the various subcategories, and petitioners had the opportunity to comment on those definitions, including the proposed definition of the Gas 1 subcategory which did allow for the limited use of liquid fuels. The EPA addressed comments received on this issue in the final rule (76 FR 15620).

Issue: The unit designed to burn gas 1 subcategory should automatically include other gaseous fuels such as petrochemical process gas and landfill gas.

The petitioners (ACC, AIF, WM) requested that the EPA redefine the unit designed to burn gas 1 subcategory to automatically include other gaseous fuels such as petrochemical process gas and LFG, especially when the LFG is routed to a treatment system prior to use or sale. The EPA proposed definitions of units designed to burn gas 1 and units designed to burn gas 2 (other), and therefore the petitioner had the opportunity to comment on these definitions and to recommend that other gases be included in the definition of the Gas 1 subcategory (75 FR 32017, 32065). The EPA addressed comments received on this issue in the final rule (76 FR 15638). Therefore, the EPA is denying the petition.

Issue: Reconsider the emission standards established for the unit designed to burn gas 2 subcategory.

Petitioners (AIF, CIBO, WM, CEG) requested that the EPA reconsider the emission standards for the unit designed to burn gas 2 subcategory in light of what they feel was a limited dataset and lack of data from a diverse set of fuel types. The EPA is denying the petition. The MACT floor methodology was open to notice and comment in the June 4, 2010 proposal. The EPA proposed emissions standards for this subcategory and the petitioners had an opportunity to comment on the proposed standards and the data on which the standards were based. The EPA further notes that the CAA requires that the MACT standards be based on the best performing sources for which the Administrator has emissions information.

Issue: Adjust the ''metal process furnaces'' subcategory definition to include any gas-fired process furnace.

The petitioners (AISI, ACCCI) requested that the EPA adjust the ''metal process furnaces'' subcategory definition to include any gas-fired process furnace. The EPA is denying the petition. The definition of the subcategory for metal process furnaces was subject to notice and comment. (75 FR 32064, 76 FR 15620).

Issue: The designed to burn rationale for subcategorization is arbitrary.

The petitioner (Sierra Club) alleged that the designed to burn rationale for subcategorization is arbitrary, especially considering the large number of co-fired units in the inventory. The EPA proposed subcategories based on boiler design, and the petitioner has not demonstrated that it was impracticable to comment on the issue. In fact, the petitioner did submit comments on the proposed rule opposing the EPA's proposed subcategorization approach. Therefore, the EPA is denying the petition.

Issue: The EPA should consider exempting units from NSR.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA consider exempting units from NSR who switch fuels, install pollution controls, or construct energy efficiency projects to meet the requirements of this rule because complying with the rule requirements will trigger NSR. The EPA is denying the petition. The applicability of NSR is outside the scope of this rulemaking. Moreover, it was not impracticable to comment on this issue during the 2011 rulemaking, in fact, comments were submitted on this issue, to which the EPA responded. See RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2729.1, excerpt 17.

Issue: Remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative.

The petitioners (AMP, MSU, PSU, Purdue, RPU, U.S. Sugar, Citizens Thermal Energy) requested that the EPA remove the 10 percent penalty for sources opting to use the emission averaging compliance alternative. The EPA is denying the petition. The EPA proposed an emissions averaging approach that included the 10 percent adjustment factor. (75 FR 32035) Therefore, the petition does not demonstrate that it was impracticable to comment on this issue. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, see section ''Emissions Averaging.''

Issue: Allow emissions averaging across subcategories.

The petitioners (MSU, PSU, Purdue, RPU, Citizens Thermal Energy) requested that the EPA allow emissions averaging across subcategories. The EPA is denying the petition. The EPA proposed an emissions averaging approach that did not allow averaging across subcategories, and petitioners therefore had the opportunity to comment recommending that the EPA allow such averaging. Responses to comment on this topic were provided in RTC document, Volume 2, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–3213.1, excerpt 175.

Issue: Allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions.

The petitioner (CIBO) requested that the EPA allow a source's actual heat input instead of the maximum design heat input to be used in the emissions averaging provisions of the final rule. The EPA proposed an emissions averaging approach that was based on the maximum rated heat input capacity, and petitioners therefore had the opportunity to comment recommending that the EPA base the averaging on actual heat input. Therefore, the EPA is denying the petition.

Issue: Reduce stack testing frequency to once every five years to reduce burden on facilities.

The petitioners (ACC, CIBO, JELD–WEN) requested that the EPA reduce stack testing frequency to once every 5 years and rely on the extensive set of continuous parameter monitoring in order to reduce burden on facilities. The EPA is denying the petition. The EPA proposed to require stack testing every year. The petition does not demonstrate that it was impracticable to comment on this issue, and the petitioners could have submitted comments requesting less frequent stack testing.

Issue: Incorporate detailed fuel sampling procedures using incorporation by reference mechanisms instead of detailing sampling procedures in the regulatory language.

The petitioner (CIBO) requested that the EPA incorporate detailed fuel sampling procedures using incorporation by reference mechanisms and citing credible literature (e.g., American Society for Testing and Materials) instead of detailing sampling procedures in the regulatory language since sampling procedures are subject to change over time. The EPA is denying the petition because the petitioner has not demonstrated that it was impracticable to comment on this issue. The EPA proposed fuel sampling procedures in the regulatory text in the June 4, 2010 proposal, and the petitioner therefore had the opportunity to comment recommending its preferred approach.

Issue: Remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis.

The petitioner (UARG) requested that the EPA remove the advanced submittal requirement for site-specific fuel monitoring plans before each analysis, especially if monthly frequency is maintained. If the fuel monitoring plan requirement remains, the petitioner requests that the EPA remove the requirement to report things that might change, such as unanticipated fuel use (based on unanticipated fuel changes). The EPA is denying the petition and disagrees with the commenter. First, the EPA proposed a fuel monitoring plan, and petitioners had the opportunity to comment on the plan requirement. The final rule requires submittal of a fuel monitoring plan 60 days before demonstrating initial compliance. The rule does not require re-submittal of this plan before each monthly analysis, see 40 CFR section 63.7521(b)(1).

Issue: Allow EPA Method 5B to demonstrate compliance with PM emission limits.

The petitioner (UARG) requested that the EPA allow EPA Method 5B to demonstrate compliance with PM emission limits. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to allow Method 5B for PM compliance demonstrations. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA allow the use of this method. For this

reason, the EPA is denying the petition on this issue.

Issue: Remove or make references to Methods 2, 2F, 2G and 4 optional.

The petitioner (UARG) requested that the EPA remove or make references to EPA Methods 2, 2F, 2G and 4 optional. The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed methods to demonstrate compliance in the June 4, 2010 proposal and did not propose to make EPA Methods 2, 2F, 2G and 4 optional. Therefore, the petitioner had the opportunity to submit comments recommending that the EPA make the use of these methods optional. For this reason, the EPA is denying the petition on this issue.

Issue: Allow sources to petition for alternative PM monitoring requirements based on source-specific limitations.

The petitioner (CEG) requested that the EPA allow sources to petition for alternative PM monitoring requirements based on source-specific limitations (e.g., common stacks with more than one subcategory). The EPA is denying this petition because it is not of central relevance to this rulemaking. The General Provisions at 40 CFR 63.8 allow sources to petition the EPA for alternative monitoring plans. Therefore, no such provision is needed in this final rule.

Issue: Allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B.

The petitioners (CIBO, CMI) requested that the EPA allow sources with overlapping CEMS regulations to comply with existing QA/QC plans or 40 CFR part 75 Appendices A and B. The EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: No justification or discussion was provided on why the EPA selected 12 hours as the averaging time period and also why the EPA selected block averages instead of rolling averages.

The petitioner (Sierra Club) alleges that the EPA provided no justification or discussion explaining why the EPA selected 12 hours as the averaging time period and why the EPA selected block averages instead of rolling averages for parameter monitor. The petitioner requested that the EPA clarify that the averaging times for continuous parameter monitoring should be the same as the averaging times during the most recent performance test. Averaging times were open to notice and comment in the June 4, 2010 proposal. In the June 2010 proposal, we required that parameters be set based on 4-hour block averages during the compliance test, and that continuous compliance be demonstrated by monitoring 12-hour block average values for most parameters. We selected this averaging period to reflect operating conditions during the performance test to ensure the control system is continuously operating at the same or better level as during a performance test demonstrating compliance with the emission limits. Therefore, the EPA is denying the petition.

Issue: The EPA position regarding treatment of ''out-of-control'' and ''maintenance'' periods as deviations is not supported or explained.

The petitioner (UARG) alleges that the EPA position regarding treatment of ''out-of-control'' and ''maintenance'' periods as deviations is not supported or explained. The petitioner requested that the EPA revise the definition of ''deviation'' to be consistent with how deviation is treated with respect to CO CEMS and CPMS. The EPA is denying the petition. The definition of deviations was open to notice and comment in the June 4, 2010 proposal.

Issue: Require checks of pressure monitoring taps only if reading is abnormal.

The petitioner (CMI) requested that the EPA require checks of pressure monitoring taps only if reading is abnormal. The requirement to check pressure tap pluggage daily was open to notice and comment in the June 2010 proposal. In addition, the EPA is denying this petition because it is not of central relevance to this rulemaking.

Issue: The EPA has not sufficiently correlated emission limits to operating parameters and should not set enforceable limits on maximum and minimum control device operating parameters.

The petitioners (UARG, AMP, CIBO) alleges that the EPA has not sufficiently correlated emission limits to operating parameters and requested the EPA not to set enforceable limits on maximum and minimum control device operating parameters. One petitioner (CIBO) requested that the rule should allow sources to set their own ESP secondary voltage requirement based on load and coal quality since power consumption by an ESP is influenced by factors other than operating load, including ESP design, amount of PM collected, and resistivity of the PM. Other petitioners (UARG and AMP) also indicate that the limits set on control devices inhibit the flexibility to operate control devices with a margin of safety. The EPA is denying the petition. Operating limits were open to notice and comment in the June 4, 2010 proposal.

Issue: The EPA should delay incorporating PS 17 in this rule until the revisions for PS 17 are completed.

The petitioner (UARG) requested that the EPA delay incorporating PS 17 in this rule, which outlines how to select and install CPMS, until the revisions for PS 17 are completed.

The EPA is denying this petition. The final rule did not incorporate PS 17, or any other PS, in the provision regarding selection and installation of CPMS and ongoing quality assurance of data from CPMS. Comments related to revising PS 17 are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2960.1, excerpt 150).

Issue: The EPA should not set an enforceable operating limit on opacity.

The petitioner (UARG) alleged that there is insufficient correlation between opacity and PM emissions and requested that the EPA not set an enforceable operating limit on opacity. The EPA is denying the petition. The EPA proposed opacity limits in the June 4, 2010 proposal and the petitioner therefore had the opportunity to comment on the proposed limits, including comments requesting that no limit be established.

Issue: Update outdated BLDS Guidance.

The petitioner (UARG) requested that the EPA update the outdated BLDS Guidance that is currently incorporated by reference. The EPA is denying this petition. The current guidance document is the most recent guidance available and comments related to revising the guidance document are outside the scope of this rulemaking. (RTC document, Chapter 11, EPA–HQ–OAR–2002–0058–3289, DCN EPA–HQ–OAR–2002–0058–2997.1, excerpt 10).

Issue: The EPA should reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control.

The petitioners (MSU, PSU, Purdue, Citizens Thermal Energy) requested that the EPA reconsider emission limits for HCl on coal-fired boilers using a hot-side ESP for particulate control. The petitioners are unaware of any HCl control devices that are compatible with a hot-side ESP. The EPA is denying the petition. The basis for subcategorization was subject to notice and comment. The EPA did not propose a separate subcategory for such units, and the petitioner could have commented recommending that the agency do so. (75 FR 32012, 76 FR 15617–18, 76 FR 80607) Further, the EPA disagrees with the petitioner that the subcategories

could be based on the level of controls installed on the unit.

Issue: The EPA should change electronic reporting requirements to avoid WebFIRE and ERT shortcomings.

The petitioner (UARG) requested that the EPA change the electronic reporting requirements to avoid WebFIRE and ERT shortcomings. The petitioner requested that to meet the EPA's obligations under the Paperwork Reduction Act the EPA specify each individual data item requested in the ERT. The petitioner also requests that the EPA explain how the ERT electronic signature mechanisms will meet the requirements of the Cross-Media Electronic Reporting Rule.

The EPA is denying the petition because it does not demonstrate that it was impracticable to comment on this issue. The EPA proposed to require the use of the ERT and WebFIRE, and the petitioner therefore had the opportunity to comment on any concerns with the proposed approach.

Issue: Eliminate gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the reporting requirements in the Title V program.

The petitioner (AIF) requested that the EPA eliminate the gas curtailment notification requirements or adjust the frequency of these notifications to be consistent with the semi-annual reporting requirements in the Title V program. The EPA is denying the petition. Reporting requirements were open to notice and comment in the June 4, 2010 proposal.

Issue: Allow facilities to become area or synthetic minor sources instead of installing controls.

The petitioner (GPSP) requested that the EPA allow facilities to become area or synthetic minor sources instead of installing controls. The EPA is denying the petition. Whether or not sources elect to become area or synthetic minor sources is not of central relevance to this rulemaking, as nothing in this rule affects whether or how a source can become a synthetic minor source (RTC document, EPA–HQ–OAR–2002–0058–3289, Volume 1, DCN EPA–HQ–OAR–2002–0058–3176.2, excerpt 4).

VI. Impacts of This Final Rule

A. What are the incremental air impacts?

Table 4 of this preamble illustrates, for each basic fuel subcategory, the total emissions reductions achieved by the final amended rule (i.e., the difference in emissions between a boiler or process heater controlled to the amended floor level of control and boilers or process heaters at the current baseline) for new and existing sources. Nationwide emissions of selected HAP (i.e., HCl, HF, mercury, metals, and VOC) will be reduced by 44,300 tpy. This is an incremental increase of 4,000 tpy in HAP reductions compared to the estimates in the March 2011 final rule. This increase is due mainly to changes in the inventory (336 units were added since the March 2011 inventory). Excluding the changes in the inventory, the amendments to the regulatory provisions themselves resulted in a decrease of 1,100 tpy of estimated reductions, part of this incremental reduction in HAP is contributed to edits to the baseline emission data received since the March 2011 final rule, as well as changes to the subcategories and emission limits as a result of this amended rule. The amendments to the final rule are expected to result in an additional 4,600 tpy of reductions in HCl emissions. The amendments are also expected to have a modest effect on mercury, estimated to range from a slight decrease of 0.12 tpy up to a slight increase of 0.96 tpy in emission reductions as a result of the changes to the regulatory requirements. Reductions in emissions of filterable PM will decrease by 18,500 tpy due to the final amended rule. Reductions in emissions of non-mercury metals (i.e., antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) will decrease by 260 tpy. In addition, the amendments are estimated to result in an additional 50,100 tpy of reductions in SO_2 emissions. A discussion of the methodology used to estimate emissions, emissions reductions, and incremental emission reductions is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

TABLE 4—SUMMARY OF TOTAL EMISSIONS REDUCTIONS FOR THE FINAL AMENDED RULE

[tons/yr]

Source	Subcategory	HCl	PM	Non mercury metals [a]	Mercury [b]	VOC
Existing Units	Limited Use	1	2	0.42	2.1E–04	0.48
	Solid units	36,737	21,367	147	0.4 to 1.5	1,619
	Liquid units	2,143	9,434	2,315	0.9 to 1	620
	Non-Continental Liquid units	35	3	1	0.01 to 0.02	23
	Gas 1 (NG/RG) units	20	117	0.3	0.01	88
	Gas 1 Metallurgical Furnaces	0.4	3	0.02	0.001	27
	Gas 2 (other) units	4	8	0.06	3.8E–03 to 4.6E–03.	40
New Units	Solid units	0	351	5	0.02	0
	Liquid units	0	0	0	0	0
	Gas 1 units	0	0	0	0	0
	Gas 1 Metallurgical Furnaces	0	0	0	0	0
	Gas 2 (other) units	0	0	0	0	0

[a] Includes antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium.

[b] Mercury reductions are presented as a range due to adjustments on reported fractions and limits of detection. See memorandum entitled ''Revised (March 2012) Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants—Major Source'' for a description of the two methods for estimating mercury reductions.

B. What are the incremental water and solid waste impacts?

The EPA estimated the additional water usage that would result from installing wet scrubbers to meet the amended emission limits for HCl would be 556 million gallons per year for existing sources compared to the current baseline. In addition to the increased water usage, an additional 160 million gallons per year of wastewater would be produced for existing sources. Only half of these incremental changes are due to changes in the regulatory provisions. The other half is due to changes in the number of identified existing units and projected new units. The annual costs of treating the additional wastewater are $1.2 million. These additional costs are accounted for in the incremental control cost estimates.

The EPA estimated the additional solid waste that would result due to the amendments to be 138,000 tpy, with nearly all due to changes in the regulatory provisions. Solid waste is generated from flyash and dust captured in PM and mercury controls as well as from spent carbon that is injected into exhaust streams or used to filter gas streams. The costs of handling the additional solid waste generated are $5.8 million. These costs are also accounted for in the incremental control costs estimates.

A discussion of the methodology used to estimate incremental impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

C. What are the incremental energy impacts?

The EPA estimated that the March 2011 final rule would result in an increase of about 1.4 billion kWh/yr in national energy usage from the electricity required to operate control devices, such as wet scrubbers, electrostatic precipitators and fabric filters which are expected to be installed to meet the final rule. The amendments are expected to decrease energy usage by a net 143 million kWh/yr compared to the March 2011 rule. These reductions are driven by the regulatory provisions of these amendments. Additionally, the EPA expects these amendments will result in a decrease of 4.4 million MMBtu/yr in fuel savings, compared with the estimates in the March 2011 final rule.

D. What are the incremental cost impacts?

For these final amendments, we estimated the incremental difference between the national costs impacts for the final amended rule and the March 2011 final rule. First, we determined the control measures, work practices, and monitoring and testing requirements that would be required by boilers and process heaters located at major source facilities to comply with the final amended rule. To estimate the national cost impacts of the final amended rule for existing sources, we used the identical methodology used to estimate the cost impacts for the March 2011 final rule with one exception. In this revised analysis, it was assumed that several liquid fuel units that reported natural gas firing capability would switch to natural gas as a compliance option instead of installing add-on controls to demonstrate compliance with the emission limits. Thus, the only costs to these units would be the tune-up work practice costs. A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

The resulting total national cost impact of the final amended rule is $4.7 billion in capital expenditures and $1.5 billion per year in total annual costs, considering fuel savings. The total capital expenditures are slightly lower than estimated for the March 2011 final rule, but the total annual costs are slightly higher than estimated for the March 2011 final rule. See 76 FR 15651. The total capital and annual costs include costs for control devices, work practices, testing and monitoring.

In order to determine the incremental cost impacts of the amended requirements and emission limits, we first estimated the cost impacts of the additional existing boilers and process heaters added to the Boiler MACT inventory database since promulgation of the March 2011 final rule and the revised number of new boilers and process heaters that could be potentially constructed. Since the March 2011 final rule, we became aware of 72 major source facilities that were not previously in the Boiler MACT inventory database. Adding the boilers and process heaters located at these newly identified major source facilities resulted in 73 additional coal-fired units, 32 additional biomass-fired units, 82 additional oil-fired units, and 149 additional gas-fired units. Our revised number of new boilers and process heaters included 82 additional biomass units, 1,728 additional gas 1 units and 13 fewer liquid units.

The resulting cost impact for these additional existing and new boilers and process heaters is $1.0 billion in capital expenditures and $0.31 billion per year in total annual costs, considering fuel savings.

Therefore, discounting the added costs for the additional boilers and process heaters included in the costs analysis, the estimated incremental cost impacts for these amended requirements on existing and new boilers and process heaters are $1.0 billion in capital expenditures and $0.13 billion per year in total annual costs less than the costs estimated in the March 2011 rule.

Table 5 of this preamble shows the total capital and annual cost impacts of the final amended rule for each subcategory. Costs include testing and monitoring costs, but not recordkeeping and reporting costs.

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE

Source	Subcategory	Estimated/ projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
Existing Units	Coal units	621	2,554	46	904
	Biomass units	502	405	29	109
	Heavy Liquid units	319	761	5.4	221
	Light Liquid units	615	712	4.2	166
	Non-Continental Liquid units	21	62	0.8	17
	Gas 1 (NG/RG) units	11,929	77	0.9	(295)

TABLE 5—SUMMARY OF TOTAL CAPITAL AND ANNUAL COSTS FOR NEW AND EXISTING SOURCES FOR THE FINAL AMENDED RULE—Continued

Source	Subcategory	Estimated/ projected number of affected units	Capital costs (10^6 $)	Testing and monitoring annualized costs (10^6 $/yr)	Annualized cost (10^6 $/yr) (considering fuel savings)
	Gas 2 (other) units	129	138	2.3	58
Energy Assessment	ALL	1,700 (Facilities).	N/A	N/A	28
New Units	Coal units	0	0	0	0
	Biomass units	82	381	5.6	[a] 99
	Liquid units	0	0	0	0
	Gas 1 (NG/RG) units	1,762	11	0	[a] 5.1
	Gas 2 (other) units	0	0	0	0

[a] Total annualized costs for new units do not account for fuel savings since no fuel savings are estimated in the first year for new units.

Potential control device cost savings and increased recordkeeping and reporting costs associated with the emissions averaging provisions in the final rule are not accounted for in either the capital or annualized cost estimates.

A discussion of the methodology used to estimate cost impacts is presented in ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' in the docket.

E. What are the economic impacts?

The EPA analyzed the economic impacts of this final amended rule using the methodology that was discussed in the March 2011 final rule RIA and in the preamble to the March 2011 final rule. See FR 76 15651. The market impact results are very similar to the results presented in the March 2011 final rule and the RIA. The agency's economic model suggests the average national price increases for industrial sectors are less than 0.01 percent, while average annual domestic production may fall by less than 0.01 percent.

Because of higher domestic prices, imports slightly rise. The results for sales tests for small businesses were somewhat reduced than those calculated for the March 2011 final rule. For the sales tests using small companies identified in the Combustion Survey, the mean cost to receipts dropped from 4 percent in the RIA to 3 percent for this final amended rule and the median was 0.2 percent for the RIA and also 0.2 percent for this final amended rule. The number of parent companies with sales tests exceeding 3 percent dropped from 8 in the RIA to 5 for this final amended rule. There was no change in the results for small public entities. Median cost is still about $1.1 million and representative small major public entities would have cost-to-revenue ratios above 10 percent. The change in employment estimates between the RIA and the final amended rule is minimal. In the RIA for the March 2011 final rule, we estimated employment changes ranging between −3,100 to +6,500 employees, with a central estimate of +1,700. For this final amended rule we estimate employment changes ranging between −2,600 to +5,400 employees, with a central estimate of +1,400. These estimated annual employment changes compared to the baseline employment, and are for the time period for which the annualized cost applies (2015 to 2029).

F. What are the benefits of this final rule?

We calculated health benefits using the methodology described in the RIA prepared for the March 21, 2011 final rule. We incorporated the revised emission reductions estimated for this reconsideration final rule into the analysis. We were unable to estimate the benefits from reducing exposure to HAP and ozone, ecosystem impairment and visibility impairment, including reducing 180,000 tons of carbon monoxide, 39,000 tons of HCl, 500 tons of HF, 2,500 tons of other metals and 3,100 to 5,300 pounds of mercury. Please refer to the full description of the unquantified benefits as well as technical details of the analysis and its limitations and uncertainties in the final Boiler RIA (March 2011). These monetized benefits are approximately 23 percent higher than the March 2011 final rule benefits due to the increase in SO_2 emission reductions associated with the additional units affected by the rule and the revised HCl limit. We estimate the total monetized benefits of this final regulatory action to be $27 billion to $67 billion at a 3 percent discount rate and $25 to $61 billion at a 7 percent discount rate. All estimates are for the implementation year (2015) in 2008$. A summary of the monetized benefits estimates at discount rates of 3 percent and 7 percent is provided in Table 6 of this preamble. A summary of the avoided health incidences is provided in Table 7 of this preamble.

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
$PM_{2.5}$-related benefits			
Direct $PM_{2.5}$	14,139	$1,200 to $2,900	$1,100 to $ $2,700
SO_2	572,000	$26,000 to $64,000	$24,000 to $61,000

TABLE 6—SUMMARY OF THE MONETIZED BENEFITS ESTIMATES FOR THE FINAL BOILER MACT—Continued

[millions of 2008$] [a b]

Pollutant	Emissions reductions (tons)	Total monetized benefits (at 3% discount rate)	Total monetized benefits (at 7% discount rate)
Total		$27,000 to $67,000	$25,000 to $61,000.

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures so numbers may not sum across rows. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing hazardous air pollutants (HAP) are not included. These estimates do not include energy disbenefits valued at $24 million (using a 3 percent discount rate). These benefits reflect existing boilers and new boilers anticipated to come on-line by 2015.

[b] There are some slight differences in the emission reductions used in the RIA and those used in the air impacts section of this preamble due to some late changes in the data that were received after the RIA was completed. Refer to the memoranda ''Revised (August 2012) Methodology for Estimating Cost and Emission Impacts for Industrial, Commercial, and Institutional Boilers and Process Heaters NESHAP—Major Source'' for a discussion of the differences.

TABLE 7—SUMMARY OF THE AVOIDED HEALTH INCIDENCES FOR THE FINAL BOILER MACT [a]

	Avoided health incidences
Premature Mortality	3,000–7,900
Morbidity	
Chronic Bronchitis	2,000
Acute Myocardial Infarction	5,000
Hospital Admissions, Respiratory	750
Hospital Admissions, Cardiovascular	1,600
Emergency Room Visits, Respiratory	3,000
Acute Bronchitis	4,600
Work Loss Days	390,000
Asthma Exacerbation	51,000
Minor Restricted Activity Days	2,300,000
Lower Respiratory Symptoms	55,000
Upper Respiratory Symptoms	41,000

[a] All estimates are for the implementation year (2015), and are rounded to two significant figures. All fine particles are assumed to have equivalent health effects because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. Benefits from reducing HAP are not included. These benefits reflect existing boilers and new boilers anticipated to come online by 2015.

G. What are the incremental secondary air impacts?

For units adding controls to meet the amended emission limits, we anticipate very minor secondary air impacts. The combustion of fuel needed to generate additional electricity would yield slight increases in emissions, including NO_X, CO, PM and SO_2 and an increase in CO_2 emissions. Since NO_X and SO_2 are covered by capped emissions trading programs and methodological limitations prevent us from quantifying the change in CO and PM, we do not estimate an increase in secondary air impacts for this final rule from additional electricity demand. We do estimate greenhouse gas impacts, which result from increased electricity consumption, to be 859,200 tpy from existing units and 79,700 tpy from new units. This is 19,200 tpy less than the estimated greenhouse gas impacts associated with the March 2011 final rule.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

Under section 3(f)(1) of Executive Order 12866 (58 FR 51735, October 4, 1993), this action is an ''economically significant regulatory action'' because it is likely to 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. Accordingly, the EPA submitted this action to the OMB for review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011) and any changes made in response to the OMB recommendations have been documented in the docket for this action.

The EPA did prepare a new RIA for this action. The EPA prepared an assessment of the changes in the costs and benefits of this final rule compared to the costs and benefits associated with the March 21, 2011, final rule. Overall, the costs and impacts are estimated to be similar to the costs and impacts associated with the previous final rule, although the distribution is somewhat different and the number of affected units in the inventory has increased by about 302 units. When comparing the costs using only those sources that were part of the final rule inventory, the costs have decreased. The EPA re-ran the multimarket model to assess changes in economic impacts, and this analysis confirmed that the overall economic impacts are similar to the previous final rule. The benefits are projected to increase by about 20 percent because of the increase in the estimated SO_2 reductions. A summary of the costs and benefits of the previous final rule is provided in the preamble to the previous final rule (*see* 76 FR 15658) and the detailed analysis for the previous final rule is provided in the RIA for the previous final rule. In addition, memoranda are provided in the docket to document the changes in costs, economic impacts, and benefits associated with this final rule, shown in Table 8.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Total Monetized Benefits [2]	$27,000 to $67,000	$24,000 to $61,000.
Total Social Costs [3]	$1,400 to $1,600	$1,400 to $1,600.
Net Benefits	$26,000 to $65,000	$23,200 to $59,000.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE FINAL BOILER MACT RECONSIDERATION IN 2015—Continued

[Millions of 2008$] [1]

	3 percent discount rate	7 percent discount rate
Non-monetized Benefits	Health effects from exposure to HAP (39,000 tons of HCl, 500 tons of HF, 3,100 to 5,300 pounds of mercury, and 2,500 tons of other metals). Health effects from exposure to other criteria pollutants (180,000 tons of CO and 572,000 tons of SO_2). Ecosystem effects. Visibility impairment.	

[1] All estimates are for the implementation year (2015), and are rounded to two significant figures.
[2] The total monetized co-benefits reflect the human health benefits associated with reducing exposure to $PM_{2.5}$ through reductions of $PM_{2.5}$ precursors such as directly emitted particles, SO_2, and NO_X and reducing exposure to ozone through reductions of VOC. It is important to note that the monetized benefits include many but not all health effects associated with $PM_{2.5}$ exposure. Monetized benefits are shown as a range from Pope et al. (2002) to Laden et al. (2006). These models assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to support the development of differential effects estimates by particle type. These estimates include the energy disbenefits valued at $24 million (using the 3 percent discount rate), which do not change the rounded totals. CO_2-related disbenefits were calculated using the ''social cost of carbon'', which is discussed further in the RIA.
[3] The methodology used to estimate social costs for one year in the multimarket model using surplus changes results in the same social costs for both discount rates.

B. Paperwork Reduction Act

The OMB has approved the information collection requirements contained in the March 21, 2011 final rule under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0551. The EPA has updated the supporting statement to reflect the final inventory and burden estimates associated with this action since some of the monitoring, recordkeeping and reporting requirements have changed since the March 21, 2011 final rule. These revised estimates have been sent to OMB for review and approval.

The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which are mandatory for all operators subject to national emission standards. These recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). All information submitted to the EPA pursuant to the recordkeeping and reporting requirements for which a claim of confidentiality is made is safeguarded according to agency policies set forth in 40 CFR part 2, subpart B.

This final rule will require maintenance inspections of the control devices but will not require any notifications or reports beyond those required by the General Provisions aside from a notification of intent to commence burning solid waste materials and notification of alternative fuel use for those units that are in the Gas 1 subcategory but burn liquid fuels for periodic testing, or during periods of gas curtailment or gas supply emergencies. The recordkeeping requirements require only the specific information needed to determine compliance.

The revised annual monitoring, reporting and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the standards) is estimated to be $95.3 million which is about the same as estimated for the March 2011 final rule. This includes 323,130 labor hours per year at a total labor cost of $30.6 million per year, and total non-labor capital costs of $64.7 million per year. This estimate includes initial and annual performance test, conducting and documenting an energy assessment, conducting fuel specifications for Gas 1 units, repeat testing under worst-case conditions for solid fuel units, conducting and documenting a tune-up, semiannual excess emission reports, maintenance inspections, developing a monitoring plan, notifications and recordkeeping. Monitoring, testing, tune-up and energy assessment costs and cost were also included in the cost estimates presented in the control costs impacts estimates in section VI.D of this preamble. The total burden for the federal government (averaged over the first 3 years after the effective date of the standard) is estimated to be 100,608 hours per year at a total labor cost of $5.3 million per year. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. In addition, the EPA is amending the table in 40 CFR part 9 of currently approved OMB control numbers for various regulations to list the regulatory citations for the information requirements contained in this final rule.

C. Regulatory Flexibility Act

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.[1] The RFA also allows an agency to ''consider a series of closely related rules as one rule for the purposes of sections'' 603 (initial regulatory flexibility analysis) and 604 (final regulatory flexibility analysis) in order to avoid ''duplicative action.'' 5 U.S.C. § 605(c). This final rule is closely related to the final major source rule, which the EPA signed on February 21, 2011. The EPA prepared a final regulatory flexibility analyses in connection with the major source rule. Therefore,

[1] Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business according to Small Business Administration (SBA) size standards by the North American Industry Classification System category of the owning entity. The range of small business size standards for the affected industries ranges from 500 to 1,000 employees, except for petroleum refining and electric utilities. In these latter two industries, the size standard is 1,500 employees and a mass throughput of 75,000 barrels/day or less, and 4 million kilowatt-hours of production or less, respectively; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

pursuant to § 605(c), the EPA is not required to complete a final regulatory flexibility analysis for this rule.

The EPA has been concerned with potential small entity impacts since it began developing the major source rule. The EPA conducted outreach to small entities and, pursuant to § 609 of RFA, convened a Small Business Advocacy Review Panel to obtain advice and recommendations from small entity representatives.

Pursuant to the RFA, the EPA used the Panel's report and prepared both an initial regulatory flexibility analysis and a final regulatory flexibility analysis in connection with the closely related major source rule. Convening an additional Panel and preparing an additional final regulatory flexibility analysis would be procedurally duplicative and is unnecessary given that the issues here are within the scope of those considered by the Panel. In addition, this final action would decrease capital and annualized costs on small entities by about 3 percent and 10 percent, respectively, relative to the closely related final rule.

D. Unfunded Mandates Reform Act

Title II of the UMRA of 1995, 2 U.S.C. 1531–1538, requires federal agencies, unless otherwise prohibited by law, to assess the effects of their regulatory actions on state, local and tribal governments and the private sector. Federal agencies must also develop a plan to provide notice to small governments that might be significantly or uniquely affected by any regulatory requirements. The plan must enable officials of affected small governments to have meaningful and timely input in the development of the EPA regulatory proposals with significant Federal intergovernmental mandates and must inform, educate, and advise small governments on compliance with the regulatory requirements.

Both this rule and the March 21, 2011 final rule contain a federal mandate that may result in expenditures of $100 million or more for state, local and tribal governments, in the aggregate, or the private sector in any one year. Accordingly, the EPA prepared under section 202 of the UMRA a written statement for the final rule. This final rule also contains a federal mandate that may result in expenditures of $100 million or more for state, local, and tribal governments, in the aggregate, or the private sector in any one year. The discussion below has been updated to reflect the changes.

1. Statutory Authority

As discussed in the March 21, 2011, final rule, the statutory authority for this final rulemaking is section 112 of the CAA. Title III of the CAA Amendments was enacted to reduce nationwide air toxic emissions. Section 112(b) of the CAA lists the 188 chemicals, compounds, or groups of chemicals deemed by Congress to be HAP. These toxic air pollutants are to be regulated by NESHAP.

Section 112(d) of the CAA directs us to develop NESHAP which require existing and new major sources to control emissions of HAP using MACT based standards. This NESHAP applies to all boilers and process heaters located at major sources of HAP emissions.

2. Social Costs and Benefits

The regulatory impact analysis prepared for the March 21, 2011 final rule, which we have revised for this final rule, including the agency's assessment of costs and benefits, is detailed in the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and in the ''Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources'' in the docket. Based on estimated compliance costs associated with this final rule and the predicted change in prices and production in the affected industries, the estimated social costs of this rule are $1.4 to 1.6 billion (2008 dollars).

It is estimated that 3 years after implementation of this final rule, HAP would be reduced by 45,000 tpy, including reductions in HCl, hydrogen fluoride, metallic HAP including mercury, and several other organic HAP from boilers and process heaters. Studies have determined a relationship between exposure to these HAP and the onset of cancer, however, the agency is unable to provide a monetized estimate of the HAP benefits at this time. In addition, there are significant annual reductions in fine particulate matter ($PM_{2.5}$) and in SO_2 that would occur, including 25 thousand tons of $PM_{2.5}$ and 558 thousand tons of SO_2. These reductions occur within 3 years after the implementation of the final regulation and are expected to continue throughout the life of the affected sources. The major health effect associated with reducing $PM_{2.5}$ and $PM_{2.5}$ precursors (such as SO_2) are a reduction in premature mortality. Other health effects associated with $PM_{2.5}$ emission reductions include avoiding cases of chronic bronchitis, heart attacks, asthma attacks and work-lost days (i.e., days when employees are unable to work). While we are unable to monetize the benefits associated with the HAP emissions reductions, we are able to monetize the benefits associated with the $PM_{2.5}$ and SO_2 emissions reductions. For SO_2 and $PM_{2.5}$, we estimated the benefits associated with health effects of PM but were unable to quantify all categories of benefits (particularly those associated with ecosystem and visibility effects). Our estimates of the monetized benefits in 2015 associated with the implementation of the final regulatory action range from $27 billion (2008 dollars) to $67 billion (2008 dollars) when using a 3 percent discount rate (or from $25 billion (2008 dollars) to $61 billion (2008 dollars) when using a 7 percent discount rate). This estimate, at a 3 percent discount rate, is about $25 billion (2008 dollars) to $65 billion (2008 dollars) higher than the estimated social costs shown earlier in this section. The general approach used to value benefits is discussed in more detail earlier in this preamble. For more detailed information on the benefits estimated for the rulemaking, refer to the RIA and the memos updating the impacts and benefits in the docket.

3. Future and Disproportionate Costs

The UMRA requires that we estimate, where accurate estimation is reasonably feasible, future compliance costs imposed by this final rule and any disproportionate budgetary effects. Our estimates of the future compliance costs of the rule are discussed previously in this preamble.

We do not believe that there will be any disproportionate budgetary effects of this final rule on any particular areas of the country, state or local governments, types of communities (e.g., urban, rural) or particular industry segments. See the results of the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).''

4. Effects on the National Economy

The UMRA requires that we estimate the effect of this final rule on the national economy. To the extent feasible, we must estimate the effect on productivity, economic growth, full employment, creation of productive jobs and international competitiveness of the U.S. goods and services, if we determine that accurate estimates are reasonably feasible and that such effect is relevant and material.

The nationwide economic impact of this final rule is presented in the

''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011)'' and a memoranda that are included in the docket, entitled ''Regulatory Impact Results for the Reconsideration Final Rule for National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources which update the RIA analyses. This analysis provides estimates of the effect of this rule on some of the categories mentioned above. The results of the economic impact analysis are summarized previously in this preamble. The results show that there will be a small impact on prices and output, and little impact on communities that may be affected by this final rule. In addition, there should be little impact on energy markets (in this case, coal, natural gas, petroleum products and electricity). Hence, the potential impacts on the categories mentioned above should be small.

5. Consultation With Government Officials

The UMRA requires that we describe the extent of the agency's prior consultation with affected state, local and tribal officials, summarize the officials' comments or concerns, and summarize our response to those comments or concerns. In addition, section 203 of the UMRA requires that we develop a plan for informing and advising small governments that may be significantly or uniquely impacted by a final rule. We consulted with state and local air pollution control officials during the development of the final rule. We have also held meetings on this final rule with many of the stakeholders from numerous individual companies, institutions, environmental groups, consultants and vendors, labor unions and other interested parties. We have added materials to the docket to document these meetings.

Consistent with section 205, the EPA has identified and considered a reasonable number of regulatory alternatives. Additional information on the costs and environmental impacts of these regulatory alternatives is presented in the docket.

The regulatory alternative upon which the emission limits in this final rule are based represents the MACT floors for all subcategories and, as a result, it is the least costly and least burdensome alternative.

This rule is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments. While some small governments may have some sources affected by this final rule, the impacts are not expected to be significant. Therefore, this final rule is not subject to the requirements of section 203 of the UMRA.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. This final rule will not impose direct compliance costs on state or local governments, and will not preempt state law. Thus, Executive Order 13132 does not apply to this action.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175 (65 FR 67249, November 9, 2000). It will not have substantial direct effects on tribal governments, on the relationship between the federal government and Indian tribes, or on the distribution of power and responsibilities between the federal government and Indian tribes, as specified in Executive Order 13175. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it is based solely on technology performance.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. For the March 21, 2011, final rule, we estimated a 0.05 percent price increase for the energy sector and a −0.02 percent percentage change in production. We estimated a 0.09 percent increase in energy imports. For more information on the estimated energy effects, please refer to the ''Regulatory Impact Analysis for the Final Industrial Boilers and Process Heaters MACT (2011).'' The analysis is available in the public docket. While we did not recreate the RIA for this final action, the energy impacts for existing sources decreased slightly, and the energy impacts for new source increased due to the increased number of new sources that is now projected. Overall, the projected energy use increased slightly but would not change the analysis that was conducted for the previous final rule. Therefore, we conclude that this final rule when implemented is not likely to have a significant adverse effect on the supply, distribution, or use of energy.

I. National Technology Transfer and Advancement Act

Section 12(d) of the NTTAA, Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs the EPA to use VCS in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through the OMB, explanations when the agency decides not to use available and applicable VCS.

This action does not involve any new technical standards from those contained in the March 21, 2011 final rule. Therefore, the EPA did not consider the use of any VCS. See 76 FR 15660–15662 for the NTTAA discussion in the March 21, 2011 final rule.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

For the March 2011 final rule, the EPA determined that the rule would not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the

level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. Compared to the previous final rule, while the amendments are somewhat less stringent for some subcategories of units and more stringent for some others, the overall increased health benefits demonstrate that the conclusions from the environmental justice analysis conducted for the previous final rule are still valid. Therefore, the EPA has determined this final rule will not have disproportionately high and adverse human or environmental effects on minority or low-income populations.

K. Congressional Review Act

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 and to the Comptroller General of the United States. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a ''major rule'' as defined by 5 U.S.C. 804(2). With the exception of the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) being lifted January 31, 2013, this rule will be effective April 1, 2013.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and Recordkeeping requirements.

Dated: December 20, 2012

Lisa P. Jackson,

Administrator.

For the reasons cited in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 2. Effective January 31, 2013, the May 18, 2011 (76 FR 28661), delay of the effective date revising subpart DDDDD at 76 FR 15451 (March 21, 2011) is lifted.

Subpart A—[Amended]

■ 3. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(19), (b)(23), (b)(35), (b)(40), (b)(69), and (b)(70).
■ b. Removing and reserving paragraph (b)(53).
■ c. Adding paragraphs (b)(46), (b)(55), and (b)(76) through (83).
■ d. Adding paragraphs (p)(12) through (20).
■ e. Adding paragraph (r).

The revisions and additions read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) * * *

(19) ASTM D95–05 (Reapproved 2010), Standard Test Method for Water in Petroleum Products and Bituminous Materials by Distillation, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(23) ASTM D4006–11, Standard Test Method for Water in Crude Oil by Distillation, including Annex A1 and Appendix X1, approved June 1, 2011, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD, table 11 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, table 13 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575 and § 63.11237.

* * * * *

(46) ASTM D4606–03 (2007), Standard Test Method for Determination of Arsenic and Selenium in Coal by the Hydride Generation/Atomic Absorption Method, approved October 1, 2007, IBR approved for table 6 to subpart DDDDD.

* * * * *

(55) ASTM D6357–11, Test Methods for Determination of Trace Elements in Coal, Coke, and Combustion Residues from Coal Utilization Processes by Inductively Coupled Plasma Atomic Emission Spectrometry, approved April 1, 2011, IBR approved for table 6 to subpart DDDDD.

* * * * *

(69) ASTM D4057–06 (Reapproved 2011), Standard Practice for Manual Sampling of Petroleum and Petroleum Products, including Annex A1, approved June 1, 2011, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

(70) ASTM D4177–95 (Reapproved 2010), Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, including Annexes A1 through A6 and Appendices X1 and X2, approved May 1, 2010, IBR approved for § 63.10005(i) and table 6 to subpart DDDDD.

* * * * *

(76) ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, approved July 15, 2011, IBR approved for § 63.7575 and § 63.11237.

(77) ASTM D975–11b, Standard Specification for Diesel Fuel Oils, approved December 1, 2011, IBR approved for § 63.7575.

(78) ASTM D5864–11 Standard Test Method for Determining Aerobic Aquatic Biodegradation of Lubricants or Their Components, approved March 1, 2011, IBR approved for table 6 to subpart DDDDD.

(79) ASTM D240–09 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD.

(80) ASTM D4208–02 (2007) Standard Test Method for Total Chlorine in Coal by the Oxygen Bomb Combustion/Ion Selective Electrode Method, approved May 1, 2007, IBR approved for table 6 to subpart DDDDD.

(81) ASTM D5192–09 Standard Practice for Collection of Coal Samples from Core, approved June 1, 2009, IBR approved for table 6 to subpart DDDDD.

(82) ASTM D7430–11ae1, Standard Practice for Mechanical Sampling of Coal, approved October 1, 2011, IBR approved for table 6 to subpart DDDDD.

(83) ASTM D6883–04, Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, approved June 1, 2004, IBR approved for table 6 to subpart DDDDD.

* * * * *

(p) * * *

(12) Method 5050 (SW–846–5050), Bomb Preparation Method for Solid Waste, Revision 0, September 1994, in

EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition IBR approved for table 6 to subpart DDDDD.

(13) Method 9056 (SW–846–9056), Determination of Inorganic Anions by Ion Chromatography, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(14) Method 9076 (SW–846–9076), Test Method for Total Chlorine in New and Used Petroleum Products by Oxidative Combustion and Microcoulometry, Revision 0, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(15) Method 1631 Revision E, Mercury in Water by Oxidation, Purge and Trap, and Cold Vapor Atomic Absorption Fluorescence Spectrometry, Revision E, EPA–821–R–02–019, August 2002, IBR approved for table 6 to subpart DDDDD.

(16) Method 200.8, Determination of Trace Elements in Waters and Wastes by Inductively Coupled Plasma—Mass Spectrometry, Revision 5.4, 1994, IBR approved for table 6 to subpart DDDDD.

(17) Method 6020A (SW–846–6020A), Inductively Coupled Plasma-Mass Spectrometry, Revision 1, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(18) Method 6010C (SW–846–6010C), Inductively Coupled Plasma-Atomic Emission Spectrometry, Revision 3, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(19) Method 7060A (SW–846–7060A), Arsenic (Atomic Absorption, Furnace Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

(20) Method 7740 (SW–846–7740), Selenium (Atomic Absorption, Furnace Technique), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD.

* * * * *

(r) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org.*

(1) TAPPI T 266, Determination of Sodium, Calcium, Copper, Iron, and Manganese in Pulp and Paper by Atomic Absorption Spectroscopy (Reaffirmation of T 266 om-02), Draft No. 2, July 2006, IBR approved for table 6 to subpart DDDDD.

(2) [Reserved]

Subpart DDDDD—[Amended]

■ 4. Section 63.7485 is revised to read as follows:

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.7575.

■ 5. Section 63.7490 is amended by adding paragraph (e) to read as follows:

§ 63.7490 What is the affected source of this subpart?

* * * * *

(e) An existing electric utility steam generating unit (EGU) that meets the applicability requirements of this subpart after the effective date of this final rule due to a change (e.g., fuel switch) is considered to be an existing source under this subpart.

■ 6. Section 63.7491 is amended by:
■ a. Revising the introductory text.
■ b. Revising paragraph (a).
■ c. Revising paragraph (c).
■ d. Revising paragraph (h)
■ e. Revising paragraph (i).
■ f. Revising paragraph (m).
■ g. Revising paragraph (n).

The revisions read as follows:

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (n) of this section are not subject to this subpart.

(a) An electric utility steam generating unit (EGU) covered by subpart UUUUU of this part.

* * * * *

(c) A boiler or process heater that is used specifically for research and development, including test steam boilers used to provide steam for testing the propulsion systems on military vessels. This does not include units that provide heat or steam to a process at a research and development facility.

* * * * *

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part, such as boilers and process heaters used as control devices to comply with subparts JJJ, OOO, PPP, and U of this part.

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, or part 60, part 61, or part 65 of this chapter provided that at least 50 percent of the average annual heat input during any 3 consecutive calendar years to the boiler or process heater is provided by regulated gas streams that are subject to another standard.

* * * * *

(m) A unit that burns hazardous waste covered by Subpart EEE of this part. A unit that is exempt from Subpart EEE as specified in § 63.1200(b) is not covered by Subpart EEE.

(n) Residential boilers as defined in this subpart.

* * * * *

■ 7. Section 63.7495 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b).
■ c. Adding paragraphs (e), (f), and (g).

The revisions and additions read as follows:

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by January 31, 2013, or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than January 31, 2016, except as provided in § 63.6(i).

* * * * *

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart and are no longer subject to part 60, subparts CCCC or DDDD beginning on the effective date of the switch as identified under the provisions of § 60.2145(a)(2) and (3) or § 60.2710(a)(2) and (3).

(f) If you own or operate an existing EGU that becomes subject to this subpart after January 31, 2013, you must

be in compliance with the applicable existing source provisions of this subpart on the effective date such unit becomes subject to this subpart.

(g) If you own or operate an existing industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for a exemption in § 63.7491(i) that becomes subject to this subpart after January 31, 2013, you must be in compliance with the applicable existing source provisions of this subpart within 3 years after such unit becomes subject to this subpart.

■ 8.Section 63.7499 is amended by revising paragraphs (d) and (f) through (l) and adding paragraphs (p) through (u) to read as follows:

§ 63.7499 What are the subcategories of boilers and process heaters?

* * * * *

(d) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solid.

* * * * *

(f) Suspension burners designed to burn biomass/bio-based solid.

(g) Fuel cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(i) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solid.

(j) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(k) Units designed to burn liquid fuel that are non-continental units.

(l) Units designed to burn gas 1 fuels.

* * * * *

(p) Units designed to burn solid fuel.

(q) Units designed to burn liquid fuel.

(r) Units designed to burn coal/solid fossil fuel.

(s) Fluidized bed units with an integrated fluidized bed heat exchanger designed to burn coal/solid fossil fuel.

(t) Units designed to burn heavy liquid fuel.

(u) Units designed to burn light liquid fuel.

■ 9. Section 63.7500 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (c).
■ c. Adding paragraph (d).
■ d. Adding paragraph (e).
■ e. Adding paragraph (f).

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b), through (e) of this section. You must meet these requirements at all times the affected unit is operating, except as provided in paragraph (f) of this section.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 11 through 13 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. The output-based emission limits, in units of pounds per million Btu of steam output, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers and process heaters that generate steam. The output-based emission limits, in units of pounds per megawatt-hour, in Tables 1 or 2 to this subpart are an alternative applicable only to boilers that generate electricity. If you operate a new boiler or process heater, you can choose to comply with alternative limits as discussed in paragraphs (a)(1)(i) through (a)(1)(iii) of this section, but on or after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

(i) If your boiler or process heater commenced construction or reconstruction after June 4, 2010 and before May 20, 2011, you may comply with the emission limits in Table 1 or 11 to this subpart until January 31, 2016.

(ii) If your boiler or process heater commenced construction or reconstruction after May 20, 2011 and before December 23, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until January 31, 2016.

(iii) If your boiler or process heater commenced construction or reconstruction after December 23, 2011 and before January 31, 2013, you may comply with the emission limits in Table 1 or 13 to this subpart until January 31, 2016.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit or an alternative monitoring parameter, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source (as defined in § 63.7490), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

* * * * *

(c) Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart.

(d) Boilers and process heaters with a heat input capacity of less than or equal to 5 million Btu per hour in the units designed to burn gas 2 (other) fuels subcategory or units designed to burn light liquid fuels subcategory must complete a tune-up every 5 years as specified in § 63.7540.

(e) Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart.

(f) These standards apply at all times the affected unit is operating, except during periods of startup and shutdown during which time you must comply only with Table 3 to this subpart.

■ 10. Section 63.7501 is revised to read as follows:

§ 63.7501 Affirmative Defense for Violation of Emission Standards During Malfunction.

In response to an action to enforce the standards set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for violations of such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) *Assertion of affirmative defense.* To establish the affirmative defense in

any action to enforce such a standard, you must timely meet the reporting requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The violation:

(i) Was caused by a sudden, infrequent, and unavoidable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner; and

(ii) Could not have been prevented through careful planning, proper design, or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Was not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when a violation occurred; and

(3) The frequency, amount, and duration of the violation (including any bypass) were minimized to the maximum extent practicable; and

(4) If the violation resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the violation on ambient air quality, the environment, and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the violation were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the affected source was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the violation resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of any emissions that were the result of the malfunction.

(b) *Report.* The owner or operator seeking to assert an affirmative defense shall submit a written report to the Administrator with all necessary supporting documentation, that it has met the requirements set forth in § 63.7500 of this section. This affirmative defense report shall be included in the first periodic compliance, deviation report or excess emission report otherwise required after the initial occurrence of the violation of the relevant standard (which may be the end of any applicable averaging period). If such compliance, deviation report or excess emission report is due less than 45 days after the initial occurrence of the violation, the affirmative defense report may be included in the second compliance, deviation report or excess emission report due after the initial occurrence of the violation of the relevant standard.

■ 11. Section 63.7505 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (c).
■ c. Revising paragraphs (d) introductory text, (d)(1) introductory text, and (d)(1)(iii).

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits, work practice standards, and operating limits in this subpart. These limits apply to you at all times the affected unit is operating except for the periods noted in § 63.7500(f).

* * * * *

(c) You must demonstrate compliance with all applicable emission limits using performance stack testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS), continuous opacity monitoring system (COMS), continuous parameter monitoring system (CPMS), or particulate matter continuous parameter monitoring system (PM CPMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride (HCl), mercury, or total selected metals (TSM) using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) Otherwise, you must demonstrate compliance for HCl, mercury, or TSM using performance testing, if subject to an applicable emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of CPMS), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or CPMS. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or CPMS), you must develop, and submit to the Administrator for approval upon request, a site-specific monitoring plan that addresses design, data collection, and the quality assurance and quality control elements outlined in § 63.8(d) and the elements described in paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing CEMS or COMS operated according to the performance specifications under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525. Using the process described in § 63.8(f)(4), you may request approval of alternative monitoring system quality assurance and quality control procedures in place of those specified in this paragraph and, if approved, include the alternatives in your site-specific monitoring plan.

* * * * *

(iii) Performance evaluation procedures and acceptance criteria (e.g., calibrations, accuracy audits, analytical drift).

* * * * *

■ 12. Section 63.7510 is revised to read as follows:

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For each boiler or process heater that is required or that you elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 or 11 through 13 of this subpart through performance testing, your initial compliance requirements include all the following:

(1) Conduct performance tests according to § 63.7520 and Table 5 to this subpart.

(2) Conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, except as specified in paragraphs (a)(2)(i) through (iii) of this section.

(i) For each boiler or process heater that burns a single type of fuel, you are not required to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to

§ 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as units that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(ii) When natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart. If gaseous fuels other than natural gas, refinery gas, or other gas 1 fuels are co-fired with other fuels and those gaseous fuels are subject to another subpart of this part, part 60, part 61, or part 65, you are not required to conduct a fuel analysis of those fuels according to § 63.7521 and Table 6 to this subpart.

(iii) You are not required to conduct a chlorine fuel analysis for any gaseous fuels. You must conduct a fuel analysis for mercury on gaseous fuels unless the fuel is exempted in paragraphs (a)(2)(i) and (ii) of this section.

(3) Establish operating limits according to § 63.7530 and Table 7 to this subpart.

(4) Conduct CMS performance evaluations according to § 63.7525.

(b) For each boiler or process heater that you elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 or 11 through 13 to this subpart for HCl, mercury, or TSM through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart. The fuels described in paragraph (a)(2)(i) and (ii) of this section are exempt from these fuel analysis and operating limit requirements. The fuels described in paragraph (a)(2)(ii) of this section are exempt from the chloride fuel analysis and operating limit requirements. Boilers and process heaters that use a CEMS for mercury or HCl are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section for the HAP for which CEMS are used.

(c) If your boiler or process heater is subject to a carbon monoxide (CO) limit, your initial compliance demonstration for CO is to conduct a performance test for CO according to Table 5 to this subpart or conduct a performance evaluation of your continuous CO monitor, if applicable, according to § 63.7525(a). Boilers and process heaters that use a CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 12, or 11 through 13 to this subpart, as specified in § 63.7525(a), are exempt from the initial CO performance testing and oxygen concentration operating limit requirements specified in paragraph (a) of this section.

(d) If your boiler or process heater is subject to a PM limit, your initial compliance demonstration for PM is to conduct a performance test in accordance with § 63.7520 and Table 5 to this subpart.

(e) For existing affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart, except as specified in paragraph (j) of this section. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section. You must complete the one-time energy assessment specified in Table 3 to this subpart no later than the compliance date specified in § 63.7495, except as specified in paragraph (j) of this section.

(f) For new or reconstructed affected sources (as defined in § 63.7490), you must complete the initial compliance demonstration with the emission limits no later than July 30, 2013 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Tables 11 through 13 to this subpart that is less stringent (that is, higher) than the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than July 29, 2016.

(g) For new or reconstructed affected sources (as defined in § 63.7490), you must demonstrate initial compliance with the applicable work practice standards in Table 3 to this subpart within the applicable annual, biennial, or 5-year schedule as specified in § 63.7540(a) following the initial compliance date specified in § 63.7495(a). Thereafter, you are required to complete the applicable annual, biennial, or 5-year tune-up as specified in § 63.7540(a).

(h) For affected sources (as defined in § 63.7490) that ceased burning solid waste consistent with § 63.7495(e) and for which the initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

(i) For an existing EGU that becomes subject after January 31, 2013, you must demonstrate compliance within 180 days after becoming an affected source.

(j) For existing affected sources (as defined in § 63.7490) that have not operated between the effective date of the rule and the compliance date that is specified for your source in § 63.7495, you must complete the initial compliance demonstration, if subject to the emission limits in Table 2 to this subpart, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete an initial tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) no later than 30 days after the re-start of the affected source and, if applicable, complete the one-time energy assessment specified in Table 3 to this subpart, no later than the compliance date specified in § 63.7495.

■ 13. Section 63.7515 is revised to read as follows:

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except as specified in paragraphs (b) through (e), (g), and (h) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, except as specified in paragraphs (b) through (e), (g), and (h) of this section.

(b) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit (or, in limited instances as specified in Tables 1 and 2 or 11 through 13 to this subpart, at or below the emission limit) for the pollutant, and if there are no changes in the operation of the individual boiler or process heater or air pollution control equipment that could increase emissions, you may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to

demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum mercury input level is waived unless the stack test is conducted for mercury. The requirement to test at maximum TSM input level is waived unless the stack test is conducted for TSM.

(c) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit (as specified in Tables 1 and 2 or 11 through 13 to this subpart) for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit, as specified in Tables 1 and 2 or 11 through 13 to this subpart).

(d) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual, biennial, or 5-year performance tune-up according to § 63.7540(a)(10), (11), or (12), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. Each 5-year tune-up specified in § 63.7540(a)(12) must be conducted no more than 61 months after the previous tune-up. For a new or reconstructed affected source (as defined in § 63.7490), the first annual, biennial, or 5-year tune-up must be no later than 13 months, 25 months, or 61 months, respectively, after the initial startup of the new or reconstructed affected source.

(e) If you demonstrate compliance with the mercury, HCl, or TSM based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart. You may comply with this monthly requirement by completing the fuel analysis any time within the calendar month as long as the analysis is separated from the previous analysis by at least 14 calendar days. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, you may decrease the fuel analysis frequency to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or you begin burning a new type of fuel, you must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

(f) You must report the results of performance tests and the associated fuel analyses within 60 days after the completion of the performance tests. This report must also verify that the operating limits for each boiler or process heater have not changed or provide documentation of revised operating limits established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

(g) For affected sources (as defined in § 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration, if subject to the emission limits in Tables 1, 2, or 11 through 13 to this subpart, no later than 180 days after the re-start of the affected source and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart. You must complete a subsequent tune-up by following the procedures described in § 63.7540(a)(10)(i) through (vi) and the schedule described in § 63.7540(a)(13) for units that are not operating at the time of their scheduled tune-up.

(h) If your affected boiler or process heater is in the unit designed to burn light liquid subcategory and you combust ultra low sulfur liquid fuel, you do not need to conduct further performance tests if the pollutants measured during the initial compliance performance tests meet the emission limits in Tables 1 or 2 of this subpart providing you demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel combusted on a monthly basis. If you intend to use a fuel other than ultra low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, you must conduct new performance tests within 60 days of burning the new fuel type.

(i) If you operate a CO CEMS that meets the Performance Specifications outlined in § 63.7525(a)(3) of this subpart to demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you are not required to conduct CO performance tests and are not subject to the oxygen concentration operating limit requirement specified in § 63.7510(a).

■ 14. Section § 63.7520 is amended by revising paragraphs (a), (c), (d), and (e) and adding paragraph (f) to read as follows:

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on the representative performance of each boiler or process heater for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

* * * * *

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and TSM if you are opting to comply with the TSM alternative standard and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1 and 2 or 11 through 13 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter (PM) concentrations, the measured HCl concentrations, the measured mercury concentrations, and the measured TSM concentrations that result from the performance test to pounds per million Btu heat input emission rates.

(f) Except for a 30-day rolling average based on CEMS (or sorbent trap monitoring system) data, if measurement results for any pollutant are reported as below the method detection level (e.g., laboratory analytical results for one or more sample components are below the method defined analytical detection level), you must use the method detection level as the measured emissions level for that pollutant in calculating compliance. The measured result for a multiple component analysis (e.g., analytical values for multiple Method 29 fractions both for individual HAP metals and for total HAP metals) may include a combination of method detection level data and analytical data reported above the method detection level.

■ 15. Section 63.7521 is revised to read as follows:

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid and liquid fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. For solid fuels and liquid fuels, you must also conduct fuel analyses for TSM if you are opting to comply with the TSM alternative standard. For gas 2 (other) fuels, you must conduct fuel analyses for mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. (For gaseous fuels, you may not use fuel analyses to comply with the TSM alternative standard or the HCl standard.) For purposes of complying with this section, a fuel gas system that consists of multiple gaseous fuels collected and mixed with each other is considered a single fuel type and sampling and analysis is only required on the combined fuel gas system that will feed the boiler or process heater. Sampling and analysis of the individual gaseous streams prior to combining is not required. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury, HCl, or TSM in Tables 1 and 2 or 11 through 13 to this subpart. Gaseous and liquid fuels are exempt from the sampling requirements in paragraphs (c) and (d) of this section and Table 6 to this subpart.

(b) You must develop a site-specific fuel monitoring plan according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section, if you are required to conduct fuel analyses as specified in § 63.7510.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each anticipated fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section, or the methods listed in Table 6 to this subpart, or use an automated sampling mechanism that provides representative composite fuel samples for each fuel type that includes both coarse and fine material.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal one-hour intervals during the testing period for sampling during performance stack testing. For monthly sampling, each composite sample shall be collected at approximately equal 10-day intervals during the month.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a uniform depth of approximately 18 inches. You must insert a clean shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling; use the same shovel to collect all samples.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break large sample pieces (e.g., larger than 3 inches) into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine and/or TSM) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in

Table 6 to this subpart, for use in Equations 7, 8, and 9 of this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable, except as specified in paragraph (f)(1) through (4) of this section.

(1) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for natural gas or refinery gas.

(2) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels that are subject to another subpart of this part, part 60, part 61, or part 65.

(3) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section on gaseous fuels for units that are complying with the limits for units designed to burn gas 2 (other) fuels.

(4) You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gas streams directly derived from natural gas at natural gas production sites or natural gas plants.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) If you intend to use an alternative analytical method other than those required by Table 6 to this subpart, you must submit the fuel analysis plan to the Administrator for review and approval no later than 60 days before the date that you intend to conduct the initial compliance demonstration described in § 63.7510.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than those exempted from fuel specification analysis under (f)(1) through (3) of this section anticipated to be burned in each boiler or process heater.

(ii) For each anticipated fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each anticipated fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6 to this subpart. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each anticipated fuel type, the analytical methods from Table 6 to this subpart, with the expected minimum detection levels, to be used for the measurement of mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 to this subpart shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, dry basis, of each sample for each other gas 1 fuel type according to the procedures in Table 6 to this subpart.

■ 16. Section § 63.7522 is revised by:
■ a. Revising paragraphs (a) through (d).
■ b. Revising paragraphs (e)(1) and (2).
■ c. Revising paragraphs (f) introductory text and (f)(1) and (2).
■ d. Revising paragraphs (g) introductory text, (g)(2)(i), (g)(2)(iv), (g)(2)(vi)(B), (g)(3) introductory text, (g)(4) introductory text, and (g)(4)(ii).
■ e. Revising paragraph (h).
■ f. Revising paragraph (i).
■ g. Revising paragraph (j)(1).
■ h. Revising paragraph (k).

The revisions read as follows:

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for PM (or TSM), HCl, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategories located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average PM (or TSM), HCl, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart as specified in paragraph (b)(1) through (3) of this section, if you satisfy the requirements in paragraphs (c) through (g) of this section.

(1) You may average units using a CEMS or PM CPMS for demonstrating compliance.

(2) For mercury and HCl, averaging is allowed as follows:

(i) You may average among units in any of the solid fuel subcategories.

(ii) You may average among units in any of the liquid fuel subcategories.

(iii) You may average among units in a subcategory of units designed to burn gas 2 (other) fuels.

(iv) You may not average across the units designed to burn liquid, units designed to burn solid fuel, and units designed to burn gas 2 (other) subcategories.

(3) For PM (or TSM), averaging is only allowed between units within each of the following subcategories and you may not average across subcategories:

(i) Units designed to burn coal/solid fossil fuel.

(ii) Stokers/sloped grate/other units designed to burn kiln dried biomass/bio-based solids.

(iii) Stokers/sloped grate/other units designed to burn wet biomass/bio-based solids.

(iv) Fluidized bed units designed to burn biomass/bio-based solid.

(v) Suspension burners designed to burn biomass/bio-based solid.

(vi) Dutch ovens/pile burners designed to burn biomass/bio-based solid.

(vii) Fuel Cells designed to burn biomass/bio-based solid.

(viii) Hybrid suspension/grate burners designed to burn wet biomass/bio-based solid.

(ix) Units designed to burn heavy liquid fuel.

(x) Units designed to burn light liquid fuel.

(xi) Units designed to burn liquid fuel that are non-continental units.

(xii) Units designed to burn gas 2 (other) gases.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on

January 31, 2013 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on January 31, 2013.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must not exceed 90 percent of the limits in Table 2 to this subpart at all times the affected units are operating following the compliance date specified in § 63.7495.

(e) * * *

(1) You must use Equation 1a or 1b or 1c of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart. Use Equation 1a if you are complying with the emission limits on a heat input basis, use Equation 1b if you are complying with the emission limits on a steam generation (output) basis, and use Equation 1c if you are complying with the emission limits on a electric generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1a)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 1b)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

So = Maximum steam output capacity of unit, i, in units of million Btu per hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 1c)}$$

Where:

AveWeightedEmissions = Average weighted emissions for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour.

Er = Emission rate (as determined during the initial compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c). If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, Eadj, determined according to § 63.7533 for that unit.

Eo = Maximum electric generating output capacity of unit, i, in units of megawatt hour, as defined in § 63.7575.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1a of this section to demonstrate that the PM (or TSM), HCl, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart that are in pounds per million Btu of heat input.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds per hour.
Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.
1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495. If the affected source elects to collect monthly data for up the 11 months preceding the first monthly period, these additional data points can be used to compute the 12-month rolling average in paragraph (f)(3) of this section.

(1) For each calendar month, you must use Equation 3a or 3b or 3c of this section to calculate the average weighted emission rate for that month. Use Equation 3a and the actual heat input for the month for each existing unit participating in the emissions averaging option if you are complying with emission limits on a heat input basis. Use Equation 3b and the actual steam generation for the month if you are complying with the emission limits on a steam generation (output) basis. Use Equation 3c and the actual steam generation for the month if you are complying with the emission limits on a electrical generation (output) basis.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3a)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of heat input, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.
Hb = The heat input for that calendar month to unit, i, in units of million Btu.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times So) \div \sum_{i=1}^{n} So \qquad \text{(Eq. 3b)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million Btu of steam output, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of steam output. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
So = The steam output for that calendar month from unit, i, in units of million Btu, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Eo) \div \sum_{i=1}^{n} Eo \qquad \text{(Eq. 3c)}$$

Where:
AveWeightedEmissions = Average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per megawatt hour, for that calendar month.
Er = Emission rate (as determined during the most recent compliance demonstration) of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per megawatt hour. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart. If you are taking credit for energy conservation measures from a unit according to § 63.7533, use the adjusted emission level for that unit, E_{adj}, determined according to § 63.7533 for that unit.
Eo = The electric generating output for that calendar month from unit, i, in units of megawatt hour, as defined in § 63.7575.
n = Number of units participating in the emissions averaging option.
1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3a of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \qquad \text{(Eq. 4)}$$

Where:
AveWeightedEmissions = average weighted emission level for PM (or TSM), HCl, or mercury, in units of pounds per million

Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of PM (or TSM), HCl, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for PM (or TSM), HCl, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart.

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

* * * * *

(g) You must develop, and submit upon request to the applicable Administrator for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

* * * * *

(2) * * *

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of January 31, 2013 and the date on which you are requesting emission averaging to commence;

* * * * *

(iv) The test plan for the measurement of PM (or TSM), HCl, or mercury emissions in accordance with the requirements in § 63.7520;

* * * * *

(vi) * * *

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the Administrator, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

* * * * *

(3) The Administrator shall review and approve or disapprove the plan according to the following criteria:

* * * * *

(4) The applicable Administrator shall not approve an emission averaging implementation plan containing any of the following provisions:

* * * * *

(ii) The inclusion of any emission source other than an existing unit in the same subcategories.

* * * * *

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average PM (or TSM), HCl, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategories, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) * * *

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n} (ELi \times Hi) \div \sum_{i=1}^{n} Hi \qquad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

* * * * *

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategories subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

■ 17. Section 63.7525 is amended by:
■ a. Revising paragraph (a)
■ b. Revising paragraph (b).
■ c. Revising paragraph (c) introductory text.
■ d. Revising paragraphs (d) introductory text and paragraphs (d)(1) through (d)(4).
■ e. Revising paragraph (e)(2).
■ f. Revising paragraph (e)(3).
■ g. Revising paragraph (f)(2).
■ h. Revising paragraph (j).
■ i. Revising paragraph (k).
■ j. Adding paragraph (l).
■ k. Adding paragraph (m).

The revisions and additions read as follows:

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a CO emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must install, operate, and maintain an oxygen analyzer system, as defined in § 63.7575, or install, certify, operate and maintain continuous emission monitoring systems for CO and oxygen according to the procedures in paragraphs (a)(1) through (7) of this section.

(1) Install the CO CEMS and oxygen analyzer by the compliance date specified in § 63.7495. The CO and oxygen levels shall be monitored at the same location at the outlet of the boiler or process heater.

(2) To demonstrate compliance with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart, you must install, certify, operate, and maintain a CO CEMS and an oxygen analyzer according to the applicable procedures under Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, the site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section. Any boiler or process heater that has a CO CEMS that is compliant with Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B, a site-specific monitoring plan developed according to § 63.7505(d), and the requirements in § 63.7540(a)(8) and paragraph (a) of this section must use the CO CEMS to comply with the applicable alternative CO CEMS emission standard listed in Tables 1, 2, or 11 through 13 to this subpart.

(i) You must conduct a performance evaluation of each CO CEMS according to the requirements in § 63.8(e) and

according to Performance Specification 4, 4A, or 4B at 40 CFR part 60, appendix B.

(ii) During each relative accuracy test run of the CO CEMS, you must be collect emission data for CO concurrently (or within a 30- to 60-minute period) by both the CO CEMS and by Method 10, 10A, or 10B at 40 CFR part 60, appendix A–4. The relative accuracy testing must be at representative operating conditions.

(iii) You must follow the quality assurance procedures (e.g., quarterly accuracy determinations and daily calibration drift tests) of Procedure 1 of appendix F to part 60. The measurement span value of the CO CEMS must be two times the applicable CO emission limit, expressed as a concentration.

(iv) Any CO CEMS that does not comply with § 63.7525(a) cannot be used to meet any requirement in this subpart to demonstrate compliance with a CO emission limit listed in Tables 1, 2, or 11 through 13 to this subpart.

(v) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Complete a minimum of one cycle of CO and oxygen CEMS operation (sampling, analyzing, and data recording) for each successive 15-minute period. Collect CO and oxygen data concurrently. Collect at least four CO and oxygen CEMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CEMS calibration, quality assurance, or maintenance activities are being performed.

(4) Reduce the CO CEMS data as specified in § 63.8(g)(2).

(5) Calculate one-hour arithmetic averages, corrected to 3 percent oxygen from each hour of CO CEMS data in parts per million CO concentration. The one-hour arithmetic averages required shall be used to calculate the 30-day or 10-day rolling average emissions. Use Equation 19–19 in section 12.4.1 of Method 19 of 40 CFR part 60, appendix A–7 for calculating the average CO concentration from the hourly values.

(6) For purposes of collecting CO data, operate the CO CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when CO data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(7) Operate an oxygen trim system with the oxygen level set no lower than the lowest hourly average oxygen concentration measured during the most recent CO performance test as the operating limit for oxygen according to Table 7 to this subpart.

(b) If your boiler or process heater is in the unit designed to burn coal/solid fossil fuel subcategory or the unit designed to burn heavy liquid subcategory and has an average annual heat input rate greater than 250 MMBtu per hour from solid fossil fuel and/or heavy liquid, and you demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CPMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (4) of this section. As an alternative to use of a PM CPMS to demonstrate compliance with the PM limit, you may choose to use a PM CEMS. If you choose to use a PM CEMS to demonstrate compliance with the PM limit instead of the alternative TSM limit, you must install, certify, maintain, and operate a PM CEMS monitoring emissions discharged to the atmosphere and record the output of the system as specified in paragraph (b)(5) through (8) of this section. For other boilers or process heaters, you may elect to use a PM CPMS or PM CEMS operated in accordance with this section in lieu of using other CMS for monitoring PM compliance (e.g., bag leak detectors, ESP secondary power, PM scrubber pressure). Owners of boilers and process heaters who elect to comply with the alternative TSM limit are not required to install a PM CPMS.

(1) Install, certify, operate, and maintain your PM CPMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(1)(i) through (iii) of this section.

(i) The operating principle of the PM CPMS must be based on in-stack or extractive light scatter, light scintillation, beta attenuation, or mass accumulation detection of PM in the exhaust gas or representative exhaust gas sample. The reportable measurement output from the PM CPMS must be expressed as milliamps.

(ii) The PM CPMS must have a cycle time (i.e., period required to complete sampling, measurement, and reporting for each measurement) no longer than 60 minutes.

(iii) The PM CPMS must be capable of detecting and responding to PM concentrations of no greater than 0.5 milligram per actual cubic meter.

(2) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the initial performance evaluation no later than July 29, 2016.

(3) Collect PM CPMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d). Express the PM CPMS output as milliamps.

(4) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CPMS output data collected during all boiler or process heater operating hours (milliamps).

(5) Install, certify, operate, and maintain your PM CEMS according to the procedures in your approved site-specific monitoring plan developed in accordance with § 63.7505(d), the requirements in § 63.7540(a)(9), and paragraphs (b)(5)(i) through (iv) of this section.

(i) You shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.8(e), and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, you shall collect PM and oxygen (or carbon dioxide) data concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) You shall perform quarterly accuracy determinations and daily calibration drift tests in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. You must perform Relative Response Audits annually and perform Response Correlation Audits every 3 years.

(iv) Within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to the EPA by successfully submitting the data electronically into the EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/erttool.html/*).

(6) For a new unit, complete the initial performance evaluation no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, complete the

initial performance evaluation no later than July 29, 2016.

(7) Collect PM CEMS hourly average output data for all boiler or process heater operating hours except as indicated in § 63.7535(a) through (d).

(8) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all boiler or process heater operating hours.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required or elect to install and operate a PM CPMS, PM CEMS, or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

* * * * *

(d) If you have an operating limit that requires the use of a CMS other than a PM CPMS or COMS, you must install, operate, and maintain each CMS according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The CPMS must complete a minimum of one cycle of operation every 15-minutes. You must have a minimum of four successive cycles of operation, one representing each of the four 15-minute periods in an hour, to have a valid hour of data.

(2) You must operate the monitoring system as specified in § 63.7535(b), and comply with the data calculation requirements specified in § 63.7535(c).

(3) Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Other situations that constitute a monitoring deviation are specified in § 63.7535(d).

(4) You must determine the 30-day rolling average of all recorded readings, except as provided in § 63.7535(c).

* * * * *

(e) * * *

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the design flow rate.

(3) You must minimize, consistent with good engineering practices, the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

* * * * *

(f) * * *

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion consistent with good engineering practices.

* * * * *

(j) If you are not required to use a PM CPMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (6) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute PM loadings for each exhaust stack, roof vent, or compartment (e.g., for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, see § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting PM emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert plant operating personnel when an increase in relative PM emissions over a preset level is detected. The alert must easily recognizable (e.g., heard or seen) by plant operating personnel.

(6) Where multiple bag leak detectors are required, the system's instrumentation and alert may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must keep fuel use records for the days the boiler or process heater was operating.

(l) For each unit for which you decide to demonstrate compliance with the mercury or HCl emissions limits in Tables 1 or 2 or 11 through 13 of this subpart by use of a CEMS for mercury or HCl, you must install, certify, maintain, and operate a CEMS measuring emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (l)(1) through (8) of this section. For HCl, this option for an affected unit takes effect on the date a final performance specification for a HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(1) Notify the Administrator one month before starting use of the CEMS, and notify the Administrator one month before stopping use of the CEMS.

(2) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(14) for a mercury CEMS and § 63.7540(a)(15) for a HCl CEMS.

(3) For a new unit, you must complete the initial performance evaluation of the CEMS by the latest of the dates specified in paragraph (l)(3)(i) through (iii) of this section.

(i) No later than July 30, 2013.

(ii) No later 180 days after the date of initial startup.

(iii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(4) For an existing unit, you must complete the initial performance evaluation by the latter of the two dates specified in paragraph (l)(4)(i) and (ii) of this section.

(i) No later than July 29, 2016.

(ii) No later 180 days after notifying the Administrator before starting to use the CEMS in place of performance testing or fuel analysis to demonstrate compliance.

(5) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions rates using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission rate (lb/MMBtu) shall be calculated using the equations in EPA Reference Method 19 at 40 CFR part 60, appendix A–7, but substituting the mercury or HCl concentration for the pollutant concentrations normally used in Method 19.

(6) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(7) The one-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler 30-day and 10-day rolling average emissions.

(8) You are allowed to substitute the use of the PM, mercury or HCl CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with the PM, mercury or HCl emissions limit, and if you are using an acid gas wet scrubber or dry sorbent injection control technology to comply with the HCl emission limit, you are allowed to substitute the use of a sulfur dioxide

(SO_2) CEMS for the applicable fuel analysis, annual performance test, and operating limits specified in Table 4 to this subpart to demonstrate compliance with HCl emissions limit.

(m) If your unit is subject to a HCl emission limit in Tables 1, 2, or 11 through 13 of this subpart and you have an acid gas wet scrubber or dry sorbent injection control technology and you use an SO_2 CEMS, you must install the monitor at the outlet of the boiler or process heater, downstream of all emission control devices, and you must install, certify, operate, and maintain the CEMS according to part 75 of this chapter.

(1) The SO_2 CEMS must be installed by the compliance date specified in § 63.7495.

(2) For on-going quality assurance (QA), the SO_2 CEMS must meet the applicable daily, quarterly, and semiannual or annual requirements in sections 2.1 through 2.3 of appendix B to part 75 of this chapter, with the following addition: You must perform the linearity checks required in section 2.2 of appendix B to part 75 of this chapter if the SO_2 CEMS has a span value of 30 ppm or less.

(3) For a new unit, the initial performance evaluation shall be completed no later than July 30, 2013, or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than July 29, 2016.

(4) For purposes of collecting SO_2 data, you must operate the SO_2 CEMS as specified in § 63.7535(b). You must use all the data collected during all periods in calculating data averages and assessing compliance, except that you must exclude certain data as specified in § 63.7535(c). Periods when SO_2 data are unavailable may constitute monitoring deviations as specified in § 63.7535(d).

(5) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis.

(6) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values.

■ 18. Section 63.7530 is amended by:
■ a. Revising paragraph (a).
■ b. Revising paragraph (b) introductory text.
■ c. Redesignating paragraph (b)(3) as paragraph (b)(4) and adding new paragraph (b)(3).
■ d. Revising newly designated paragraph (b)(4).
■ e. Revising paragraph (c), (c)(2) through (4).
■ f. Adding paragraph (c)(5).
■ g. Revising paragraphs (d), (e), (g), and (h).
■ h. Adding paragraph (i).

The revisions and additions read as follows:

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. The requirement to conduct a fuel analysis is not applicable for units that burn a single type of fuel, as specified by § 63.7510(a)(2)(i). If applicable, you must also install, operate, and maintain all applicable CMS (including CEMS, COMS, and CPMS) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(4) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) through (3) of this section, as applicable, and as specified in § 63.7510(a)(2). (Note that § 63.7510(a)(2) exempts certain fuels from the fuel analysis requirements.) However, if you switch fuel(s) and cannot show that the new fuel(s) does (do) not increase the chlorine, mercury, or TSM input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

* * * * *

(3) If you opt to comply with the alternative TSM limit, you must establish the maximum TSM fuel input (TSMinput) for solid or liquid fuels during the initial fuel analysis according to the procedures in paragraphs (b)(3)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of TSM.

(ii) During the fuel analysis for TSM, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of TSM, and the average TSM concentration of each fuel type burned (TSMi).

(iii) You must establish a maximum TSM input level using Equation 9 of this section.

$$TSMinput = \sum_{i=1}^{n} (TSMi \times Qi) \qquad \text{(Eq. 9)}$$

Where:

TSMinput = Maximum amount of TSM entering the boiler or process heater through fuels burned in units of pounds per million Btu.

TSMi = Arithmetic average concentration of TSM in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of TSM. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of TSM.

(4) You must establish parameter operating limits according to paragraphs (b)(4)(i) through (ix) of this section. As indicated in Table 4 to this subpart, you are not required to establish and comply with the operating parameter limits when you are using a CEMS to monitor and demonstrate compliance with the applicable emission limit for that control device parameter.

(i) For a wet acid gas scrubber, you must establish the minimum scrubber effluent pH and liquid flow rate as defined in § 63.7575, as your operating limits during the performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for HCl and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flow rate, and

pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate operating limit at the higher of the minimum values established during the performance tests.

(ii) For any particulate control device (e.g., ESP, particulate wet scrubber, fabric filter) for which you use a PM CPMS, you must establish your PM CPMS operating limit and determine compliance with it according to paragraphs (b)(4)(ii)(A) through (F) of this section.

(A) Determine your operating limit as the average PM CPMS output value recorded during the most recent performance test run demonstrating compliance with the filterable PM emission limit or at the PM CPMS output value corresponding to 75 percent of the emission limit if your PM performance test demonstrates compliance below 75 percent of the emission limit. You must verify an existing or establish a new operating limit after each repeated performance test. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(*1*) Your PM CPMS must provide a 4–20 milliamp output and the establishment of its relationship to manual reference method measurements must be determined in units of milliamps.

(*2*) Your PM CPMS operating range must be capable of reading PM concentrations from zero to a level equivalent to at least two times your allowable emission limit. If your PM CPMS is an auto-ranging instrument capable of multiple scales, the primary range of the instrument must be capable of reading PM concentration from zero to a level equivalent to two times your allowable emission limit.

(*3*) During the initial performance test or any such subsequent performance test that demonstrates compliance with the PM limit, record and average all milliamp output values from the PM CPMS for the periods corresponding to the compliance test runs (e.g., average all your PM CPMS output values for three corresponding 2-hour Method 5I test runs).

(B) If the average of your three PM performance test runs are below 75 percent of your PM emission limit, you must calculate an operating limit by establishing a relationship of PM CPMS signal to PM concentration using the PM CPMS instrument zero, the average PM CPMS values corresponding to the three compliance test runs, and the average PM concentration from the Method 5 or performance test with the procedures in paragraphs (b)(4)(ii)(B)(*1*) through (*4*) of this section.

(*1*) Determine your instrument zero output with one of the following procedures:

(*i*) Zero point data for *in-situ* instruments should be obtained by removing the instrument from the stack and monitoring ambient air on a test bench.

(*ii*) Zero point data for *extractive* instruments should be obtained by removing the extractive probe from the stack and drawing in clean ambient air.

(*iii*) The zero point may also be established by performing manual reference method measurements when the flue gas is free of PM emissions or contains very low PM concentrations (*e.g.,* when your process is not operating, but the fans are operating or your source is combusting only natural gas) and plotting these with the compliance data to find the zero intercept.

(*iv*) If none of the steps in paragraphs (b)(4)(ii)(B)(*1*)(*i*) through (*iii*) of this section are possible, you must use a zero output value provided by the manufacturer.

(*2*) Determine your PM CPMS instrument average in milliamps, and the average of your corresponding three PM compliance test runs, using equation 10.

$$\bar{x} = \frac{1}{n}\sum_{i=1}^{n} X_1 \, , \bar{y} = \frac{1}{n}\sum_{i=1}^{n} Y_1 \qquad \text{(Eq. 10)}$$

Where:

X_1 = the PM CPMS data points for the three runs constituting the performance test,

Y_1 = the PM concentration value for the three runs constituting the performance test, and

n = the number of data points.

(*3*) With your instrument zero expressed in milliamps, your three run average PM CPMS milliamp value, and your three run average PM concentration from your three compliance tests, determine a relationship of lb/MMBtu per milliamp with equation 11.

$$R = \frac{Y_1}{(X_1 - z)} \qquad \text{(Eq. 11)}$$

Where:

R = the relative lb/MMBtu per milliamp for your PM CPMS,

Y_1 = the three run average lb/MMBtu PM concentration,

X_1 = the three run average milliamp output from you PM CPMS, and

z = the milliamp equivalent of your instrument zero determined from (B)(i).

(*4*) Determine your source specific 30-day rolling average operating limit using the lb/MMBtu per milliamp value from Equation 11 in equation 12, below. This sets your operating limit at the PM CPMS output value corresponding to 75 percent of your emission limit.

$$O_l = z + \frac{0.75(L)}{R} \qquad \text{(Eq. 12)}$$

Where:

O_l = the operating limit for your PM CPMS on a 30-day rolling average, in milliamps.

L = your source emission limit expressed in lb/MMBtu,

z = your instrument zero in milliamps, determined from (B)(i), and

R = the relative lb/MMBtu per milliamp for your PM CPMS, from Equation 11.

(C) If the average of your three PM compliance test runs is at or above 75 percent of your PM emission limit you must determine your 30-day rolling average operating limit by averaging the PM CPMS milliamp output corresponding to your three PM performance test runs that demonstrate compliance with the emission limit using equation 13 and you must submit all compliance test and PM CPMS data according to the reporting requirements in paragraph (b)(4)(ii)(F) of this section.

$$O_h = \frac{1}{n}\sum_{i=1}^{n} X_1 \qquad \text{(Eq. 13)}$$

Where:

X_1 = the PM CPMS data points for all runs i,

n = the number of data points, and

O_h = your site specific operating limit, in milliamps.

(D) To determine continuous compliance, you must record the PM

CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new operating hour. Use Equation 14 to determine the 30-day rolling average.

$$30-\text{day} = \frac{\sum_{i=1}^{n} Hpv_i}{n} \qquad \text{(Eq. 14)}$$

Where:

30-day = 30-day average.

Hpvi = is the hourly parameter value for hour i

n = is the number of valid hourly parameter values collected over the previous 720 operating hours.

(E) Use EPA Method 5 of appendix A to part 60 of this chapter to determine PM emissions. For each performance test, conduct three separate runs under the conditions that exist when the affected source is operating at the highest load or capacity level reasonably expected to occur. Conduct each test run to collect a minimum sample volume specified in Tables 1, 2, or 11 through 13 to this subpart, as applicable, for determining compliance with a new source limit or an existing source limit. Calculate the average of the results from three runs to determine compliance. You need not determine the PM collected in the impingers (''back half'') of the Method 5 particulate sampling train to demonstrate compliance with the PM standards of this subpart. This shall not preclude the permitting authority from requiring a determination of the ''back half'' for other purposes.

(F) For PM performance test reports used to set a PM CPMS operating limit, the electronic submission of the test report must also include the make and model of the PM CPMS instrument, serial number of the instrument, analytical principle of the instrument (e.g. beta attenuation), span of the instruments primary analytical range, milliamp value equivalent to the instrument zero output, technique by which this zero value was determined, and the average milliamp signals corresponding to each PM compliance test run. (iii) For a particulate wet scrubber, you must establish the minimum pressure drop and liquid flow rate as defined in § 63.7575, as your operating limits during the three-run performance test during which you demonstrate compliance with your applicable limit. If you use a wet scrubber and you conduct separate performance tests for PM and TSM emissions, you must establish one set of minimum scrubber liquid flow rate and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the HCl performance test. If you conduct multiple performance tests, you must set the minimum liquid flow rate and pressure drop operating limits at the higher of the minimum values established during the performance tests.

(iii) For an electrostatic precipitator (ESP) operated with a wet scrubber, you must establish the minimum total secondary electric power input, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit. (These operating limits do not apply to ESP that are operated as dry controls without a wet scrubber.)

(iv) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(v) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test during which you demonstrate compliance with your applicable limit.

(vi) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alert is not activated more than 5 percent of the operating time during a 6-month period.

(vii) For a minimum oxygen level, if you conduct multiple performance tests, you must set the minimum oxygen level at the lower of the minimum values established during the performance tests.

(viii) The operating limit for boilers or process heaters that demonstrate continuous compliance with the HCl emission limit using a SO_2 CEMS is to install and operate the SO_2 according to the requirements in § 63.7525(m) establish a maximum SO_2 emission rate equal to the highest hourly average SO_2 measurement during the most recent three-run performance test for HCl.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (5) of this section.

* * * * *

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided t-statistic test described in Equation 15 of this section.

$$P90 = mean + (SD \times t) \qquad \text{(Eq. 15)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the mean of pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu. SD is calculated as the sample standard

deviation divided by the square root of the number of samples.

t = t distribution critical value for 90th percentile ($t_{0.1}$) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a t-Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for HCl, the HCl emission rate that you calculate for your boiler or process heater using Equation 16 of this section must not exceed the applicable emission limit for HCl.

$$HCl = \sum_{i=1}^{n} \left(Ci90 \times Qi \times 1.028 \right) \qquad \text{(Eq. 16)}$$

Where:

HCl = HCl emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of HCl to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 17 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n} \left(Hgi90 \times Qi \right) \qquad \text{(Eq. 17)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(5) To demonstrate compliance with the applicable emission limit for TSM for solid or liquid fuels, the TSM emission rate that you calculate for your boiler or process heater from solid fuels using Equation 18 of this section must not exceed the applicable emission limit for TSM.

$$Metals = \sum_{i=1}^{n} \left(TSM90i \times Qi \right) \qquad \text{(Eq. 18)}$$

Where:

Metals = TSM emission rate from the boiler or process heater in units of pounds per million Btu.

TSMi90 = 90th percentile confidence level concentration of TSM in fuel, i, in units of pounds per million Btu as calculated according to Equation 11 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest TSM content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of ''1'' for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest TSM content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour or a unit in the unit designed to burn gas 1 subcategory, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility at the time of the assessment.

* * * * *

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of another gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i) and according to the frequency listed in § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g). For samples where the initial mercury specification has not been exceeded, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specification outlined in the definition of other gas 1 fuels.

(h) If you own or operate a unit subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart, you must meet the work practice standard according to Table 3 of this subpart. During startup and shutdown, you must only follow the work practice standards according to item 5 of Table 3 of this subpart.

(i) If you opt to comply with the alternative SO_2 CEMS operating limit in Tables 4 and 8 to this subpart, you may do so only if your affected boiler or process heater:

(1) Has a system using wet scrubber or dry sorbent injection and SO_2 CEMS installed on the unit; and

(2) At all times, you operate the wet scrubber or dry sorbent injection for acid gas control on the unit consistent with § 63.7500(a)(3); and

(3) You establish a unit-specific maximum SO_2 operating limit by

collecting the minimum hourly SO_2 emission rate on the SO_2 CEMS during the paired 3-run test for HCl. The maximum SO_2 operating limit is equal to the highest hourly average SO_2 concentration measured during the most recent HCl performance test.

■ 19. Section 63.7533 is amended by:
■ a. Revising the section heading.
■ b. Revising paragraph (a).
■ c. Revising paragraphs (b)(1) and (4).
■ d. Revising paragraphs (c) introductory text, (c)(1)(i) and (ii), (c)(2)(i), and (c)(3).
■ e. Revising paragraph (d) through (f).
■ f. Adding paragraph (g).

The revisions and addition read as follows:

§ 63.7533 Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent output-based emission limits, instead of the heat input-based limits listed in Table 2 to this subpart, and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using efficiency credits according to the procedures in this section. You may use this compliance approach for an existing affected boiler for demonstrating initial compliance according to § 63.7522(e) and for demonstrating monthly compliance according to § 63.7522(f). Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the efficiency credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the efficiency credit according to the procedures in paragraphs (b) through (f) of this section. You cannot use this compliance approach for a new or reconstructed affected boiler. Additional guidance from the Department of Energy on efficiency credits is available at: *http://www.epa.gov/ttn/atw/boiler/boilerpg.html.*

(b) * * *

(1) The benchmark from which efficiency credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

* * * * *

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. If possible, use actual data that are current and timely rather than estimated data.

(c) Efficiency credits can be generated if the energy conservation measures were implemented after January 1, 2008 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate efficiency credits:

(i) Energy conservation measures implemented on or before January 1, 2008, unless the level of energy demand reduction is increased after January 1, 2008, in which case credit will be allowed only for change in demand reduction achieved after January 1, 2008.

(ii) Efficiency credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to energy conservation measures identified in the energy assessment. In this case, the bench established for the affected boiler to which the credits from the shutdown will be applied must be revised to include the benchmark established for the shutdown boiler.

(2) * * *

(i) Calculate annual credits for all energy demand points. Use Equation 19 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

* * * * *

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 1, 2008. Credits shall be calculated using Equation 19 of this section as follows:

(i) The overall equation for calculating credits is:

$$ECredits = \left(\sum_{i=1}^{n} EIS_{iactual} \right) \div EI_{baseline} \qquad \text{(Eq. 19)}$$

Where:

ECredits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, expressed as a decimal fraction of the baseline energy input.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure, i, implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input baseline for the affected boiler, million Btu per year.

n = Number of energy conservation measures included in the efficiency credit for the affected boiler.

(ii) [Reserved]

(d) The owner or operator shall develop, and submit for approval upon request by the Administrator, an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an efficiency credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the efficiency credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. If requested, you must submit the implementation plan for efficiency credits to the Administrator for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the efficiency credit approach.

(e) The emissions rate as calculated using Equation 20 of this section from each existing boiler participating in the efficiency credit option must be in compliance with the limits in Table 2 to this subpart at all times the affected unit is operating, following the compliance date specified in § 63.7495.

(f) You must use Equation 20 of this section to demonstrate initial compliance by demonstrating that the emissions from the affected boiler participating in the efficiency credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - ECredits) \quad \text{(Eq. 20)}$$

Where:

E_{adj} = Emission level adjusted by applying the efficiency credits earned, lb per million Btu steam output (or lb per MWh) for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output (or lb per MWh) for the affected boiler.

ECredits = Efficiency credits from Equation 19 for the affected boiler.

(g) As part of each compliance report submitted as required under § 63.7550, you must include documentation that the energy conservation measures implemented continue to generate the credit for use in demonstrating compliance with the emission limits.

■ 20. Section 63.7535 is amended by revising the section heading and paragraphs (b), (c), and (d) to read as follows:

§ 63.7535 Is there a minimum amount of monitoring data I must obtain?

* * * * *

(b) You must operate the monitoring system and collect data at all required intervals at all times that each boiler or process heater is operating and compliance is required, except for periods of monitoring system malfunctions or out of control periods (see § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks, required zero and span adjustments, and scheduled CMS maintenance as defined in your site-specific monitoring plan. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must record and make available upon request results of CMS performance audits and dates and duration of periods when the CMS is out of control to completion of the corrective actions necessary to return the CMS to operation consistent with your site-specific monitoring plan. You must use all the data collected during all other periods in assessing compliance and the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits, calibration checks, and required zero and span adjustments), failure to collect required data is a deviation of the monitoring requirements. In calculating monitoring results, do not use any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities. You must calculate monitoring results using all other monitoring data collected while the process is operating. You must report all periods when the monitoring system is out of control in your annual report.

■ 21. Section 63.7540 is revised to read as follows:

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit in Tables 1 and 2 or 11 through 13 to this subpart, the work practice standards in Table 3 to this subpart, and the operating limits in Table 4 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (19) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in either of the following:

(i) Lower emissions of HCl, mercury, and TSM than the applicable emission limit for each pollutant, if you demonstrate compliance through fuel analysis.

(ii) Lower fuel input of chlorine, mercury, and TSM than the maximum values calculated during the last performance test, if you demonstrate compliance through performance testing.

(3) If you demonstrate compliance with an applicable HCl emission limit through fuel analysis for a solid or liquid fuel and you plan to burn a new type of solid or liquid fuel, you must recalculate the HCl emission rate using Equation 12 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the HCl emission rate.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the HCl emission rate from your boiler or process heater under these new conditions using Equation 12 of § 63.7530. The recalculated HCl emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable HCl emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the

procedures in § 63.7520 to demonstrate that the HCl emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). In recalculating the maximum chlorine input and establishing the new operating limits, you are not required to conduct fuel analyses for and include the fuels described in § 63.7510(a)(2)(i) through (iii).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 13 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 13 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the mercury emission rate.

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alert and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the periods which would cause an alert are no more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alert, the time corrective action was initiated and completed, and a brief description of the cause of the alert and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the conditions exist for an alert. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alert time is counted. If corrective action is required, each alert shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alert time shall be counted as the actual amount of time taken to initiate corrective action.

(8) To demonstrate compliance with the applicable alternative CO CEMS emission limit listed in Tables 1, 2, or 11 through 13 to this subpart, you must meet the requirements in paragraphs (a)(8)(i) through (iv) of this section.

(i) Continuously monitor CO according to §§ 63.7525(a) and 63.7535.

(ii) Maintain a CO emission level below or at your applicable alternative CO CEMS-based standard in Tables 1 or 2 or 11 through 13 to this subpart at all times the affected unit is operating.

(iii) Keep records of CO levels according to § 63.7555(b).

(iv) You must record and make available upon request results of CO CEMS performance audits, dates and duration of periods when the CO CEMS is out of control to completion of the corrective actions necessary to return the CO CEMS to operation consistent with your site-specific monitoring plan.

(9) The owner or operator of a boiler or process heater using a PM CPMS or a PM CEMS to meet requirements of this subpart shall install, certify, operate, and maintain the PM CPMS or PM CEMS in accordance with your site-specific monitoring plan as required in § 63.7505(d).

(10) If your boiler or process heater has a heat input capacity of 10 million Btu per hour or greater, you must conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (vi) of this section. This frequency does not apply to limited-use boilers and process heaters, as defined in § 63.7575, or units with continuous oxygen trim systems that maintain an optimum air to fuel ratio.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the burner inspection until the first outage, not to exceed 36 months from the previous inspection. At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection;

(iv) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NO_X requirement to which the unit is subject;

(v) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer; and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater;

(B) A description of any corrective actions taken as a part of the tune-up; and

(C) The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour (except as specified in paragraph (a)(12) of this section), you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance.

(12) If your boiler or process heater has a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour and the unit is in the units designed to burn gas 1; units designed to burn gas 2 (other); or units designed to burn light liquid subcategories, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a tune-up of the boiler or process heater every 5 years as specified in paragraphs (a)(10)(i) through (vi) of this section to demonstrate continuous compliance. You may delay the burner inspection specified in paragraph (a)(10)(i) of this section until the next scheduled or unscheduled unit shutdown, but you must inspect each burner at least once every 72 months.

(13) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within 30 calendar days of startup.

(14) If you are using a CEMS measuring mercury emissions to meet requirements of this subpart you must install, certify, operate, and maintain the mercury CEMS as specified in paragraphs (a)(14)(i) and (ii) of this section.

(i) Operate the mercury CEMS in accordance with performance specification 12A of 40 CFR part 60, appendix B or operate a sorbent trap based integrated monitor in accordance with performance specification 12B of 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly mercury concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a mercury CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the mercury mass emissions rate to the atmosphere according to the requirements of performance specifications 6 and 12A of 40 CFR part 60, appendix B, and quality assurance procedure 6 of 40 CFR part 60, appendix F.

(15) If you are using a CEMS to measure HCl emissions to meet requirements of this subpart, you must install, certify, operate, and maintain the HCl CEMS as specified in paragraphs (a)(15)(i) and (ii) of this section. This option for an affected unit takes effect on the date a final performance specification for an HCl CEMS is published in the **Federal Register** or the date of approval of a site-specific monitoring plan.

(i) Operate the continuous emissions monitoring system in accordance with the applicable performance specification in 40 CFR part 60, appendix B. The duration of the performance test must be the maximum of 30 unit operating days or 720 hours. For each day in which the unit operates, you must obtain hourly HCl concentration data, and stack gas volumetric flow rate data.

(ii) If you are using a HCl CEMS, you must install, operate, calibrate, and maintain an instrument for continuously measuring and recording the HCl mass emissions rate to the atmosphere according to the requirements of the applicable performance specification of 40 CFR part 60, appendix B, and the quality assurance procedures of 40 CFR part 60, appendix F.

(16) If you demonstrate compliance with an applicable TSM emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum TSM input using Equation 9 of § 63.7530. If the results of recalculating the maximum TSM input using Equation 9 of § 63.7530 are higher than the maximum total selected input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the TSM emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b). You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(17) If you demonstrate compliance with an applicable TSM emission limit through fuel analysis for solid or liquid fuels, and you plan to burn a new type of fuel, you must recalculate the TSM emission rate using Equation 14 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section. You are not required to conduct fuel analyses for the fuels described in § 63.7510(a)(2)(i) through (iii). You may exclude the fuels described in § 63.7510(a)(2)(i) through (iii) when recalculating the TSM emission rate.

(i) You must determine the TSM concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of TSM.

(iii) Recalculate the TSM emission rate from your boiler or process heater under these new conditions using Equation 14 of § 63.7530. The recalculated TSM emission rate must be less than the applicable emission limit.

(18) If you demonstrate continuous PM emissions compliance with a PM CPMS you will use a PM CPMS to establish a site-specific operating limit corresponding to the results of the performance test demonstrating compliance with the PM limit. You will conduct your performance test using the test method criteria in Table 5 of this subpart. You will use the PM CPMS to demonstrate continuous compliance with this operating limit. You must repeat the performance test annually and reassess and adjust the site-specific operating limit in accordance with the results of the performance test.

(i) To determine continuous compliance, you must record the PM CPMS output data for all periods when the process is operating and the PM CPMS is not out-of-control. You must demonstrate continuous compliance by using all quality-assured hourly average data collected by the PM CPMS for all operating hours to calculate the arithmetic average operating parameter in units of the operating limit (milliamps) on a 30-day rolling average basis, updated at the end of each new boiler or process heater operating hour.

(ii) For any deviation of the 30-day rolling PM CPMS average value from the established operating parameter limit, you must:

(A) Within 48 hours of the deviation, visually inspect the air pollution control device (APCD);

(B) If inspection of the APCD identifies the cause of the deviation, take corrective action as soon as possible and return the PM CPMS measurement to within the established value; and

(C) Within 30 days of the deviation or at the time of the annual compliance test, whichever comes first, conduct a PM emissions compliance test to determine compliance with the PM emissions limit and to verify or re-establish the CPMS operating limit. You are not required to conduct additional testing for any deviations that occur between the time of the original deviation and the PM emissions compliance test required under this paragraph.

(iii) PM CPMS deviations from the operating limit leading to more than four required performance tests in a 12-month operating period constitute a separate violation of this subpart.

(19) If you choose to comply with the PM filterable emissions limit by using PM CEMS you must install, certify, operate, and maintain a PM CEMS and record the output of the PM CEMS as specified in paragraphs (a)(19)(i) through (vii) of this section. The compliance limit will be expressed as a 30-day rolling average of the numerical emissions limit value applicable for your unit in Tables 1 or 2 or 11 through 13 of this subpart.

(i) Install and certify your PM CEMS according to the procedures and requirements in Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix B to part 60 of this chapter, using test criteria outlined in Table V of this rule. The reportable measurement output from the PM CEMS must be expressed in units of the applicable emissions limit (e.g., lb/MMBtu, lb/MWh).

(ii) Operate and maintain your PM CEMS according to the procedures and requirements in Procedure 2— Quality Assurance Requirements for Particulate Matter Continuous Emission Monitoring Systems at Stationary Sources in Appendix F to part 60 of this chapter.

(A) You must conduct the relative response audit (RRA) for your PM CEMS at least once annually.

(B) You must conduct the relative correlation audit (RCA) for your PM CEMS at least once every 3 years.

(iii) Collect PM CEMS hourly average output data for all boiler operating hours except as indicated in paragraph (i) of this section.

(iv) Calculate the arithmetic 30-day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler or process heater operating hours.

(v) You must collect data using the PM CEMS at all times the unit is operating and at the intervals specified this paragraph (a), except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities.

(vi) You must use all the data collected during all boiler or process heater operating hours in assessing the compliance with your operating limit except:

(A) Any data collected during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities conducted during monitoring system malfunctions in calculations and report any such periods in your annual deviation report;

(B) Any data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, repairs associated with periods when the monitoring system is out of control, or required monitoring system quality assurance or control activities conducted during out of control periods in calculations used to report emissions or operating levels and report any such periods in your annual deviation report;

(C) Any data recorded during periods of startup or shutdown.

(vii) You must record and make available upon request results of PM CEMS system performance audits, dates and duration of periods when the PM CEMS is out of control to completion of the corrective actions necessary to return the PM CEMS to operation consistent with your site-specific monitoring plan.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 or 11 through 13 to this subpart that apply to you. These instances are deviations from the emission limits or operating limits, respectively, in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must follow the sampling frequency specified in paragraphs (c)(1) through (4) of this section and conduct this sampling according to the procedures in § 63.7521(f) through (i).

(1) If the initial mercury constituents in the gaseous fuels are measured to be equal to or less than half of the mercury specification as defined in § 63.7575, you do not need to conduct further sampling.

(2) If the initial mercury constituents are greater than half but equal to or less than 75 percent of the mercury specification as defined in § 63.7575, you will conduct semi-annual sampling. If 6 consecutive semi-annual fuel analyses demonstrate 50 percent or less of the mercury specification, you do not need to conduct further sampling. If any semi-annual sample exceeds 75 percent of the mercury specification, you must return to monthly sampling for that fuel, until 12 months of fuel analyses again are less than 75 percent of the compliance level.

(3) If the initial mercury constituents are greater than 75 percent of the mercury specification as defined in § 63.7575, you will conduct monthly sampling. If 12 consecutive monthly fuel analyses demonstrate 75 percent or less of the mercury specification, you may decrease the fuel analysis frequency to semi-annual for that fuel.

(4) If the initial sample exceeds the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting this fuel is not part of the unit designed to burn gas 1 subcategory and must be in compliance with the emission and operating limits for the appropriate subcategory. You may elect to conduct additional monthly sampling while complying with these emissions and operating limits to demonstrate that the fuel qualifies as another gas 1 fuel. If 12 consecutive monthly fuel analyses samples are at or below the mercury specification as defined in § 63.7575, each affected boiler or process heater combusting the fuel can elect to switch back into the unit designed to burn gas 1 subcategory until the mercury specification is exceeded.

(d) For startup and shutdown, you must meet the work practice standards according to item 5 of Table 3 of this subpart.

■ 22. Section 63.7541 is amended by revising paragraphs (a)(3) and (4) to read as follows:

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

* * * * *

(a) * * *

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 30-day rolling average parameter values at or above the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating parameter, maintain the 30-day rolling

average parameter values consistent with the approved monitoring plan.

* * * * *

■ 23. Section 63.7545 is amended by:
■ a. Revising paragraphs (a) through (c).
■ b. Revising paragraphs (e) introductory text, (e)(1), (e)(2), (e)(3), (e)(4), (e)(5) introductory text, and (e)(5)(i).
■ c. Adding paragraph (e)(5)(ii).
■ d. Revising paragraphs (e)(8)(i) and (iii).
■ e. Revising paragraph (f) introductory text.
■ f. Revising paragraphs (g)(1) and (2).
■ g. Revising paragraphs (h) introductory text and (h)(1) and (3).
■ h. Removing paragraph (h)(4).

The revisions and addition read as follows:

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before January 31, 2013, you must submit an Initial Notification not later than 120 days after January 31, 2013.

(c) As specified in § 63.9(b)(4) and (5), if you startup your new or reconstructed affected source on or after January 31, 2013, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

* * * * *

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each boiler or process heater, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for all boiler or process heaters at the facility according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable. If you are not required to conduct an initial compliance demonstration as specified in § 63.7530(a), the Notification of Compliance Status must only contain the information specified in paragraphs (e)(1) and (8).

(1) A description of the affected unit(s) including identification of which subcategories the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit to comply with this subpart, description of the fuel(s) burned, including whether the fuel(s) were a secondary material determined by you or the EPA through a petition process to be a non-waste under § 241.3 of this chapter, whether the fuel(s) were a secondary material processed from discarded non-hazardous secondary materials within the meaning of § 241.3 of this chapter, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits, and including:

(i) Identification of whether you are complying with the PM emission limit or the alternative TSM emission limit.

(ii) Identification of whether you are complying with the output-based emission limits or the heat input-based (i.e., lb/MMBtu or ppm) emission limits,

(3) A summary of the maximum CO emission levels recorded during the performance test to show that you have met any applicable emission standard in Tables 1, 2, or 11 through 13 to this subpart, if you are not using a CO CEMS to demonstrate compliance.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing, a CEMS, or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using efficiency credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on January 31, 2013.

(ii) [Reserved]

* * * * *

(8) * * *

(i) ''This facility complies with the required initial tune-up according to the procedures in § 63.7540(a)(10)(i) through (vi).''

* * * * *

(iii) Except for units that burn only natural gas, refinery gas, or other gas 1 fuel, or units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: ''No secondary materials that are solid waste were combusted in any affected unit.''

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart of this part, part 60, 61, or 65, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

* * * * *

(g) * * *

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategories under this subpart.

* * * * *

(h) If you have switched fuels or made a physical change to the boiler and the fuel switch or physical change resulted in the applicability of a different subcategory, you must provide notice of the date upon which you switched fuels or made the physical change within 30 days of the switch/change. The notification must identify:

(1) The name of the owner or operator of the affected source, as defined in § 63.7490, the location of the source, the boiler(s) and process heater(s) that have switched fuels, were physically changed, and the date of the notice.

* * * * *

(3) The date upon which the fuel switch or physical change occurred.

■ 24. Section 63.7550 is revised to read as follows:

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report, according to paragraph (h) of this section, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of this section. For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12), respectively, and not subject to emission

limits or operating limits, you may submit only an annual, biennial, or 5-year compliance report, as applicable, as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for each boiler or process heater in § 63.7495 and ending on July 31 or January 31, whichever date is the first date that occurs at least 180 days (or 1, 2, or 5 years, as applicable, if submitting an annual, biennial, or 5-year compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for each boiler or process heater in § 63.7495. The first annual, biennial, or 5-year compliance report must be postmarked or submitted no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than January 31.

(c) A compliance report must contain the following information depending on how the facility chooses to comply with the limits set in this rule.

(1) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv) and (xiv) of this section.

(2) If a facility is complying with the fuel analysis they must submit a compliance report with the information in paragraphs (c)(5)(i) through (iv), (vi), (x), (xi), (xiii), (xv) and paragraph (d) of this section.

(3) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the information in (c)(5)(i) through (iv), (vi), (vii), (ix), (xi), (xiii), (xv) and paragraph (d) of this section.

(4) If a facility is complying with an emissions limit using a CMS the compliance report must contain the information required in paragraphs (c)(5)(i) through (vi), (xi), (xiii), (xv) through (xvii), and paragraph (e) of this section.

(5)(i) Company and Facility name and address.

(ii) Process unit information, emissions limitations, and operating parameter limitations.

(iii) Date of report and beginning and ending dates of the reporting period.

(iv) The total operating time during the reporting period.

(v) If you use a CMS, including CEMS, COMS, or CPMS, you must include the monitoring equipment manufacturer(s) and model numbers and the date of the last CMS certification or audit.

(vi) The total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(vii) If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(viii) A statement indicating that you burned no new types of fuel in an individual boiler or process heater subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a HCl emission limit, you must submit the calculation of chlorine input, using Equation 7 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of HCl emission rate using Equation 12 of § 63.7530 that demonstrates that your source is still meeting the emission limit for HCl emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 13 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a TSM emission limit, you must submit the calculation of TSM input, using Equation 9 of § 63.7530, that demonstrates that your source is still within its maximum TSM input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of TSM emission rate, using Equation 14 of § 63.7530, that demonstrates that your source is still meeting the emission limit for TSM emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(ix) If you wish to burn a new type of fuel in an individual boiler or process heater subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, or the maximum TSM input operating limit using Equation 9 of § 63.7530 you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(x) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for individual boilers or process heaters subject to emission limits, and any fuel specification analyses conducted according to §§ 63.7521(f) and 63.7530(g).

(xi) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(xii) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and CPMS, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(xiii) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or

may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(xiv) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.

(xv) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(xvi) For each reporting period, the compliance reports must include all of the calculated 30 day rolling average values based on the daily CEMS (CO and mercury) and CPMS (PM CPMS output, scrubber pH, scrubber liquid flow rate, scrubber pressure drop) data.

(xvii) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (3) of this section.

(1) A description of the deviation and which emission limit or operating limit from which you deviated.

(2) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(3) If the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an individual boiler or process heater where you are using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (e)(1) through (9) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (i.e., what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) A characterization of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) A brief description of the source for which there was a deviation.

(9) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) [Reserved]

(g) [Reserved]

(h) You must submit the reports according to the procedures specified in paragraphs (h)(1) through (3) of this section.

(1) Within 60 days after the date of completing each performance test (defined in § 63.2) as required by this subpart you must submit the results of the performance tests, including any associated fuel analyses, required by this subpart and the compliance reports required in § 63.7550(b) to the EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). Performance test data must be submitted in the file format generated through use of the EPA's Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/index.html*). Only data collected using test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. Owners or operators who claim that some of the information being submitted for performance tests is confidential business information (CBI) must submit a complete ERT file including information claimed to be CBI on a compact disk or other commonly used electronic storage media (including, but not limited to, flash drives) to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: WebFIRE Administrator, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT file with the CBI omitted must be submitted to the EPA via CDX as described earlier in this paragraph. At the discretion of the Administrator, you must also submit these reports, including the confidential business information, to the Administrator in the format specified by the Administrator. For any performance test conducted using test methods that are not listed on the ERT Web site, the owner or operator shall submit the results of the performance test in paper submissions to the Administrator.

(2) Within 60 days after the date of completing each CEMS performance evaluation test (defined in 63.2) you must submit the relative accuracy test audit (RATA) data to the EPA's Central Data Exchange by using CEDRI as mentioned in paragraph (h)(1) of this section. Only RATA pollutants that can be documented with the ERT (as listed on the ERT Web site) are subject to this requirement. For any performance evaluations with no corresponding RATA pollutants listed on the ERT Web site, the owner or operator shall submit the results of the performance evaluation in paper submissions to the Administrator.

(3) You must submit all reports required by Table 9 of this subpart electronically using CEDRI that is accessed through the EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due the report you must submit the report to the Administrator at the appropriate address listed in § 63.13. At the discretion of the Administrator, you must also submit these reports, to the Administrator in the format specified by the Administrator.

■ 25. Section 63.7555 is amended by:

■ a. Revising paragraphs (d) introductory text and (d)(2) through (6).

■ b. Adding paragraphs (d)(9) through (11).

■ c. Revising paragraphs (f) through (h).

■ d. Adding paragraphs (i) and (j).

The revisions and additions read as follows:

§ 63.7555 What records must I keep?

* * * * *

(d) For each boiler or process heater subject to an emission limit in Tables 1, 2, or 11 through 13 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (11) of this section.

* * * * *

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1) and (2) of this chapter, you must keep a record that documents how the secondary material meets each of the legitimacy criteria under § 241.3(d)(1) of this chapter. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4) of this chapter, you must keep records as to how the operations that produced the fuel satisfy the definition of processing in § 241.2 of this chapter. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c) of this chapter, you must keep a record that documents how the fuel satisfies the requirements of the petition process. For operating units that combust non-hazardous secondary materials as fuel per § 241.4 of this chapter, you must keep records documenting that the material is listed as a non-waste under § 241.4(a) of this chapter. Units exempt from the incinerator standards under section 129(g)(1) of the Clean Air Act because they are qualifying facilities burning a homogeneous waste stream do not need to maintain the records described in this paragraph (d)(2).

(3) For units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of HCl emission rates, using Equation 12 of § 63.7530, that were done to demonstrate compliance with the HCl emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or HCl emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or HCl emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 13 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit (or, in specific instances noted in Tables 1 and 2 or 11 through 13 to this subpart, less than the applicable emission limit), and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

* * * * *

(9) A copy of all calculations and supporting documentation of maximum TSM fuel input, using Equation 9 of § 63.7530, that were done to demonstrate continuous compliance with the TSM emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of TSM emission rates, using Equation 14 of § 63.7530, that were done to demonstrate compliance with the TSM emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum TSM fuel input or TSM emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate TSM fuel input, or TSM emission rates, for each boiler and process heater.

(10) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(11) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

* * * * *

(f) If you elect to use efficiency credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specification for mercury for the unit designed to burn gas 1 subcategory, you must maintain monthly records (or at the frequency required by § 63.7540(c)) of the calculations and results of the fuel specification for mercury in Table 6.

(h) If you operate a unit in the unit designed to burn gas 1 subcategory that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, gaseous fuel subject to another subpart under this part, other gas 1 fuel, or gaseous fuel subject to another subpart of this part or part 60, 61, or 65, you must keep records of the total hours per calendar year that alternative fuel is burned and the total hours per calendar year that the unit operated during periods of gas curtailment or gas supply emergencies.

(i) You must maintain records of the calendar date, time, occurrence and duration of each startup and shutdown.

(j) You must maintain records of the type(s) and amount(s) of fuels used during each startup and shutdown.

■ 26. Section 63.7570 is amended by revising paragraph (a) and paragraph (b) introductory text to read as follows:

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by the EPA, or an Administrator such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency (as well as the EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this

subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency, however, the EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

* * * * *

■ 27. Section 63.7575 is amended by:

■ a. Adding in alphabetical order definitions for ''10-day rolling average,'' ''30-day rolling average,'' ''Annual capacity factor,'' ''Average annual heat input rate,'' ''Benchmark,'' ''Biodiesel,'' ''Daily block average,'' ''Efficiency credit,'' ''Energy management program,'' ''Fluidized bed boiler with an integrated fluidized bed heat exchanger,'' ''Heavy liquid,'' ''Light liquid,'' '' ''Major source for oil and natural gas production facilities,'' ''Minimum oxygen level,'' ''Other combustor'', ''Oxygen analyzer system'', ''Oxygen trim system'', ''Pile burner'', ''Regulated gas stream'', ''Residential boiler,'' ''Residual oil'', ''Secondary material,'' ''Shutdown'', ''Sloped grate'', ''Startup'', ''Stoker/sloped grate/other unit designed to burn kiln dried biomass,'' Stoker/sloped grate/other unit designed to burn wet biomass,'' ''Suspension burner,'' ''Total selected metals (TSM),'' ''Traditional fuel,'' ''Ultra low sulfur liquid fuel,'' ''Unit designed to burn heavy liquid subcategory,'' ''Unit designed to burn light liquid subcategory,'' and ''Vegetable oil.''

■ b. Revising the definitions for ''Boiler,'' ''Boiler system,'' ''Coal,'' Commercial/institutional boiler,'' ''Deviation,'' ''Distillate oil,'' ''Dry scrubber,'' ''Dutch oven,'' ''Electric utility steam generating unit,'' ''Energy assessment,'' ''Energy use system,'' ''Equivalent,'' ''Federally enforceable,'' ''Fluidized bed boiler'', ''Fuel cell,'' ''Fuel type,'' ''Gaseous fuel,'' ''Heat input,'' ''Hot water heater,'' ''Hybrid suspension grate boiler,'' ''Industrial boiler,'' ''Limited-use boiler or process heater,'' ''Liquid fuel,'' ''Load fraction,'' ''Metal process furnaces,'' ''Minimum activated carbon injection rate,'' ''Minimum scrubber liquid flow rate,'' ''Minimum sorbent injection rate,'' ''Natural gas,'' ''Other gas 1 fuel,'' ''Period of natural gas curtailment or supply interruption,'' ''Process heater,'' ''Qualified energy assessor,'' ''Residual oil,'' ''Solid fossil fuel,'' ''Steam output,'' ''Stoker,'' ''Temporary boiler,'' ''Tune-up,'' ''Unit designed to burn gas 1 subcategory,'' ''Unit designed to burn gas 2 (other) subcategory,'' ''Unit designed to burn liquid subcategory,'' ''Unit designed to burn liquid fuel that is a non-continental unit,'' ''Unit designed to burn solid fuel,'' ''Waste heat boiler,'' ''Waste heat process heater.''

■ c. Removing the definitions for ''Benchmarking,'' ''Emission credit,'' ''Liquid fuel subcategory,'' and ''Suspension boiler.''

The revisions read as follows:

§ 63.7575 What definitions apply to this subpart?

* * * * *

10-day rolling average means the arithmetic mean of the previous 240 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 240 hours should be consecutive, but not necessarily continuous if operations were intermittent.

30-day rolling average means the arithmetic mean of the previous 720 hours of valid operating data. Valid data excludes hours during startup and shutdown, data collected during periods when the monitoring system is out of control as specified in your site-specific monitoring plan, while conducting repairs associated with periods when the monitoring system is out of control, or while conducting required monitoring system quality assurance or quality control activities, and periods when this unit is not operating. The 720 hours should be consecutive, but not necessarily continuous if operations were intermittent.

* * * * *

Annual capacity factor means the ratio between the actual heat input to a boiler or process heater from the fuels burned during a calendar year and the potential heat input to the boiler or process heater had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity.

Average annual heat input rate means total heat input divided by the hours of operation for the 12 months preceding the compliance demonstration.

* * * * *

Benchmark means the fuel heat input for a boiler or process heater for the one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

Biodiesel means a mono-alkyl ester derived from biomass and conforming to ASTM D6751–11b, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels (incorporated by reference, see § 63.14).

* * * * *

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control systems, steam systems, and condensate return systems.

* * * * *

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of ''coal'' includes synthetic fuels derived from coal, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

* * * * *

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, elementary and secondary schools, libraries, religious establishments, governmental buildings, hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

* * * * *

Daily block average means the arithmetic mean of all valid emission concentrations or parameter levels recorded when a unit is operating measured over the 24-hour period from 12 a.m. (midnight) to 12 a.m. (midnight), except for periods of startup and shutdown or downtime.

Deviation.

(1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any applicable requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation.

* * * * *

Distillate oil means fuel oils that contain 0.05 weight percent nitrogen or less and comply with the specifications for fuel oil numbers 1 and 2, as defined by the American Society of Testing and Materials in ASTM D396 (incorporated by reference, see § 63.14) or diesel fuel oil numbers 1 and 2, as defined by the American Society for Testing and Materials in ASTM D975 (incorporated by reference, see § 63.14), kerosene, and biodiesel as defined by the American Society of Testing and Materials in ASTM D6751–11b (incorporated by reference, see § 60.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems used as control devices in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the dutch oven and burn in a pile on its floor. Fluidized bed boilers are not part of the dutch oven design category.

Electric utility steam generating unit (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. To be ''capable of combusting'' fossil fuels, an EGU would need to have these fuels allowed in their operating permits and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities). In addition, fossil fuel-fired EGU means any EGU that fired fossil fuel for more than 10.0 percent of the average annual heat input in any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year after April 16, 2012.

* * * * *

Efficiency credit means emission reductions above those required by this subpart. Efficiency credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Boilers that are shut down cannot be used to generate credits unless the facility provides documentation linking the permanent shutdown to implementation of the energy conservation measures identified in the energy assessment.

Energy assessment means the following for the emission units covered by this subpart:

(1) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of less than 0.3 trillion Btu (TBtu) per year will be 8 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 50 percent of the affected boiler(s) energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing an 8-hour on-site energy assessment.

(2) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity of 0.3 to 1.0 TBtu/year will be 24 on-site technical labor hours in length maximum, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s) and any on-site energy use system(s) accounting for at least 33 percent of the energy (e.g., steam, hot water, process heat, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities, within the limit of performing a 24-hour on-site energy assessment.

(3) The energy assessment for facilities with affected boilers and process heaters with a combined heat input capacity greater than 1.0 TBtu/year will be up to 24 on-site technical labor hours in length for the first TBtu/yr plus 8 on-site technical labor hours for every additional 1.0 TBtu/yr not to exceed 160 on-site technical hours, but may be longer at the discretion of the owner or operator of the affected source. The boiler system(s), process heater(s), and any on-site energy use system(s) accounting for at least 20 percent of the energy (e.g., steam, process heat, hot water, or electricity) production, as applicable, will be evaluated to identify energy savings opportunities.

(4) The on-site energy use systems serving as the basis for the percent of affected boiler(s) and process heater(s) energy production in paragraphs (1), (2), and (3) of this definition may be segmented by production area or energy use area as most logical and applicable to the specific facility being assessed (e.g., product X manufacturing area; product Y drying area; Building Z).

* * * * *

Energy management program means a program that includes a set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility. Facilities may establish their program through energy management systems compatible with ISO 50001.

Energy use system includes the following systems located on-site that use energy (steam, hot water, or electricity) provided by the affected boiler or process heater: process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot water systems; building envelop; and lighting; or other systems that use steam, hot water, process heat, or electricity provided by the affected boiler or process heater. Energy use systems are only those systems using energy clearly produced by affected boilers and process heaters.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite

consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an ''as received'' basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, HCl) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

* * * * *

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including, but not limited to, the requirements of 40 CFR parts 60, 61, 63, and 65, requirements within any applicable state implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process that is not a pulverized coal boiler.

Fluidized bed boiler with an integrated fluidized bed heat exchanger means a boiler utilizing a fluidized bed combustion where the entire tube surface area is located outside of the furnace section at the exit of the cyclone section and exposed to the flue gas stream for conductive heat transfer. This design applies only to boilers in the unit designed to burn coal/solid fossil fuel subcategory that fire coal refuse.

* * * * *

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, and suspension burners are not part of the fuel cell subcategory.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas and process gases that are regulated under another subpart of this part, or part 60, part 61, or part 65 of this chapter, are exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, returned condensate, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Heavy liquid includes residual oil and any other liquid fuel not classified as a light liquid.

* * * * *

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous, liquid, or biomass/bio-based solid fuel and is withdrawn for use external to the vessel. Hot water boilers (i.e., not generating steam) combusting gaseous, liquid, or biomass fuel with a heat input capacity of less than 1.6 million Btu per hour are included in this definition. The 120 U.S. gallon capacity threshold to be considered a hot water heater is independent of the 1.6 MMBtu/hr heat input capacity threshold for hot water boilers. Hot water heater also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The biomass fuel combusted in these units exceeds a moisture content of 40 percent on an as-fired annual heat input basis. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler. Fluidized bed, dutch oven, and pile burner designs are not part of the hybrid suspension grate boiler design category.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Light liquid includes distillate oil, biodiesel, or vegetable oil.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10 percent.

Liquid fuel includes, but is not limited to, light liquid, heavy liquid, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, biodiesel, vegetable oil, and comparable fuels as defined under 40 CFR 261.38.

Load fraction means the actual heat input of a boiler or process heater divided by heat input during the performance test that established the minimum sorbent injection rate or minimum activated carbon injection rate, expressed as a fraction (e.g., for 50 percent load the load fraction is 0.5).

Major source for oil and natural gas production facilities, as used in this subpart, shall have the same meaning as in § 63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment, as defined in this section), and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control;

(2) Emissions from processes, operations, or equipment that are not part of the same facility, as defined in this section, shall not be aggregated; and

(3) For facilities that are production field facilities, only HAP emissions from glycol dehydration units and storage vessels with the potential for flash emissions shall be aggregated for a major source determination. For facilities that are not production field facilities, HAP emissions from all HAP emission units shall be aggregated for a major source determination.

Metal process furnaces are a subcategory of process heaters, as defined in this subpart, which include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

* * * * *

Minimum activated carbon injection rate means load fraction multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum oxygen level means the lowest hourly average oxygen level measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

* * * * *

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (e.g., to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

* * * * *

Minimum sorbent injection rate means:

(1) The load fraction multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits; or

(2) For fluidized bed combustion, the lowest average ratio of sorbent to sulfur measured during the most recent performance test.

* * * * *

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquefied petroleum gas, as defined in ASTM D1835 (incorporated by reference, see § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

* * * * *

Other combustor means a unit designed to burn solid fuel that is not classified as a dutch oven, fluidized bed, fuel cell, hybrid suspension grate boiler, pulverized coal boiler, stoker, sloped grate, or suspension boiler as defined in this subpart.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed a maximum concentration of 40 micrograms/cubic meters of mercury.

Oxygen analyzer system means all equipment required to determine the oxygen content of a gas stream and used to monitor oxygen in the boiler or process heater flue gas, boiler or process heater, firebox, or other appropriate location. This definition includes oxygen trim systems. The source owner or operator must install, calibrate, maintain, and operate the oxygen analyzer system in accordance with the manufacturer's recommendations.

Oxygen trim system means a system of monitors that is used to maintain excess air at the desired level in a combustion device. A typical system consists of a flue gas oxygen and/or CO monitor that automatically provides a feedback signal to the combustion air controller.

* * * * *

Period of gas curtailment or supply interruption means a period of time during which the supply of gaseous fuel to an affected boiler or process heater is restricted or halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas due to normal market fluctuations not during periods of supplier delivery restriction does not constitute a period of natural gas curtailment or supply interruption. On-site gaseous fuel system emergencies or equipment failures qualify as periods of supply interruption when the emergency or failure is beyond the control of the facility.

Pile burner means a boiler design incorporating a design where the anticipated biomass fuel has a high relative moisture content. Grates serve to support the fuel, and underfire air flowing up through the grates provides oxygen for combustion, cools the grates, promotes turbulence in the fuel bed, and fires the fuel. The most common form of pile burning is the dutch oven.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3 of this chapter, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves. Waste heat process heaters are excluded from this definition.

* * * * *

Qualified energy assessor means:

(1) Someone who has demonstrated capabilities to evaluate energy savings opportunities for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

* * * * *

Regulated gas stream means an offgas stream that is routed to a boiler or process heater for the purpose of achieving compliance with a standard under another subpart of this part or part 60, part 61, or part 65 of this chapter.

Residential boiler means a boiler used to provide heat and/or hot water and/or as part of a residential combined heat and power system. This definition includes boilers located at an institutional facility (e.g., university campus, military base, church grounds) or commercial/industrial facility (e.g., farm) used primarily to provide heat and/or hot water for:

(1) A dwelling containing four or fewer families; or

(2) A single unit residence dwelling that has since been converted or subdivided into condominiums or apartments.

Residual oil means crude oil, fuel oil that does not comply with the specifications under the definition of distillate oil, and all fuel oil numbers 4, 5, and 6, as defined by the American Society of Testing and Materials in ASTM D396–10 (incorporated by reference, *see* § 63.14(b)).

* * * * *

Secondary material means the material as defined in § 241.2 of this chapter.

Shutdown means the cessation of operation of a boiler or process heater for any purpose. Shutdown begins either when none of the steam from the boiler is supplied for heating and/or producing electricity, or for any other purpose, or at the point of no fuel being fired in the boiler or process heater, whichever is earlier. Shutdown ends when there is no steam and no heat being supplied and no fuel being fired in the boiler or process heater.

Sloped grate means a unit where the solid fuel is fed to the top of the grate from where it slides downwards; while sliding the fuel first dries and then ignites and burns. The ash is deposited at the bottom of the grate. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a sloped grate design.

Solid fossil fuel includes, but is not limited to, coal, coke, petroleum coke, and tire derived fuel.

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Startup means either the first-ever firing of fuel in a boiler or process heater for the purpose of supplying steam or heat for heating and/or producing electricity, or for any other purpose, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam or heat from the boiler or process heater is supplied for heating, and/or producing electricity, or for any other purpose.

Steam output means:

(1) For a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output,

(2) For a boiler that cogenerates process steam and electricity (also known as combined heat and power), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour), and

(3) For a boiler that generates only electricity, the alternate output-based emission limits would be calculated using Equations 21 through 25 of this section, as appropriate:

(i) For emission limits for boilers in the unit designed to burn solid fuel subcategory use Equation 21 of this section:

$$EL_{OBE} = EL_T \times 12.7\ MMBtu/Mwh \quad (Eq.\ 21)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(ii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn coal use Equation 22 of this section:

$$EL_{OBE} = EL_T \times 12.2\ MMBtu/Mwh \quad (Eq.\ 22)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iii) For PM and CO emission limits for boilers in one of the subcategories of units designed to burn biomass use Equation 23 of this section:

$$EL_{OBE} = EL_T \times 13.9\ MMBtu/Mwh \quad (Eq.\ 23)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(iv) For emission limits for boilers in one of the subcategories of units designed to burn liquid fuels use Equation 24 of this section:

$$EL_{OBE} = EL_T \times 13.8\ MMBtu/Mwh \quad (Eq.\ 24)$$

Where:

EL_{OBE} = Emission limit in units of pounds per megawatt-hour.

EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

(v) For emission limits for boilers in the unit designed to burn gas 2 (other)

subcategory, use Equation 25 of this section:

$$EL_{OBE} = EL_T \times 10.4\ MMBtu/Mwh \quad (Eq.\ 25)$$

Where:
EL_{OBE} = Emission limit in units of pounds per megawatt-hour.
EL_T = Appropriate emission limit from Table 1 or 2 of this subpart in units of pounds per million Btu heat input.

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers. Fluidized bed, dutch oven, pile burner, hybrid suspension grate, suspension burners, and fuel cells are not considered to be a stoker design.

Stoker/sloped grate/other unit designed to burn kiln dried biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and is not in the stoker/sloped grate/other units designed to burn wet biomass subcategory.

Stoker/sloped grate/other unit designed to burn wet biomass means the unit is in the units designed to burn biomass/bio-based solid subcategory that is either a stoker, sloped grate, or other combustor design and any of the biomass/bio-based solid fuel combusted in the unit exceeds 20 percent moisture on an annual heat input basis.

Suspension burner means a unit designed to fire dry biomass/biobased solid particles in suspension that are conveyed in an airstream to the furnace like pulverized coal. The combustion of the fuel material is completed on a grate or floor below. The biomass/biobased fuel combusted in the unit shall not exceed 20 percent moisture on an annual heat input basis. Fluidized bed, dutch oven, pile burner, and hybrid suspension grate units are not part of the suspension burner subcategory.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location within the facility and performs the same or similar function for more than 12 consecutive months, unless the regulatory agency approves an extension. An extension may be granted by the regulating agency upon petition by the owner or operator of a unit specifying the basis for such a request. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another within the facility but continues to perform the same or similar function and serve the same electricity, steam, and/or hot water system in an attempt to circumvent the residence time requirements of this definition.

Total selected metals (TSM) means the sum of the following metallic hazardous air pollutants: arsenic, beryllium, cadmium, chromium, lead, manganese, nickel and selenium.

Traditional fuel means the fuel as defined in § 241.2 of this chapter.

Tune-up means adjustments made to a boiler or process heater in accordance with the procedures outlined in § 63.7540(a)(10).

* * * * *

Ultra low sulfur liquid fuel means a distillate oil that has less than or equal to 15 ppm sulfur.

* * * * *

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply interruptions of any duration are also included in this definition.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, and no liquid fuels. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year, are included in this definition. Gaseous fuel boilers and process heaters that are not in the unit designed to burn gas 1 subcategory and that burn liquid fuel during periods of gas curtailment or gas supply interruption of any duration are also included in this definition.

Unit designed to burn heavy liquid subcategory means a unit in the unit designed to burn liquid subcategory where at least 10 percent of the heat input from liquid fuels on an annual heat input basis comes from heavy liquids.

Unit designed to burn light liquid subcategory means a unit in the unit designed to burn liquid subcategory that is not part of the unit designed to burn heavy liquid subcategory.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Units in the unit design to burn gas 1 or unit designed to burn gas 2 (other) subcategories during periods of gas curtailment or gas supply interruption of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater meeting the definition of the unit designed to burn

liquid subcategory located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns only solid fuels or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Vegetable oil means oils extracted from vegetation.

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Waste heat boiler means a device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators. Waste heat boilers are heat exchangers generating steam from incoming hot exhaust gas from an industrial (e.g., thermal oxidizer, kiln, furnace) or power (e.g., combustion turbine, engine) equipment. Duct burners are sometimes used to increase the temperature of the incoming hot exhaust gas.

Waste heat process heater means an enclosed device that recovers normally unused energy (i.e., hot exhaust gas) and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters. This definition includes both fired and unfired waste heat process heaters.

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■ 28. Table 1 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.28 lb per MWh.	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.0E–07 [a] lb per MMBtu of heat input.	8.7E–07 [a] lb per MMBtu of steam output or 1.1E–05 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	1.1E–03 lb per MMBtu of steam output or 1.4E–02 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 2.9E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.2E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	5.8E–01 lb per MMBtu of steam output or 6.8 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (2.7E–05 lb per MMBtu of steam output or 3.7E–04 lb per MWh).	Collect a minimum of 2 dscm per run.

NMED Exhibit 80 - 0057

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.5E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (4.2E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.2E–01 lb per MMBtu of steam output or 2.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 0.14 lb per MWh; or (1.1E–04 [a] lb per MMBtu of steam output or 1.2E–03 [a] lb per MWh).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	3.1E–02 lb per MMBtu of steam output or 4.2E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	330 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	3.5E–01 lb per MMBtu of steam output or 3.6 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	4.3E–03 lb per MMBtu of steam output or 4.5E–02 lb per MWh; or (5.2E–05 lb per MMBtu of steam output or 5.5E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1.1 lb per MMBtu of steam output or 1.0E+01 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 [a] lb per MMBtu of heat input).	3.0E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (5.1E–05 lb per MMBtu of steam output or 4.1E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 12 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	3.3E–02 lb per MMBtu of steam output or 3.7E–01 lb per MWh; or (5.5E–04 lb per MMBtu of steam output or 6.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	4.4E–04 lb per MMBtu of heat input.	4.8E–04 lb per MMBtu of steam output or 6.1E–03 lb per MWh.	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input.	5.3E–07 [a] lb per MMBtu of steam output or 6.7E–06 [a] lb per MWh.	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	Or the emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	1.5E–02 lb per MMBtu of steam output or 1.8E–01 lb per MWh; or (8.2E–05 lb per MMBtu of steam output or 1.1E–03 lb per MWh).	Collect a minimum of 3 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	1.2E–03 [a] lb per MMBtu of steam output or 1.6E–02 [a] lb per MWh; or (3.2E–05 lb per MMBtu of steam output or 4.0E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	2.5E–02 lb per MMBtu of steam output or 3.2E–01 lb per MWh; or (9.4E–04 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

[c] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before January 31, 2013, you may comply with the emission limits in Tables 11, 12 or 13 to this subpart until January 31, 2016. On and after January 31, 2016, you must comply with the emission limits in Table 1 to this subpart.

■ 29. Table 2 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	2.2E–02 lb per MMBtu of heat input.	2.5E–02 lb per MMBtu of steam output or 0.27 lb per MWh.	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 120 liters per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	5.7E–06 lb per MMBtu of heat input.	6.4E–06 lb per MMBtu of steam output or 7.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM)	4.0E–02 lb per MMBtu of heat input; or (5.3E–05 lb per MMBtu of heat input).	4.2E–02 lb per MMBtu of steam output or 4.9E–01 lb per MWh; or (5.6E–05 lb per MMBtu of steam output or 6.5E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.11 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	160 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.14 lb per MMBtu of steam output or 1.7 lb per MWh; 3-run average.	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	0.12 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.3E–01 lb per MMBtu of steam output or 1.5 lb per MWh; 3-run average.	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1.4 lb per MMBtu of steam output or 17 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.7E–02 lb per MMBtu of heat input; or (2.4E–04 lb per MMBtu of heat input).	4.3E–02 lb per MMBtu of steam output or 5.2E–01 lb per MWh; or (2.8E–04 lb per MMBtu of steam output or 3.4E–04 lb per MWh).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	4.2E–01 lb per MMBtu of steam output or 5.1 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	3.7E–01 lb per MMBtu of steam output or 4.5 lb per MWh; or (4.6E–03 lb per MMBtu of steam output or 5.6E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	4.6E–01 lb per MMBtu of steam output or 5.2 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	1.1E–01 lb per MMBtu of heat input; or (1.2E–03 lb per MMBtu of heat input).	1.4E–01 lb per MMBtu of steam output or 1.6 lb per MWh; or (1.5E–03 lb per MMBtu of steam output or 1.7E–02 lb per MWh).	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
10. Suspension burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1.9 lb per MMBtu of steam output or 27 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	5.2E–02 lb per MMBtu of steam output or 7.1E–01 lb per MWh; or (6.6E–03 lb per MMBtu of steam output or 9.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solid.	a. CO (or CEMS)	770 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	8.4E–01 lb per MMBtu of steam output or 8.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.8E–01 lb per MMBtu of heat input; or (2.0E–03 lb per MMBtu of heat input).	3.9E–01 lb per MMBtu of steam output or 3.9 lb per MWh; or (2.8E–03 lb per MMBtu of steam output or 2.8E–02 lb per MWh).	Collect a minimum of 1 dscm per run.
12. Fuel cell units designed to burn biomass/bio-based solid.	a. CO	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.4 lb per MMBtu of steam output or 12 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	2.0E–02 lb per MMBtu of heat input; or (5.8E–03 lb per MMBtu of heat input).	5.5E–02 lb per MMBtu of steam output or 2.8E–01 lb per MWh; or (1.6E–02 lb per MMBtu of steam output or 8.1E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate units designed to burn biomass/bio-based solid.	a. CO (or CEMS)	2,800 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	2.8 lb per MMBtu of steam output or 31 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	4.4E–01 lb per MMBtu of heat input; or (4.5E–04 lb per MMBtu of heat input).	5.5E–01 lb per MMBtu of steam output or 6.2 lb per MWh; or (5.7E–04 lb per MMBtu of steam output or 6.3E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
14. Units designed to burn liquid fuel.	a. HCl	1.1E–03 lb per MMBtu of heat input.	1.4E–03 lb per MMBtu of steam output or 1.6E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	2.0E–06 lb per MMBtu of heat input.	2.5E–06 lb per MMBtu of steam output or 2.8E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784 [b] collect a minimum of 2 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	6.2E–02 lb per MMBtu of heat input; or (2.0E–04 lb per MMBtu of heat input).	7.5E–02 lb per MMBtu of steam output or 8.6E–01 lb per MWh; or (2.5E–04 lb per MMBtu of steam output or 2.8E–03 lb per MWh).	Collect a minimum of 1 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh.	1 hr minimum sampling time.
	b. Filterable PM (or TSM)	7.9E–03 lb per MMBtu of heat input; or (6.2E–05 lb per MMBtu of heat input).	9.6E–03 lb per MMBtu of steam output or 1.1E–01 lb per MWh; or (7.5E–05 lb per MMBtu of steam output or 8.6E–04 lb per MWh).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	0.13 lb per MMBtu of steam output or 1.4 lb per MWh; 3-run average.	1 hr minimum sampling time.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during startup and shutdown . . .	The emissions must not exceed the following alternative output-based limits, except during startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM)	2.7E–01 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	3.3E–01 lb per MMBtu of steam output or 3.8 lb per MWh; or (1.1E–03 lb per MMBtu of steam output or 1.2E–02 lb per MWh).	Collect a minimum of 2 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.16 lb per MMBtu of steam output or 1.0 lb per MWh.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input.	2.9E–03 lb per MMBtu of steam output or 1.8E–02 lb per MWh.	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	1.4E–05 lb per MMBtu of steam output or 8.3E–05 lb per MWh.	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. Filterable PM (or TSM)	6.7E–03 lb per MMBtu of heat input or (2.1E–04 lb per MMBtu of heat input).	1.2E–02 lb per MMBtu of steam output or 7.0E–02 lb per MWh; or (3.5E–04 lb per MMBtu of steam output or 2.2E–03 lb per MWh).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote a, your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 30. Table 3 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the following applicable work practice standards:

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with a continuous oxygen trim system that maintains an optimum air to fuel ratio, or a heat input capacity of less than or equal to 5 million Btu per hour in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid, or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater every 5 years as specified in § 63.7540.
2. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of less than 10 million Btu per hour in the unit designed to burn heavy liquid or unit designed to burn solid fuel subcategories; or a new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour, but greater than 5 million Btu per hour, in any of the following subcategories: unit designed to burn gas 1; unit designed to burn gas 2 (other); or unit designed to burn light liquid.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.
3. A new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540. Units in either the Gas 1 or Metal Process Furnace subcategories will conduct this tune-up as a work practice for all regulated emissions under this subpart. Units in all other subcategories will conduct this tune-up as a work practice for dioxins/furans.
4. An existing boiler or process heater located at a major source facility, not including limited use units.	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. A facility that operates under an energy management program compatible with ISO 50001 that includes the affected units also satisfies the energy assessment requirement. The energy assessment must include the following with extent of the evaluation for items a. to e. appropriate for the on-site technical hours listed in § 63.7575: a. A visual inspection of the boiler or process heater system.

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS—Continued

If your unit is . . .	You must meet the following . . .
	b. An evaluation of operating characteristics of the boiler or process heater systems, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints. c. An inventory of major energy use systems consuming energy from affected boilers and process heaters and which are under the control of the boiler/process heater owner/operator. d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage. e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, if identified. f. A list of cost-effective energy conservation measures that are within the facility's control. g. A list of the energy savings potential of the energy conservation measures identified. h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
5. An existing or new boiler or process heater subject to emission limits in Table 1 or 2 or 11 through 13 to this subpart during startup.	You must operate all CMS during startup. For startup of a boiler or process heater, you must use one or a combination of the following clean fuels: natural gas, synthetic natural gas, propane, distillate oil, syngas, ultra-low sulfur diesel, fuel oil-soaked rags, kerosene, hydrogen, paper, cardboard, refinery gas, and liquefied petroleum gas. If you start firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases, you must vent emissions to the main stack(s) and engage all of the applicable control devices except limestone injection in fluidized bed combustion (FBC) boilers, dry scrubber, fabric filter, selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). You must start your limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR systems as expeditiously as possible. Startup ends when steam or heat is supplied for any purpose. You must comply with all applicable emission limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of startup, as specified in § 63.7535(b). You must keep records during periods of startup. You must provide reports concerning activities and periods of startup, as specified in § 63.7555.
6. An existing or new boiler or process heater subject to emission limits in Tables 1 or 2 or 11 through 13 to this subpart during shutdown.	You must operate all CMS during shutdown. While firing coal/solid fossil fuel, biomass/bio-based solids, heavy liquid fuel, or gas 2 (other) gases during shutdown, you must vent emissions to the main stack(s) and operate all applicable control devices, except limestone injection in FBC boilers, dry scrubber, fabric filter, SNCR, and SCR. You must comply with all applicable emissions limits at all times except for startup or shutdown periods conforming with this work practice. You must collect monitoring data during periods of shutdown, as specified in § 63.7535(b). You must keep records during periods of shutdown. You must provide reports concerning activities and periods of shutdown, as specified in § 63.7555.

■ 31. Table 4 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7500, you must comply with the applicable operating limits:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control on a boiler not using a PM CPMS.	Maintain the 30-day rolling average pressure drop and the 30-day rolling average liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

When complying with a Table 1, 2, 11, 12, or 13 numerical emission limit using . . .	You must meet these operating limits . . .
2. Wet acid gas (HCl) scrubber control on a boiler not using a HCl CEMS.	Maintain the 30-day rolling average effluent pH at or above the lowest one-hour average pH and the 30-day rolling average liquid flow rate at or above the lowest one-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not using a PM CPMS.	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alert is not activated more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not using a PM CPMS.	a. This option is for boilers and process heaters that operate dry control systems (i.e., an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. This option is only for boilers and process heaters not subject to PM CPMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the 30-day rolling average total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control on a boiler not using a mercury CEMS.	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.
6. Any other add-on air pollution control type on units not using a PM CPMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.
9. Oxygen analyzer system	For boilers and process heaters subject to a CO emission limit that demonstrate compliance with an O_2 analyzer system as specified in § 63.7525(a), maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test, as specified in Table 8. This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a).
10. SO_2 CEMS	For boilers or process heaters subject to an HCl emission limit that demonstrate compliance with an SO_2 CEMS, maintain the 30-day rolling average SO_2 emission rate at or below the highest hourly average SO_2 concentration measured during the most recent HCl performance test, as specified in Table 8.

■ 32. Table 5 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for ''1. Particulate matter.''
■ b. Remove the entry for ''5. Dioxins/Furans''.
■ c. Redesignating the entries for ''2. Hydrogen chloride,'' ''3. Mercury,'' and ''4. CO'' as ''3. Hydrogen chloride,'' ''4. Mercury,'' and ''5. CO,'' respectively.
■ d. Revising the newly redesignated entries for ''4. Mercury'' and ''5. CO.''
■ e. Add entry for ''2. Total selected metals.''

The revisions and addition read as follows:

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
1. Filterable PM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the PM emission concentration	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. TSM	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant . . .	You must . . .	Using . . .
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the TSM emission concentration ...	Method 29 at 40 CFR part 60, appendix A–8 of this chapter
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. HCl	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the HCl emission concentration	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
5. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas.	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a measurement span value of 2 times the concentration of the applicable emission limit.

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■ 33. Table 6 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a](for coal) or EPA 1631 or EPA 1631E or ASTM D6323[a] (for solid), or EPA 821–R–01–013 (for liquid or solid), or ASTM D4177[a] (for liquid), or ASTM D4057[a] (for liquid), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or EPA 3050[a] (for solid fuel), or EPA 821–R–01–013[a] (for liquid or solid), or equivalent.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a], ASTM E871[a], or ASTM D5864[a], or ASTM D240, or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722[a] (for coal), EPA SW–846–7471B[a] (for solid samples), or EPA SW–846–7470A[a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of mercury per MMBtu of heat content.	Equation 8 in § 63.7530.
	h. Calculate the mercury emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 12 in § 63.7530.
2. HCl	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M§[a] (for coal), or ASTM D5198§[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), ASTM D5864, ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a], or D5864[a], or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels) or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250[a], ASTM D6721[a], ASTM D4208[a] (for coal), or EPA SW–846–5050[a] or ASTM E776[a] (for solid fuel), or EPA SW–846–9056[a] or SW–846–9076[a] (for solids or liquids) or equivalent.
	g. Convert concentrations into units of pounds of HCl per MMBtu of heat content.	Equation 7 in § 63.7530.
	h. Calculate the HCl emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 11 in § 63.7530.
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample and convert to units of micrograms per cubic meter.	Method 30B (M30B) at 40 CFR part 60, appendix A–8 of this chapter or ASTM D5954[a], ASTM D6350[a], ISO 6978–1:2003(E)[a], or ISO 6978–2:2003(E)[a], or EPA–1631[a] or equivalent.
	b. Measure mercury concentration in the exhaust gas when firing only the other gas 1 fuel is fired in the boiler or process heater.	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A or Method 102 at 40 CFR part 61, appendix B of this chapter, or ASTM Method D6784[a] or equivalent.
4. TSM for solid fuels	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D5192[a], or ASTM D7430[a], or ASTM D6883[a], or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for coal or biomass), or ASTM D4177[a],(for liquid fuels)or ASTM D4057[a] (for liquid fuels),or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] or TAPPI T266[a] (for biomass), or EPA 3050[a] or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or ASTM D5864[a] for liquids and other solids, or ASTM D240[a] or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871[a], or D5864, or ASTM D240[a], or ASTM D95[a] (for liquid fuels), or ASTM D4006[a] (for liquid fuels), or ASTM D4177[a] (for liquid fuels) or ASTM D4057[a] (for liquid fuels), or equivalent.
	f. Measure TSM concentration in fuel sample ..	ASTM D3683[a], or ASTM D4606[a], or ASTM D6357[a] or EPA 200.8[a] or EPA SW–846–6020[a], or EPA SW–846–6020A[a], or EPA SW–846–6010C[a], EPA 7060[a] or EPA 7060A[a] (for arsenic only), or EPA SW–846–7740[a] (for selenium only).
	g. Convert concentrations into units of pounds of TSM per MMBtu of heat content.	Equation 9 in § 63.7530.
	h. Calculate the TSM emission rate from the boiler or process heater in units of pounds per million Btu.	Equations 10 and 13 in § 63.7530.

[a] Incorporated by reference, see § 63.14.

■ 34. Table 7 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for ''1. Particulate matter or mercury,''.
■ b. Revising the entry for ''2. Hydrogen Chloride,''.
■ c. Revising the entry for ''3. Mercury,''.
■ d. Revising the entry for ''4. Carbon monoxide''.

The revisions read as follows:

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. PM, TSM, or mercury	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum scrubber pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the scrubber pressure drop and liquid flow rate monitors and the PM or mercury performance test.	(a) You must collect scrubber pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests. (b) Determine the lowest hourly average scrubber pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the PM or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests. (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. HCl	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the HCl performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the HCl performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and HCl or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
	c. Alternative Maximum SO_2 emission rate.	i. Establish a site-specific maximum SO_2 emission rate operating limit according to § 63.7530(b).	(1) Data from SO_2 CEMS and the HCl performance test.	(a) You must collect the SO_2 emissions data according to § 63.7525(m) during the most recent HCl performance tests.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) The maximum SO_2 emission rate is equal to the lowest hourly average SO_2 emission rate measured during the most recent HCl performance tests.
3. Mercury	a. Activated carbon injection	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury performance test.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (*e.g.,* actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen analyzer system specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests. (b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
*	*	*	*	*	*	*

■ 35. Table 8 to subpart DDDDD of part 63 is revised to read as follows:

As stated in § 63.7540, you must show continuous compliance with the emission limitations for each boiler or process heater according to the following:

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. PM CPMS	a. Collecting the PM CPMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average PM CPMS output data to less than the operating limit established during the performance test according to § 63.7530(b)(4).
3. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
4. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
5. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
	b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average pH at or above the operating limit established during the performance test according to § 63.7530(b).
6. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
7. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
8. Emission limits using fuel analysis	a. Conduct monthly fuel analysis for HCl or mercury or TSM according to Table 6 to this subpart; and b. Reduce the data to 12-month rolling averages; and c. Maintain the 12-month rolling average at or below the applicable emission limit for HCl or mercury or TSM in Tables 1 and 2 or 11 through 13 to this subpart.
9. Oxygen content	a. Continuously monitor the oxygen content using an oxygen analyzer system according to § 63.7525(a). This requirement does not apply to units that install an oxygen trim system since these units will set the trim system to the level specified in § 63.7525(a)(2). b. Reducing the data to 30-day rolling averages; and c. Maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen level measured during the most recent CO performance test.
10. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Maintaining the operating load such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test according to § 63.7520(c).
11. SO_2 emissions using SO_2 CEMS	a. Collecting the SO_2 CEMS output data according to § 63.7525; b. Reducing the data to 30-day rolling averages; and c. Maintaining the 30-day rolling average SO_2 CEMS emission rate to a level at or below the minimum hourly SO_2 rate measured during the most recent HCl performance test according to § 63.7530.

■ 36. Table 9 to subpart DDDDD of part 63 is amended by revising the entry for ''1. Compliance report'' to read as follows:

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (5); and	Semiannually, annually, biennially, or every 5 years according to the requirements in § 63.7550(b).
* * * * * * *		

■ 37. Table 10 to subpart DDDDD of part 63 is amended by:
■ a. Revising the entry for ''§ 63.6(i)''.
■ b. Revising the entry for ''§ 63.7(e)(1)''.
■ c. Revising the entry for ''63.8(g)''.
■ d. Revising the entry for ''§ 63.10(e) and (f)''.
■ e. Adding an entry for ''§ 63.10(e)''.
The revisions and addition read as follows.

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
* * * * * * *		
§ 63.6(i)	Extension of compliance	Yes. Note: Facilities may also request extensions of compliance for the installation of combined heat and power, waste heat recovery, or gas pipeline or fuel feeding infrastructure as a means of complying with this subpart.

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

Citation	Subject	Applies to subpart DDDDD
*	* * *	* * *
§ 63.7(e)(1)	Conditions for conducting performance tests	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a) to (c).
*	* * *	* * *
§ 63.8(g)	Reduction of monitoring data	Yes.
*	* * *	* * *
§ 63.10(e)	Additional reporting requirements for sources with CMS.	Yes.
§ 63.10(f)	Waiver of recordkeeping or reporting requirements.	Yes.
*	* * *	* * *

■ 38. Add Table 11 to subpart DDDDD of part 63 to read as follows:

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Mercury	8.0E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Mercury	2.0E–06 lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
4. Units designed to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
6. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
7. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
8. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
9. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run
12. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	8.0E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
15. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,100 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel ..	a. HCl	4.4E–04 lb per MMBtu of heat input ...	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.

TABLE 11 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
17. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
18. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run
19. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run
20. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input ...	For M26A, collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input ...	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provisions of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.
[b] Incorporated by reference, see § 63.14.

■ 39. Add Table 12 to subpart DDDDD of part 63 to read as follows:

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	3.5E–06 [a] lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
2. Units design to burn coal/solid fossil fuel.	a. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
3. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
4. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
5. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
6. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
7. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (390 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
9. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	260 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
10. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	470 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–03 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER MAY 20, 2011, AND BEFORE DECEMBER 23, 2011—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
12. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
13. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
14. Units designed to burn liquid fuel	a. HCl	4.4E–04 lb per MMBtu of heat input	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.8E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
15. Units designed to burn heavy liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–02 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
16. Units designed to burn light liquid fuel.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
17. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 4 dscm per run.
18. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote ''a'', your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

■ 40. Add Table 13 to subpart DDDDD of part 63 to read as follows:

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. HCl	0.022 lb per MMBtu of heat input	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 120 liters per run.
	b. Mercury	8.6E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
2. Pulverized coal boilers designed to burn coal/solid fossil fuel.	a. Carbon monoxide (CO) (or CEMS).	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (320 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.8E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (340 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.8E–02 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (230 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
5. Fluidized bed units with an integrated heat exchanger designed to burn coal/solid fossil fuel.	a. CO (or CEMS)	140 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (150 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 lb per MMBtu of heat input; or (2.3E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
6. Stokers/sloped grate/others designed to burn wet biomass fuel.	a. CO (or CEMS)	620 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (410 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.0E–02 lb per MMBtu of heat input; or (2.6E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
7. Stokers/sloped grate/others designed to burn kiln-dried biomass fuel.	a. CO	460 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.2E–01 lb per MMBtu of heat input; or (4.0E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO (or CEMS)	230 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM).	9.8E–03 lb per MMBtu of heat input; or (8.3E–05 [a] lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
9. Suspension burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	2,400 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	5.1E–02 lb per MMBtu of heat input; or (6.5E–03 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
10. Dutch Ovens/Pile burners designed to burn biomass/bio-based solids.	a. CO (or CEMS)	810 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	3.6E–02 lb per MMBtu of heat input; or (3.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
11. Fuel cell units designed to burn biomass/bio-based solids.	a. CO	910 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.0E–02 lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
12. Hybrid suspension grate boiler designed to burn biomass/bio-based solids.	a. CO (or CEMS)	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3 percent oxygen, 30-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	2.6E–02 lb per MMBtu of heat input; or (4.4E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
13. Units designed to burn liquid fuel ..	a. HCl	1.2E–03 lb per MMBtu of heat input ...	For M26A: Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	b. Mercury	4.9E–07 [a] lb per MMBtu of heat input	For M29, collect a minimum of 4 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 4 dscm.
14. Units designed to burn heavy liquid fuel.	a. CO (or CEMS)	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average; or (18 ppm by volume on a dry basis corrected to 3 percent oxygen, 10-day rolling average).	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.3E–03 lb per MMBtu of heat input; or (7.5E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
15. Units designed to burn light liquid fuel.	a. CO (or CEMS)	130 [a] ppm by volume on a dry basis corrected to 3 percent oxygen; or (60 ppm by volume on a dry basis corrected to 3 percent oxygen, 1-day block average)..	1 hr minimum sampling time.
	b. Filterable PM (or TSM).	1.1E–03 [a] lb per MMBtu of heat input; or (2.9E–05 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.
16. Units designed to burn liquid fuel that are non-continental units.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-run average based on stack test; or (91 ppm by volume on a dry basis corrected to 3 percent oxygen, 3-hour rolling average).	1 hr minimum sampling time.

TABLE 13 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER DECEMBER 23, 2011, AND BEFORE JANUARY 31, 2013—Continued

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Using this specified sampling volume or test run duration . . .
	b. Filterable PM (or TSM).	2.3E–02 lb per MMBtu of heat input; or (8.6E–04 lb per MMBtu of heat input).	Collect a minimum of 2 dscm per run.
17. Units designed to burn gas 2 (other) gases.	a. CO	130 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. HCl	1.7E–03 lb per MMBtu of heat input	For M26A, Collect a minimum of 2 dscm per run; for M26, collect a minimum of 240 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input	For M29, collect a minimum of 3 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. Filterable PM (or TSM).	6.7E–03 lb per MMBtu of heat input; or (2.1E–04 lb per MMBtu of heat input).	Collect a minimum of 3 dscm per run.

[a] If you are conducting stack tests to demonstrate compliance and your performance tests for this pollutant for at least 2 consecutive years show that your emissions are at or below this limit and you are not required to conduct testing for CEMS or CPMS monitor certification, you can skip testing according to § 63.7515 if all of the other provision of § 63.7515 are met. For all other pollutants that do not contain a footnote "a", your performance tests for this pollutant for at least 2 consecutive years must show that your emissions are at or below 75 percent of this limit in order to qualify for skip testing.

[b] Incorporated by reference, see § 63.14.

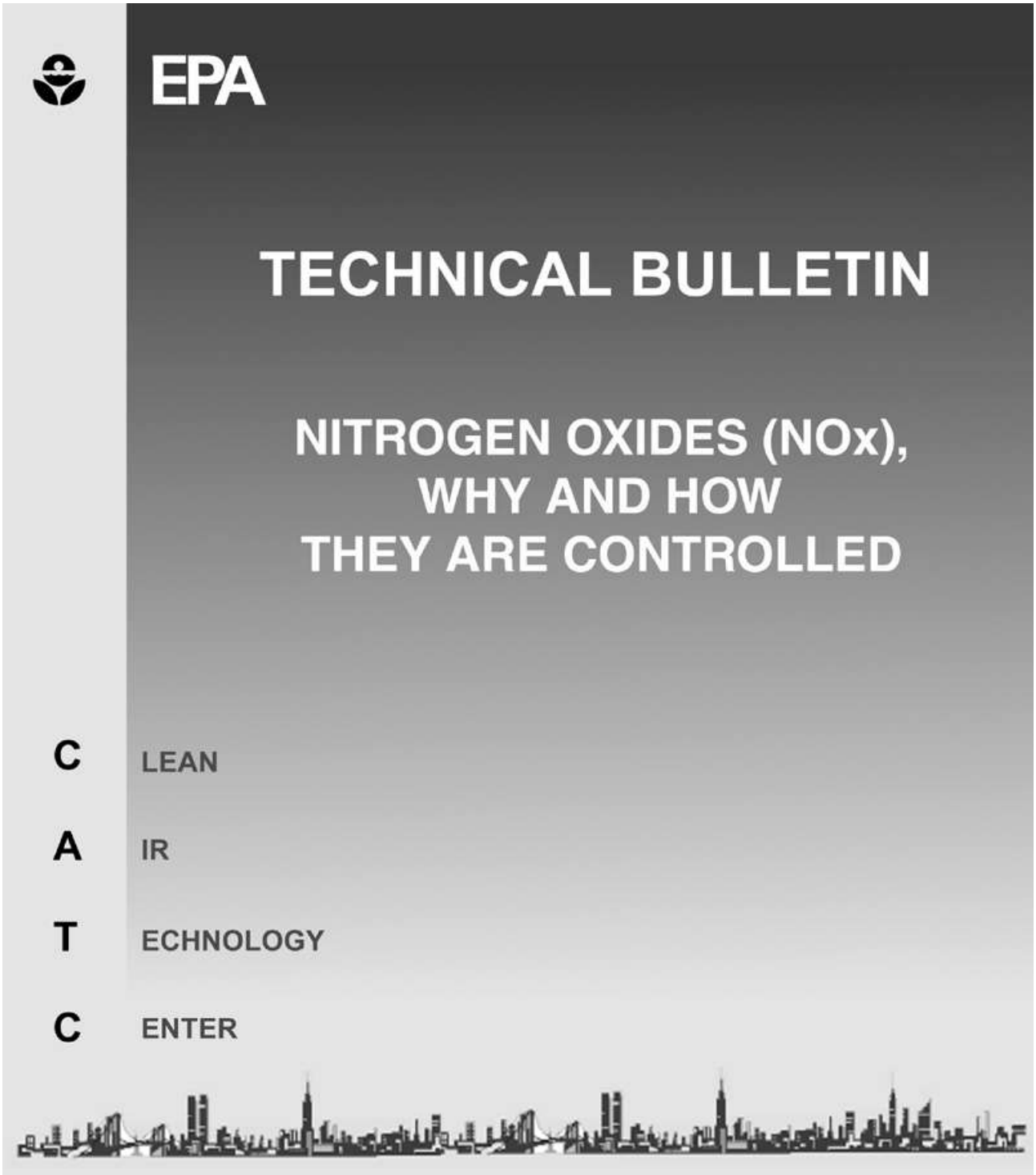
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United States Environmental Protection Agency
Air

Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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Nitrogen Oxides (NOx), Why and How They Are Controlled

Prepared by

Clean Air Technology Center (MD-12)
Information Transfer and Program Integration Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
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DISCLAIMER

This report has been reviewed by the Information Transfer and Program Integration Division of the Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency and approved for publication. Approval does not signify that the contents of this report reflect the views and policies of the U.S. Environmental Protection Agency. Mention of trade names or commercial products is not intended to constitute endorsement or recommendation for use. Copies of this report are available form the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, Virginia 22161, telephone number (800) 553-6847.

CORRECTION NOTICE

This document, EPA-456/F-99-006**a**, corrects errors found in the original document, EPA-456/F-99-006. These corrections are:

Page 8, fourth paragraph: "Destruction or Recovery Efficiency" has been changed to "Destruction or Removal Efficiency;"

Page 10, Method 2. Reducing Residence Time: This section has been rewritten to correct for an ambiguity in the original text.

Page 20, Table 4. Added Selective Non-Catalytic Reduction (SNCR) to the table and added acronyms for other technologies.

Page 29, last paragraph: This paragraph has been rewritten to correct an error in stating the configuration of a typical cogeneration facility.

Page30, Internal Combustion Reciprocating Engines: A sentence has been added to the end of this section to refer the readers to Table 13 for more information;

Page 41, third through seventh paragraphs: These paragraphs were renumbered to correct for a numbering error (numbers 6 and 7 were used twice).

NMED Exhibit 81

FORWARD

The **Clean Air Technology Center (CATC)** serves as a resource on all areas of emerging and existing air pollution prevention and control technologies, and provides public access to data and information on their use, effectiveness and cost. In addition, the CATC will provide technical support, including access to EPA's knowledge base, to government agencies and others, as resources allow, related to the technical and economic feasibility, operation and maintenance of these technologies.

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- **SBAP - Small Business Assistance Program**
- **International Technology Transfer Center for Global Greenhouse Gasses**

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This technical bulletin was made possible through the diligent and persistent efforts of Lyndon Cox, Senior Environmental Employee with the Clean Air Technology Center (CATC). Lyndon did an exceptional job identifying information sources, gathering relative data and putting this bulletin together. The CATC also appreciates the helpful and timely comments and cooperation of the following peer reviewers:

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In addition, the CATC thanks the individuals, companies and institutions who supplied information on nitrogen oxide abatement technology used to prepare this Technical Bulletin. Contributors are indicated in the REFERENCES section of this bulletin.

NMED Exhibit 81

TABLE OF CONTENTS

TOPIC **Page**

WHY SHOULD WE CONTROL NOx? 1

WHAT IS NITROGEN OXIDE? 2

WHERE DOES NOx COME FROM? 4

HOW DOES NOx AFFECT THE ENVIRONMENT? 5

ARE THERE OTHER NOx RELATED ISSUES? 7

WHAT ABATEMENT AND CONTROL PRINCIPLES APPLY? 8

WHAT ABATEMENT TECHNOLOGIES ARE AVAILABLE? 11
- EXTERNAL COMBUSTION 11
  - EXTERNAL COMBUSTION: POLLUTION PREVENTION METHODS 15
    - LESS EXCESS AIR (LEA) 15
    - BURNERS OUT OF SERVICE (BOOS) 15
    - OVER FIRE AIR (OFA) 15
    - LOW NOx BURNERS (LNB) 15
    - FLUE GAS RECIRCULATION 15
    - WATER OR STEAM INJECTION 16
    - REDUCED AIR PREHEAT 16
    - FUEL REBURNING 16
    - COMBUSTION OPTIMIZATION 16
    - AIR STAGING 16
    - FUEL STAGING 17
    - OXYGEN INSTEAD OF AIR FOR COMBUSTION 17
    - INJECTION OF OXIDANT 17
    - CATALYTIC COMBUSTION 17
    - ULTRA-LOW NOx FUELS 17
    - NON-THERMAL PLASMA 18
  - EXTERNAL COMBUSTION: ADD-ON CONTROL TECHNOLOGY 18
    - SELECTIVE CATALYTIC REDUCTION (SCR) 18
    - SELECTIVE NON-CATALYTIC REDUCTION (SNCR) 18
    - SORPTION - BOTH ADSORPTION AND ABSORPTION 19
    - COMBINED TECHNOLOGY APPROACHES 19

NMED Exhibit 81

TABLE OF CONTENTS (continued)

TOPIC **Page**

INTERNAL COMBUSTION 19
INTERNAL COMBUSTION: POLLUTION PREVENTION METHODS 20
LOW NOx BURNERS (LNB) 20
STEAM / WATER INJECTION 20
CATALYTIC COMBUSTION 20
AIR-FUEL RATIO AND IGNITION TYPE 21
PRE-STRATIFIED CHARGE (PSC) 21
LEAN BURN 21
INTERNAL COMBUSTION: ADD-ON CONTROL TECHNOLOGY 21
SELECTIVE CATALYTIC REDUCTION 21
NON-SELECTIVE CATALYTIC REDUCTION (NSCR) 22
NON-THERMAL PLASMA REACTORS 22

DO FUELS AND COMBUSTION TYPE AFFECT ABATEMENT? 22
SOLID FUELS 22
LIQUID FUELS 23
SEMI-SOLID FUELS 23
GAS FUEL 24
COMBUSTION SYSTEMS 24
DRY BOTTOM BOILERS - WALLED FIRED, FRONT-FIRED or OPPOSED-FIRED 25
DRY BOTTOM BOILERS - TANGENTIALLY FIRED 26
WET BOTTOM (SLAG TAP) BOILERS 26
FLUIDIZED BED 27
STOKERS WITH TRAVELING GRATE 28
STOKERS WITH SPREADERS 28
GAS TURBINES 29
INTERNAL COMBUSTION RECIPROCATING ENGINES 30

WHAT DOES NOx ABATEMENT AND CONTROL COST? 30

ARE THESE METHODS SUFFICIENT? 34

CONCLUSIONS 40

REFERENCES 42

NMED Exhibit 81

FIGURES

1. NOx Map 6

2. Ozone Map 6

TABLES

1. Nitrogen Oxides 2

2. NOx Control Methods 9

3. External Combustion NOx Limiting technologies 12

4. Internal combustion NOx Limiting Technologies 20

5. Common Combustion Systems 24

6. NOx technologies currently used for dry bottom wall-fired, front-fired or opposed fired boilers 25

7. NOx technologies currently used for dry bottom tangentially fired boilers 26

8. NOx technologies currently used for wet bottom (slag tap) boilers 27

9. NOx technologies currently used for fluidized bed combustion 28

10. NOx technologies currently used for stokers with traveling grates 29

11. NOx technologies currently used for stokers with spreader grates 30

12. NOx technologies currently used for gas turbines 31

13. NOx technologies currently used for stationary internal combustion engines 31

14. 1993 Costs of NOx Controls 32

15. 1997 Costs of NOx Controls 33

16. Unit Costs for NOx Control Technologies for Non-Utility Stationary Sources 35

NMED Exhibit 81

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NMED Exhibit 81

Nitrogen Oxides (NOx), Why and How They Are Controlled

When we try to look only at one thing in Nature,
we find it connected to everything else.
John Muir

Nitrogen oxides (NOx) are a very interesting and important family of air polluting chemical compounds. This bulletin explains why NOx are important air pollutants and how NOx are formed and react in the atmosphere. This bulletin also discusses the principles on which all NOx control and pollution prevention technologies are based; available NOx technologies for various combustion sources; and performance and cost of NOx technologies..

WHY SHOULD WE CONTROL NOx?

NOx represent a family of seven compounds. Actually, EPA regulates only nitrogen dioxide (NO_2) as a surrogate for this family of compounds because it is the most prevalent form of NOx in the atmosphere that is generated by anthropogenic (human) activities. NO_2 is not only an important air pollutant by itself, but also reacts in the atmosphere to form ozone (O_3) and acid rain. It is important to note that the ozone that we want to minimize is tropospheric ozone; that is, ozone in the ambient air that we breathe. We are not talking about stratospheric ozone in the upper atmosphere that we cannot breathe. Stratospheric ozone protects us and the troposphere from ionizing radiation coming from the sun.

EPA has established National Ambient Air Quality Standards (NAAQS) for NO_2 and tropospheric ozone. The NAAQS define levels of air quality that are necessary, with a reasonable margin of safety, to protect public health (primary standard) and public welfare (secondary standard) from any known or anticipated adverse effects of pollution. The primary and secondary standard for NO_2 is 0.053 parts per million (ppm) (100 micrograms per cubic meter), annual arithmetic mean concentration.

Tropospheric ozone has been and continues to be a significant air pollution problem in the United States and is the primary constituent of smog. Large portions of the country do not meet the ozone NAAQS and thereby expose large segments of the population to unhealthy levels of ozone in the air. NO_2 reacts in the presence of air and ultraviolet light (UV) in sunlight to form ozone and nitric oxide (NO). The NO then reacts with free radicals in the atmosphere, which are also created by the UV acting on volatile organic compounds (VOC). The free radicals then recycle NO to NO_2. In this way, each molecule of NO can produce ozone multiple times.[40] This will continue until the VOC are reduced to short chains of carbon compounds that cease to be photo reactive (a reaction caused by light). A VOC molecule can usually do this about 5 times.

In addition to the NO_2 and Ozone NAAQS concerns, NOx and sulfur oxides (SOx) in the

NMED Exhibit 81

atmosphere are captured by moisture to form acid rain. Acid rain, along with cloud and dry deposition, severely affects certain ecosystems and directly affects some segments of our economy. All of these facts indicate an obvious need to reduce NOx emissions. However, to successfully do so, we must understand the generation and control of the NOx family of air pollutants.

WHAT IS A NITROGEN OXIDE?

Diatomic molecular nitrogen (N_2) is a relatively inert gas that makes up about 80% of the air we breathe. However, the chemical element nitrogen (N), as a single atom, can be reactive and have ionization levels (referred to as valence states) from plus one to plus five. Thus nitrogen can form several different oxides. Using the Niels Bohr model of the atom, valence state relates to the number of electrons which are either deficient (positive valence) or surplus (negative valence) in the ion when compared with the neutral molecule. The family of NOx compounds and their properties are listed in Table 1.

Table 1. Nitrogen Oxides (NOx)

Formula	Name	Nitrogen Valence	Properties
N_2O	nitrous oxide	1	colorless gas water soluble
NO N_2O_2	nitric oxide dinitrogen dioxide	2	colorless gas slightly water soluble
N_2O_3	dinitrogen trioxide	3	black solid water soluble, decomposes in water
NO_2 N_2O_4	nitrogen dioxide dinitrogen tetroxide	4	red-brown gas very water soluble, decomposes in water
N_2O_5	dinitrogen pentoxide	5	white solid very water soluble, decomposes in water

Oxygen ions are always at valence minus 2. Depending upon the number of oxygen ions (always balanced by the valence state of nitrogen), NOx can react to either deplete or enhance ozone concentrations. The nitrogen ion in these oxides really does a dance in which it has (at different times) various numbers of oxygen ions as partners. Nitrogen changes its number of partners when it changes its ionization energy level. This happens whenever NOx: (1) is hit with a photon of ionizing radiation (UV or a shorter wavelength light); (2) is hit with enough photons that together transfer enough energy to change its ionization level; (3) is catalyzed; (4) is stimulated sufficiently by thermal (IR) energy; (5) reacts with a chemically oxidizing or reducing radical (an ionized fragment of a molecule); or (6) reacts with a chemically oxidizing or reducing

ion (an atom with unbalanced electrical charge).

When any of these oxides dissolve in water and decompose, they form nitric acid (HNO_3) or nitrous acid (HNO_2). Nitric acid forms nitrate salts when it is neutralized. Nitrous acid forms nitrite salts. Thus, NOx and its derivatives exist and react either as gases in the air, as acids in droplets of water, or as a salt. These gases, acid gases and salts together contribute to pollution effects that have been observed and attributed to acid rain.

Nitrous oxide (N_2O), NO, and NO_2 are the most abundant nitrogen oxides in the air. N_2O (also known as laughing gas) is produced abundantly by biogenic sources such as plants and yeasts. It is only mildly reactive, and is an analgesic (i.e., unlike an anaesthetic you still feel pain, but you feel so good that you just don't mind it). N_2O is an ozone depleting substance which reacts with O_3 in both the troposphere (i.e., below 10,000 feet above sea level) and in the stratosphere (50,000 - 150,000 feet). N_2O has a long half-life, estimated at from 100 to 150 years.

Oxidation of N_2O by O_3 can occur at any temperature and yields both molecular oxygen (O_2) and either NO or two NO molecules joined together as its dimer, dinitrogen dioxide (N_2O_2). The NO or N_2O_2 then oxidizes quickly (in about two hours) to NO_2. The NO_2 then creates an ozone molecule out of a molecule of oxygen (O_2) when it gets hit by a photon of ionizing radiation from sunlight. N_2O is also a "Greenhouse Gas" which, like carbon dioxide (CO_2), absorbs long wavelength infrared radiation to hold heat radiating from Earth, and thereby contributes to global warming.

Emissions of NOx from combustion are primarily in the form of NO. According to the Zeldovich equations, NO is generated to the limit of available oxygen (about 200,000 ppm) in air at temperatures above 1,300°C (2,370°F). At temperatures below 760°C (1,400°F), NO is either generated in much lower concentrations or not at all. Combustion NO is generated as a function of air to fuel ratio and is more pronounced when the mixture is on the fuel-lean side of the stoichiometric ratio[50] (the ratio of chemicals which enter into reaction). The Zeldovich equations are:

$$N_2 + O \rightarrow NO + N$$
$$N + O_2 \rightarrow NO + O$$
$$N + OH \rightarrow NO + H$$

Except for NO from soils, lightning and natural fires, NO is largely anthropogenic (i.e., generated by human activity). Biogenic sources are generally thought to account for less than 10% of total NO emissions. NO produces the same failure to absorb oxygen into the blood as carbon monoxide (CO). However, since NO is only slightly soluble in water, it poses no real threat except to infants and very sensitive individuals.

NO_2 is present in the atmosphere and in acid rain. It produces nitric acid (HNO_3) when dissolved in water. When NO_2 reacts with a photon to make O_2 become O_3, NO_2 becomes NO. This NO is then oxidized within hours to NO_2 by radicals from the photo reaction of VOC. Therefore, our

present ozone concentration is the product of both NOx and VOC pollution.

Dinitrogen trioxide (N_2O_3) and dinitrogen tetroxide (N_2O_4) exist in very small concentrations in flue gas. However, they exist in such low concentrations in the atmosphere that both their presence and their effect are often ignored. N_2O_4 is two NO_2 molecules joined together (another dimer) and reacts like NO_2; so, the presence of N_2O_4 may be masked by the more abundant NO_2.

Dinitrogen pentoxide (N_2O_5) is the most highly ionized form of nitrogen oxide. It is generated in air in a very small concentration, unless it is emitted from a process (such as a nitric acid production facility) that is specifically designed to generate it. N_2O_5 is highly reactive, and forms nitric acid (HNO_3) when it decomposes in water.

Some experts feel that NO_2 is a good surrogate for NOx because NO is rapidly converted to NO_2, and N_2O has such a long life because it is not highly reactive. Others feel that due to their role in forming ozone, both NO and NO_2 should be considered NOx. Still others feel that all nitrogen oxides (including N_2O) need to be regulated. NO and NO_2 are certainly the most plentiful forms of NOx and they are largely (but not exclusively) from anthropogenic sources. N_2O is largely biogenic, and as such is not subject to regulation. For environmental purposes, using the concentration of NO_2 as a surrogate for the concentration of NOx has seemed to suffice, for it is the precursor for ozone.

WHERE DOES NOx COME FROM?

Automobiles and other mobile sources contribute about half of the NOx that is emitted. Electric power plant boilers produce about 40% of the NOx emissions from stationary sources.[34] Additionally, substantial emissions are also added by such anthropogenic sources as industrial boilers, incinerators, gas turbines, reciprocating spark ignition and Diesel engines in stationary sources, iron and steel mills, cement manufacture, glass manufacture, petroleum refineries, and nitric acid manufacture. Biogenic or natural sources of nitrogen oxides include lightning, forest fires, grass fires, trees, bushes, grasses, and yeasts.[1] These various sources produce differing amounts of each oxide. The anthropogenic sources are approximately shown as:

Mobile Sources	Electric Power Plants	Everything Else
50%	20%	30%

This shows a graphic portrayal of the emissions of our two greatest sources of NOx. If we could reduce the NOx emissions from just these two leading categories, we might be able to live with the rest. However, don't expect either of these categories to become zero in the foreseeable future. We cannot expect the car, truck, bus, and airplane to disappear. The zero-emission car is still on the drawing board and not on the production line. Also, social customs will have to change before consumption of electricity can be reduced.

NMED Exhibit 81

In all combustion there are three opportunities for NOx formation. They are:

1. Thermal NOx - The concentration of "thermal NOx" is controlled by the nitrogen and oxygen molar concentrations and the temperature of combustion. Combustion at temperatures well below 1,300°C (2,370°F) forms much smaller concentrations of thermal NOx.

2. Fuel NOx - Fuels that contain nitrogen (e.g., coal) create "fuel NOx" that results from oxidation of the already-ionized nitrogen contained in the fuel.

3. Prompt NOx - Prompt NOx is formed from molecular nitrogen in the air combining with fuel in fuel-rich conditions which exist, to some extent, in all combustion. This nitrogen then oxidizes along with the fuel and becomes NOx during combustion, just like fuel NOx. The abundance of prompt NOx is disputed by the various writers of articles and reports - probably because they each are either considering fuels intrinsically containing very large or very small amounts of nitrogen, or are considering burners that are intended to either have or not have fuel-rich regions in the flame.

HOW DOES NOx AFFECT THE ENVIRONMENT?

Because NOx are transparent to most wavelengths of light (although NO_2 has a brownish color and the rare N_2O_3 is black), they allow the vast majority of photons to pass through and, therefore, have a lifetime of at least several days. Because NO_2 is recycled from NO by the photo reaction of VOC to make more ozone, NO_2 seems to have an even longer lifetime and is capable of traveling considerable distances before creating ozone. Weather systems usually travel over the earth's surface and allow the atmospheric effects to move downwind for several hundred miles. This was noted in EPA reports more than twenty years ago. These reports found that each major city on the East coast has a plume of ozone that extends more than a hundred miles out to sea before concentrations drop to 100 parts per billion (ppb). Another report cited the same phenomenon for St. Louis. Therefore, this problem was not just on the sea coast. Since ozone in clean air has a lifetime of only a few hours, this phenomenon is a measure of the effect and the persistence of both VOC and NOx.

Differences in the distance estimates between the emission of NOx and the generation of ozone may be related to differences in plume transport (wind) speeds as well as other meteorological and air quality factors. It is important to note that, under the right conditions, power plant plumes may travel relatively long distances overnight with little loss of VOC, NO and NO_2 . These pollutants can thus be available to participate in photochemical reactions at distant locations on the following day.[41] Figure 1 shows a map of NOx concentration drawn by the Center for Air Pollution Impact and Trend Analysis (CAPITA) at Washington University in St. Louis and reported to the Ozone Transport Assessment Group, a national workgroup that addressed the problem of ground-level ozone (smog) and the long-range transport of air pollution across the Eastern United States. OTAG was a partnership among the EPA, the Environmental Council of the States (ECOS) and various industry and environmental groups with the goal of developing a thoughtful assessment and a consensus agreement for reducing ground-level ozone and the

pollutants that cause it. The animated version of Figure 1 shows the trajectory of NOx emissions moving with the weather over an 8 day period.

Figure 2 is a map of ozone concentration that shows the same trajectory over the 8 day period. The animated version shows concentrations of both NOx and ozone moving with the weather for several hundred miles.[5]

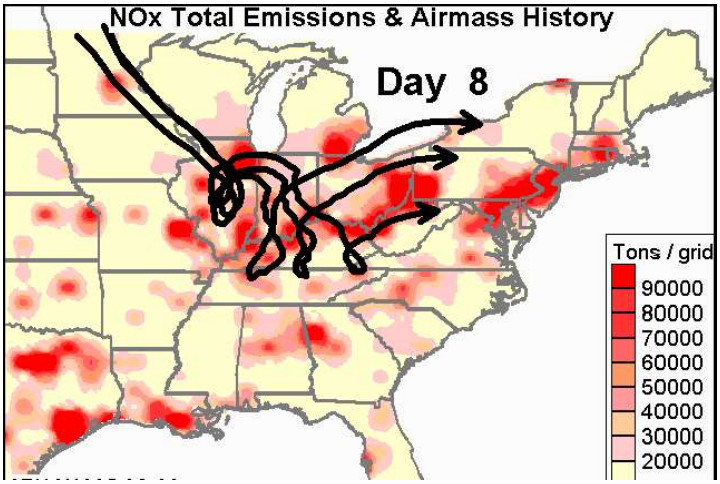


Figure 2 NOx Map

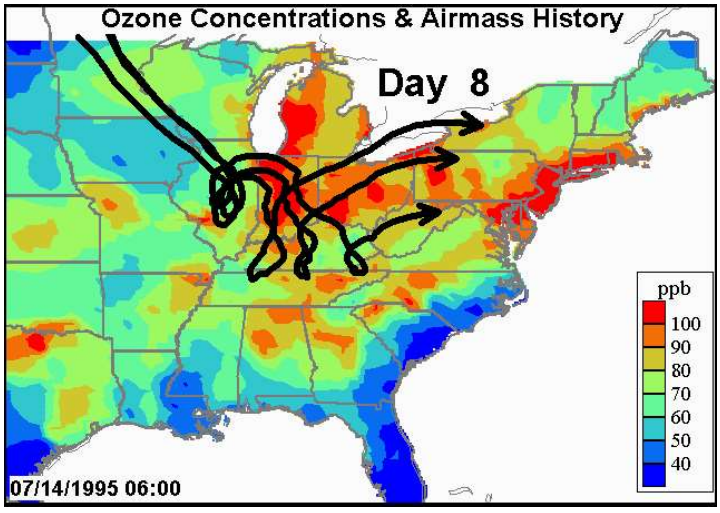


Figure 3 Ozone Map

Ozone is the primary constituent of smog. Between 1970 and 1990, we in the United States have tried to control ozone primarily by controlling the emissions of VOC. However, we have had mixed results, for although some areas reduced their VOC emissions and attained their ozone goals, others have not. It now appears that the communities that failed to meet their ozone goals

may not be completely at fault, for they appear to be affected by NOx and VOC emissions in the air coming to them. To meet the ozone NAAQS, EPA must now regulate emissions of NOx regionally.

ARE THERE OTHER NOx RELATED ISSUES?

Yes. Nutrient enrichment problems (eutrophication) occur in bodies of water when the availability of either nitrates or phosphates become too large. As a result, the ratios of nitrogen to phosphorus, silicon, and iron and other nutrients are altered. This alteration may induce changes in phytoplankton, produce noxious or toxic brown or red algal blooms (which are called "red tides"), or stimulate other plant growth. The algal blooms and plant growth produce a shadow and cause the death of other plants in the water, which depletes the oxygen content of the water (hypoxia) when the plants die, sink, and decay. Such eutrophication can make the bottom strata of water unihabitable for both marine animals (such as fish and shellfish) and aquatic plants. It can progress to virtually the complete depth of the water. It is estimated that between 12% and 44% of the nitrogen loading of coastal water bodies comes from the air.[40] Inland lakes are also affected in this way.

Another dimension of the problem is that high temperature combustion can convert sulfur in fuel to SO_2 and SO_3. While SO_2 is toxic and forms sulfurous acid when dissolved in water, SO_3 is both toxic and hygroscopic (moisture absorbing) and forms sulfuric acid by combining with moisture in the atmosphere. SO_2 and SO_3 form sulfites and sulfates when their acids are neutralized. Both of these acids can form solid particles by reacting with ammonia in air. SO_2 and SO_3 also contribute to pH (acidity) changes in water, which can adversely affect both land and aquatic life. Therefore, both NOx and SOx from combustion can kill plants and animals.

CAPITA has shown that there are about equal amounts by weight of sulfate/sulfite, nitrate and organic particles making up 90% of Particulate Matter less than 2.5 microns in aerodynamic diameter (PM-2.5). This was confirmed by Brigham Young University researchers. The Six Cities Study, published in the *New England Journal of Medicine* in 1990, has shown that illness and premature death are closely correlated with the amount of PM-2.5 in the air. Therefore, there is epidemiological data indicting nitrogen oxides, sulfur oxides, and/or organic compounds as PM-2.5 aerosols. There is currently no evidence that separately examines the health effects of each of these substances. PM-2.5 usually appear as smog, smoke, white overcast, haze, or fog which does not clear when air warms up. Brown smog is colored by nitrogen dioxide.

Because the nitric acid, sulfurous acid and sulfuric acid react with ammonia in air to form solid crystals that are much smaller than 2.5 microns and can be nucleation sites for particle growth, we need to be concerned about each of these pollutants. Some research indicates that even insoluble particles much smaller than 2.5 microns in size can exhibit severe toxic effects.[38] The smallest particles that have shown toxicity have a diameter of about 3% to 5% of the wavelength of any color of visible light. Therefore, these particles are too small to even scatter light and cannot even be detected optically.

Acid deposition occurs from airborne acidic or acidifying compounds, principally sulfates (SO_4^{-2}) and nitrates (NO_3^{-1}), that can be transported over long distances before returning to earth. This occurs through rain or snow (wet deposition), fog or cloud water (cloud deposition), or transfer of gases or particles (dry deposition). While severity of damage depends on the sensitivity of the receptor, acid deposition and NOx "represent a threat to natural resources, ecosystems, visibility, materials, and public health."(section 401(a)(1) of the Clean Air Act).[40]

WHAT ABATEMENT AND CONTROL PRINCIPLES APPLY?

NOx abatement and control technology is a relatively complex issue. We shall try to provide a structure to the spectrum of NOx pollution prevention and control technologies by first giving the principles that are used. Then we shall describe the more successful pollution prevention and emission control technologies and strategies.

Please note that abatement and control of NOx from nitric acid manufacturing and "pickling" baths differs from abatement and control at combustion sources. Combustion sources all have NOx in a large flow of flue gas, while nitric acid manufacturing plants and pickling baths try to contain the NOx. Wet scrubbers (absorbers) can control NOx emissions from acid plants and pickling, and can use either alkali in water, water alone, or hydrogen peroxide as the liquid that captures the NOx.[3] The wet scrubber operates by liquid flowing downward by gravity through a packing medium, opposed by an upward flow of gas. Scrubbers operate on the interchange of substances between gas and liquid. This requires that the height of the absorber, type of packing, liquid flow, liquid properties, gas properties, and gas flow should collectively cause a scrubber to have the desired control efficiency. Chapter 9 of the OAQPS Control Cost Manual provides guidance on the application, sizing, and cost of these scrubbers (referred to as gas absorbers). Also, Table 16 in this Bulletin presents some information for non-combustion NOx sources. Other then that, non-combustion NOx sources are not addressed in this Bulletin.

For combustion sources, this Bulletin defines abatement and emission control principles and states the Destruction or Removal Efficiency (DRE) that each successful technology is capable of achieving. The effectiveness of pollution prevention measures in reducing NO and NO_2 generation also is expressed in terms of relative DRE; i.e., the amount NOx generation is reduced by using a prevention technology compared to NOx generation when not using that technology. Then, specific boiler types and combustion systems and applicable NOx technologies for each system are discussed. Finally, the cost of these technologies is considered.

Many new combustion systems incorporate NOx prevention methods into their design and generate far less NOx then similar but older systems. As a result, considering DRE (even a relative DRE) for NOx may be inappropriate. Comparing estimated or actual NOx emissions from a new, well-designed system to NOx emitted by a similar well-controlled and operated older system may be the best way of evaluating how effectively a new combustion system minimizes NOx emissions.

Table 2 lists principles or methods that are used to reduce NOx. Basically there are six

NMED Exhibit 81

principles, with the seventh being an intentional combination of some subset of the six.

Table 2. NOx Control Methods [6,7]

Abatement or Emission Control Principle or Method	Successful Technologies	Pollution Prevention Method (P2) or Add-on Technology (A)
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning Low NOx Burners (LNB) Combustion Optimization Burners Out Of Service (BOOS) Less Excess Air (LEA) Inject Water or Steam Over Fire Air (OFA) Air Staging Reduced Air Preheat Catalytic Combustion	P2 P2 P2 P2 P2 P2 P2 P2 P2 P2 P2
2.Reducing residence time at peak temperature	Inject Air Inject Fuel Inject Steam	P2 P2 P2
3. Chemical reduction of NOx	Fuel Reburning (FR) Low NOx Burners (LNB) Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)	P2 P2 A A
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor Inject Oxidant	A A
5. Removal of nitrogen	Oxygen Instead Of Air Ultra-Low Nitrogen Fuel	P2 P2
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	A A
7. Combinations of these Methods	All Commercial Products	P2 and A

Method 1. Reducing Temperature -- Reducing combustion temperature means avoiding the stoichiometric ratio (the exact ratio of chemicals that enter into reaction). Essentially, this technique dilutes calories with an excess of fuel, air, flue gas, or steam. Combustion controls use different forms of this technique and are different for fuels with high and low nitrogen content.

Control of NOx from combustion of high nitrogen content fuels (e.g., coal) can be understood by the net stoichiometric ratio. Control of the NOx from combustion of low nitrogen fuels (such as gas and oil) can be seen as lean versus rich fuel/air ratios. Either way, this technique avoids the ideal stoichiometric ratio because this is the ratio that produces higher temperatures that generate higher concentrations of thermal NOx.

Combustion temperature may be reduced by: (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit temperature by diluting energy input; (3) injecting cooled oxygen-depleted flue gas into the combustion air to dilute energy; (4) injecting cooled flue gas with added fuel; or (5) injecting water or steam. Low-NOx burners are based partially on this principle.[8,9,10] The basic technique is to reduce the temperature of combustion products with an excess of fuel, air, flue gas, or steam. This method keeps the vast majority of nitrogen from becoming ionized (i.e., getting a non-zero valence).

Method 2. Reducing Residence Time -- Reducing residence time at high combustion temperatures can be done by ignition or injection timing with internal combustion engines. It can also be done in boilers by restricting the flame to a short region in which the combustion air becomes flue gas. This is immediately followed by injection of fuel, steam, more combustion air, or recirculating flue gas. This short residence time at peak temperature keeps the vast majority of nitrogen from becoming ionized. This bears no relationship to total residence time of a flue gas in a boiler.

Method 3. Chemical Reduction of NOx – This technique provides a chemically reducing (i.e., reversal of oxidization) substance to remove oxygen from nitrogen oxides. Examples include Selective Catalytic Reduction (SCR) which uses ammonia, Selective Non-Catalytic Reduction (SNCR) which use ammonia or urea, and Fuel Reburning (FR). Non-thermal plasma, an emerging technology, when used with a reducing agent, chemically reduces NOx. All of these technologies attempt to chemically reduce the valence level of nitrogen to zero after the valence has become higher.[11] Some low-NOx burners also are based partially on this principle.

Method 4. Oxidation of NOx -- This technique intentionally raises the valence of the nitrogen ion to allow water to absorb it (i.e., it is based on the greater solubility of NOx at higher valence). This is accomplished either by using a catalyst, injecting hydrogen peroxide, creating ozone within the air flow, or injecting ozone into the air flow. Non-thermal plasma, when used without a reducing agent, can be used to oxidize NOx. A scrubber must be added to the process to absorb N_2O_5 emissions to the atmosphere. Any resultant nitric acid can be either neutralized by the scrubber liquid and then sold (usually as a calcium or ammonia salt), or collected as nitric acid to sell to customers.[12, 49]

Method 5. Removal of nitrogen from combustion -- This is accomplished by removing nitrogen as a reactant either by: (1) using oxygen instead of air in the combustion process; or (2) using ultra-low nitrogen content fuel to form less fuel NOx. Eliminating nitrogen by using oxygen tends to produce a rather intense flame that must be subsequently and suitably diluted. Although Method 2 can lower the temperature quickly to avoid forming excessive NOx, it cannot

eliminate nitrogen oxides totally if air is the quench medium. Hot flue gas heats the air that is used to quench it and this heating generates some thermal NOx. This method also includes reducing the net excess air used in the combustion process because air is 80% nitrogen. Using ultra-low-nitrogen content fuels with oxygen can nearly eliminate fuel and prompt NOx.[13]

Method 6. Sorption, both adsorption and absorption -- Treatment of flue gas by injection of sorbents (such as ammonia, powdered limestone, aluminum oxide, or carbon) can remove NOx and other pollutants (principally sulfur). There have been successful efforts to make sorption products a marketable commodity. This kind of treatment has been applied in the combustion chamber, flue, and baghouse. The use of carbon as an adsorbent has not led to a marketable product, but it is sometimes used to limit NOx emissions in spite of this. The sorption method is often referred to as using a dry sorbent, but slurries also have been used. This method uses either adsorption or absorption followed by filtration and/or electrostatic precipitation to remove the sorbent.

Method 7. Combinations of these methods -- Many of these methods can be combined to achieve a lower NOx concentration than can be achieved alone by any one method. For example, a fuel-rich cyclone burner (Method 1) can be followed by fuel reburn (Method 3) and over-fire air (Method 1). This has produced as much as a 70% reduction in NOx.[55] Other control technologies that are intended to primarily reduce concentrations of sulfur also strongly affect the nitrogen oxide concentration. For example, the SOx-NOx-ROx-Box (SNRB) technology uses a limestone sorbent in the flue gas from the boiler to absorb sulfur. This is followed by ammonia injection and SCR using catalyst fibers in the baghouse filter bags. The sulfur is recovered from the sorbent and the sorbent regenerated by a Claus process. This has demonstrated removal of up to 90% of the NOx along with 80% of the SOx.[39, 42] EBARA of Japan reported that an electron beam reactor with added ammonia removed 80% of the SO_2 and 60% of the NOx for a utility boiler in China.[54] FLS Milo and Sons reported at the same symposium that 95% of the SO_2 and 70%-90% of the NOx were removed in several demonstrations of their SNAP technology, which is based upon an aluminum oxide adsorber with Claus regeneration.[56]

WHAT ABATEMENT TECHNOLOGIES ARE AVAILABLE?

In this report existing NOx abatement technologies are divided into two categories, external combustion applications (e.g., boilers, furnaces and process heaters) and internal combustion applications (e.g., stationary internal combustion engines and turbines). These categories are further subdivided into pollution prevention (which reduces NOx generation) and add-on control technologies (which reduces NOx emissions).

EXTERNAL COMBUSTION

For external combustion applicable technologies are shown in Table 3 (based on Table 2 in Select the Right NOx Control Technology, Stephen Wood, Chemical Engineering Progress, January 1994).

NMED Exhibit 81

Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Less Excess Air (LEA)	Reduces oxygen availability	Easy modification	Low NOx reduction	High CO Flame length Flame stability	All fuels
Off Stoichiometric a. Burners Out of Service (BOOS) b. Over Fire Air (OFA)	staged combustion	Low cost No capital cost for BOOS	a. Higher air flow for CO b. high capital cost	Flame length Fan capacity Header pressure	All fuels Multiple burners for BOOS
Low NOx Burner (LNB)	Internal staged combustion	Low operating cost Compatible FGR	Moderately high capital cost	Flame length Fan capacity Turndown stability	All fuels
Flue Gas Recirculation (FGR)	<30% flue gas recirculated with air, decreasing temperature	High NOx reduction potential for low nitrogen fuels	Moderately high capital cost and operating cost Affects heat transfer and system pressures	Fan capacity Furnace pressure Burner pressure drop Turndown stability	All fuels Low nitrogen fuels
Water/Steam Injection	Reduces flame temperature	Moderate capital cost NOx reduction similar to FGR	Efficiency penalty Fan power higher	Flame stability Efficiency penalty	All fuels as Low nitrogen fuels
Reduced Air Preheat	Air not preheated, reduces flame temperature	High NOx reduction potential	Significant efficiency loss (1% per 40°F)	Fan capacity Efficiency penalty	All fuels Low nitrogen fuels
Selective Catalytic reduction (SCR) (add-on technology)	Catalyst located in the air flow, promotes reaction between ammonia and NOx	High NOx removal	Very high capital cost High operating cost Catalyst siting Increased pressure drop Possible water wash required	Space requirements Ammonia slip Hazardous waste Disposal	All fuels

NMED Exhibit 81

Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Selective Non-Catalytic Reduction (SNCR) (add-on technology) a. urea b. ammonia	Inject reagent to react with NOx	a. Low capital cost Moderate NOx removal Non-toxic chemical b. Low operating cost Moderate NOx removal	a. Temperature dependent NOx reduction less at lower loads b. Moderately high capital cost Ammonia storage, handling, injection system	a. Furnace geometry Temperature profile b. Furnace geometry Temperature profile	All fuels
Fuel Reburning	Inject fuel to react with NOx	Moderate cost Moderate NOx removal	Extends residence time	Furnace temperature profile	All fuels (pulverized solid)
Combustion Optimization	Change efficiency of primary combustion	Minimal cost	Extends residence time	Furnace temperature profile	Gas Liquid fuels
Catalytic Combustion	Catalyst causes combustion to be at low temperature	Lowest possible NOx	Very high capital cost High operating cost Catalyst siting	Space requirements Disposal	Gas Liquid fuels
Non-Thermal Plasma	Reducing agent ionized or oxidant created in flow	Moderate cost Easy siting High NOx removal	Fouling possible Ozone emission possible	Uses electrical power	All fuels
Inject Oxidant	Chemical oxidant injected in flow	Moderate cost	Nitric acid removal	Add-on	All fuels
Oxygen instead of Air	Uses oxygen to oxidize fuel	Moderate to high cost Intense combustion	Eliminates prompt NOx Furnace alteration	Equipment to handle oxygen	All fuels
Ultra-Low Nitrogen Fuel	Uses low -nitrogen fuel	Eliminates fuel NOx No capital cost	Slight rise in operating cost	Minimal change	All ultra-low nitrogen fuels

NMED Exhibit 81

Table 3. External Combustion NOx Limiting Technologies					
Technique	**Description**	**Advantages**	**Disadvantages**	**Impacts**	**Applicability**
Use Sorbents (add-on technology) in: a. Combustion b. Duct to Baghouse c. Duct to Electrostatic Precipitator	Use a chemical to absorb NOx or an adsorber to hold it	Can control other pollutants as well as NOx Moderate operating cost	Cost of handling sorbent Space for the sorbent storage and handling	Add-on	All fuels
Air Staging	Admit air in separated stages	Reduce peak combustion temperature	Extend combustion to a longer residence time at lower temperature	Adds ducts and dampers to control air Furnace modification	All fuels
Fuel Staging	Admit fuel in separated stages	Reduce peak combustion temperature	Extend combustion to a longer residence time at lower temperature	Adds fuel injectors to other locations Furnace modification	All fuels

NMED Exhibit 81

EXTERNAL COMBUSTION: POLLUTION PREVENTION METHODS

LESS EXCESS AIR (LEA)

Excess air flow for combustion has been correlated to the amount of NOx generated. Limiting the net excess air flow to under 2% can strongly limit NOx content of flue gas. Although there are fuel-rich and fuel-lean zones in the combustion region, the overall net excess air is limited when using this approach.[43]

BURNERS OUT OF SERVICE (BOOS)

Multiple-burner equipment can have part of an array of burners with some "burners out of service" (not feeding fuel, but supplying air or flue gas). This allows the burners around them to supply fuel and air to air or flue gas flowing from the BOOS. The result is combustion by stages with temperature always lower than when all burners are in service. Thus, thermal NOx is lower. The degree to which NOx generation is reduced depends upon the spatial relationship of the BOOS to the other burners.[44]

OVER FIRE AIR (OFA)

When primary combustion uses a fuel-rich mixture, use of OFA completes the combustion. Because the mixture is always off-stoichiometric when combustion is occurring, the temperature is held down. After all other stages of combustion, the remainder of the fuel is oxidized in the over fire air. This is usually not a grossly excessive amount of air.

LOW NOx BURNERS (LNB)

A LNB provides a stable flame that has several different zones. For example, the first zone can be primary combustion. The second zone can be Fuel Reburning (FR) with fuel added to chemically reduce NOx. The third zone can be the final combustion in low excess air to limit the temperature. There are many variations on the LNB theme of reducing NOx. The LNB has produced up to 80% DRE.[17,18, 32, 33] This can be one of the least expensive pollution prevention technologies with high DRE. LNB have had problems with designs that had flame attaching to the burners, resulting in a need for maintenance. We believe that these design problems should now be a thing of the past.

FLUE GAS RECIRCULATION (FGR)

Recirculation of cooled flue gas reduces temperature by diluting the oxygen content of combustion air and by causing heat to be diluted in a greater mass of flue gas. Heat in the flue gas can be recovered by a heat exchanger. This reduction of temperature lowers the NOx concentration that is generated. If combustion temperature is held down to below 1,400 °F, the thermal NOx formation will be negligible.[50]

NMED Exhibit 81

WATER OR STEAM INJECTION

Injection of water or steam causes the stoichiometry of the mixture to be changed and adds steam to dilute calories generated by combustion. Both of these actions cause combustion temperature to be lower. If temperature is sufficiently reduced, thermal NOx will not be formed in as great a concentration.

REDUCED AIR PREHEAT

Air is usually preheated to cool the flue gases, reduce the heat losses, and gain efficiency. However, this can raise the temperature of combustion air to a level where NOx forms more readily. By reducing air preheat, the combustion temperature is lowered and NOx formation is suppressed. This can lower efficiency, but can limit NOx generation.

FUEL REBURNING (FR)

Recirculation of cooled flue gas with added fuel (this can be natural gas, pulverized coal, or even oil spray) causes dilution of calories, similar to FGR, and primary combustion temperature can be lowered. Also, when added as a secondary combustion stage, the presence of added fuel chemically reduces newly generated NOx to molecular nitrogen. Added fuel is only partially consumed in reducing NOx and burning is completed in a later stage using either combustion air nozzles or over-fire-air. This technique has been demonstrated to be effective with residence times from 0.2 seconds to 1.2 seconds and has achieved up to 76% DRE. [17]

COMBUSTION OPTIMIZATION

Combustion optimization refers to the active control of combustion. In a natural gas fired boiler, by decreasing combustion efficiency from 100% to 99%, NOx generation dropped to a much more acceptable level.[14,15] For coal-fired boilers a 20% to 60% reduction in NOx has been experienced. These active combustion control measures seek to find an optimum combustion efficiency and to control combustion (and hence emissions) at that efficiency. Another approach uses a neural network computer program to find the optimum control point.[16] Still another approach is to use software to optimize inputs for the defined output.[52,53]

One vendor decreases the amount of air that is pre-mixed with fuel from the stoichiometric ratio (ratio that produces the hottest flame) to lengthen the flame at the burner and reduce the rate of heat release per unit volume. This can work where the boiler tubes are far enough away from the burner. Carbon monoxide, unburned fuel, and partially burned fuel that result can then be subsequently oxidized in over-fire-air at a lower temperature. Combustion must be optimized for the conditions that are encountered. 50% DRE has been reported.[14]

AIR STAGING

Combustion air is divided into two streams. The first stream is mixed with fuel in a ratio that

NMED Exhibit 81

produces a reducing flame. The second stream is injected downstream of the flame and makes the net ratio slightly excess air compared to the stoichiometric ratio. DRE up to 99% have been reported.[51]

FUEL STAGING

This is staging of combustion using fuel instead of the air. Fuel is divided into two streams. The first stream feeds primary combustion that operates in a reducing fuel to air ratio. The second stream is injected downstream of primary combustion, causing the net fuel to air ratio to be only slightly oxidizing. Excess fuel in primary combustion dilutes heat to reduce temperature. The second stream oxidizes the fuel while reducing the NOx to N_2. This is reported to achieve a 50% DRE.[51]

OXYGEN INSTEAD OF AIR FOR COMBUSTION

An example of this is a cyclone burner where the flame is short and intense. Excess fuel air or steam, injected just after the combustion chamber per Method 2 is sufficient to rapidly quench the flue gas to below NOx formation temperature. Combustion can then be completed in over-fire air. Oxygen can now be separated from air at a low enough cost to make this economical.[13] This technique has reduced NOx by up to 20%[23] in burners using conventional fuel. This technique also is usable with low-NOx burners to prevent the prompt NOx from being formed.

INJECTION OF OXIDANT

The oxidation of nitrogen to its higher valence states makes NOx soluble in water. When this is done a gas absorber can be effective. Oxidants that have been injected into the air flow are ozone, ionized oxygen, or hydrogen peroxide. Non-thermal plasma generates oxygen ions within the air flow to achieve this. Other oxidants have to be injected and mixed in the flow. Nitric acid can be absorbed by water, hydrogen peroxide, or an alkaline fluid. Calcium or ammonia dissolved in the water can make an alkaline fluid that will react with nitric and sulfuric acids to produce a nitrate or sulfate salt that can be recovered. Alternatively, using water or hydrogen peroxide to absorb NOx can provide nitric acid for the commercial market.

CATALYTIC COMBUSTION

Use of a catalyst to cause combustion to occur below NO formation temperatures can provide a suitable means of limiting temperature. This technique is not used often because it is very load sensitive. However, where it is used, catalytic combustion can achieve less than a 1 ppm concentration of NOx in the flue gas.

ULTRA-LOW NITROGEN FUELS

These fuels can avoid NOx that results from nitrogen contained in conventional fuels. The result can be up to a 70% reduction in NOx emissions.[43] Now there are ultra-low-nitrogen liquid fuel

oils. These oils contain 15-20 times less nitrogen than standard No. 2 fuel oil. This oil is now commercially available and competitively priced. Ultra-low-nitrogen oil is most frequently used in Southern California where the air pollution is particularly a problem. Natural gas can be considered a low-nitrogen fuel. Coke (the quenched char from coal) can also be an ultra-low-nitrogen fuel because nitrogen in the volatile fraction of the coal is removed in making coke.

NON-THERMAL PLASMA

Using methane and hexane as reducing agents, non-thermal plasma has been shown to remove NOx in a laboratory setting with a reactor duct only 2 feet long. The reducing agents were ionized by a transient high voltage that created a non-thermal plasma. The ionized reducing agents reacted with NOx and achieved a 94% DRE. There are indications that an even higher DRE can be achieved. A successful commercial vendor uses ammonia as a reducing agent to react with NOx in an electron beam generated plasma. Such a short reactor can meet available space requirements for virtually any plant. The non-thermal plasma reactor could also be used without reducing agent to generate ozone and use that ozone to raise the valence of nitrogen for subsequent absorption as nitric acid.

EXTERNAL COMBUSTION: ADD-ON CONTROL TECHNOLOGY

Add-on controls are applicable to a broad range of sources and fuels. This differs from the pollution prevention techniques listed above in that the prevention techniques must be adapted to the circumstances of their use.

SELECTIVE CATALYTIC REDUCTION (SCR)

SCR uses a catalyst to react injected ammonia to chemically reduce NOx. It can achieve up to a 94% DRE[34] and is one of the most effective NOx abatement techniques. However, this technology has a high initial cost. In addition, catalysts have a finite life in flue gas and some ammonia "slips through" without being reacted. SCR has historically used precious metal catalysts, but can now also use base-metal and zeolite catalysts. The base-metal and zeolite catalysts operate at much different temperatures then the precious metal catalysts.[11]

SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR ammonia or urea is injected within a boiler or in ducts in a region where temperature is between 900°C and 1100°C. This technology is based on temperature ionizing the ammonia or urea instead of using a catalyst or non-thermal plasma. This temperature "window" – which is reported differently by various authors -- is important because outside of it either more ammonia "slips" through or more NOx is generated than is being chemically reduced. The temperature "window" is different for urea and ammonia. Reduction of the NOx by SNCR can have up to a 70% DRE.[23,35,43]

NMED Exhibit 81

SORPTION – BOTH ADSORPTION AND ABSORPTION

Several methods are used to inject and remove adsorbent or absorbent. One method sprays dry powdered limestone into the flue gas. The limestone then reacts with both sulfuric acid and nitric acid. There also is a spray dryer approach that sprays a slurry of powdered limestone and aqueous ammonia into the flue gas. The limestone preferentially reacts with the sulfur while the ammonia preferentially reacts with the NOx. In-duct injection of dry sorbents is another example of this technique and can reduce pollutants in three stages: (1) in the combustion chamber, (2) in the flue gas duct leading to the baghouse, and (3) in the flue gas duct leading to the electrostatic precipitator. The by products formed by sorption are gypsum (calcium sulfate) that is sold to make wallboard, and ammonium nitrate that can be sold to make either an explosive or a fertilizer. Sorption is reported to have up to a 60% DRE.[23, 31] Another version uses carbon injected into the air flow to finish the capture of NOx. The carbon is captured in either the baghouse or the ESP just like other sorbents. There are many absorbents and adsorbents available.

COMBINED TECHNOLOGY APPROACHES

Very seldom is only one method or principle used alone. The choice depends upon the type of combustion system, type of boiler or other energy conversion device, and type of fuel used. Available technologies will be narrowed by consideration of turndown ratio, stability of combustion, availability or access to burners, air supply controls, fuel impurities, and cost among other factors.

There are many examples and here are a few of them. Selective catalytic reduction of NOx to N_2 can be followed by selective oxidation of sulfur dioxide to sulfur trioxide. Then sulfuric acid is formed followed by scrubbing sulfuric acid from the flue gas.[30]

LNB can be used in conjunction with SCR or SNCR to achieve a greater overall DRE than any of these can achieve alone. Water/steam injection can be used with SCR to achieve a DRE greater than SCR can achieve alone. Fuel reburning and SCR can be used together as well as separately, to get the maximum NOx reduction.[57]

INTERNAL COMBUSTION

Now we turn to internal combustion, which usually occurs at elevated pressures. Again, we divide the technologies between pollution prevention techniques and add-on technologies. This is shown in Table 4.

These techniques can be used in combination. Pollution prevention techniques do not have to be used separately. Add-on techniques could be used sequentially after a pollution prevention technique when they do not impose conflicting demands on the process.

NMED Exhibit 81

Table 4. Internal Combustion NOx Limiting Technologies

Pollution Prevention	Add-On Control
Low-NOx Burners (LNB)	Selective Catalytic Reduction (SCR)
Steam/Water Injection	Selective Non-Catalytic Reduction (SNCR)
Catalytic Combustion	Non-Selective Catalytic Reduction (NSCR)
Air-Fuel Ratio and Ignition Type	Non-Thermal Plasma
Pre-Stratified Charge	
Lean Burn	

INTERNAL COMBUSTION: POLLUTION PREVENTION METHODS

LOW NOx BURNERS (LNB)

Combining the use of LNB with closely controlled air/fuel ratio and water/steam injection can yield emissions as low as 10 ppm from gas turbines.[46]

STEAM/ WATER INJECTION

To reduce combustion temperature, steam or water can be mixed with the air flow. This lowers combustion temperature to below 1,400°F to limit NOx generation to about 40 ppm.[46] This can cause the concentration of CO and unburned hydrocarbons emitted from a turbine to be increased. However, these can be burned by either a catalyst bed, afterburner, or another stage of combustion. This otherwise wasted fuel and heat can also be recovered in co-generation boilers.

CATALYTIC COMBUSTION

A catalyst is used to react fuel with air at a lower temperature than normal combustion at which generation of significant amounts of NOx does not occur. Emissions under 1 ppm NOx have been reported.[46] However, if this combustion is for a turbine, turbine efficiency may depend upon achieving a higher temperature. When a catalyst is present, you also need to assure that NOx will not be formed at the combustion temperature that results.

This technology has a relatively high capital and operation and maintenance cost because there is both a substantial initial investment and a replacement cost for the catalyst. The need for replacement and, therefore, replacement cost are usually driven by impurities in the fuel. However, catalytic combustion generates possibly the lowest level of thermal NOx.

AIR-FUEL RATIO AND IGNITION TYPE

For internal combustion reciprocating engines, retardation of injection or spark ignition, or an air-fuel ratio that departs from stoichiometric conditions will reduce peak temperature. Lower peak temperature will limit the amount of NOx formation. This technique can achieve up to 50% control efficiency.[19, 48]

When a three-way catalyst is used for spark ignition engines, exhaust gas must have no more than 0.5% oxygen. This technique can be up to 98% effective.

The use of plasma ignition (an alternating current or AC system) instead of a direct current (DC) spark ignition system can also allow a greater fuel-lean departure from the stoichiometric ratio. NOx emissions from internal combustion engines using plasma ignition have been reported to be reduced by up to 97%.[20,21, 45]

Delaying injection of fuel in a compression ignition (diesel) engine can reduce the NOx emissions. The amount of this reduction will depend upon the engine, valving, and fuel. Excessive timing retard can cause combustion instability or misfire.[48] However, some claims of high effectiveness are to be found with ostensibly excessive retard.

PRE-STRATIFIED CHARGE (PSC)

PSC refers to an engine equipped with a pre-combustion chamber that receives a rich enough air/fuel mixture to ignite dependably. This pre-combustion chamber fires a jet of flame into the main combustion chamber (cylinder). The main combustion chamber has a fuel-lean mixture that needs pre-combustion flame to ignite it reliably. The injected flame also produces a swirl in the main combustion chamber that acts like stratified charge combustion. This dependably ignites the lean main cylinder mixture. The PSC can achieve NOx emissions of 2 grams/horsepower-hour (g/hp-hr) or 140 ppm.[48]

LEAN BURN

Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NOx emissions. These can achieve less than 1.0 gram/brake horsepower-hour according to the RACT-BACT-LAER Clearinghouse (RBLC) (http://www.epa.gov/ttn/catc, then select RBLC).

INTERNAL COMBUSTION ADD-ON CONTROL TECHNOLOGY

SELECTIVE CATALYTIC REDUCTION (SCR)

As with boilers, SCR can be used to obtain up to a 90% DRE of NOx. When used with a LNB or steam/water injection, NOx can be reduced to 5-10 ppm.[46] With compression ignition engines, zeolite catalysts achieve a DRE of 90+%, while base-metal catalysts can achieve a 80% to 90% DRE.[48]

NON-SELECTIVE CATALYTIC REDUCTION (NSCR)

NSCR is the same technique used in automobile applications as a three-way catalytic converter. It does not require injection of a reducing agent because it uses unburned hydrocarbons as a reducing agent. The catalyst requires that exhaust have no more than 0.5% oxygen. This technique uses a fuel rich mixture that, combined with back pressure from exhaust flow through the catalyst, increases the brake specific fuel consumption of the engine. However, NOx control of 90% to 98% can be achieved.[48]

NON-THERMAL PLASMA REACTORS

This approach uses a non-thermal plasma to ionize ammonia, urea, hexane, methane or other reducing agents injected into a flue gas. Combined with the effect of temperature, non-thermal plasma ionizes the reducing agent that reacts with nitrogen oxides achieving a 94% DRE. This decreases the amount of reducing chemicals that "slips" through unreacted.[20,44] The use of non-thermal plasma was developed to ionize pollutants and act as a catalyst to control NOx in diesel exhaust.[36]

DO FUELS AND COMBUSTION TYPE AFFECT ABATEMENT?

Yes they do. Here again, we find a spectrum of types, almost enough to make every gas turbine, internal combustion engine, boiler, or furnace seem unique. The type of fuel can vary with the vein of the mine from which coal was obtained, the well in the oilfield from which crude oil came, the refinery for petroleum based fuels, or the supplier of natural gas. Thus the concentration of impurities will vary between sources, refineries, and suppliers. Even "natural gas" (methane) may contain some "supplier gas" (propane, butane, and carbon monoxide) which will cause the composition of "natural gas" to vary.

The type of combustion system (low-NOx burner, over-fire air, tangential firing, wall firing, etc) also will sometimes limit options. Each type of boiler, each type of fuel, each combustion system, and each construction of a boiler puts constraints on what is possible. It is not possible to treat each combination of combustion system and fuel in detail in this Technical Bulletin; however, we will try to show the picture while painting with broad strokes.

The choice of fuel and combustion system often depends upon: (1) what can or cannot be adjusted; (2) whether ducts are suitable for sorption; (3) what the effect on boiler maintenance will be; (4) the temperature profile in the flow: (5) how the combustion system can be modified; (6) what types of burners can be used; and (7) what can either be added or modified. The list does not end there, but continues. Let us consider some fuels with these limitations in mind.

SOLID FUELS

In burning a solid fuel (such as coal), combustion control is achieved by first getting the primary burner to gasify the volatile fraction of a fuel. The volatile fraction is carried away from char by

NMED Exhibit 81

air flow, oxidized in the air flow, and becomes flue gas. Char needs more combustion air to burn and provide further heat, part of which is used to volatilize additional fuel. To control combustion temperature, you traditionally would limit combustion air through the char fraction. The volatile fraction is oxidized in over-fire-air or a secondary stage of burner and must have its air separately controlled. The balance of combustion air between these stages must be adjusted for composition of fuel being used, boiler loading, and transient loads. Because all of these parameters will vary continually, provisions to make balancing adjustments dynamically are recommended.

Pulverized coal can be burned similar to oil. The flame is usually well defined and, depending on particle size, char may remain in suspension in flue gas throughout burning. The volatile fraction burns in air even as char is burned. If the particles are too coarse, char will continue burning on its trajectory after leaving the flame, but will stop burning at some point. The trade jargon for this is " unburned carbon (UBC)," "carbon in the ash (CIA)," or "loss of ignition (LOI)." These terms refer to carbon in char that does not burn along the trajectory. UBC is minimized by grinding particles finer and classifying particles so that larger ones are returned to the roller mill or grinder. Particles will become fly ash if they are small enough. UBC ranging from 0.5% to 5% is considered acceptable. Therefore, particle size at ignition is important. The major concerns are to control stoichiometry and combustion temperature to minimize unburned carbon in ash.

Biomass is another solid fuel, but burning biomass char is less of a concern than with coal. Biomass cannot be pulverized to small particles, but can burn to ash in a short time. As with the burning of all char, ash and fly ash are problems, but can be treated with a slag tap or ash pit, baghouse, and/or electrostatic precipitator.

LIQUID FUELS

Liquid fuels burn like the volatile fraction of solid fuel provided that the droplets are small enough. Liquid fuels usually have less nitrogen content than solid fuels. Combustion of liquids and gases can be controlled much more readily than char from solid fuel because combustion is less dependent on the history of the past few minutes of demand. Combustion is also completed essentially without residual ash. The fuel-air ratio can be used to control combustion temperature and can be adjusted to minimize NOx generation. The flame can be well-defined and combustion is essentially completed within the flame. Therefore, burning oil or liquid-from-coal or liquid-from-gas is different from burning coal because there is usually less nitrogen in the fuel, a lack of char, complete burning within the flame and a lack of ash.

SEMI-SOLID FUELS

Semi-solid fuels are residuals from refineries. They are not clean burning like distillates and often are not even liquid at room temperature. Many impurities typically found in crude oil are concentrated in semi-solid residual fuel. These fuels can contain more nitrogen than coal, but usually contain less sulfur.[50] Therefore, semi-solid fuels are intermediate between coal and oil. They often have somewhat less impurities than coal (although they can have more impurities),

NMED Exhibit 81

but they do produce ash.

GAS FUEL

Natural gas is desulfurized before it is sent in a pipeline. Therefore, natural gas has almost no sulfur, essentially no impurities, and no ash. The only thing that varies is heat content per cubic meter. This variance is caused by natural gas producers supplementing natural gas with propane, liquified petroleum gas (butane), carbon monoxide, or other gaseous fuel. As a result, air to fuel ratio must be controllable to allow for changes in the stoichiometric ratio.

COMBUSTION SYSTEMS

To take advantage of a specific NOx abatement technology, a combustion system must either have certain features in place, or needed system modifications must be technically and economically feasible. Therefore, when identifying applicable pollution prevention and emission control technologies, we must first consider combustion system design. The major types of combustion systems are shown in Table 5.[23]

Table 5. Common Combustion Systems

Type of Combustion Unit	Fuel
Dry bottom boilers - wall-fired, front-fired or opposed-fired	pulverized coal, gas, or liquid
Dry bottom boilers - tangentially fired	pulverized coal, gas, or liquid
Wet bottom (slag tap) boilers - cyclone-type burners	pulverized coal, gas, or liquid
Fluidized bed	coal
Stokers with traveling grate.	crushed coal
Stokers with spreader grate	crushed coal.
Gas turbines	gas and liquid
Internal combustion engines	gas and liquid

Each NOx abatement technology has different implementations, development histories, and, therefore, commercial status. Selection of a technology must occur after an engineering study to determine technical and economic feasibility of each NOx technology. This includes how each technology can be implemented and its cost. Options may be limited by inability to adjust combustion system air flow appropriately, ducts that are at the wrong temperature, or ducts that

NMED Exhibit 81

are too short to provide adequate mixing. These problems can be solved, but may require too much modification to make them economical.

DRY BOTTOM BOILERS - WALL-FIRED, FRONT-FIRED or OPPOSED-FIRED

Dry bottom pulverized coal, gas, and liquid fuel wall-fired boilers have used low-NOx burners to inject fuel and air from lower walls. Front-fired boilers have burners on one wall. Opposed-fired boilers have burners on front and back walls. These boilers typically use methods that reduce peak temperature, reduce residence time at peak temperature, or chemically reduce NOx (Methods 1, 2 & 3). These methods are used for large utility boilers in which combustion efficiency is all-important. NOx oxidation with absorption and removal of nitrogen (Methods 4 and 5) represent newer technologies that may be applied in the future. Using a sorbent (Method 6) is already in use for some boilers. See Table 6 for NOx technologies used for dry bottom wall-fired, front-fired or opposed-fired boilers.

Table 6: NOx technologies currently used for dry bottom wall-fired, front-fired or opposed-fired boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Low NOx Burners (LNB) Combustion Optimization Burners Out Of Service (BOOS) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR) Low NOx Burners (LNB)	35-90%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

NMED Exhibit 81

DRY BOTTOM BOILERS - TANGENTIALLY FIRED

Dry bottom pulverized coal, gas, or liquid fuel tangentially-fired boilers use jets from each corner of a furnace to inject fuel and combustion air in a swirl. The injected mix of fuel and combustion air forms a fireball in the center of the boiler. This firing configuration is used in medium sized utility and large industrial boilers. This combustion technique holds flame temperatures down (Method 1). In addition, chemical reduction of NOx (Method 3) is frequently used. NOx oxidation (Method 4) techniques may be used in the future. Sorbents (Method 6) are already used for some boilers. See Table 7 for NOx technologies used for dry bottom tangentially fired boilers.

Table 7: NOx technologies currently used for dry bottom tangentially fired boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

WET BOTTOM (SLAG TAP) BOILERS

Wet bottom (slag tap) boilers use cyclone burners to create an intense flame. The flame is so hot that it melts ash, which then becomes slag that must be removed via a slag tap. These boilers are known to have higher NOx generation because combustion temperature is so high. As a result, this high temperature combustion technique is not widely used because the NOx concentration necessarily must be greater. Removal of non-fuel nitrogen as a reactant from the combustion process (Method 5) applies here. Reducing residence time at peak temperature, chemical

reduction of NOx, and NOx oxidation with absorption (Methods 2, 3 & 4) also apply to this combustion system. In addition, some slag tap boilers may be using sorbents (Method 6). There are recent reports that reducing peak temperature (Method 1) so that ash just melts has been used. See Table 8 for NOx technologies used for slag tap boilers.

Table 8: NOx technologies currently used for wet bottom (slag tap) boilers.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	30-70%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	20-50%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Use Oxygen Instead Of Air Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

FLUIDIZED BED

Fluidized bed combustion occurs in a bed of crushed coal that has air flowing upward through it to make coal particles behave like a fluid. Boiler pipes can be either submerged in the bed or exposed to the hot gases after they leave the bed. The fluidized bed is temperature controlled (Method 1). The bed also is a chemically reducing region in which available oxygen is consumed by carbon (Method 3) that reduces ionization of nitrogen. Excess air is injected (Method 2) over the fluidized bed to complete combustion of CO and other burnables. This allows for the addition of pulverized limestone (Method 6) to coal in the fluidized bed. Sulfur oxides then react with the limestone to form gypsum, a marketable product. Gypsum must be separated from the ash. As a result, NOx generation can be essentially limited to prompt NOx and fuel NOx. See Table 9 for NOx technologies used for fluidized bed combustion units.

NMED Exhibit 81

Table 9: NOx techniques currently used for fluidized bed combustion.

NOx Abatement Method	Techniques Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Over Fire Air (OFA) Less Excess Air (LEA) Reduced Air Preheat	No Data
2.Reducing residence time at peak temperature	Inject Steam	No Data
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction(SNCR) Fuel Reburning (FR)	35-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

STOKERS WITH TRAVELING GRATE

Stokers with traveling grate cause the coal to move as it burns. Thus, char combustion is in one zone while volatiles are liberated and combusted in another zone. These stokers are commonly used with industrial boilers that are smaller than utility boilers. Reducing peak temperature, chemical reduction of NOx, and sorbents (Methods 1, 3 & 6) usually are applied. Perhaps NOx oxidation (Method 4) also will apply in the future. See Table 10 for NOx technologies used for stokers with traveling grates.

STOKERS WITH SPREADERS

Stokers with spreaders throw coal over the grate in a controlled manner. Coal is crushed, but particles are typically larger than pulverized coal. Therefore, combustion of volatiles begins while coal is in flight and combustion of char occurs on the grate. This system is used with somewhat larger boilers than stokers with traveling grates. It can be used in power plants, but this combustion system is used mainly for industrial boilers. Like stokers with traveling grates, reducing peak temperature, chemical reduction of NOx, and sorbents (Methods 1, 3, and 6) usually are applied. Perhaps NOx oxidation (Method 4) also will apply in the future. See Table 11 for NOx technologies used for stokers with Spreader grates.

NMED Exhibit 81

Table 10: NOx technologies currently used for stokers with traveling grates.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Combustion Optimization Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	35-50%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion	50-70%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	55-80%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

GAS TURBINES

Gas turbines use the Brayton Cycle with a burner to raise temperature of gas after compression and before expansion through the turbine. Turbines mainly use reducing peak temperature and reducing residence time (Methods 1 and 2) approaches to limit NOx emissions. Because addition of particles to air flow entering the turbine would accelerate erosion of turbine blades, sorbents (Method 6) could only be applied after the expansion in the turbine. NOx reduction (Method 3) has been used to treat exhaust gases. Many turbine operators claim that they use "good combustion practices" that do reduce the particles that produce visible emissions (which they equate with pollution), but say nothing about the NOx emissions which are not visible.

Cogeneration units use a gas turbine to generate electricity and provide preheated combustion air for a boiler. Gas turbine exhaust is typically 10-15% oxygen and can be used to provide combustion air for a low pressure boiler. That boiler can be used to provide steam for another turbine, a process heater, a space heater, or some combination of these. If a steam turbine is used to generate electricity, it may constrain what can be done. Sorbent particles can be introduced to a flow after it leaves a gas turbine in order to control NOx. There has also been some success in reducing NOx concentrations when burning biomass fuels in a boiler. See Table 12 for NOx technologies used for gas turbines.

NMED Exhibit 81

Table 11: NOx technologies currently used for stokers with spreader grates.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Flue Gas Recirculation (FGR) Natural Gas Reburning (NGR) Low NOx Burners (LNB) Combustion Optimization Over Fire Air (OFA) Less Excess Air (LEA) Inject Water or Steam Reduced Air Preheat	50-65%
2.Reducing residence time at peak temperature	Air Staging of Combustion Fuel Staging of Combustion Inject Steam	50-65%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR)	35-80%
4. Oxidation of NOx with subsequent absorption	Inject Oxidant Non-Thermal Plasma Reactor (NTPR)	60-80%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Combustion Chambers Sorbent In Ducts	60-90%

INTERNAL COMBUSTION RECIPROCATING ENGINES

Internal combustion engines use air-to-fuel ratio and ignition/injection timing to control maximum temperature and residence time. This can reduce the concentration of NOx that is generated by reducing peak temperature (Method 1). Valve timing adjustments can reduce residence time at peak temperature (Method 2) to control NOx formation. Chemical reduction of NOx (Method 3) is used in catalytic converters to reduce NOx to N_2. Some stationary engines use both Method 3 and NOx oxidation (Method 4). A non-thermal plasma reactor was developed for treatment of diesel exhaust, but is not yet marketed to our knowledge. A plasma ignition system allows greater freedom in the air-fuel ratio and the ignition timing of spark ignition engines. See Table 13 for NOx technologies used for stationary internal combustion engines.

WHAT DOES NOx ABATEMENT AND CONTROL COST?

The cost of NOx abatement and control has been changing rapidly with dramatic reductions in recent years. Table 14 gives the 1993 cost as given in the Alternative Control Techniques

NMED Exhibit 81

Table 12: NOx technologies currently used for gas turbines.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Natural Gas Reburning (NGR) Low NOx Burners (LNB) Inject Water or Steam Reduced Air Preheat Catalytic Combustion	70-85%
2.Reducing residence time at peak temperature	Air Staging of Combustion Inject Steam	70-80%
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Fuel Reburning (FR) Low NOx Burners (LNB)	70-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	No Data
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Ducts	60-90%

Table 13: NOx technologies currently used for stationary internal combustion engines.

NOx Abatement Method	Technique Now Available	Efficiency
1. Reducing peak temperature	Air/fuel Ratio Timing of Ignition/Type of Ignition Pre-Stratified Combustion	20-97%
2.Reducing residence time at peak temperature	Valve Timing	No Data
3. Chemical reduction of NOx	Selective Catalytic Reduction (SCR) Non-Selective Catalytic Reduction (NCSR)	80-90%
4. Oxidation of NOx with subsequent absorption	Non-Thermal Plasma Reactor (NTPR)	80-95%
5. Removal of nitrogen	Ultra-Low Nitrogen Fuel	No Data
6. Using a sorbent	Sorbent In Exhaust Ducts Adsorber in fixed Bed	60-90%

NMED Exhibit 81

Table 14. 1993 Costs of NOx Controls

	Cost of NOx Controls in 1993 Dollars					
Control Device	Low -Cap. $/MMBTU	High -Cap. $/MMBTU	Low - Oper. $/MMBTU	High -Oper. $/MMBTU	Low $/ton	High $/ton
LNB	650	8,300	340	1,500	240	4,300
LNB + FGR					650	7,630
SNCR	1,600	3,300	680	1,200	N/A	N/A
(1994 ESTIMATE)					700	1,300
SCR	2,400	20,000	1,500	5,800	1,810	10,900
(1994 ESTIMATE)					500	2,800

Document NOx Emissions from Industrial/Commercial/Institutional Boilers (EPA 453/R-94-022).
The EPA Region III Low-NOx Control Technology Study in 1994 said that low-NOx burners had both beneficial effects on operating costs and detrimental effects on the burners, their life expectancy, and the boilers in which they were installed. Coal quality and some boiler designs caused NOx to remain high even after low-NOx burners were in place. Capital costs ranged from $1.91 to $54.24 per kW. Operating costs ranged from $-23,000 (a profit) to $1,113,750 per year. Thus, no reliable cost estimates could be obtained regarding low-NOx burner operation. Coal quality, boiler capacity, and burner design were among the variables influencing this cost. Many plants could not even give an estimate. SNCR cost between $700 and $1,300 per ton of NOx reduced. SCR cost between $500 and $2,800 per ton of NOx reduced.[25] However, cost per ton of NOx removed for all technologies is apparently becoming smaller.

These costs vary by control technique; type of fuel; grade of fuel; size of boiler, engine or turbine; type of boiler, or turbine; and other factors. Other costs were also changing with time. Therefore you need to examine the costs of these NOx control technologies for a specific application and at a particular time.

These preliminary cost estimates will also be further reduced as operating experience is gained, competition sharpens, and design iterations eliminate the high-maintenance or life-shortening features. Confidence in this view of the future is based upon reports that some users of low-NOx burners had already seen in 1994 that operating costs could be reduced to make the changeover yield a net profit. SCR and SNCR costs may also have declined further, since there is now competition for these technologies.

NMED Exhibit 81

This analysis was supported by 1997 cost figures. These are presented in Table 15. This table is from the Analyzing Electric Power Generation Under the CAAA [26]. It appears that competition and improved designs are still driving the costs downward. The Table was presented in that publication and is presented here for your convenience.

Table 15. 1997 Costs of NOx Controls

Analyzing Electric Power Generation Under the CAAA -- Cost Estimates[26]					
Boiler Type	Control Type	Capital Cost	Fixed O & M	Variable O& M	% Control
		$/kW	$/kW/yr	mils/kWh	
Wall Fired	LNB w/o OFA	16.8	0.25	0.05	67.5
Wall Fired	LNB w/ OFA	22.8	0.35	0.07	67.5
Tang-Fired	LNB w/ OFA	32.3	0.49	0	47.3
Tang-Fired LNB w/ SOFA		34.7	0.53	0	52.3
Tang Fired LNB w/ BOFA		46.7	0.71	0.02	57.3
Cell Burners	Non Plug-In Comb. Ctl.	22.8	0.34	0.07	60
Cyclone	Coal Reburning	70.7	1.07	0.25	50
Wet Bottom	NOx Comb. Ctl.	9.6	0.14	0.05	50
Vert. Fired	NOx Comb. Ctl.	10.8	0.17	0.05	40
	SCR -Low NOx Rate	69.7	6.12	0.24	70
	SCR- High NOx Rate	71.8	6.38	0.4	80
	SNCR-Low NOx Rate	16.6	0.24	0.82	40
	SNCR-Cyclone	9.6	0.14	1.27	35
	SNCR-High NOx Rate	19	0.29	0.88	35
	Nat.Gas Reburn-Low	32.4	0.49		40
	Nat.Gas Reburn-High	32.4	0.49		50

Note that in Table 8 the following acronyms are used:

LNB is low-NOx burner
OFA is closed coupled overfire air
SOFA is separate over fire air
BOFA is both close coupled and over fire air
Comb. Ctl. is combined controls

The Institute of Clean Air Companies also suggests that in 1999 SCR will cost $50 - $80 per kW for retrofit to units, which relates to $400-$1800 per ton of NOx that is destroyed.[34] Their cost estimate for SNCR ranges from $5-$15 per kW, which relates to $400-$2000 per ton of NOx that is destroyed.[35] Cost-effectiveness does not correlate with boiler capacity alone - other variables such as type and quality of fuel, type of boiler, SNCR/SCR design, etc enter into the analysis.

While the "Performance of Selective Catalytic Reduction on Coal-fired Steam Generating Units" study was for Germany, it cited a recent cost range for SCR from $52 to $77 per kW with retrofit units tending to have lower costs. Thus, the costs in Germany were very similar to costs in the U.S.A., except that retrofit costs usually are greater in the United States.

Table 16, Unit Costs for NOx control Technologies for Non-Utility Stationary Sources, is from the report "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis." The report was prepared for EPA by the Pechan-Avanti Group. It indicates efficiencies and cost estimates for various NOx technologies for the year 2007. This appears to be a conservative estimate of efficiency and cost. Efficiencies indicated in the table tend to be lower than currently demonstrated efficiencies. Costs were based on historical information and, therefore, should be high estimates because NOx technology costs appear to be declining over time. The table was included here to indicate the relative efficiency and cost of NOx technologies for specific types of combustion systems.

The Alternative Control Techniques Document NOx Emissions from Stationary Reciprocating Internal Combustion Engines contains cost algorithms for the pollution prevention techniques and control technology applied to internal reciprocating engines. Costs for NOx elimination run from $250/ton to $1,300/ton for engines larger than 1,000 horsepower. For smaller engines the cost runs from $400/ton to over $3,500/ton.

ARE THESE METHODS SUFFICIENT?

YES, these methods are sufficient to meet the present goal of reducing NOx emissions 2 million tons below 1980 emissions.[47] The goal appears to be set at a level that can be achieved based on the state of NOx technology in 1996. However, we will have to see whether achieving our present goal provides the needed relief. A still more stringent set of standards may become necessary at sometime in the future.

As a high-technology nation and with a large urban and suburban population, we depend on automobiles, buses, airplanes, railroads, and trucks for transportation. We also depend upon electric power for computers, lights, air conditioning, and commerce. Therefore, we seem caught in a dilemma, for, while we depend on transportation, vehicles produce most of our NOx. While we also consume electric power as part of our market economy, electric power generation also generates over 40% of our NOx from stationary sources in 1995.[34]

We also need to generate less NOx without regard to the ionization level of the nitrogen. In 1999, we are currently not capable of doing that. Therefore, we must do the best that we can,

NMED Exhibit 81

Table 16: Unit Costs for NO_x Control Technologies for Non-Utility Stationary Sources

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
ICI Boilers - Coal/Wall	SNCR	40	1,870	1,380
ICI Boilers - Coal/Wall	LNB	50	3,490	2,600
ICI Boilers - Coal/Wall	SCR	70	2,910	2,450
ICI Boilers - Coal/FBC	SNCR - Urea	75	1,220	910
ICI Boilers - Coal/Stoker	SNCR	40	1,810	1,350
ICI Boilers - Coal/Cyclone	SNCR	35	1,480	1,110
ICI Boilers - Coal/Cyclone	Coal Reburn	50	3,730	710
ICI Boilers - Coal/Cyclone	NGR	55	3,730	710
ICI Boilers - Coal/Cyclone	SCR	80	1,840	1,560
ICI Boilers - Residual Oil	LNB	50	940	1,020
ICI Boilers - Residual Oil	SNCR	50	5,600	1,950
ICI Boilers - Residual Oil	LNB + FGR	60	2,670	920
ICI Boilers - Residual Oil	SCR	80	3,460	1,840
ICI Boilers - Distillate Oil	LNB	50	2,810	4,950
ICI Boilers - Distillate Oil	SNCR	50	10,080	3,520
ICI Boilers - Distillate Oil	LNB + FGR	60	5,960	1,810
ICI Boilers - Distillate Oil	SCR	80	6,480	3,460
ICI Boilers - Natural Gas	LNB	50	1,950	1,560
ICI Boilers - Natural Gas	SNCR	50	8,400	2,930
ICI Boilers - Natural Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Natural Gas	OT + WI	65	1,620	760
ICI Boilers - Natural Gas	SCR	80	5,190	2,770
ICI Boilers - Wood/Bark/Stoker	SNCR - Urea	55	2,090	1,430
ICI Boilers - Wood/Bark/FBC	SNCR - Ammonia	55	1,660	1,210
ICI Boilers - MSW/Stoker	SNCR - Urea	55	2,610	1,830
ICI Boilers - Process Gas	LNB	50	1,950	1,560
ICI Boilers - Process Gas	LNB + FGR	60	6,110	1,420
ICI Boilers - Process Gas	OT + WI	65	1,620	760
ICI Boilers - Process Gas	SCR	80	4,990	2,570
ICI Boilers - Coke	SNCR	40	1,870	1,380
ICI Boilers - Coke	LNB	50	3,490	2,600
ICI Boilers - Coke	SCR	70	2,910	2,450
ICI Boilers - LPG	LNB	50	2,810	4,950
ICI Boilers - LPG	SNCR	50	10,000	3,440
ICI Boilers - LPG	LNB + FGR	60	5,960	1,810
ICI Boilers - LPG	SCR	80	6,240	3,220
ICI Boilers - Bagasse	SNCR - Urea	55	2,090	1,430
ICI Boilers - Liquid Waste	LNB	50	940	1,020
ICI Boilers - Liquid Waste	SNCR	50	5,560	1,910
ICI Boilers - Liquid Waste	LNB + FGR	60	2,670	920
ICI Boilers - Liquid Waste	SCR	80	3,320	1,710
Internal Combustion Engines - Oil	IR	25	1,840	1,160

NMED Exhibit 81

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Internal Combustion Engines - Oil	SCR	80	4,690	1,850
Internal Combustion Engines - Gas	IR	20	2,430	1,320
Internal Combustion Engines - Gas	AF RATIO	20	3,730	900
Internal Combustion Engines - Gas	AF + IR	30	3,430	1,080
Internal Combustion Engines - Gas	L-E (Medium Speed)	87	890	N/A
Internal Combustion Engines - Gas	L-E (Low Speed)	87	4,000	1,500
Internal Combustion Engines - Gas	SCR	90	5,547	1,075
IC Engines - Gas, Diesel, LPG	IR	25	1,840	1,160
IC Engines - Gas, Diesel, LPG	SCR	80	4,690	1,850
Gas Turbines - Oil	Water Injection	68	3,080	1,540
Gas Turbines - Oil	SCR + Water Injection	90	4,240	1,860
Gas Turbines - Natural Gas	Water Injection	76	3,590	1,750
Gas Turbines - Natural Gas	Steam Injection	80	2,490	1,190
Gas Turbines - Natural Gas	LNB	84	1,170	240
Gas Turbines - Natural Gas	SCR + LNB	94	4,850	1,140
Gas Turbines - Natural Gas	SCR + Steam Injection	95	3,750	1,570
Gas Turbines - Natural Gas	SCR + Water Injection	95	5,040	2,060
Gas Turbines - Jet Fuel	Water Injection	68	3,080	1,540
Gas Turbines - Jet Fuel	SCR + Water Injection	90	4,240	1,860
Process Heaters - Distillate Oil	LNB	45	8,290	2,320
Process Heaters - Distillate Oil	LNB + FGR	48	10,130	4,000
Process Heaters - Distillate Oil	SNCR	60	6,210	3,230
Process Heaters - Distillate Oil	ULNB	74	5,110	1,450
Process Heaters - Distillate Oil	SCR	75	18,970	12,520
Process Heaters - Distillate Oil	LNB + SNCR	78	7,160	3,630
Process Heaters - Distillate Oil	LNB + SCR	92	18,770	10,910
Process Heaters - Residual Oil	LNB + FGR	34	8,330	3,290
Process Heaters - Residual Oil	LNB	37	6,010	1,690
Process Heaters - Residual Oil	SNCR	60	3,730	2,050
Process Heaters - Residual Oil	ULNB	73	3,080	860
Process Heaters - Residual Oil	LNB + SNCR	75	4,730	2,510
Process Heaters - Residual Oil	SCR	75	10,560	7,170
Process Heaters - Residual Oil	LNB + SCR	91	11,170	6,550
Process Heaters - Natural Gas	LNB	50	5,250	4,290
Process Heaters - Natural Gas	LNB + FGR	55	7,610	5,890
Process Heaters - Natural Gas	SNCR	60	5,560	3,740
Process Heaters - Natural Gas	ULNB	75	3,580	2,870
Process Heaters - Natural Gas	SCR	75	24,840	16,760
Process Heaters - Natural Gas	LNB + SNCR	80	6,960	5,080
Process Heaters - Natural Gas	LNB + SCR	88	23,880	16,500
Process Heaters - Process Gas	LNB	50	5,250	4,290
Process Heaters - Process Gas	LNB + FGR	55	7,610	5,890
Process Heaters - Process Gas	SNCR	60	5,560	3,740
Process Heaters - Process Gas	ULNB	75	3,580	2,870
Process Heaters - Process Gas	SCR	75	24,840	16,760
Process Heaters - Process Gas	LNB + SNCR	80	6,960	5,080
Process Heaters - Process Gas	LNB + SCR	88	23,880	16,500

NMED Exhibit 81

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Process Heaters - LPG	LNB	45	8,290	2,320
Process Heaters - LPG	LNB + FGR	48	10,130	4,000
Process Heaters - LPG	SNCR	60	6,210	3,230
Process Heaters - LPG	ULNB	74	5,110	1,450
Process Heaters - LPG	SCR	75	18,970	12,520
Process Heaters - LPG	LNB + SNCR	78	7,160	3,630
Process Heaters - LPG	LNB + SCR	92	18,770	10,910
Process Heaters - Other Fuel	LNB + FGR	34	8,330	3,290
Process Heaters - Other Fuel	LNB	37	6,010	1,690
Process Heaters - Other Fuel	SNCR	60	3,730	2,050
Process Heaters - Other Fuel	ULNB	73	3,080	860
Process Heaters - Other Fuel	LNB + SNCR	75	4,730	2,510
Process Heaters - Other Fuel	SCR	75	10,560	7,170
Process Heaters - Other Fuel	LNB + SCR	91	11,170	6,550
Adipic Acid Manufacturing	Thermal Reduction	81	1,000	1,000
Adipic Acid Manufacturing	Extended Absorption	86	210	210
Nitric Acid Manufacturing	Extended Absorption	95	840	840
Nitric Acid Manufacturing	SCR	97	1,010	1,010
Nitric Acid Manufacturing	SNCR	98	940	940
Glass Manufacturing - Container	Electric Boost	10	17,050	17,050
Glass Manufacturing - Container	Cullet Preheat	25	2,240	2,240
Glass Manufacturing - Container	LNB	40	4,040	4,040
Glass Manufacturing - Container	SNCR	40	3,320	3,320
Glass Manufacturing - Container	SCR	75	4,550	4,550
Glass Manufacturing - Container	OXY-Firing	85	10,960	10,960
Glass Manufacturing - Flat	Electric Boost	10	5,540	5,540
Glass Manufacturing - Flat	LNB	40	1,660	1,660
Glass Manufacturing - Flat	SNCR	40	1,380	1,380
Glass Manufacturing - Flat	SCR	75	1,490	1,490
Glass Manufacturing - Flat	OXY-Firing	85	4,530	4,530
Glass Manufacturing - Pressed	Electric Boost	10	20,910	20,910
Glass Manufacturing - Pressed	Cullet Preheat	25	1,930	1,930
Glass Manufacturing - Pressed	LNB	40	3,570	3,570
Glass Manufacturing - Pressed	SNCR	40	3,080	3,080
Glass Manufacturing - Pressed	SCR	75	5,170	5,170
Glass Manufacturing - Pressed	OXY-Firing	85	9,310	9,310
Cement Manufacturing - Dry	Mid-Kiln Firing	30	1,110	1,110
Cement Manufacturing - Dry	LNB	30	1,340	1,340
Cement Manufacturing - Dry	SNCR - Urea Based	50	1,280	1,280
Cement Manufacturing - Dry	SNCR - NH3 Based	50	1,490	1,490
Cement Manufacturing - Dry	SCR	80	6,850	6,850
Cement Manufacturing - Wet	Mid-Kiln Firing	30	1,010	1,010
Cement Manufacturing - Wet	LNB	30	1,260	1,260
Cement Manufacturing - Wet	SCR	80	5,840	5,840
Iron & Steel Mills - Reheating	LEA	13	3,160	3,160
Iron & Steel Mills - Reheating	LNB	66	720	720
Iron & Steel Mills - Reheating	LNB + FGR	77	900	900

NMED Exhibit 81

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
Iron & Steel Mills - Annealing	LNB	50	1,350	1,350
Iron & Steel Mills - Annealing	LNB + FGR	60	1,790	1,790
Iron & Steel Mills - Annealing	SNCR	60	3,130	3,130
Iron & Steel Mills - Annealing	LNB + SNCR	80	3,460	3,460
Iron & Steel Mills - Annealing	SCR	85	8,490	8,490
Iron & Steel Mills - Annealing	LNB + SCR	90	9,070	9,070
Iron & Steel Mills - Galvanizing	LNB	50	1,170	1,170
Iron & Steel Mills - Galvanizing	LNB + FGR	60	1,370	1,370
Municipal Waste Combustors	SNCR	45	2,140	2,140
Medical Waste Incinerators	SNCR	45	8,570	8,570
Space Heaters - Distillate Oil	LNB	50	2,810	4,950
Space Heaters - Distillate Oil	SNCR	50	10,000	3,440
Space Heaters - Distillate Oil	LNB + FGR	60	5,960	1,810
Space Heaters - Distillate Oil	SCR	80	6,240	3,220
Space Heaters - Natural Gas	LNB	50	1,950	1,560
Space Heaters - Natural Gas	SNCR	50	8,330	2,860
Space Heaters - Natural Gas	LNB + FGR	60	6,110	1,420
Space Heaters - Natural Gas	OT + WI	65	1,620	760
Space Heaters - Natural Gas	SCR	80	4,990	2,570
Ammonia - NG-Fired Reformers	LNB	50	1,950	1,560
Ammonia - NG-Fired Reformers	SNCR	50	8,330	2,860
Ammonia - NG-Fired Reformers	LNB + FGR	60	6,110	1,420
Ammonia - NG-Fired Reformers	OT + WI	65	1,620	760
Ammonia - NG-Fired Reformers	SCR	80	4,990	2,570
Ammonia - Oil-Fired Reformers	LNB	50	940	1,020
Ammonia - Oil-Fired Reformers	SNCR	50	5,560	1,910
Ammonia - Oil-Fired Reformers	LNB + FGR	60	2,670	920
Ammonia - Oil-Fired Reformers	SCR	80	3,320	1,710
Lime Kilns	Mid-Kiln Firing	30	1,110	1,110
Lime Kilns	LNB	30	1,340	1,340
Lime Kilns	SNCR - Urea Based	50	1,280	1,280
Lime Kilns	SNCR - NH3 Based	50	1,490	1,490
Lime Kilns	SCR	80	6,850	6,850
Comm./Inst. Incinerators	SNCR	45	2,140	2,140
Indust. Incinerators	SNCR	45	2,140	2,140
Sulfate Pulping - Recovery Furnaces	LNB	50	1,950	1,560
Sulfate Pulping - Recovery Furnaces	SNCR	50	8,330	2,860
Sulfate Pulping - Recovery Furnaces	LNB + FGR	60	6,110	1,420
Sulfate Pulping - Recovery Furnaces	OT + WI	65	1,620	760
Sulfate Pulping - Recovery Furnaces	SCR	80	4,990	2,570
Ammonia Prod; Feedstock Desulfurization	LNB + FGR	60	6,110	1,420
Plastics Prod-Specific; (ABS) Resin	LNB + FGR	55	7,610	5,890
Starch Mfg; Combined Operations	LNB + FGR	55	7,610	5,890

NMED Exhibit 81

Source Type/Fuel Type	Control Technology	Percent Reduction (%)	Ozone Season Cost Effectiveness ($1990/ton) Small*	Large*
By-Product Coke Mfg; Oven Underfiring	SNCR	60	3,130	3,130
Pri Cop Smel; Reverb Smelt Furn	LNB + FGR	60	1,790	1,790
Iron Prod; Blast Furn; Blast Htg Stoves	LNB + FGR	77	900	900
Steel Prod; Soaking Pits	LNB + FGR	60	1,790	1,790
Fuel Fired Equip; Process Htrs; Pro Gas	LNB + FGR	55	7,610	5,890
Sec Alum Prod; Smelting Furn/Reverb	LNB	50	1,350	1,350
Steel Foundries; Heat Treating Furn	LNB	50	1,350	1,350
Fuel Fired Equip; Furnaces; Natural Gas	LNB	50	1,350	1,350
Asphaltic Conc; Rotary Dryer; Conv Plant	LNB	50	5,250	4,290
Ceramic Clay Mfg; Drying	LNB	50	5,250	4,290
Coal Cleaning-Thrml Dryer; Fluidized Bed	LNB	50	3,490	2,600
Fbrglass Mfg; Txtle-Type Fbr; Recup Furn	LNB	40	4,040	4,040
Sand/Gravel; Dryer	LNB + FGR	55	7,610	5,890
Fluid Cat Cracking Units; Cracking Unit	LNB + FGR	55	7,610	5,890
Conv Coating of Prod; Acid Cleaning Bath	LNB	50	5,250	4,290
Natural Gas Prod; Compressors	SCR	20	5,547	1,075
In-Process; Bituminous Coal; Cement Kiln	SNCR - urea based	50	1,280	1,280
In-Process; Bituminous Coal; Lime Kiln	SNCR - urea based	50	1,280	1,280
In-Process Fuel Use;Bituminous Coal; Gen	SNCR	40	1,420	1,060
In-Process Fuel Use; Residual Oil; Gen	LNB	37	6,010	1,690
In-Process Fuel Use; Natural Gas; Gen	LNB	50	5,250	4,290
In-Proc;Process Gas;Coke Oven/Blast Furn	LNB + FGR	55	7,610	5,890
In-Process; Process Gas; Coke Oven Gas	LNB	50	5,250	4,290
Surf Coat Oper;Coating Oven Htr;Nat Gas	LNB	50	5,250	4,290
Solid Waste Disp;Gov;Other Incin;Sludge	SNCR	45	2,140	2,140

NOTE: *Small source cost per ton values are used to estimate control costs for all sources with 1995 NO_x emissions below 1 ton per day. If the ozone season daily 1995 baseline NO_x value is 1 ton or more, the cost per ton value for large sources is used.
N/A = not applicable. The population of medium speed gas-fired IC engines are all considered small.

NMED Exhibit 81

and hope that we can endure while looking for the discovery and cost-reduction of the "better technology" that is capable of meeting the goal of sustainability. The reference literature suggests that the leading edge of pollution prevention and control technology in 1999 is capable of about 94%-99% control of NOx or 1 ppm-5 ppm of NOx.[27,28]

As we all know, the leading edge technology always costs more because engineering has not yet shifted from feasibility to cost-reduction, and competition in the technology is not fully developed. Therefore, we can expect technology to be more affordable with time and to also improve its capability. We should expect to see the goal change with time as the technology advances, and as the achievable goal becomes both more stringent and more economically feasible. At one time, the capabilities that we now have seemed beyond imagining, and the costs seemed prohibitive. We live in an interesting time when the NOx pollution prevention, abatement, and control technology is becoming more capable and more affordable.

CONCLUSIONS

1. Different fuels require different combustion, abatement and control techniques. Different coals have a varying content of volatile ingredients. The nitrogen content of fuel is important, as are the content of sulfur, lead, mercury and other contaminants. Ultra-low nitrogen content fuels have been developed and are already cost competitive. Thus, we can achieve some control of NOx from the lowered concentration of nitrogen in the fuel without investing in changed burner designs.[29]

2. The design of the boiler, internal combustion engine, or gas turbine has a major effect on the operation. NOx formation tends to increase with an increase in boiler capacity, because larger boilers tend to have more intense combustion with higher combustion temperatures and longer residence time for flue gases. The same appears to be true of engines and turbines.

3. Staging of the combustion is implicit in several pollution prevention techniques. Tandem application (or use of hybrid control technology) of NOx control techniques (first SNCR, then SCR in the duct, and then sorption before the ESP which is referred to as "polishing") have been used to achieve an overall reduction of 90+% in NOx and 80% in SOx, even without using low-NOx burners to lower NOx generation.

4. Combustion of natural gas and petroleum distillates can be controlled in much the same way as pulverized coal. The major differences between coal and natural gas or oil are that gas and oil: (1) generally are lower in sulfur and ash; (2) usually are lower in nitrogen; and (3) probably are lower in lead and mercury. Thus, gas and oil do not deactivate a catalyst used in Selective Catalytic Reduction (SCR) at the same rate that coal or semi-solid fuels do.

5. The semi-solid petroleum products can actually have higher levels of sulfur, nitrogen and other impurities than coal. They do not have as much char or ash as coal, but have more than the lighter distillates.

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6. We should expect the declining cost trend of control technology to continue as operating experience is gained, firing techniques are adapted to fuels, design flaws are corrected, and new designs appear. We should expect to see costs become less as they are driven down by competition between suppliers of successful technologies.

7. NOx control technology appears capable of more than just meeting EPA's present goal and this should provide emission credits that can be traded to those firms that choose to continue emitting poorly controlled emissions. The sale of these credits by those that over-corrected for the present goal should further offset any net costs in adopting these control technologies.

8. Commercially available NOx control systems are already available. The availability of these technologies was part of the basis of the recent NOx SIP Call and Title IV regulations.

9. There has been an economic incentive to make combustion more efficient and to innovate ways to control nitrogen oxides. However, the amount of time and money that must be invested for a full-scale test of a strategy is significant. Acceptance requires that a technology be tried and succeed before a larger scale test is even contemplated. This delays acceptance of improved techniques.

10. There seems to be no control technology which is clearly superior for all combustion systems, boilers, engines, or fuels. Lacking a clear winner, one must select fuels and control technology either from among those already proven, or from a growing number of new and promising ideas.

11. The end of the search for control technologies is not yet in sight, and the search must continue. Past research must of necessity give ambivalent answers, because there are so many conflicting factors. However, at under $150 per ton of NOx prevented and with up to 80% control efficiency, the low-NOx burner, where applicable, appears to be among the least expensive emission control technologies. SCR is more expensive, but can obtain up to 94% control efficiency. SNCR can be adopted without the initial cost of catalyst, although it is somewhat less effective. LNB, SCR and SNCR are all viable technologies across a wide spectrum of applications.

12. Research and development will have to continue to seek more effective answers and try to balance them against cost and efficiency. The cost will decrease as technology advances, operating experience is gained, competition becomes sharper, design flaws are corrected, and better designs become available. Reliability can only be gained with time. Cost will be reduced with time and experience. We also must expect that the level of pollution prevention and control technology effectiveness will improve with time.

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TECHNICAL REPORT DATA

(Please read Instructions on reverse before completing)

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15. SUPPLEMENTARY NOTES

For more information, call the CATC Information Line at (919) 541-0800 or access the CATC Web page at www.epa.gov/ttn/catc

16. ABSTRACT

The purpose of this document is to educate people about nitrogen oxides, how they are formed, the danger that they represent, and how emissions can be controlled. This knowledge is needed to make an informed choice of the control technology that is to be used.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
nitrous oxide, nitric oxide, nitrogen dioxide, dinitrogen pentoxide, nitrous acid, nitric acid, ozone, volatile organic compounds, VOC, generation, pollution prevention, control technology, control technologies, emission control, acid rain, combustion, boilers, gas turbines, internal combustion engines, cost of emission controls, air pollution	air pollution control technology, combustion, pollution prevention, nitrogen oxides, boilers, internal combustion engines, diesel engines	

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Utah Admin. Code 307-504-4

Current through Bulletin 2021-13, July 1, 2021

Section R307-504-4 - Tank Truck Loading Requirements

(1) Tanker trucks used for intermediate hydrocarbon liquid or produced water shall be loaded using bottom filling or a submerged fill pipe.

(2) VOC emissions during truck loading operations shall be controlled at all times using a vapor capture line. The vapor capture line shall be connected from the tanker truck to a control device or process, resulting in a minimum 95 percent VOC destruction efficiency.

(a) Well sites in operation on January 1, 2018 shall comply with R307-504-4(2) no later than July 1, 2019.

Utah Admin. Code R307-504-4

Adopted by Utah State Bulletin Number 2014-21, effective 10/7/2014

Amended by Utah State Bulletin Number 2018-7, effective 3/5/2018

IN THE UNITED STATES DISTRICT COURT
FOR THE WESTERN DISTRICT OF PENNSYLVANIA

UNITED STATES OF AMERICA, and COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION, Plaintiffs, v. MARKWEST LIBERTY MIDSTREAM & RESOURCES, L.L.C., and OHIO GATHERING COMPANY, L.L.C., Defendants.	Civil Action No. 2:18-cv-00520-LPL CONSENT DECREE

TABLE OF CONTENTS

I. JURISDICTION AND VENUE 2
II. APPLICABILITY AND SALES OR TRANSFERS OF OWNERSHIP AND OPERATION INTERESTS 3
III. DEFINITIONS 5
IV. INJUNCTIVE RELIEF 9
V. CIVIL PENALTY 14
VI. SUPPLEMENTAL ENVIRONMENTAL PROJECTS 16
VII. COMMONWEALTH-ONLY COMMUNITY ENVIRONMENTAL PROJECT 20
VIII. PERMITS 22
IX. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS 24
X. THIRD PARTY VERIFICATION 25
XI. RECORDKEEPING AND REPORTING 29
XII. STIPULATED PENALTIES 33
XIII. FORCE MAJEURE 37
XIV. DISPUTE RESOLUTION 39
XV. INFORMATION COLLECTION AND RETENTION 42
XVI. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS 44
XVII. COSTS 48
XVIII. NOTICES 48
XIX. EFFECTIVE DATE 50
XX. RETENTION OF JURISDICTION 51
XXI. MODIFICATION 51
XXII. TERMINATION 51
XXIII. PUBLIC PARTICIPATION 52
XXIV. SIGNATORIES/SERVICE 53
XXV. INTEGRATION 53
XXVI. FINAL JUDGMENT 53
XXVII. 26 U.S.C. SECTION 162(f)(2)(A)(ii) IDENTIFICATION 54
XXVIII. APPENDICES 54

WHEREAS, Plaintiffs the United States of America ("United States"), on behalf of the United States Environmental Protection Agency ("EPA"), and the Commonwealth of Pennsylvania, Department of Environmental Protection ("PADEP"), simultaneously with the lodging of this Consent Decree, filed a complaint pursuant to Section 113(b) of the Clean Air Act ("Act"), 42 U.S.C. § 7413(b). The complaint seeks injunctive relief and civil penalties for violations of the Clean Air Act's Prevention of Significant Deterioration ("PSD") provisions, 42 U.S.C. §§ 7490-7492; the Non-Attainment New Source Review ("NSR") provisions, 42 U.S.C. §§ 7501-7515; and the state implementation plans ("SIPs") adopted thereunder by the Commonwealth of Pennsylvania and the State of Ohio, and approved by EPA pursuant to Section 110 of the Act, 42 U.S.C. § 7410, at certain compressor stations and at stand-alone pigging stations ("stand-alone facilities") owned and operated by Defendants MarkWest Liberty Midstream & Resources, L.L.C. and Ohio Gathering Company, L.L.C., (collectively, "MarkWest") in the Marcellus Shale and Utica Shale formations in Pennsylvania and Ohio;

WHEREAS, PADEP is the agency of the Commonwealth of Pennsylvania charged with the implementation and enforcement of the Air Pollution Control Act, 35 P.S. § 4001 *et seq.*;

WHEREAS, MarkWest is engaged in natural gas gathering operations in western Pennsylvania and eastern Ohio;

WHEREAS, this is the first civil enforcement action brought by the United States or PADEP concerning emissions from natural gas pig launchers and receivers at compressor stations or at stand-alone facilities;

WHEREAS, MarkWest has investigated and evaluated the development, design, fabrication, and testing of new technologies for sampling and estimating volatile organic

compound ("VOC") emissions from pig launcher and receiver operations and alternatives for reducing VOC emissions from natural gas pig launchers and receivers at compressor stations and stand-alone facilities;

WHEREAS, MarkWest has undertaken numerous design enhancements of launchers and receivers at compressor stations and stand-alone facilities in Pennsylvania and Ohio that have substantially reduced VOC, methane, and ethane emissions, including the design, installation and/or operation of high-to-low pressure natural gas transfer lines, pig ramps, and liquid drains;

WHEREAS, MarkWest expressly denies and does not admit any liability to the United States or PADEP arising out of the conduct, transactions or occurrences alleged in the Complaint; and

WHEREAS, the Parties acknowledge that this Consent Decree has been negotiated by all Parties in good faith and will avoid litigation among the Parties, and the Court, by entering this Consent Decree, finds that this Consent Decree is fair, reasonable, and in the public interest.

NOW, THEREFORE, before the taking of any testimony, without the adjudication or admission of any issue of fact or law except as provided in Section I, and with the consent of the Parties,

IT IS HEREBY ADJUDGED, ORDERED, AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter of this action and over the Parties, pursuant to 28 U.S.C. §§ 1331, 1345, 1355 and 1367, and Section 113(b) of the Act, 42 U.S.C. § 7413(b). Venue is proper in this judicial district pursuant to Section 113(b) of the Act, 42 U.S.C. § 7413(b), and 28 U.S.C. §§ 1391(b) and (c), and 1395(a), because violations alleged

in the Complaint are alleged to have occurred, and MarkWest conducts business, in this judicial district. MarkWest consents to and shall not challenge entry of this Consent Decree or this Court's jurisdiction to enter and enforce this Decree, and further consents to venue in this judicial district solely for the purpose of entering and enforcing this Consent Decree.

2. For purposes of this Consent Decree, MarkWest agrees that the Complaint states claims upon which relief may be granted.

II. APPLICABILITY AND SALES OR TRANSFERS OF OWNERSHIP AND OPERATION INTERESTS

3. The obligations of this Consent Decree apply to and are binding upon the United States, PADEP, and MarkWest, and any of their respective successors or assigns, or other entities or persons otherwise bound by law.

4. In the event that MarkWest proposes to sell or transfer ownership or operation, in whole or in part, of any of the Covered Facilities, to an entity unrelated to MarkWest ("Third Party"), MarkWest shall notify the Third Party in writing of the existence of this Consent Decree prior to the closing of such sale or transfer. MarkWest shall send a copy of this written notification to the United States and PADEP pursuant to Section XVIII (Notices) prior to the proposed closing.

5. MarkWest shall condition any sale or transfer, in whole or part, of ownership or operation of any of the Covered Facilities upon the execution by the Third Party of a modification to this Consent Decree to make the terms and conditions of this Consent Decree related to the ownership or operation of the transferred Covered Facilities applicable to the Third Party. No earlier than thirty (30) Days after giving notice to a successor in interest pursuant to Paragraph 4, MarkWest may file a motion to modify this Consent Decree with the Court to make

the terms and conditions of the Consent Decree related to the ownership or operation of the transferred Covered Facilities applicable to the Third Party. MarkWest shall be released from the requirements of this Consent Decree with respect to the transferred Covered Facilities unless the Court finds that the Third Party does not have the financial or technical ability to comply with the requirements of this Consent Decree.

6. This Consent Decree shall not be construed to impede the sale or transfer of any asset or interest between MarkWest and any Third Party so long as the requirements of this Consent Decree are met.

7. Paragraphs 3-5 shall not be construed to affect or apply to mergers or other corporate transactions in which MarkWest is acquired by a Third Party and the surviving entity, by operation of law, assumes all of MarkWest's assets and liabilities pursuant to the Consent Decree relating to the Covered Facilities.

8. MarkWest shall (a) provide a copy of this Consent Decree to all officers of MarkWest and managers who will be responsible for implementation of the terms of this Consent Decree, and ensure that any employees and contractors whose duties might reasonably include compliance with any provision of this Consent Decree are made aware of those requirements of this Consent Decree that fall within such persons' duties; and (b) place an electronic version of the Consent Decree on its internal environmental website. MarkWest shall be responsible for ensuring that all employees and contractors involved in performing any work pursuant to this Consent Decree perform such work in compliance with the requirements of this Consent Decree.

9. In any action to enforce this Consent Decree, MarkWest shall not raise as a defense to liability or stipulated penalty the failure by any of its officers, directors, employees, agents, or contractors to take any actions necessary to comply with the provisions of this Consent Decree. This Section does not preclude MarkWest from holding any employee, agent, or contractor who is alleged to have not complied with this Consent Decree liable for their actions. Nothing herein shall preclude MarkWest, in an action to enforce this Consent Decree pursuant to Paragraph 78, from raising the failure of any contractor to take any actions necessary to comply with the provisions of this Consent Decree as a mitigating factor with regard to any non-injunctive relief sought.

III. DEFINITIONS

10. For purposes of this Consent Decree, every term expressly defined by this Section shall have the meaning given that term herein. Every other term used in this Decree that is defined in the Act, 42 U.S.C. § 7401 *et seq.*, or in the regulations promulgated pursuant to the Act, but not defined in this Section, shall mean in this Decree what such term means under the Act or those regulations.

a. "CD Emissions Reductions" shall mean any VOC emissions reductions that result from any projects, controls, or any other actions used to comply with this Consent Decree at any of the facilities listed on Appendices 1, 3 (with the exception of Route 18), or 4.

b. "Commercially and Operationally Appropriate" shall mean that: (1) fewer than 50% of anticipated pigging events at the pig launcher or receiver will be for pipeline inspection purposes; and (2) the costs of installing a shorter barrel at the pig launcher or receiver

would not be unreasonably disproportionate to the benefits of VOC emissions reductions achieved by use of a shorter barrel.

c. "Commercially Reasonable and Technically Feasible" shall mean that connection of a high pressure launcher or receiver to a low pressure line does not require MarkWest to: (1) use more than 100 feet of piping to achieve such a connection; (2) connect to a low pressure line located outside the fenceline of the facility where the high pressure launcher or receiver will be located; or (3) incur costs that would be unreasonably disproportionate to the benefits of VOC emissions reductions achieved by the installation and operation of such a connection to a low pressure line.

d. "Complaint" shall mean the complaint filed by the United States and PADEP in this action.

e. "Compressor Stations" shall mean the compressor stations identified in Appendices 1 and 4 to this Consent Decree.

f. "Consent Decree" or "Decree" shall mean this Decree and all appendices attached hereto (listed in Section XXVII (Appendices)).

g. "Covered Facilities" shall mean all MarkWest facilities identified in Appendices 1-5.

h. "Day" shall mean a calendar day unless expressly stated to be a business day. In computing any period of time under this Decree, where the last day would fall on a Saturday, Sunday, or federal holiday, the period shall run until the close of business of the next business day.

i. "EPA" shall mean the United States Environmental Protection Agency and any of its successor departments or agencies.

j. "Effective Date" shall have the definition provided in Section XIX (Effective Date).

k. "Flare" shall mean a combustion device used to control emissions from equipment in VOC service.

l. "Jumper Line" shall mean an enclosed piping system attached to the vent line of a pig launcher or receiver that routes the contents of a pig launcher or receiver into a lower pressure gathering system.

m. "Liquid or Residue Gas Service" shall refer to any pipelines downstream of a MarkWest processing plant that convey natural gas liquids or processed natural gas (residue gas).

n. "MarkWest" shall mean Ohio Gathering Company, L.L.C., and MarkWest Liberty Midstream & Resources, L.L.C.

o. "Mobile Flare" shall mean a trailer-mounted flare.

p. "Ohio SIP" shall mean the federally-approved State Implementation Plan ("SIP") adopted by the State of Ohio.

q. "Ohio VOC Permitting Threshold" shall mean, for Ohio air contaminant sources, actual VOC emissions exceeding 10 pounds per day from an air contaminant source, or potential VOC emissions from an air contaminant source alone or in combination with similar sources at the same facility in excess of 25 tons per year.

r. "PADEP" shall mean the Commonwealth of Pennsylvania, Department of Environmental Protection.

s. "Paragraph" shall mean a portion of this Decree identified by an Arabic numeral.

t. "Parties" shall mean the United States, PADEP, and MarkWest.

u. "Party" shall mean the United States, PADEP, or MarkWest.

v. "Pennsylvania SIP" shall mean the federally-approved State Implementation Plan ("SIP") adopted by the Commonwealth of Pennsylvania.

w. "Pigging" shall mean the process of introducing and subsequently removing a specialized device (called a "pig") into a natural gas pipeline to push liquids through the pipeline into a slug catcher and/or designated system.

x. "Pig Ramp" shall mean a device installed inside the barrel of a pig receiver designed and intended to prevent liquid accumulation in the barrel and minimize release of volatile liquids into the environment during retrieval of the pig.

y. "Project Dollars" shall mean MarkWest's direct costs incurred in implementing the Supplemental Environmental Projects identified in subparagraphs b. and c. of Paragraph 28 to the extent that such costs: (i) comply with the requirements set forth in Section VI and (ii) constitute MarkWest's direct payments associated with such projects or MarkWest's external costs for contractors, vendors, and equipment. Project Dollars shall not include MarkWest's internal personnel costs incurred to oversee the implementation of the Supplemental Environmental Projects identified in subparagraphs b. and c. of Paragraph 28.

z. "Real Gas Law" shall mean $PV = (m/M_w)RTZ$ where:

P = pressure inside the pipe (psfa) pound per square foot actual

V = actual volume of pipe (ft^3)

m = mass of material (lb)

M_w = molecular weight of the mixture (lb/lbmol)

R = universal gas constant (1545 psfa*ft3/lbmol*°R^{-1})

T = temperature of mixture (°R)

Z = compressibility factor (unitless)

Solving for mass yields: $m = PVM_w/(RTZ)$.

aa. "Section" shall mean a portion of this Decree identified by a Roman numeral.

bb. "Stand-Alone Facilities" shall mean the MarkWest sites where natural gas pig launchers and/or receivers are located that are identified in Appendices 3, 5, and 6.

cc. "System" shall mean all of MarkWest's pig launchers and receivers in Pennsylvania and Ohio.

dd. "United States" shall mean the United States of America, acting on behalf of EPA.

ee. "VOC" or "VOCs" shall mean volatile organic compounds, as defined in 40 C.F.R. § 51.100(s), and which does not include methane or ethane.

IV. INJUNCTIVE RELIEF

11. Emission Calculations. For purposes of compliance with the Consent Decree, MarkWest shall calculate the mass of VOC emissions from pigging operations at facilities listed in Appendices 1 through 5 using the Real Gas Law multiplied by a factor of 1.2.

12. Pennsylvania Compressor Stations. No later than the Effective Date, at the MarkWest Compressor Stations identified in Appendix 1, MarkWest shall:

a. connect each high pressure pig launcher and receiver by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch; and

c. install and use Pig Ramps in pig receivers.

13. Pennsylvania Compressor Station Dehydrator Flares. At the MarkWest Compressor Stations identified in Appendix 2, MarkWest shall replace existing dehydrator flares with enclosed air-assisted flares. The replacement enclosed air-assisted flare system shall include a 3 horsepower blower (with a variable frequency drive), a single point burner tip, a gas enrichment stream and shutdown/startup control logic panels, and shall raise regenerator off-gas Btu value to ensure a clean burn. These flares shall achieve a minimum 98% destruction and removal efficiency ("DRE").

14. Pennsylvania Stand-Alone Facilities. No later than the Effective Date, MarkWest shall implement those elements of injunctive relief identified in this Paragraph that apply, as specified in Appendix 3, to each specific pig launcher and receiver located at each of the MarkWest Stand-Alone Facilities identified in Appendix 3. Where applicable, MarkWest shall:

a. connect high pressure pig launchers and receivers by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch; and

c. install and use Pig Ramps in pig receivers.

15. Pennsylvania Launcher/Receiver Smith Tee Emissions Flare Replacement. At the Smith Tee Stand-Alone Facility (the location of which is identified in Appendix 3) in Pennsylvania**,** MarkWest shall replace the existing flare with a new "candlestick" flare. The replacement candlestick flare system shall be designed to (a) provide smokeless and low heat radiation flaring, (b) maintain its pilot light in winds up to 50 mph, and (c) generate a hydrocarbon gas-air mixture using an air inspirator ignition.

16. Loffert (Joe Cain) Pennsylvania Stand-Alone Facility. At the Loffert (Joe Cain) Stand-Alone Facility (the location of which is identified in Appendix 3)**,** MarkWest shall continue to operate the redesigned and modified discharge piping installed in 2016.

17. Closure of Drugmand, Stewart Route 50, and Graham Header Stations. No later than twelve (12) months after the Effective Date, MarkWest shall permanently close and cease operations of all launchers and receivers located at the Drugmand Station (located at 40.32917258600, -80.28226258100) and Stewart Route 50 Station (located at 40.28446667, -80.35458611) and all high pressure launchers and receivers located at the Graham Header Station (located at 40.83600748440, -80.08065377390). MarkWest shall permanently remove all pig launchers and receivers that are subject to this Paragraph. Until MarkWest permanently ceases operations of the referenced launchers and receivers, MarkWest shall continue to use the existing Pig Ramps, Jumper Lines, and Flares to reduce VOC emissions during pigging operations.

18. Ohio Compressor Stations. No later than the Effective Date, MarkWest shall implement those elements of injunctive relief identified in this Paragraph that apply, as specified

in Appendix 4, to each specific pig launcher and receiver located at each of the MarkWest Compressor Stations identified in Appendix 4. Where applicable, MarkWest shall:

a. connect high pressure pig launchers and receivers by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch;

c. install and use Pig Ramps in pig receivers; and

d. when necessary to ensure that VOC emissions do not exceed the Ohio VOC Permitting Threshold, use a Mobile Flare to control VOC emissions.

19. Ohio Stand-Alone Facilities. No later than the Effective Date, MarkWest shall implement those elements of injunctive relief identified in this Paragraph that apply, as specified in Appendix 5, to each specific high pressure launcher and receiver located at each of the MarkWest Stand-Alone Facilities identified in Appendix 5. Where applicable, MarkWest shall:

a. connect high pressure pig launchers and receivers by Jumper Lines to a low pressure gathering line;

b. operate Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch;

c. install and use Pig Ramps in pig receivers; and

d. when necessary to ensure compliance with the Ohio SIP, use a Mobile Flare to control VOC emissions.

20. New Launchers and Receivers. For pig launchers and receivers constructed in Pennsylvania and Ohio after the Effective Date and prior to Termination, MarkWest shall, subject to the exception in subparagraph e., below:

a. connect each high pressure pig launcher or receiver by Jumper Lines to a low pressure gathering line where such connection is Commercially Reasonable and Technically Feasible;

b. use Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch;

c. at each new receiver, install and use a Pig Ramp or, with prior EPA written approval, technology that achieves equivalent emissions reductions;

d. at high pressure pig launchers and receivers, use shorter barrels than those presently used in the System, provided that the high pressure pig launcher or receiver is not in Liquid or Residue Gas Service and use of a shorter barrel is Commercially and Operationally Appropriate; and

e. in the event that MarkWest determines that any of the requirements in subparagraphs a., b., or d. above would pose a material adverse risk to worker safety, MarkWest may inform EPA of such risk and the reasons therefore, and upon written approval by EPA be excused from that requirement.

21. Existing Receivers. MarkWest shall install Pig Ramps in all pig receivers located at the Stand-Alone Facilities identified in Appendix 6.

22. At each high pressure pig launcher and receiver that MarkWest currently operates in Pennsylvania and Ohio that is not located at a Covered Facility, MarkWest shall connect such

high pressure pig launcher and receiver by pipe to a low pressure gathering line where such connection is Commercially Reasonable and Technically Feasible and operate such Jumper Lines to depressurize such launchers and receivers prior to opening the launcher or receiver hatch.

23. Liquid Containment Enhancement. For each launcher or receiver located at any MarkWest Compressor Station or Stand-Alone Facility identified in Appendices 1, 3, 4, 5, or 6, and each new launcher or receiver constructed after the Effective Date but prior to Termination in Pennsylvania and Ohio, MarkWest shall install and use liquid containers with grounded steel receptacles that are covered at all times when not in use.

V. CIVIL PENALTY

24. No later than thirty (30) Days after the Effective Date, MarkWest shall pay as a civil penalty $610,000. MarkWest shall pay 80% of this penalty to the United States, and 20% to PADEP. MarkWest shall pay interest on any amount past due, at the rate specified in 28 U.S.C. § 1961.

25. Federal Payment Instructions. MarkWest shall make the penalty payment to the United States at https://www.pay.gov to the U.S. Department of Justice account, in accordance with instructions provided to MarkWest by the Financial Litigation Unit ("FLU") of the United States Attorney's Office for the Western District of Pennsylvania after the Effective Date. The payment instructions provided by the FLU will include a Consolidated Debt Collection System ("CDCS") number that MarkWest shall use to identify this payment, as well as any others required to be made in accordance with this Consent Decree. The FLU will provide payment instructions to MarkWest to:

Christopher L. Rimkus
Managing Counsel – Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Christopher.rimkus@markwest.com

MarkWest may change the individual to receive payment instructions on its behalf by providing written notice of such change in accordance with Section XVIII (Notices). At the time of payment, MarkWest shall send notice that payment has been made to the United States and EPA in accordance with Section XVIII (Notices). Such notice shall state that it is for the civil penalty owed pursuant to the Consent Decree, and shall reference the CDCS number, the civil action number, and DOJ Case No. 90-5-2-1-11374.

26. Pennsylvania Payment Instructions. The MarkWest penalty payment to Pennsylvania shall be made by Electronic Funds Transfer in accordance with instructions to be provided to MarkWest by PADEP. The payment instructions will include ABA and Account numbers that MarkWest shall use to identify all payments required to be made to PADEP in accordance with this Consent Decree. PADEP will provide the payment instructions to:

Christopher L. Rimkus
Managing Counsel – Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Christopher.rimkus@markwest.com

MarkWest may change the individual to receive payment instructions on its behalf by providing written notice of such change in accordance with Section XVIII (Notices). At the time of payment, MarkWest shall send notice that payment has been made to PADEP. This notice shall include (a) the name, address, phone number and entity making payment, (b) the civil action

number of this case, (c) the reference/confirmation number and advice number of the transmittal, (d) the amount of the payment, (e) the date of the payment, and (f) the sending bank's Federal identification number.

27. Not Tax Deductible. MarkWest shall not deduct any penalties paid under this Section or Section XII (Stipulated Penalties) in calculating its federal, state, or local income tax.

VI. SUPPLEMENTAL ENVIRONMENTAL PROJECTS

28. MarkWest shall perform the following Supplemental Environmental Projects in accordance with all provisions of this Section:

a. Innovation Transfer and Emission Control Education. MarkWest will disseminate and make available for use by other oil and gas companies its proprietary design for Pig Ramps, which has been shown to reduce liquid accumulation and emissions from pig launcher and receiver operations. In order to promote the rapid adoption of this innovative device, MarkWest will make available on a public website, no later than six (6) months after the Effective Date, a royalty-free license and information on the Pig Ramp design. MarkWest will also provide educational presentations and host four demonstration or training sessions per year over a three-year period (for a total of 12 sessions), with technical staff available in-person at each session, to demonstrate and encourage the installation and adoption of the technologies developed by MarkWest to reduce VOC emissions from pig launchers and receivers throughout the oil and gas industry. In conjunction with such presentations and demonstrations, MarkWest will develop comprehensive and detailed educational materials on the effective installation, maintenance, and use of Pig Ramps and Jumper Lines to reduce VOC emissions from pig launchers and receivers. Within twelve (12) months of the Effective Date, MarkWest will make

any such materials available on the same website provided for in this Paragraph for the publication of a royalty-free Pig Ramp license and information on Pig Ramp design.

b. Humphreys Compressor Station Ambient Air Monitoring SEP. In accordance with Appendix 7, MarkWest shall install and operate, for a period of at least seven hundred twenty (720) days, one (1) meteorological station and two (2) air sampling stations for sampling and analyzing speciated and total VOCs and reduced sulfur compounds ("RSCs"). One air sampling station will be located upwind and the other downwind of the Humphreys Compressor Station ("HCS") in Barnesville, Ohio. Within one hundred twenty (120) days of the Effective Date, MarkWest shall submit a plan ("Humphreys Monitoring Plan") to EPA for approval to conduct an ambient air monitoring SEP ("Humphreys SEP") near the HCS in accordance with the requirements of this subparagraph and Appendix 7. Following EPA approval of the Humphreys Monitoring Plan, MarkWest shall install and operate the meteorological and air sampling stations in accordance with the approved Humphreys Monitoring Plan and Appendix 7. MarkWest shall submit quarterly information reports and annual reports to EPA as required by the approved Humphreys Monitoring Plan and Appendix 7.

c. Harmon Creek Ambient Air Monitoring SEP. In accordance with Appendix 8, MarkWest shall install and operate, for a period of at least seven hundred twenty (720) days, one (1) meteorological station and three (3) VOC air sampling stations located around the proposed Harmon Creek Gas Processing Plant ("Harmon Creek") in Smith Township, Washington County, Pennsylvania. Within one hundred twenty (120) days of the Effective Date, MarkWest shall submit a plan ("Harmon Creek Monitoring Plan") to EPA and PADEP, for approval by EPA in consultation with PADEP, to conduct an ambient air monitoring SEP near

Harmon Creek in accordance with the requirements of this subparagraph and Appendix 8. Following EPA approval (in consultation with PADEP) of the Harmon Creek Monitoring Plan, MarkWest shall install and operate the meteorological and air sampling stations in accordance with the approved Harmon Creek Monitoring Plan and Appendix 8. MarkWest shall submit quarterly information reports and annual reports to EPA and PADEP as required by the approved Harmon Creek Monitoring Plan and Appendix 8.

d. MarkWest shall spend not less than $2,000,000 in Project Dollars to implement the SEPs described in subparagraphs b. and c.

29. With regard to the SEPs identified in Paragraph 28, MarkWest certifies the truth and accuracy of each of the following:

a. That all cost information provided to EPA in connection with EPA's approval of the SEPs is complete and accurate and that MarkWest in good faith estimates that the cost to implement the SEPs is $2,400,000;

b. That, as of the date of executing this Consent Decree, MarkWest is not required to perform or develop the SEPs by any federal, state or local law, or regulation and is not required to perform or develop the SEPs by agreement, grant, or as injunctive relief awarded in any other action in any forum;

c. That the SEPs are not projects that MarkWest was planning or intending to construct, perform or implement other than in settlement of the claims resolved in this Decree;

d. That MarkWest has not received and will not receive credit for the SEPs in any other enforcement action;

e. That MarkWest will not receive any reimbursement for any portion of the SEPs from any other person;

f. That MarkWest is not a party to any open federal financial assistance transaction that is funding or could fund the same activity as the SEPs. For purposes of these certifications, the term "open federal financial assistance transaction" refers to a grant, cooperative agreement, loan, federally-guaranteed loan guarantee, or other mechanism for providing federal financial assistance whose performance period has not yet expired.

30. SEP Completion Report. Within thirty (30) Days after completion of a SEP, MarkWest shall submit a SEP Completion Report to the United States and PADEP in accordance with Section XVIII (Notices) of this Consent Decree. Each SEP Completion Report shall contain the following information:

a. A detailed description of the SEP as implemented;

b. A description of any problems encountered in completing the SEP and solutions thereto;

c. An itemized list of all eligible SEP costs expended;

d. Certification that the SEP has been fully implemented pursuant to the provisions of this Decree; and

e. To the extent feasible, a description of the environmental or public health benefits resulting from implementation of the SEPs.

31. The United States may, in its sole discretion, require MarkWest to provide information in addition to that described in Paragraph 30 ("SEP Completion Report") in order to evaluate MarkWest's SEP Completion Report.

32. After receiving a SEP Completion Report, the United States will notify MarkWest whether or not MarkWest has satisfactorily completed the SEP. If MarkWest has not completed the SEP in accordance with this Consent Decree, stipulated penalties may be assessed under Section XII (Stipulated Penalties) of this Consent Decree.

33. MarkWest may invoke dispute resolution under Section XIV of the Decree (Dispute Resolution) regarding EPA's determination of (i) whether MarkWest has satisfactorily performed a SEP and (ii) the amount of eligible SEP costs. No other disputes arising under this Section are subject to Dispute Resolution.

34. MarkWest shall ensure that each submission required under this Section is signed by a MarkWest official with knowledge of the SEP and bears the certification language set forth in Paragraph 63.

35. If MarkWest references the SEPs under this Consent Decree in any press conference, press release, or similar formal public statement, MarkWest shall include language in substantially the following form: "This project was undertaken in connection with the settlement of an enforcement action under the Clean Air Act brought by the United States and PADEP against certain MarkWest entities."

36. For federal income tax purposes, MarkWest agrees that it will neither capitalize into inventory or basis nor deduct any costs or expenditures incurred in performing the SEPs.

VII. COMMONWEALTH-ONLY COMMUNITY ENVIRONMENTAL PROJECT

37. In order to settle the matters contained herein, and in addition to the PADEP portion of the civil penalty identified in Section V (Civil Penalty), MarkWest shall, as a Commonwealth-Only Community Environmental Project ("CEP"), permanently transfer

ownership to PADEP of the equipment used in the Harmon Creek Ambient Air Monitoring SEP, identified in Paragraph 38, below (hereinafter "Monitoring Equipment CEP").

38. Within sixty (60) days of the completion of the Harmon Creek Ambient Air Monitoring SEP (Paragraph 28.c), MarkWest shall permanently transfer ownership of the following equipment ("Equipment") to PADEP, for PADEP's use within Pennsylvania:

Compound Analyzer	Consolidated Analytical Systems (CAS) AirmOzone Auto-Gas Chromatograph (GC) (along with ancillary equipment needed to operate it (i.e. stuff in the box))
Wind Speed/Direction	R.M. Young Model 05305 Wind Monitor AQ
Temperature and Delta Temperature	R.M. Young Platinum RTD Model 41342 ambient temperature sensor
Temperature and Delta Temperature	R.M. Young Model 43502 aspirated radiation shield
Relative Humidity	Campbell Scientific Inc (CSI) EE181 relative humidity/temperature probe
Solar Radiation	Hukseflux LP02
Net Radiation	Kipp & Zonen NR-LITE net radiometer
Barometric Pressure	CS106 Vaisala PTB110 barometer
10-Meter Tower	Model UT30 10-meter guyed aluminum tower
Telecommunications	Sierra Wireless RV50 modem (Verizon)
Data Acquisition System	Campbell Scientific, Inc. CR1000x data acquisition system

39. The Monitoring Equipment CEP falls within the definition of CEP in PADEP's "Policy for the Acceptance of Community Environmental Projects in Conjunction with Assessment of Civil Penalty" (Technical Guidance Document Number 012-4180-001).

40. PADEP has determined that the Monitoring Equipment CEP will provide a substantial public health and environmental benefit to Pennsylvania and that the Monitoring Equipment CEP is not something that MarkWest is otherwise legally required to do.

41. MarkWest shall not deduct any costs incurred in connection with or in any way associated with the Monitoring Equipment CEP for any tax purpose or otherwise obtain favorable tax treatment for those costs. If requested to do so by PADEP, MarkWest shall submit an affidavit of the corporate officer responsible for the financial affairs of MarkWest certifying that MarkWest has not deducted or otherwise obtained favorable tax treatment of any of the costs of the Monitoring Equipment CEP.

42. MarkWest agrees that whenever it publicizes, in any press conference, press release, or similar formal public statement, the Monitoring Equipment CEP, it will state that the Monitoring Equipment CEP was undertaken as part of the settlement of an enforcement action with PADEP.

VIII. PERMITS

43. Pennsylvania Appendix 1 and Appendix 3 Facilities. For each Pennsylvania Compressor Station identified on Appendix 1 with the exception of Baker, Redd, and Tupta Day, and each Pennsylvania Stand-Alone Facility identified on Appendix 3 with the exception of Route 18, MarkWest will submit complete applications to PADEP, using PADEP application forms, seeking to incorporate as "applicable requirements" the injunctive relief listed in Paragraphs 12 through 16 of this Consent Decree into non-Title V state-only operating permits ("SOOPs") for those Covered Facilities that are federally enforceable and will survive termination of this Consent Decree. VOC emissions from pigging operations in the SOOP

applications shall be determined in accordance with Paragraph 11. If, after the Effective Date, PADEP issues a revised version of its January 2015 General Plan Approval and/or General Operating Permit BAQ-GPA/GP-5 (Natural Gas Processing Stations, Processing Plants, and Transmission Stations) ("GP-5"), MarkWest will submit complete applications to PADEP, using PADEP application forms, seeking authorization to operate Baker, Redd, and Tupta Day Compressor Stations under the revised GP-5.

44. Permits to be Issued by PADEP. PADEP will review and act on such permit applications submitted by MarkWest. Any challenges to PADEP's issuance or denial of a permit application must be filed with the Pennsylvania Environmental Hearing Board.

45. Ohio Compressor Stations. For each Ohio Compressor Station identified on Appendix 4, MarkWest will submit complete applications to the Ohio Environmental Protection Agency ("OEPA") seeking to incorporate as "applicable requirements" the injunctive relief identified in Paragraph 18 (Ohio Compressor Stations) of the Consent Decree into non-Title V Permits to Install and Operate that are federally enforceable and will survive termination of this Consent Decree.

46. Other Covered Ohio Stand-Alone Facilities. For each pig launcher and receiver identified in Appendix 5, MarkWest will submit complete applications to OEPA seeking coverage under Ohio General Permit GP 21.1 (Pigging at an Oil and Gas Compressor Station/Other Site).

NMED Exhibit 85

IX. PROHIBITION ON NETTING CREDITS OR OFFSETS FROM REQUIRED CONTROLS

47. Prohibitions. MarkWest shall neither generate nor use any CD Emissions Reductions: (i) as netting reductions; (ii) as emissions offsets; or (iii) to apply for, obtain, trade, or sell any emission reduction credits in any permit application.

48. Outside the Scope of the Prohibitions. Nothing in this Section is intended to prohibit MarkWest from seeking to, nor PADEP or Ohio EPA from denying MarkWest's request to:

a. Use or generate emission reductions from emissions units that are covered by this Consent Decree to the extent that the proposed emissions reductions represent the difference between CD Emissions Reductions and more stringent control requirements that MarkWest may elect to accept for those emissions units in a permitting process, except as provided in this Paragraph;

b. Use or generate emissions reductions from emissions units that are not subject to an emission limitation or control requirement pursuant to this Consent Decree; or

c. Use CD Emissions Reductions for compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding Prevention of Significant Deterioration and non-attainment New Source Review rules, but including, for example, Reasonably Achievable Control Technology ("RACT") rules that apply to MarkWest); provided, however, that MarkWest shall not be allowed to trade or sell any CD Emissions Reductions.

X. THIRD PARTY VERIFICATION

49. Third-Party Audit. MarkWest will retain, at its expense, a qualified third-party consultant, not employed by MarkWest or any of its subsidiary or affiliated companies (a "Third Party Auditor"), to lead an audit team to perform the audit described in this Section. The audit team shall include, for coordination of onsite inspection activities only, at least one MarkWest employee or contractor familiar with the Compressor Stations and Stand-Alone Facilities being audited. MarkWest shall make available to the Third-Party Auditor all of MarkWest's non-privileged records requested by the Third-Party Auditor that are reasonably related to the scope of the audit required under this Section. MarkWest may, however, require that the Third-Party Auditor execute a confidentiality agreement prior to providing any documents or records containing Confidential Business Information. MarkWest shall provide the Third-Party Auditor with access to those Compressor Stations and Stand-Alone Facilities that are the subject of the audit required by this Section and shall provide all reasonable assistance to allow the Third-Party Auditor to conduct the audit required by this Section, including making employees, affiliates, or contractors available to answer questions or provide information.

50. Third-Party Auditor Selection Process. Within sixty (60) Days after the Effective Date, MarkWest shall notify the United States and PADEP in writing of MarkWest's recommended Third-Party Auditor and provide statements of qualification for that consultant for performance of the services as Third-Party Auditor. Such statements of qualification shall identify those other services, in addition to those to be performed as Third-Party Auditor, that may be performed for MarkWest in the foreseeable future. EPA, in consultation with PADEP, may disapprove of MarkWest's recommended Third-Party Auditor if it determines that the

consultant lacks the necessary qualifications to serve as Third-Party Auditor. EPA shall state the reasons for its disapproval of the consultant as Third-Party Auditor in writing, and the MarkWest recommendation and EPA approval process will be repeated with MarkWest having thirty (30) Days from the date of disapproval to propose an alternate consultant and provide statements of qualification. In the event a consultant is not approved within thirty (30) Days of MarkWest's first submission under this Paragraph, all deadlines in this Section shall be extended by the total number of Days it takes to approve the consultant minus thirty (30) Days. For example, if it takes forty-five (45) Days to approve the consultant, MarkWest's deadlines would be extended by fifteen (15) Days (*i.e.*, 45 – 30 = 15).

51. MarkWest shall ensure that the Third-Party Auditor complies with the following terms: (a) the Third-Party Auditor shall provide written advance notice as soon as practicable to MarkWest, the United States, and PADEP in the event that the Third-Party Auditor is unable to continue to serve as the Third-Party Auditor under this Consent Decree; (b) the Third-Party Auditor shall provide EPA and PADEP with a written advance schedule of any facility visits, telephone calls, or other meetings with MarkWest or its agents or contractors and shall invite EPA and PADEP to participate in person or by teleconference; (c) the Third Party Auditor shall use the Real Gas Law, as defined herein, and calculate VOC emissions consistent with Paragraph 11 (Emission Calculations); (d) the Third-Party Auditor shall promptly disclose to the United States and PADEP any conflicts of interests for it or its subcontractors that may arise with respect to its performance of the audit and, in the event of a conflict, the Third-Party Auditor shall take any and all action to resolve such conflict; and (e) the individual Third-Party audit team personnel who conducted or otherwise participated in auditing services pursuant to this

Consent Decree shall not accept employment by MarkWest for a period of at least one (1) year following completion of the audit.

52. Scope of Audit. Within eighteen (18) months of the Effective Date, the Third-Party Auditor shall conduct an audit of the installation and operation of the injunctive relief required pursuant to Section IV to determine compliance with this Consent Decree at a total of five (5) of the Compressor Stations or Stand-Alone Facilities identified in Appendices 1 and 3, except the Baker, Redd, and Tupta Day Compressor Stations, and a total of five (5) Compressor Stations or Stand-Alone Facilities identified in Appendices 4 and 5.

53. Third-Party Audit Report. Within twenty-one (21) months of the Effective Date, the Third-Party Auditor shall simultaneously provide a draft Audit Report to MarkWest, EPA, and PADEP. Within forty-five (45) Days after receipt of the draft Audit Report, MarkWest shall provide comments on the draft Audit Report, if any, to the Third-Party Auditor, EPA, and PADEP. As part of such comments, MarkWest shall, if needed, identify within the draft Third-Party Audit Report any Confidential Business Information ("CBI"), and such information shall be designated by the Third-Party Auditor as CBI in the final Third-Party Audit Report submitted to EPA and PADEP. EPA and PADEP shall treat the draft Third-Party Audit Report, in its entirety, as CBI. The Third-Party Auditor shall provide in writing its basis for accepting or rejecting the comments of MarkWest on the draft Third-Party Audit Report. Within twenty-four (24) months of the Effective Date, the Third-Party Auditor shall submit a Third-Party Audit Report to MarkWest, EPA and PADEP. The Third-Party Audit Report shall identify any requirement of the injunctive relief specified in Section IV where MarkWest is not in compliance and, for each such requirement: (i) provide a detailed description of the basis for this conclusion

regarding noncompliance, including a summary of any relevant oral communications between the Third-Party Auditor and any of MarkWest's officers, agents, or employees; and (ii) attach relevant supporting documentation.

54. Response to Third-Party Audit Report. Within one hundred twenty (120) Days after receiving the Third-Party Audit Report, MarkWest shall (1) serve on the United States and PADEP a schedule for remedying any deficiencies identified in the Third-Party Audit Report, and/or (2) serve a notice on the United States and PADEP that MarkWest disputes the Third-Party Auditor's findings, in whole or part, and specifies the factual, technical, or legal basis of that disagreement. Any disagreement between the United States and MarkWest and/or PADEP and MarkWest over MarkWest's response to the Third-Party Audit Report shall be resolved according to the Dispute Resolution provisions of the Consent Decree in Section XIV.

55. The United States and PADEP shall not be bound by any Third-Party Audit Report generated pursuant to this Consent Decree. The United States and/or PADEP may accept or reject, in whole or in part, the Third-Party Auditor's findings, conclusions, and/or recommendations. If the United States or PADEP determines that MarkWest is in violation of any Consent Decree requirement for which stipulated penalties are provided under Section XII (Stipulated Penalties), MarkWest shall be subject to the assessment of such penalties, regardless of the Third-Party Audit Report, in accordance with the provisions of Section XII (Stipulated Penalties), and subject to MarkWest's right to invoke the provisions of Section XIV (Dispute Resolution).

56. MarkWest may terminate its contract with the Third-Party Auditor only for good cause shown and with the consent of the United States, in consultation with PADEP; such

consent not to be unreasonably withheld. For the purposes of this Paragraph, "good cause" includes, but is not limited to, incompetence, fraudulent actions, and any failure by the Third-Party Auditor to comply with all applicable laws and MarkWest policies relating to (1) worker health and safety, or (2) environmental compliance and protection. In the event MarkWest terminates its contract with the Third-Party Auditor, MarkWest shall select a new consultant consistent with the process in Paragraph 50.

57. Except as otherwise provided herein, the Third-Party Audit Report shall not be subject to any privilege or the attorney work product doctrine. Nothing in this Section shall prevent MarkWest from designating as CBI portions of the Third-Party Audit Report or other documents prepared by the Third-Party Auditor.

XI. RECORDKEEPING AND REPORTING

58. Status Reports. After the Effective Date and until termination of the Consent Decree, MarkWest shall submit periodic reports ("Status Reports") on the status of the injunctive relief and SEPs required by the Consent Decree. The first such Status Report shall cover the first six-month period after the Effective Date and shall be due within sixty (60) Days after the end of the six-month period. Each subsequent Status Report shall cover a one (1) year period and shall be due within sixty (60) Days after the end of annual period covered. Each Status Report shall contain the following information:

a. The date(s) of replacement of any Dehydrator Flares at compressor stations listed in Appendix 2 of this Decree, as required by Paragraph 13.

b. The date of the replacement of the candlestick flare at the Smith Tee facility, as required by Paragraph 15.

c. The status of the closure of launchers and receivers located at the Drugmand, Stewart Route 50, and Graham Header facilities. If the facility is closed, provide the date the facility ceased operation, as required by Paragraph 17.

d. The date of any SEP Completion Reports submitted under Paragraph 30. Also, identify for which SEP the completion report was submitted.

e. For any new launcher or receiver constructed after the Effective Date but prior to the Termination Date of this Decree, as provided in Paragraph 20, provide the date(s) and location of any:

i. Jumper Lines installed;

ii. Pig Ramps installed;

iii. An explanation for not installing Jumper Lines or Pig Ramps;

iv. Any instances where a Jumper Line was not used prior to opening the hatch;

v. An explanation for not using shorter barrels at high pressure launchers and receivers.

f. For each launcher or receiver subject to the requirements of Paragraphs 12, 14, 18 and 19, provide, as applicable to each specific pig launcher or receiver, the date(s) and locations of:

i. Jumper Lines installed;

ii. Pig Ramps installed; and

iii. Liquid Containment Vessels installed.

g. Copies of each permit application submitted to PADEP pursuant to Paragraph 43.

h. Copies of each permit application or application seeking coverage under a general permit submitted to OEPA pursuant to Paragraphs 45 and 46.

i. Date on which OEPA granted any permit or approval to operate under a general permit in response to applications submitted pursuant to Paragraphs 45 and 46.

j. Date that any Jumper Line was installed pursuant to the requirements of Paragraph 22.

k. Dates that Pig Ramps were installed for each receiver as required by Paragraph 21.

l. Dates that a Mobile Flare was operated as required by Paragraphs 18 and 19.

m. Status update for the HCS and Harmon Creek monitoring SEPs as set forth in Paragraph 28.b. and c. until those SEPs are completed.

59. Maintenance of Consent Decree Records. MarkWest shall maintain records necessary to demonstrate compliance with this Consent Decree.

60. Pigging Event Records. For each pigging event that occurs at a launcher or receiver subject to the requirements of Paragraphs 12, 14, 18, and 19, MarkWest shall maintain records of the following information:

a. Identification number of the launcher or receiver;

b. Location of the launcher or receiver;

c. Date and time of pigging;

d. The launcher or receiver pressure prior to venting to the atmosphere, and prior to routing emissions to a flare, where applicable;

e. Gas composition data representative of the composition of gas at the facility. This data shall be updated at least annually;

f. In the case of pig launchers and receivers identified in Appendices 4 and 5, whether a Mobile Flare was used as required by Paragraphs 18 and 19; and

g. In the case of pig launchers and receivers identified in Appendices 4 and 5, any additional records necessary to demonstrate that the emissions from each launcher and receiver did not exceed the emissions threshold applicable to each launcher and receiver under Paragraphs 18 and 19.

61. Whenever any violation of this Consent Decree, or any other event affecting MarkWest's performance under this Decree, may pose an immediate threat to public health or welfare or the environment, MarkWest shall notify EPA and PADEP orally or by electronic transmission as soon as possible, but no later than 24 hours after MarkWest first knew of the violation or event.

62. All reports pursuant to this Section shall be submitted to the persons designated in Section XVIII of this Consent Decree (Notices).

63. Certification. Each report submitted by MarkWest under this Decree shall be signed by an official of MarkWest and include the following certification:

> I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I have no personal knowledge that the information submitted is other than true, accurate, and complete. I am aware that there are significant

> penalties for submitting false information, including the possibility of fine and imprisonment for knowingly and willfully submitting a material false statement.

This certification requirement does not apply to emergency or similar notifications where compliance would be impractical.

64. The reporting requirements of this Consent Decree do not relieve MarkWest of any reporting obligations required by the Act or implementing regulations, or by any other federal, state, or local law, regulation, permit or requirement.

65. Any information provided pursuant to this Consent Decree may be used by the United States or PADEP in any proceeding to enforce the provisions of this Consent Decree and as otherwise permitted by law.

XII. STIPULATED PENALTIES

66. MarkWest shall be liable for stipulated penalties for violations of this Consent Decree as specified below, unless excused under Section XIII (Force Majeure) of the Decree, or reduced or waived by the United States or the United States and PADEP (in the case of violations at Facilities located in Pennsylvania) pursuant to Paragraph 72. For violations occurring at Facilities in Pennsylvania, stipulated penalties are due to both the United States and PADEP, with fifty percent (50%) of the total amount of stipulated penalties paid to the United States, and fifty percent (50%) to PADEP. For violations occurring at Facilities in Ohio, one hundred percent (100%) of the penalty shall be paid to the United States.

67. Tier 1 Stipulated Penalties. The following stipulated penalties shall accrue per violation per Day for each violation of the following requirements of this Consent Decree: (1) connection of high pressure to low pressure Jumper Lines under Paragraphs 12.a., 14.a., 18.a.,

and 19.a.; (2) use of Jumper Lines before depressurizing under Paragraphs 12.b., 14.b., 18.b., and 19.b; (3) installation of dehydrator flares at Compressor Stations pursuant to Paragraph 13; (4) replacement of the flare at the Smith Tee Stand-Alone Facility under Paragraph 15; (5) operation of the redesigned and modified discharge piping at Loffert (Joe Cain) Pennsylvania Stand-Alone Facility pursuant to Paragraph 16; and (6) closure of pig launchers and receivers at the Drugmand, Stewart Route 50, and Graham Header Stations pursuant to Paragraph 17.

Penalty Per Violation Per Day	Period of Noncompliance
$2,250	1st through 14th Day
$3,500	15th through 30th Day
$5,000	31st Day and beyond.

68. Tier 2 Stipulated Penalties. The following stipulated penalties shall accrue per violation per Day for each violation of each of the following requirements of this Consent Decree: (1) installation and use of Pig Ramps under Paragraphs 12.c., 14.c., 18.c., and 19.c.; and (2) timely submission of Status Reports under Paragraph 58:

Penalty Per Violation Per Day	Period of Noncompliance
$500	1st through 14th Day
$1,000	15th through 30th Day
$1,500	31st Day and beyond.

69. Stipulated Penalties for SEPs. The following stipulated penalties shall accrue per Day for each violation of the following SEP requirements, as set forth in Paragraph 28.a-c. of this Consent Decree: (1) failure to timely submit SEP work plans required by Paragraph 28.b and .c. (2) failure to timely make available on a public website a royalty-free license and/or

information on the Pig Ramp design; (3) failure to timely make available on a public website materials on the effective installation, maintenance, and use of Pig Ramps and Jumper Lines; (4) failure to install the air sampling or meteorological stations at HCS and Harmon Creek as required by Paragraph 28.b. and c.; (5) material failure to operate the monitoring or meteorological stations as required by Paragraph 28.b. and c.; (6) failure to timely provide the meteorological data and/or sampling data as set forth in Paragraph 28.b. and c.; and (7) failure to timely submit a SEP Completion Report pursuant to Paragraph 30:

Penalty Per Day of Violation	Period of Noncompliance
$500	1st through 14th Day
$1,000	15th through 30th Day
$2,500	31st Day and beyond.

70. Stipulated penalties under this Section shall begin to accrue on the Day after performance is due or on the Day a violation occurs, whichever is applicable, and shall continue to accrue until performance is satisfactorily completed or until the violation ceases. Stipulated penalties shall accrue simultaneously for separate violations of this Consent Decree. The penalties that accrue for each violation or failure to perform an obligation do not increase from one period of noncompliance to the next unless the violations or failures to perform are continuous.

71. MarkWest shall pay stipulated penalties to the United States and PADEP within thirty (30) Days of a written demand by the United States and/or PADEP.

72. Either the United States or PADEP may, in the unreviewable exercise of their respective discretion, reduce or waive stipulated penalties otherwise due them under this Consent Decree.

73. Stipulated penalties shall continue to accrue during any Dispute Resolution, but need not be paid until the following:

a. If the dispute is resolved by agreement or MarkWest does not seek judicial review of EPA's written position provided pursuant to Paragraph 87, MarkWest shall pay the stipulated penalties determined to be owing, together with interest, to the United States and PADEP within thirty (30) Days of the effective date of the agreement or the expiration of Paragraph 88's period for seeking judicial resolution of a dispute.

b. If the dispute is appealed to the Court and the United States and/or PADEP prevail, MarkWest shall pay all penalties determined by the Court to be owing, together with interest, within sixty (60) Days of receiving the Court's decision or order, except if the District Court's decision is appealed, and then as provided in Subparagraph c., below.

c. If any Party appeals the District Court's decision, MarkWest shall pay all penalties determined to be owing by the final decision of the appellate court, together with interest, within thirty (30) Days of receiving the final appellate court decision.

74. If MarkWest fails to pay stipulated penalties according to the terms of this Consent Decree, MarkWest shall be liable for interest on such penalties, as provided in 28 U.S.C. § 1961, accruing from the date payment became due until full payment is made.

75. MarkWest shall pay stipulated penalties owing to the United States in accordance with the procedures for payment of civil penalties specified in Paragraph 25. The transmittal letter required by Paragraph 25 shall specify that the payment is for stipulated penalties.

76. MarkWest shall pay stipulated penalties due under this Consent Decree to PADEP in accordance with the procedures for payment of civil penalties specified in Paragraph 26.

77. The payment of stipulated penalties and interest, if any, shall not alter in any way MarkWest's obligation to complete the performance of the requirements of this Consent Decree.

78. Subject to the provisions of Section XVI (Effect of Settlement/Reservation of Rights), the stipulated penalties provided for in this Consent Decree shall be in addition to any other rights, remedies, or sanctions available to the United States and PADEP for MarkWest's violations of this Consent Decree or applicable law. Where a violation of this Decree is also a violation of relevant statutory or regulatory requirements, MarkWest shall be allowed a credit for any stipulated penalties paid against any statutory penalties imposed for such violation under the applicable federal or state requirement.

XIII. FORCE MAJEURE

79. "Force majeure," for purposes of this Consent Decree, is defined as any event arising from a cause or causes beyond the control of MarkWest, of any entity controlled by MarkWest, or of MarkWest's contractors, that delays or prevents the performance of any obligation under this Decree despite MarkWest's best efforts to fulfill the obligation. The requirement that MarkWest exercise "best efforts to fulfill the obligation" includes using reasonable efforts to anticipate any potential force majeure event and best efforts to address the effects of any such event (a) as it is occurring and (b) after it has occurred in order to minimize

delay and any adverse effects of the delay to the greatest extent possible. Force majeure does not include MarkWest's financial inability to perform any obligation under this Decree.

80. If any event occurs or has occurred that may delay the performance of any obligation under this Consent Decree, for which MarkWest intends or may intend to assert a claim of force majeure, MarkWest shall provide notice orally or by electronic transmission within three (3) Days of when MarkWest first knew that the event might cause a delay to the addresses provided in Section XVIII of this Consent Decree (Notices). Within fifteen (15) Days of this initial notification, MarkWest shall provide in writing to EPA and, if the event involves a facility in Pennsylvania, PADEP, to the extent available: an explanation and description of the reasons for the delay; the anticipated duration of the delay; all actions taken or to be taken to prevent or minimize the delay; a schedule for implementation of any measures to be taken to mitigate the delay or the effect of the delay; and MarkWest's rationale for attributing such delay to a force majeure event if it intends to assert such a claim. MarkWest shall include with any notice all available documentation necessary to support the claim that the delay was attributable to a force majeure. Any material failure to comply with the above requirements that prejudices EPA's ability to assess MarkWest's claim of force majeure shall preclude MarkWest from asserting any claim of force majeure for that event for the period of time of such failure to comply.

81. If EPA agrees that the delay or anticipated delay is attributable to a force majeure, the time for performance of the obligations under this Consent Decree that are affected by the force majeure event will be extended by EPA for such time as is necessary to complete those obligations. An extension of the time for performance of the obligations affected by the force

majeure event shall not, of itself, extend the time for performance of any other obligation. EPA will notify MarkWest in writing of the length of the extension, if any, for performance of the obligations affected by the force majeure.

82. If EPA does not agree that the delay or anticipated delay has been or will be caused by a force majeure event, EPA will notify MarkWest in writing of its decision.

83. If MarkWest elects to invoke the dispute resolution procedures set forth in Section XIV (Dispute Resolution) of this Consent Decree with regard to a force majeure event, it shall do so no later than thirty (30) Days after receipt of EPA's notice. In any such proceeding, MarkWest bears the burden of demonstrating by a preponderance of the evidence that the delay or anticipated delay has been or will be caused by a force majeure, that the duration of the delay or the extension sought was or will be warranted under the circumstances, that best efforts were exercised to avoid and mitigate the effects of the delay, and that MarkWest complied with the requirements of Paragraphs 79 and 80. If MarkWest carries this burden, the delay at issue shall be deemed not to be a violation of the affected obligation of this Decree.

XIV. DISPUTE RESOLUTION

84. Unless otherwise expressly provided for in this Consent Decree, the dispute resolution procedures of this Section shall be the exclusive mechanism to resolve any dispute arising under or with respect to this Consent Decree.

85. Informal Dispute Resolution. Any dispute subject to dispute resolution under this Consent Decree shall first be the subject of informal negotiations. The dispute shall be considered to have arisen when MarkWest disputes a decision of the United States and sends the United States and PADEP a written Notice of Dispute. Such Notice of Dispute shall state clearly

the matter in dispute. The period of informal negotiations shall not exceed ninety (90) Days from the date the dispute arises, unless that period is modified by written agreement. If the Parties cannot resolve a dispute by informal negotiations, then the position advanced by the United States, after consultation with PADEP, shall be considered binding unless, within ninety (90) Days after the conclusion of the informal negotiation period, MarkWest invokes formal dispute resolution procedures as set forth below.

86. Formal Dispute Resolution. MarkWest shall invoke formal dispute resolution procedures, within the time period provided in the preceding Paragraph, by serving on the United States and PADEP a written Statement of Position regarding the matter in dispute. The MarkWest Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting MarkWest's position and any supporting documentation relied upon by MarkWest.

87. The United States, after consultation with PADEP, shall serve its Statement of Position within forty-five (45) Days of receipt of MarkWest's Statement of Position. The United States' Statement of Position shall include, but need not be limited to, any factual data, analysis, or opinion supporting that position and any supporting documentation relied upon by the United States. The United States' Statement of Position shall be binding on MarkWest unless MarkWest files a motion for judicial review of the dispute in accordance with the following Paragraph.

88. MarkWest may seek judicial review of the dispute by filing with the Court and serving on the United States, in accordance with Section XVIII of this Consent Decree (Notices), a motion requesting judicial resolution of the dispute. The motion must be filed within thirty (30) Days of receipt of the United States' Statement of Position pursuant to the preceding Paragraph.

The motion shall contain a written statement of MarkWest's position on the matter in dispute, including any supporting factual data, analysis, opinion, or documentation, and shall set forth the relief requested and any schedule within which the dispute must be resolved for orderly implementation of the Consent Decree.

89. The United States shall respond to MarkWest's motion within the time period allowed by the Local Rules of this Court for responses to dispositive motions. MarkWest may file a reply memorandum to the extent permitted by the Local Rules.

90. Standard of Review.

a. Disputes Concerning Matters Accorded Record Review. Except as otherwise provided in this Consent Decree, in any dispute brought under Paragraph 85 and 86 above pertaining to a matter that involves EPA's exercise of discretion under this Consent Decree, MarkWest shall have the burden of proof based on the administrative record (including the Parties' Statements of Position) and the applicable standard of review as set forth in the Administrative Procedure Act, 5 U.S.C. § 500 *et seq*.

b. Other Disputes. Except as otherwise provided in this Consent Decree, in any other dispute brought under Paragraphs 85 and 86 above, MarkWest shall bear the burden of demonstrating that its position complies with this Consent Decree.

91. The invocation of dispute resolution procedures under this Section shall not, by itself, extend, postpone, or affect in any way any obligation of MarkWest under this Consent Decree, unless and until final resolution of the dispute so provides. Stipulated penalties with respect to the disputed matter shall continue to accrue from the first day of noncompliance, but payment shall be stayed pending resolution of the dispute as provided in Paragraph 73 above. If

MarkWest does not prevail on the disputed issue, subject to the Court's order, stipulated penalties shall be assessed and paid as provided in Section XII (Stipulated Penalties).

XV. INFORMATION COLLECTION AND RETENTION

92. The United States and PADEP, and their respective representatives, including attorneys, contractors, and consultants, shall have the right of entry into any facility identified on Appendices 1-6, at all reasonable times, upon presentation of proper credentials, to:

a. monitor the progress of activities required under this Decree;

b. verify any data or information submitted to the United States or PADEP in accordance with the terms of this Decree;

c. obtain samples and, upon request, splits of any samples taken by MarkWest or its representatives, contractors, or consultants related to MarkWest's performance of its obligations under this Decree;

d. obtain documentary evidence, including photographs and similar data; and

e. assess MarkWest's compliance with this Decree.

93. Upon request, MarkWest shall provide EPA, PADEP, or their authorized representatives, splits or duplicates of any samples taken by MarkWest in performing its obligations under this Decree. EPA or PADEP shall provide MarkWest splits of any samples taken by EPA or PADEP or their authorized representatives.

94. Until two (2) years after the termination of this Consent Decree, MarkWest shall retain, and shall instruct its contractors and agents performing work under this Consent Decree to preserve all non-identical copies of all documents, records, or other information (including documents, records, or other information in electronic form) in its or its contractors' or agents'

possession or control, or that come into its or its contractors' or agents' possession or control, and that relate in any manner to MarkWest's performance of its obligations under this Decree. This information-retention requirement shall apply regardless of any contrary corporate or institutional policies or procedures. At any time during this information-retention period, upon request by the United States or PADEP, MarkWest shall provide copies of any non-privileged documents, records, or other non-privileged information required to be maintained under this Paragraph to the United States or PADEP.

95. At the conclusion of the information-retention period provided in the preceding Paragraph, MarkWest shall notify the United States and PADEP at least sixty (60) days prior to the destruction of any records subject to the requirements of this Section and, upon request by the United States or PADEP, MarkWest shall deliver any such documents, records, or other information to EPA and PADEP.

96. MarkWest may assert that certain documents, records, or other information are privileged under the attorney-client privilege or any other privilege recognized by federal law. If MarkWest asserts such a privilege, it shall provide the following: (1) the title of the document, record, or information; (2) the date of the document, record, or information; (3) the name and title of each author of the document, record, or information; (4) the name and title of each addressee and recipient; (5) a description of the subject of the document, record, or information; and (6) the privilege asserted by MarkWest. However, no documents, records, or other information created or generated in order to comply with the requirements of this Consent Decree shall be withheld on grounds of privilege.

97. MarkWest may also assert that information required to be provided under this Section is protected as Confidential Business Information ("CBI") under 40 C.F.R. Part 2 or applicable state law. As to any information that MarkWest seeks to protect as CBI, MarkWest shall follow the procedures set forth in 40 C.F.R. Part 2 or applicable state law.

98. This Consent Decree in no way limits or affects any right of entry and inspection, or any right to obtain information, held by the United States or PADEP pursuant to applicable federal or state laws, regulations, or permits, nor does it limit or affect any duty or obligation of MarkWest to maintain documents, records, or other information imposed by applicable federal or state laws, regulations, or permits.

XVI. EFFECT OF SETTLEMENT/RESERVATION OF RIGHTS

99. This Consent Decree resolves the civil and administrative claims that the United States may have against MarkWest for the following violations of the Clean Air Act through the date of lodging:

a. With respect to the Pennsylvania Compressor Stations identified on Appendix 1, the Pennsylvania Stand-Alone Facilities (with the exception of Route 18) identified in Appendix 3, and the Drugmand, Stewart Route 50, and Graham Header Stations identified in Paragraph 17, failure to comply with (i) the PSD provisions, 42 U.S.C. §§ 7490-7492; (ii) the NSR provisions, 42 U.S.C. §§ 7501-7515; (iii) the Title V provisions, 42 U.S.C. §§ 7661-7661f; and (iv) provisions of the Pennsylvania SIP implementing Pennsylvania's PSD permitting program, NSR permitting program, Title V permitting program, and Plan Approval and Operating Permit programs;

b. With respect to the Pennsylvania Stand-Alone Facilities identified in Appendix 6 and the Route 18 Stand-Alone Facility identified in Appendix 3, failure to comply with the provisions of the Pennsylvania SIP implementing Pennsylvania's Plan Approval and Operating Permit programs;

c. With respect to the Ohio Compressor Stations identified on Appendix 4, failure to comply with (i) the PSD provisions with respect to VOC, 42 U.S.C. §§ 7490-7492; (ii) the Title V provisions, 42 U.S.C. §§ 7661-7661f; and (iii) the provisions of the Ohio SIP implementing Ohio's Title V operating permit program and Ohio's permit to install and operate program;

d. With respect to the Ohio Stand-Alone Facilities identified in Appendix 5, failure to comply with the provisions of the Ohio SIP implementing Ohio's minor source permit to install and operate program; and

e. With respect to the Ohio Stand-Alone Facilities identified in Appendix 6, failure to comply with the provisions of the Ohio SIP implementing Ohio's minor source permit to install and operate program, and failure to comply with the recordkeeping provisions of the Ohio SIP.

100. This Consent Decree resolves all of PADEP's civil claims against MarkWest pursuant to Sections 9.1 and 13.6(a) of the Air Pollution Control Act ("APCA"), 35 P.S. §§ 4009.1 and 4013.6(a), through the date of lodging for the following violations of the APCA and its implementing regulations:

a. With respect to the Pennsylvania Compressor Stations identified in Appendix 1, the Pennsylvania Stand-Alone Facilities (with the exception of Route 18) identified

in Appendix 3, and the Drugmand, Stewart Route 50, and Graham Header Stations identified in Paragraph 17, failure to comply with (i) the Plan Approval and Operating Permit programs; (ii) the PSD permitting program; (iii) the NSR permitting program; and (iv) the Title V permitting program.

b. With respect to the Pennsylvania Stand-Alone Facilities identified on Appendix 6 and the Route 18 Stand-Alone Facility identified in Appendix 3, failure to comply with the Plan Approval and Operating Permit programs.

101. The United States and PADEP reserve all legal and equitable remedies available to enforce the provisions of this Consent Decree, except as expressly stated in Paragraphs 78, 99 and 100. This Consent Decree does not limit the rights of the United States or PADEP to obtain penalties or injunctive relief under the Act or implementing regulations, or under other federal or state laws, regulations, or permit conditions, except as expressly specified in Paragraphs 99 and 100. The United States and PADEP further retain all legal and equitable remedies to address any imminent and substantial endangerment to the public health or welfare or the environment arising at, or posed by, any MarkWest facility, whether related to the violations addressed in this Decree or otherwise.

102. In any subsequent administrative or judicial proceeding initiated by the United States or PADEP for injunctive relief, civil penalties, or other appropriate relief relating to the facilities subject to this Consent Decree or MarkWest's alleged violations, MarkWest shall not assert, and may not maintain, any defense or claim based upon the principles of waiver, res judicata, collateral estoppel, issue preclusion, claim preclusion, claim-splitting, or other defenses based upon any contention that the claims raised by the United States or PADEP in the

subsequent proceeding were or should have been brought in the instant case, except with respect to claims that have been specifically resolved pursuant to Paragraphs 99 and 100.

103. This Consent Decree is not a permit, or a modification of any permit, under any federal, state, or local laws or regulations. MarkWest is responsible for achieving and maintaining complete compliance with all applicable federal, state, and local laws, regulations, and permits; and MarkWest's compliance with this Decree shall be no defense to any action commenced pursuant to any such laws, regulations, or permits, except as set forth herein. The United States and PADEP do not, by their consent to the entry of this Decree, warrant or aver in any manner that MarkWest's compliance with any aspect of this Decree will result in compliance with provisions of the Act, the APCA, or with any other provisions of federal, state, or local laws, regulations, or permits.

104. This Consent Decree does not limit or affect the rights of MarkWest, of the United States, or of PADEP against any third parties not party to this Decree, nor does it limit the rights of third parties not party to this Decree against MarkWest, except as otherwise provided by law.

105. This Consent Decree shall not be construed to create rights in, or grant any cause of action to, any third party not party to this Decree.

106. MarkWest expressly denies and does not admit any liability to the United States or PADEP arising out of the conduct, transactions or occurrences alleged in the Complaint. Nothing in this Consent Decree shall be construed as an admission of MarkWest's liability, nor shall MarkWest's performance of any obligation under this Decree be considered any admission

of liability. This Consent Decree shall not be admissible against MarkWest in any administrative or judicial proceeding, except in a proceeding initiated by the Parties to enforce this Decree.

XVII. COSTS

107. The Parties shall bear their own costs of this action, including attorneys' fees, except that the United States and PADEP shall be entitled to collect the costs (including attorneys' fees) incurred in any action necessary to collect any portion of the civil penalty or any stipulated penalties due, but not paid, by MarkWest.

XVIII. NOTICES

108. Unless otherwise specified herein, whenever notifications, submissions, statements of position, or communications are required by this Consent Decree (referred in this Paragraph as a "notice" or "notices"), they shall be made electronically as described below, unless such notices are unable to be uploaded to the CDX electronic system (in the case of EPA) or transmitted by email (in the case of any other party). For all notices to EPA, MarkWest shall register for the CDX electronic system and upload such notices at https://cdx.epa.gov/epa_home.asp. Any notice that cannot be uploaded or electronically transmitted via email shall be provided in writing to the addresses below:

As to the United States by email:	eescdcopy.enrd@usdoj.gov Re: DJ# 90-5-2-1-11374
As to the United States by mail:	EES Case Management Unit Environment and Natural Resources Division U.S. Department of Justice Box 7611 Ben Franklin Station Washington, D.C. 20044-7611 Re: DOJ No. 90-5-2-1-11374

As to EPA:

Director, Air Enforcement Division
Office of Civil Enforcement
U.S. EPA Headquarters, MC 2242A
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

And

For notices relating to Ohio facilities:

U.S. EPA Region V
77 W. Jackson Boulevard
Chicago, IL 60604
Attn: Compliance Tracker
R5airenforcement@epa.gov

And

For notices relating to Pennsylvania facilities:

Director, Air Enforcement
U.S. EPA Region III
1650 Arch Street
Philadelphia, PA 19103

As to PADEP:

Mark R. Gorog, P.E.
Regional Manager
Department of Environmental Protection
Air Quality Program
Southwest Regional Office
400 Waterfront Drive
Pittsburgh, PA 15222
Phone: 412.442.4150
Fax: 412.442.4194
mgorog@pa.gov

And

Lori McNabb
Environmental Group Manager
Department of Environmental Protection – Field Operations
Air Quality Program

Northwest Regional Office
230 Chestnut Street
Meadville, PA 16335
Phone: 814.332.6634
Fax: 814.332.6121
lmcnabb@pa.gov

As to MarkWest:

General Counsel
MPLX LP
200 East Hardin Street
Findlay, Ohio 45840
lawdepartment.notices@markwest.com

Managing Counsel – Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Christopher.rimkus@markwest.com

And

Environmental Director – Northeast Operations
MarkWest Energy Partners, L.P.
1515 Arapahoe St., Suite 1600
Denver, CO 80202
Robert.mchale@markwest.com

109. Any Party may, by written notice to the other Parties, change its designated notice recipient or notice address provided above.

110. Notices submitted pursuant to this Section shall be deemed submitted upon electronic transmission or mailing, unless otherwise provided in this Consent Decree or by mutual agreement of the Parties in writing.

XIX. EFFECTIVE DATE

111. The Effective Date of this Consent Decree is the date upon which this Consent Decree is entered by the Court or a motion to enter the Decree is granted, whichever is first, as recorded by the Court's docket.

XX. RETENTION OF JURISDICTION

112. The Court shall retain jurisdiction over this case, until termination of this Consent Decree pursuant to Section XXII (Termination), for the purpose of (a) resolving disputes arising under this Decree pursuant to Section XIV (Dispute Resolution), (b) entering orders modifying this Decree pursuant to Section XXI (Modification), or (c) effectuating or enforcing compliance with the terms of this Decree.

XXI. MODIFICATION

113. The terms of this Decree, including any attached appendices, may be modified only by a subsequent written agreement signed by all the Parties. Where the modification constitutes a material change to this Decree, it shall be effective only upon approval by the Court.

114. Any disputes concerning modification of this Consent Decree shall be resolved pursuant to Section XIV (Dispute Resolution). The Party seeking the modification bears the burden of demonstrating that it is entitled to the requested modification in accordance with Federal Rule of Civil Procedure 60(b).

XXII. TERMINATION

115. After MarkWest has fulfilled its obligations to (a) pay the civil penalty in Paragraph 24, (b) implement all injunctive relief, (c) obtain permits pursuant to Section VIII (Permits); (d) implement the Third Party Verification program and submit a satisfactory Third-Party Audit Report; (e) complete all SEPs, (f) complete the Commonwealth-only Community Environmental Project, and (g) pay any stipulated penalties not waived or reduced by the United States or PADEP under Section XII (Stipulated Penalties) pursuant to Paragraph 72, MarkWest

may send to the United States and PADEP a Request for Termination, which shall be certified in accordance with Paragraph 63, stating that MarkWest has satisfied those requirements, together with all reasonably necessary supporting documentation.

116. Following receipt by the United States and PADEP of MarkWest's Request for Termination, the Parties shall confer informally concerning the Request and any disagreement that the Parties may have as to whether MarkWest has satisfactorily complied with the requirements for termination of this Consent Decree. If the United States, after consultation with PADEP, agrees that the Decree may be terminated, the Parties shall submit for the Court's approval a joint stipulation terminating the Decree.

117. If the United States, after consultation with PADEP, does not agree that the Decree may be terminated, MarkWest may invoke Dispute Resolution under Section XIV of this Decree (Dispute Resolution). However, MarkWest shall not seek Dispute Resolution of any dispute regarding termination until sixty (60) Days after service of its Request for Termination.

XXIII. PUBLIC PARTICIPATION

118. This Consent Decree will be lodged with the Court for a period of not less than thirty (30) Days for public notice and comment in accordance with 28 C.F.R. § 50.7. The United States reserves the right to withdraw or withhold its consent if the comments regarding the Consent Decree disclose facts or considerations indicating that the Decree is inappropriate, improper, or inadequate. MarkWest consents to entry of this Decree without modification without further notice and agrees not to withdraw from or oppose entry of this Decree by the Court or to challenge any provision of the Decree, unless the United States has notified MarkWest in writing that it no longer supports entry of the Decree or has modified the Decree.

XXIV. SIGNATORIES/SERVICE

119. Each undersigned representative of MarkWest, PADEP, and the Assistant Attorney General for the Environment and Natural Resources Division of the Department of Justice certifies that he or she is fully authorized to enter into the terms and conditions of this Consent Decree and to execute and legally bind the Party he or she represents to this document.

120. This Consent Decree may be signed in counterparts, and its validity shall not be challenged on that basis.

121. MarkWest agrees to accept service of process by mail with respect to all matters arising under or relating to this Consent Decree. MarkWest agrees to accept service in that manner and to waive the formal service requirements set forth in Rule 4 of the Federal Rules of Civil Procedure and any applicable Local Rules of this Court including, but not limited to, service of a summons. MarkWest need not file an answer to the Complaint in this action unless or until the Court expressly declines to enter this Decree.

XXV. INTEGRATION

122. This Consent Decree and its Appendices constitute the final, complete, and exclusive agreement and understanding among the Parties with respect to the settlement embodied in the Decree. There are no representations, agreements, or understandings relating to the settlement other than those expressly contained in this Consent Decree.

XXVI. FINAL JUDGMENT

123. Upon approval and entry of this Consent Decree by the Court, this Decree shall constitute a final judgment of the Court as to the United States, PADEP, and MarkWest under Fed. R. Civ. P. 54 and 58.

XXVII. 26 U.S.C. SECTION 162(f)(2)(A)(ii) IDENTIFICATION

124. For purposes of the identification requirement of Section 162(f)(2)(A)(ii) of the Internal Revenue Code, 26 U.S.C. § 162(f)(2)(A)(ii), performance of Section II (Applicability), Paragraph 8, Section IV (Injunctive Relief), Paragraphs 11 – 23, Section VIII (Permits), Paragraphs 43 - 46, Section X (Third Party Verification), Paragraphs 49 – 54, Section XI (Recordkeeping and Reporting), Paragraphs 58(a)-(c) and (e) – (l), 59 – 60, and 62 – 63, and Section XIV (Information Collection and Retention), Paragraphs 92 - 95, is restitution or required to come into compliance with law.

XXVIII. APPENDICES

125. The following appendices are attached to and part of this Consent Decree:

"Appendix 1" is a list of MarkWest compressor stations in Pennsylvania subject to Paragraph 12;

"Appendix 2" is a list of MarkWest compressor stations in Pennsylvania subject to Paragraph 13;

"Appendix 3" is a list of MarkWest Stand-Alone Facilities in Pennsylvania subject to Paragraph 14;

"Appendix 4" is a list of MarkWest Compressor Stations, and specific launchers and receivers at each of those Compressor Stations, in Ohio subject to Paragraph 18;

"Appendix 5" is a list of MarkWest Stand-Alone Facilities, and specific launchers and receivers at each of those Stand-Alone Facilities, in Ohio subject to Paragraph 19;

"Appendix 6" is a list of MarkWest Stand-Alone Facilities in Pennsylvania and in Ohio subject, as applicable, to Paragraphs 21 and 23;

"Appendix 7" is the Humphreys Ambient Air Monitoring SEP for the Humphreys Compressor Station in Ohio; and

"Appendix 8" is the Harmon Creek Ambient Air Monitoring SEP for the Harmon Creek Gas Processing Plant in Pennsylvania.

Dated and entered this _____ day of _____, 2018.

_____

UNITED STATES DISTRICT JUDGE
Western District of Pennsylvania

THE UNDERSIGNED PARTY enters this Consent Decree in this action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR PLAINTIFF UNITED STATES OF AMERICA:

Date: 4/20/18

[redacted]

JEFFREY H. WOOD
Acting Assistant Attorney General
Environment & Natural Resources Division
United States Department of Justice
950 Pennsylvania Avenue, NW
Washington, DC 20530

Date: 4/20/18

[redacted]

MARK C. ELMER
Senior Counsel
Environmental Enforcement Section
Environment & Natural Resources Division
United States Department of Justice
999 18th Street, South Terraces, Suite 370
Denver, Colorado 80202

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY:

Date: April 16, 2018

[redacted]
ROSEMARIE KELLEY
Director, Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC 20460

Date: April 16, 2018

[redacted]
APPLE CHAPMAN
Deputy Director, Air Enforcement Division
Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC 20460

Date: April 16, 2018

[redacted]
KATHRYN PIRROTTA CABALLERO
Senior Attorney, Air Enforcement Division
Office of Civil Enforcement
Office of Enforcement and Compliance Assurance
United States Environmental Protection Agency
Washington, DC 20460

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 3:

4/16/2018
Date

[redacted]
COSMO SERVIDIO
Regional Administrator
United States Environmental Protection Agency, Region III

4/15/18
Date

[redacted]
MARY B. COE
Regional Counsel
Office of Regional Counsel
United States Environmental Protection Agency, Region III
Philadelphia, PA 19103

4/16/18
Date

[redacted]
DOUGLAS J. SNYDER
Assistant Regional Counsel
Office of Regional Counsel
United States Environmental Protection Agency, Region III
Philadelphia, PA 19103

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 5:

4/19/2018
Date

[redacted]

T. LEVERETT NELSON
Regional Counsel
Office of Regional Counsel
United States Environmental Protection
Agency, Region V
Chicago, IL 60604

THE UNDERSIGNED PARTY enters this Consent Decree in the action captioned *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR PLAINTIFF COMMONWEALTH OF PENNSYLVANIA, DEPARTMENT OF ENVIRONMENTAL PROTECTION:

4/11/18
Date

[redacted]
GEORGE HARTENSTEIN
Deputy Secretary for Waste Air
Radiation and Remediation
Department of Environmental Protection
Rachel Carson State Office Building
400 Market Street
Harrisburg, PA 17101

Ap. 14, 2018
Date

[redacted]
ALEXANDRA C. CHIARUTTINI
Chief Counsel
Department of Environmental Protection
Rachel Carson State Office Building
400 Market Street
Harrisburg, PA 17101

April 19, 2018
Date

[redacted]
MICHAEL J. HEILMAN
Assistant Regional Counsel
Department of Environmental Protection
Office of Chief Counsel
400 Waterfront Drive
Pittsburgh, PA 15222

THE UNDERSIGNED PARTIES enter into this Consent Decree in the matter of *United States, et al. v. MarkWest Liberty Midstream & Resources, L.L.C., et al.*

FOR DEFENDANT MARKWEST LIBERTY MIDSTREAM & RESOURCES, L.L.C.

Date: April 13, 2018

[redacted]

MICHAEL J. HENNIGAN
President
MarkWest Liberty Midstream & Resources, L.L.C.

FOR DEFENDANT OHIO GATHERING COMPANY, L.L.C.

Date: April 13, 2018

[redacted]

MICHAEL J. HENNIGAN
President
Ohio Gathering Company, L.L.C.

APPENDIX 1

Pennsylvania Compressor Stations Subject to Paragraph 12

Compressor Station	Coordinates
1. 3 Brothers	40.33119792490, -80.38033471710
2. Baker	40.08051389, -80.222575
3. Brigich	40.28964213860, -80.23951772010
4. Carpenter	40.11364210760, -80.48247261960
5. Dryer	40.24287923210, -80.46833245070
6. Fulton	40.28485243400, -80.30122700440
7. Godwin	40.24572395910, -80.31131155010
8. Hoskins	40.17991189320, -80.41232597640
9. Johnston	40.27515606030, -80.23270970570
10. Lowry	40.24932187010, -80.36840279130
11. Redd	40.14328889, -80.19907778
12. Royal Oak	40.76560317060, -80.03657298740
13. Shaw	40.23917195340, -80.28146975710

Compressor Station	Coordinates
14. Smith	40.41698982380, -80.35687488560
15. Stewart	40.28269070850, -80.34980728680
16. Trillith	40.85454091700, -80.10256057730
17. Tupta Day	40.11326944, -80.22364167
18. Voll	40.83941511830, -80.05602366480
19. Welling	40.19014693410, -80.35981800720

Appendix 2

Pennsylvania Compressor Stations Subject to Paragraph 13

Compressor Station	Coordinates
1. 3 Brothers	40.33119792490, -80.38033471710
2. Carpenter	40.11364210760, -80.48247261960
3. Royal Oak	40.76560317060, -80.03657298740
4. Smith	40.41698982380, -80.35687488560
5. Trillith	40.85454091700, -80.10256057730
6. Welling	40.19014693410, -80.35981800720

Appendix 3

Applicability of Injunctive Relief in Paragraph 14 to Launchers and Receivers at Pennsylvania Stand-Alone Facilities

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
1. Huntington Farms			40.24179301380, -80.31836096160
a. Godwin to Huntington Farms HP Receiver	Yes	Yes	
b. Huntington Farms to Houston HP Launcher	Yes	No	
c. Huntington Farms to Welling HP Launcher	Yes	No	
d. Huntington Farms to Shaw HP Launcher	Yes	No	
e. Lowry to Huntington Farms HP Receiver	Yes	Yes	
f. Lowry Meter to Huntington Farms LP Receiver	No	Yes	

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
2. Loffert (Joe Cain)			40.35937332930, -80.31124654080
a. 3 Bros to Loffert (Joe Cain) HP Receiver	Yes	Yes	
b. Loffert (Joe Cain) to Drugmand HP Launcher	Yes	No	
c. Smith to Loffert (Joe Cain) HP Receiver	Yes	Yes	
d. Airport to Loffert (Joe Cain) LP Receiver	No	Yes	
e. Malinky LP Receiver	No	Yes	
3. Post Road			40.16793683830, -80.39937478710
a. Hoskins to Post Road HP Receiver	No	Yes	
4. Route 18			40.33220420730, -80.36049705900
a. Stewart to Rt 18 HP Receiver	No	Yes	

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
b. Carns to Rt 18 LP Receiver	No	Yes	
c. Inches to Rt 18 LP Receiver	No	Yes	
5. Smith Tee			40.22352411360, -80.45690851150
a. Dryer to Smith Tee HP Receiver	No	Yes	
b. Smith Tee to Hoskins HP Launcher	No	No	
c. Smith Tee to Lowry HP Launcher	No	No	
6. Wilhelm			40.10854085660, -80.44762638940
a. Welling to Wilhelm HP Receiver	Yes	Yes	
b. Wilhelm to Carpenter HP Receiver	Yes	Yes	
c. Wilhelm to Majorsville HP Launcher	Yes	No	

Stand-Alone Facility	¶ 14.a.-b. Apply? (Install and Use Jumper Line)	¶ 14.c. Applies? (Install and Use Pig Ramp)	Coordinates
d. Claysville to Wilhelm LP Receiver	No	Yes	
e. Greathouse to Wilhelm LP Receiver	No	Yes	
f. Hamilton to Wilhelm LP Receiver	No	Yes	

Appendix 4

Applicability of Injunctive Relief in Paragraph 18 to Launchers and Receivers at Ohio Compressor Stations

Compressor Station	¶ 18.a.-b. Apply? (Install and Use Jumper Line)	¶ 18.c. Applies? (Install and Use Pig Ramp)	¶ 18.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
1. Arrowhead				40.175580, -81.073237
a. 70T to Arrowhead HP Receiver	Yes	Yes	Yes	
b. Arrowhead to Cadiz Launcher	Yes	No	Yes	
c. Wagner to Arrowhead Receiver	No	Yes	No	
d. Darla to Arrowhead Receiver	No	Yes	No	
e. Miller Road to Arrowhead Receiver	No	Yes	No	
2. Barnesville West				40.009219, -81.181596
a. Barnesville West 12” Launcher	Yes	No	Yes	
b. Magee to Barnesville West Receiver	No	Yes	No	
c. 70T to Barnesville West Receiver	No	Yes	No	
3. Harrison West				40.209936, -81.217978
a. Harrison West to Cadiz Launcher	Yes	No	Yes	
b. Scott Hill to Harrison West Receiver	No	Yes	No	
c. Clay 20” Receiver	No	Yes	No	
4. Humphreys				39.906906, -81.188574
a. Humphreys to Tri-County Launcher	Yes	No	Yes	
b. Wheatley to Humphreys Receiver	No	Yes	Yes	

Compressor Station	¶ 18.a.-b. Apply? (Install and Use Jumper Line)	¶ 18.c. Applies? (Install and Use Pig Ramp)	¶ 18.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
c. Stronz Receiver	No	Yes	No	
d. Stuzman Receiver	No	Yes	No	
5. Lake				40.278232, -81.181580
a. Lake to Cadiz Launcher	Yes	No	Yes	
b. Central to Lake Receiver	No	Yes	No	
c. Kinsey Receiver	No	Yes	No	
d. Boy Scout Receiver	No	Yes	No	
6. Morristown				40.058737, -81.096102
a. Morristown 12” Launcher	Yes	No	Yes	
b. Morristown 20” Receiver	No	Yes	No	
7. Tri-County				39.939357, -81.227774
a. Shannon to Tri-County Receiver	Yes	Yes	Yes	
b. Tri-County to Seneca Launcher	Yes	No	Yes	
c. Tri-County to McCort 20” Launcher	No	No	Yes	
d. Humphreys to Tri-County Receiver	Yes	Yes	Yes	
e. Tri-County to Magee Launcher	No	No	Yes	

Appendix 5

Applicability of Injunctive Relief in Paragraph 19 to Launchers and Receivers at Stand-Alone Facilities in Ohio

Stand-Alone Facility	¶ 19.a.-b. Apply? (Install and Use Jumper Line)	¶ 19.c. Applies? (Install Pig Ramp)	¶ 19.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
1. 70T				40.047342, -81.143914
a. Shannon to 70T Receiver	Yes	Yes	Yes	
b. 70T to Arrowhead Launcher	Yes	No	Yes	
c. Morristown 12" Receiver	Yes	Yes	Yes	
2. 513 Station				40.002087, -81.301192
a. 513 to Magee Launcher	No	No	Yes	
b. Neff Receiver	No	Yes	Yes	
c. Flesher Receiver	No	Yes	Yes	
3. BK Stevens Station				40.195014, -81.172019
a. BK Stevens Launcher	No	No	Yes	
b. Michael 12" Receiver	No	Yes	No	
4. Blaze Station				40.109623, -81.296475
c. Blaze Road Launcher	No	No	Yes	
d. Lawson Receiver	No	Yes	No	
5. Marshall Road Station				40.109600, -81.333299
a. Guernsey 20" Launcher	No	No	Yes	
b. Blaze Road Receiver	No	Yes	Yes	
c. Guernsey 12" Receiver	No	Yes	No	
6. Smyrna McClelland Station				40.199200, -81.245391
a. Guernsey 20" Receiver	No	Yes	Yes	
b. Clay 12" Receiver	No	Yes	No	
c. Clay 20" Launcher	No	No	No	
7. Boston McCort Receiver Station				39.921722, -81.207956
a. McCort to Wheatley	No	No	Yes	

Stand-Alone Facility	¶ 19.a.-b. Apply? (Install and Use Jumper Line)	¶ 19.c. Applies? (Install Pig Ramp)	¶ 19.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
Launcher				
b. Tri-County to McCort 20" Receiver	No	Yes	Yes	
c. McCort 12" Receiver	No	Yes	No	
8. McGee Station				39.945758, -81.234022
a. 513 to McGee Receiver	No	Yes	Yes	
b. McGee to Barnsville West Launcher	No	No	Yes	
c. Tri-County to McGee Receiver	No	Yes	Yes	
d. Brothers Receiver	No	Yes	No	
9. Neff Station				39.994326, -81.385291
a. Neff Launcher	No	No	Yes	
b. Shugert Daddy Receiver	No	Yes	No	
c. Onega Receiver	No	Yes	No	
d. Detweiler Receiver	No	Yes	No	
10. Oxford Siefert Station				40.028938, -81.305076
a. Flesher Launcher	No	No	Yes	
b. Karen Receiver	No	Yes	No	
11. Shannon				40.015606, -81.191986
a. Shannon to Tri-County Receiver	Yes	Yes	Yes	
b. Shannon to 70T Launcher	Yes	No	Yes	
Barnesville West 12" Receiver	Yes	Yes	Yes	
12. Scott Hill Station				40.213707, -81.199295
a. Scott Hill to Harrison West Launcher	No	No	No	

Stand-Alone Facility	¶ 19.a.-b. Apply? (Install and Use Jumper Line)	¶ 19.c. Applies? (Install Pig Ramp)	¶ 19.d. Applies? (Use of Mobile Flare as Necessary)	Coordinates
b. BK Stevens Receiver	No	Yes	No	
c. Scott Hill to Yoder Launcher	No	No	No	
13. Wheatley Station				39.910131, -81.201674
a. McCort to Wheatley Receiver	No	Yes	Yes	
b. Wheatley to Humphreys Launcher	No	No	Yes	

Appendix 6

Pennsylvania and Ohio Stand-Alone Facilities Subject to Paragraph 21

Pennsylvania

	Stand-Alone Facility	Coordinates	
1.	Airport L/R Site	40.37395927760,	-80.30305865130
2.	Amwell Meter Site	40.14614613440,	-80.20302966240
3.	Best Site L/R Site	40.23147156770,	-80.33893228910
4.	Brenckle Header	40.84400668670,	-80.01438657980
5.	Bowen Rd L/R Site	40.35620228600,	-80.29091780790
6.	Drugmand L/R Site	40.32121915270,	-80.30277507650
7.	Meter Site Greco	40.09104915880,	-80.20974335020
8.	Houston National Fuel M&R Site	40.24940452070,	-80.34876507660
9.	Lowry Meter Station & L/R Site	40.24942497510,	-80.34873637460
10.	Mounts Road L/R Site	40.13289991020,	-80.31682797040
11.	Hoskins L/R Station	40.24945714620,	-80.26379790300
12.	Patterson Rd (Avella) L/R Site	40.27381420040,	-80.42744742360
13.	ROW Bame	40.81714493130,	-80.08961472930
14.	ROW Bare	40.41178582760,	-80.35589611000
15.	ROW Behm	40.79583936330,	-80.04148611180
16.	ROW Best	40.23164739230,	-80.33641676650
17.	ROW Breakneck	40.77764731670,	-80.08564275290
18.	Claysville Taylorstown Rd L/R Site	40.14849469170,	-80.40984054650

	Stand-Alone Facility	Coordinates	
19.	Fallen Timber Rd L/R Site	40.27072933350,	-80.49157469860
20.	Hillcrest Ln L/R Site	40.21167059680,	-80.34995610710
21.	Scenic Dr (Chase) L/R Site	40.19905575650,	-80.44969751100
22.	Fox Road (Cravat Coal) L/R Site	40.20519747190,	-80.42570011420
23.	Oakleaf Rd L/R Site	40.25409971610,	-80.37131701950
24.	Lynn Portal Rd L/R Site	40.25874697060,	-80.36964903040
25.	Grimes L/R Site	40.13299991620,	-80.43109470140
26.	McGowan Rd L/R Site	40.14279324820,	-80.22140131220
27.	Buck Run Rd L/R Site	40.18536844860,	-80.44308026640
28.	Brush Run Rd L/R Site	40.20720289960,	-80.37080643150
29.	Scenic Dr (Falconi) L/R Site	40.26595604250,	-80.46084767610
30.	Deerfield Rd L/R Site	40.11630590800,	-80.27285940870
31.	ROW Hamilton	40.85929594380,	-80.14286462350
32.	Pleasant Valley Rd (Hanes) L/R Site	40.16377825080,	-80.34140927220
33.	Buck Run Rd (Hercules) L/R Site	40.13837364120,	-80.42497159930
34.	Toll Gate Rd L/R Site	40.10314260290,	-80.46782350840
35.	ROW JRGL	40.84398338570,	-80.10487271690
36.	Hackney Station Rd L/R Site	40.03182652570,	-80.21131940660
37.	Valleyview Rd L/R Site	40.40304581570,	-80.33243646710
38.	Sugar Run Rd	40.23188521750,	-80.47933489330
39.	Meddings Rd (Little) L/R Site	40.26507985420,	-80.23774634660

	Stand-Alone Facility	Coordinates	
40.	ROW LL Property	40.84029348320,	-80.08598831230
41.	Walker Rd L/R Site	40.35085903180,	-80.42689905960
42.	Strope Rd L/R Site	40.33513883610,	-80.44326981090
43.	Nickolay Rd L/R Site	40.30167354440,	-80.40734222390
44.	McMaster L/R Site	40.31124638210,	-80.30097450590
45.	Caldwell Rd L/R Site	40.28261382140,	-80.35555972230
46.	ROW Pallack	40.85004087970,	-80.08157787530
47.	ROW Parees	40.38722027540,	-80.30502008320
48.	Scenic Dr (Pete Zappi) L/R Site	40.20364205010,	-80.44809086520
49.	McAdams Rd (Phelan) L/R Site	40.09539268620,	-80.22951699520
50.	Carns Lane L/R Site	40.32423905170,	-80.36576671750
51.	ROW Powell	40.74363745330,	-79.9604929242(
52.	Patterson Rd (R. Margaria) L/R Site	40.28723537050,	-80.43589296710
53.	Agape Rd (Rukavina) L/R Site	40.26725418690,	-80.36329205560
54.	Fox Rd (Rush) L/R Site	40.22866432510,	-80.42395307960
55.	Patterson Ln (L/R) Site	40.22064084750,	-80.33797828550
56.	Joffre Cherry Valley Rd L/R Site	40.35359238190,	-80.33301815770
57.	ROW Schilling	40.75341364380,	-79.99506226040
58.	Dille Rd (Strawn) L/R Site	40.04603091090,	-80.24107217480
59.	ROW Varner	40.17378970270,	-80.46539519780
60.	Lynn Rd L/R Site	40.22840547500,	-80.32462392150

	Stand-Alone Facility	Coordinates	
61.	ROW Warner	40.84397086940,	-80.11171987180
62.	ROW West	40.75104115670,	-79.97716026150
63.	Dille Rd (Whitmer) L/R Site	40.04048742890,	-80.23640364280
64.	Sharp Meter Site (Ridge Ave L/R Site)	40.26769369990,	-80.21010761160
65.	Swain Hill	40.81898776310,	-80.08484177090
66.	Temple T L/R Site	40.22417625130,	-80.44906886280
67.	Agape Rd (Triple) L/R Site	40.26804165920,	-80.36563975230
68.	Well Pad Bare	40.40342650950,	-80.37723290090
69.	Well Pad Behm	40.79672204020,	-80.03451440360
70.	Well Pad BNBC	40.77079850210,	-80.10355358670
71.	Well Pad Breakneck	40.77075318260,	-80.10355581720
72.	Well Pad Burgh	40.87569389260,	-80.12625895460
73.	Well Pad Carol Baker	40.23009012030,	-80.27796334060
74.	Well Pad Carson B	40.84625933330,	-80.03219656250
75.	Well Pad Chase	40.20175530230,	-80.46770417890
76.	Durkacs L/R Site	40.283977778,	-80.229130555
77.	Well Pad Eleanor West	40.20710177410,	-80.38557015700
78.	Well Pad Ferree	40.72843685230,	-79.90603378450
79.	Well Pad Franklin 2	40.14094073750,	-80.26221722840
80.	Well Pad Gilliland	40.84241439010,	-80.03392781810
81.	Well Pad John Miller	40.21521587750,	-80.31559765760

Stand-Alone Facility		Coordinates	
82.	Well Pad Kraeer	40.21816609360,	-80.45752184520
83.	Well Pad Lynn	40.82164973840,	-79.96377223130
84.	Well Pad MCC	40.34397056500,	-80.43256951140
85.	Well Pad McElhinney	40.77986241940,	-80.01889964030
86.	Well Pad Meyer	40.77357077330,	-80.08385907690
87.	Well Pad Midler A	40.29650600530,	-80.41270793020
88.	Well Pad Paxton	40.25621631280,	-80.24725325410
89.	Well Pad Plesniak	40.87216680500,	-80.08007954920
90.	Well Pad Pollana	40.30559829300,	-80.36009428140
91.	Well Pad R. Margaria	40.28531146480,	-80.43233486240
92.	Well Pad Stebbins	40.79463038620,	-79.96722033100
93.	Well Pad Stefkovich	40.27733921230,	-80.45377227360
94.	Well Pad Talarico	40.79264245230,	-80.08005861390
95.	Well Pad Worstell	40.27474883780,	-80.21630888150
96.	Well Pad Aloe	40.36361111,	-80.2692444
97.	Well Pad Imperial East	40.38121944,	-80.25612778
98.	Well Pad Imperial North	40.3847611,	-80.27874444
99.	Well Pad Charelli	40.3543667,	-80.28129722
100.	Well Pad Drugmand	40.32065,	-80.3023578
101.	Well Pad Franklin 1	40.15145556,	-80.25371667
102.	Well Pad June Hoskins	40.24821111,	-80.2627001

Stand-Alone Facility		Coordinates	
103.	Well Pads Wylie	40.26177222,	-80.27190833
104.	Well Pad Avella Lands	40.27136944,	-80.43052778
105.	Well Pad Breese	40.14353611,	-80.39037778
106.	Well Pad Campbell	40.27816389,	-80.48513611
107.	Well Pad Chappel	40.21136111,	-80.35252778
108.	Well Pad Cravit Coal	40.20503611,	-80.42930833
109.	Well Pad CC 41-44	40.25441944,	-80.37799167
110.	Well Pad CC 6-9, 25	40.25972778,	-80.38564167
111.	Well Pad Old McDonald	40.12071111,	-80.43345013
112.	Well Pad Earl Redd	40.14277778,	-80.22141111
113.	Well Pad Falconi	40.26966389,	-80.50097221
114.	Well Pad Folly Hollow	40.11380833,	-80.26863056
115.	Well Pad Georgetti	40.24512222,	-80.48410833
116.	Well Pad McAdoo	40.21458333,	-80.49498056
117.	Well Pad Goettle	40.23987778,	-80.46559444
118.	Well Pad Kennedy	40.23206389,	-80.48385556
119.	Well Pad Hanes	40.16891944,	-80.35004722
120.	Well Pad Hercules	40.14573611,	-80.42516944
121.	Well Pad Hunter	40.09600278,	-80.47336945
122.	Well Pad Kearny	40.02977222,	-80.21465833
123.	Well Pad Kendall	40.40645556,	-80.32643333
124.	Well Pad MCC West	40.33761389,	-80.44501944

Stand-Alone Facility		Coordinates	
125.	Well Pad McIntyre	40.29370278,	-80.39157778
126.	Well Pad Minichi	40.30496389,	-80.32689444
127.	Well Pad McMasters	40.31078056,	-80.30234722
128.	Well Pad Ohio Valley	40.27660556,	-80.34920833
129.	Well Pad Johnston	40.27631389,	-80.23965278
130.	Well Pad Painter	40.27277222,	-80.25871111
131.	Well Pad Parees	40.39088611,	-80.299152778
132.	Well Pad Pete Zappi	40.20325556,	-80.44185833
133.	Well Pad Phelan	40.09114722,	-80.24646389
134.	Well Pad Rukavina	40.26523333,	-80.36197501
135.	Well Pad Rush	40.22270556,	-80.41881111
136.	Well Pad R. Carslise	40.21708056,	-80.33216389
137.	Well Pad Sasso	40.36851111,	-80.35763889
138.	Well Pad Strawn	40.04582222,	-80.25218888
139.	Well Pad Varner	40.172416667,	-80.46723056
140.	Varner to E. Zappi Launcher	40.17558889,	-80.46682503
141.	Well Pad Ward	40.22967003,	-80.32365278
142.	Well Pad Whitmer	40.02379167,	-80.24307502
143.	Well Pad Costanzo	40.26727222,	-80.35452778
144.	Well Pad Yanavich	40.21778333,	-80.26991667
145.	Well Pad Dorothy Green	40.19993611,	-80.47827501
146.	Well Pad Troyer Farms	40.28809722,	-80.21635833

Stand-Alone Facility		Coordinates	
147.	Well Pad Khouri	40.20993889,	-80.40015015
148.	Well Pad Kopko	40.21137778,	-80.29239724
149.	Well Pad Kraeer West	40.21553333,	-80.46209722
150.	Well Pad Carnes Donald	40.28363889,	-80.38654723
151.	Well Pad Lehman	40.29895555,	-80.37828333
152.	Well Pad Kancel	40.28785556,	-80.41620278
153.	Well Pad W. Cowden	40.30847503,	-80.37043611
154.	Well Pad CC 17-19, 45-47	40.26315002,	-80.40854722
155.	Well Pad Photon	40.26468333,	-80.21717505
156.	Well Pad L. Smith	40.12773611,	-80.34577801
157.	ROW L. Smith L/R	40.11939442,	-80.34563611
158.	Well Pad A&D Ferguson	40.29096667,	-80.24841667
159.	Well Pad Engle	40.30635278,	-80.23452504
160.	Well Pad Bloom	40.84400691,	-80.01438658
161.	Well Pad Bricker	40.85586944,	-80.02126111
162.	Well Pad Graham	40.83919444,	-80.05586667
163.	Well Pad Shipley	40.82048333,	-80.00895556
164.	Well Pad Ballie Trust	40.76065556,	-80.08748065
165.	Well Pad Lamperski	40.80330833,	-80.02951111
166.	Well Pad R. Knauf	40.80346111,	-80.06258889
167.	Well Pad Burr-Brennan	40.87219167,	-80.04880833
168.	Well Pad Ceasar	40.88700833,	-80.09868889

Stand-Alone Facility		Coordinates	
169.	Well Pad Flinner	40.89144167,	-80.07206667
170.	Well Pad Hamilton	40.85896944,	-80.14835005
171.	Well Pad L&L Properties	40.83417502,	-80.08932503
172.	Well Pad Pallack	40.85868333,	-80.09930556
173.	Well Pad Schilling	40.75428334,	-79.99429722
174.	Well Pad Reno	40.73497781,	-79.89145278
175.	Well Pad West	40.74006111,	-79.99027503
176.	Well Pad R. Double	40.79726112,	-80.08143056
177.	Well Pad JRGL	40.81681389,	-80.12953611
178.	Well Pad Powell	40.76466944,	-79.94619167
179.	Well Pad Perry	40.87980556,	-80.18103611
180.	Well Pad Warner	40.84784722,	-80.11418333
181.	Well Pad Bell	40.76255556,	-80.13437222
182.	Well Pad Bame	40.80087222,	-80.09644278
183.	Well Pad Alex Paris	40.29338333,	-80.46162222
184.	Well Pad Bedillion Day	40.11590833,	-80.22677222
185.	Well Pad Bigley	40.13135833,	-80.18826388
186.	Well Pad Burkett	40.32740555,	-80.45561111
187.	Well Pad Carns	40.32583888,	-80.37212777
188.	Well Pad Clingerman	40.25311388,	-80.32005833
189.	Well Pad Farabee	40.06371666,	-80.20518888
190.	Well Pad Gillett	40.18281666,	-80.36071067

Stand-Alone Facility		Coordinates	
191.	Well Pad Godwin	40.24441389,	-80.30912499
192.	Well Pad Noble-Greathouse	40.10858889,	-80.44535564
193.	Well Pad Inches	40.34806667,	-80.36915556
194.	Well Pad John Day	40.12205834,	-80.21701670
195.	Well Pad Kearns	40.20641389,	-80.41984722
196.	Well Pad Lindley	40.03942778,	-80.29100833
197.	Well Pad Lois Miller	40.24075833,	-80.36516944
198.	Well Pad O'Donnell	40.23306944,	-80.35092230
199.	Well Pad Mele	40.25098889,	-80.29406944
200.	Buffalo Creek Launcher	40.17696388,	-80.40658333
201.	Prospect Road Launcher	40.80188333,	-80.05266944
202.	Well Pad Malinky	40.36193889,	-80.30718611
203.	Cowden Pad	40.329463888,	-80.282280555
204.	Elm Rd.	40.283461111,	-80.314280555
205.	Well Pad Constance Zappi	40.179097222,	-80.406086111
206.	Well Pad Little	40.255397222,	-80.236719444

Ohio

	Stand-Alone Facility	Coordinates
1.	Bolton Launcher Station	39.938144, -81.206353
2.	Wright Station	39.933098, -81.208784
3.	Caston Miller Receiver Station	40.130142, -81.323137
4.	Coal Run Eagle Creek Station	40.067335, -81.099467
5.	Eagle Creek Receiver Station	40.080931, -81.115004
6.	Groh Receiver Station	40.112375, -81.366465
7.	Heavillin Road Station	40.268289, -81.148645
8.	Inherst Station	39.889863, -81.177801
9.	Leatherwood Station	39.966288, -81.273205
10.	Greenlawn Road Station	39.985663, -81.287137
11.	Jones Station	39.79069, -81.059774
12.	Kinsey Station	40.289319, -81.279951
13.	Crum Road Station	39.861991, -81.045932
14.	National OCO Road Station	40.083685, -81.016877
15.	Miller Road Station	40.109296, -81.070266
16.	Eldon Road Station	39.950794, -81.259223
17.	Oak Hill Road Station	40.100566, -81.021299
18.	Old Piedmont Kimble Station	40.197874, -81.193600
19.	Ripley Station-2	40.144020, -81.305489
20.	Buskirk Lane Detweiler Station	39.994646, -81.393084

	Stand-Alone Facility	Coordinates
21.	Stutzman Station-2	39.891061, -81.171815
22.	Mt. Olivett Shugert Station - 3	40.038708, -81.146225
23.	Tyson Receiver Station	40.187745, -81.162444
24.	Westhawk Station	39.843335, -81.030991
25.	Wagner Station	40.1735277, -81.07825
26.	Boyscout Station	40.25867025, -81.21354888
27.	Mt. Olivett Shugert Station	40.04909476, -81.12826697
28.	BK Stephens-2	40.18575333, -81.1665594
29.	Stout Station	40.18622222, -81.20461111
30.	Clay Station	40.17324326, -81.22616504
31.	Noble Station	39.94673422, -81.28760737
32.	Marshall Road Station	40.1072222, -81.3307222
33.	Clark South Station	39.893337, -81.145224
34.	Shriver Station	39.840238, -81.046996
35.	Ohio 556 Station	39.856315, -80.996473
36.	Hudson Road Station	39.861175, -81.017864
37.	Trembly Ridge Road Station	39.809928, -81.040442
38.	Vozar Station	40.198232, -81.207992
39.	Caston Station	40.133954, -81.326833
40.	Lawson LND Station	40.127986, -81296972
41.	Bedway Station	40.076193, -81.024371
42.	McGee Station	39.94562771, -81.23406919

	Stand-Alone Facility	Coordinates
43.	Miller Station	40.12941667, -81.31125
44.	Puskarich Station	40.202308, -81.16281
45.	Bahmer Station	39.94816886, -81.20429452
46.	Red Hill Tarbert Station	40.201221, -81.179773
47.	Lake LND Stattion	40.148834, -81.297728
48.	Brothers Station	39.95147891, -81.21878497
49.	Triple B Station	40.06924617, -81.07527801
50.	Hayes Station	40.044293, -81.121239
51.	Shugert Daddy Station	40.00523641, -81.41198983
52.	Jones Launcher Station	40.25474023, -81.16676636
53.	Amanda Station	39.8886365, -81.17061957
54.	Wesley Station	39.89328118, -81.15947025
55.	Michael Station	40.19500259, -81.17202306
56.	Darla Station	40.17793958, -81.07410902
57.	Karen Station	40.02580771, -81.29045958
58.	Detweiler Station	39.98857029, -81.38588845
59.	Groh Station	40.11030961, -81.37014543
60.	Onega Station	39.99941027, -81.43802381
61.	Cadiz Road Piedmont Clay Station	40.17769444, -81.23427778
62.	J Anderson Station	39.974759, -81.270049
63.	J Hall Station	39.991753, -81.260724
64.	Stiers Station	39.951932, -81434505

	Stand-Alone Facility	Coordinates
65.	Swallie Station	40.039191, -81.139875
66.	Milliken Station	40.174307, -81.239336
67.	Stronz Station	39.931337, -81.123607

APPENDIX 7

HUMPHREYS AMBIENT AIR MONITORING SEP FOR THE HUMPHREYS COMPRESSOR STATION IN OHIO

A. General Requirements

1. Pursuant to Section VI of the Consent Decree, and in accordance with the specifications and provisions in this Appendix, MarkWest will install, operate, and maintain an ambient air monitoring system ("AAMS") at the Humphreys Compressor Station and provide data as required by this Appendix and the Consent Decree.

2. Within 120 Days of the Effective Date, MarkWest shall submit to EPA for review and approval a plan (the "Humphreys Monitoring Plan") that shall include, at a minimum:

   a. An identification of the location of the meteorological station required by this Appendix and how this location meets this Appendix's requirements.

   b. Compliance with the monitoring requirements in 40 C.F.R. Part 58, Appendix E, and in accordance with the NATTS guidance document available at https://www3.epa.gov/ttnamti1/files/ambient/airtox/NATTS%20TAD%20Revision%203_FINAL%20October%202016.pdf

   c. A Quality Assurance Project Plan ("QAPP") that describes the Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure: (i) that the results of this SEP meet project specifications; and (ii) the accuracy, validity, representativeness, and usability of the data obtained by all monitoring equipment, including the stationary equipment and systems identified in Section B of this Appendix (Stationary Equipment Requirements). The QAPP shall follow the outline and guidance in the EPA publication entitled "QA Handbook for Air Pollution Measurement Systems, Volume II, Ambient Air Quality Monitoring Program," EPA-454/B-13-003, May 2013.

   d. A description of the implementation of Data Availability (Paragraph 17) requirements of this Appendix.

   e. A schedule, with a start date contingent upon approval of the Humphreys Monitoring Plan, for expeditiously purchasing, installing, upgrading, and commencing operation of specifically-identified systems and equipment that met all requirements of this Appendix.

3. Upon EPA approval of the Humphreys Monitoring Plan, in compliance with the

schedule in the approved Humphreys Monitoring Plan, MarkWest shall purchase or lease all equipment specified in the Humphreys Monitoring Plan, shall complete the installation of all such equipment, and shall upgrade all systems or stations as set forth in the approved Humphreys Monitoring Plan.

4. MarkWest shall promptly correct deficient implementation of its Humphreys Monitoring Plan. Any disputes related to the Humphreys Monitoring Plan or this Appendix shall be resolved pursuant to the procedures set forth in Section XIII (Dispute Resolution) of the Consent Decree.

5. MarkWest may seek EPA approval to modify the Humphreys Monitoring Plan at any time during the effective period of this Consent Decree.

B. Stationary Equipment Requirements

6. Overview. The AAMS shall include:

   a. A meteorological station to monitor meteorological parameters (Paragraph 7);

   b. Upwind and downwind stations to monitor air pollutants (Paragraphs 8-12); and

   c. A Data Acquisition System for all upwind, downwind, and meteorological stations (Paragraph 13).

7. Instruments for Measuring and Recording Wind Speed, Wind Direction, Ambient Temperature, and Barometric Pressure. Specific meteorological parameters will be continuously monitored to obtain data representative of the meteorological conditions at each facility. The data set produced shall be adequate to correlate hourly block average conditions and thirty-minute rolling average conditions (collected on a five-minute basis) with pollutant measurements and transport.

   a. Continuously measured meteorological parameters shall include hourly block average and thirty-minute rolling average horizontal wind speed and wind direction, the standard deviation of horizontal wind direction (sigma theta), air temperature, and barometric pressure. Wind speed and direction shall be measured at a height of approximately 10 meters. Temperature and barometric pressure shall be measured at a height of 2 to 3 meters. The sensors shall, to the extent practicable, be positioned away from, or above, obstructions such as buildings, trees, and process units that may interfere with wind direction measurements.

   b. Wind direction and sigma theta measurement data shall be auto-corrected to True North, rounded to the nearest whole degree. Wind speed data shall be reported in meters per second, rounded to the nearest tenth.

c. Air temperature data shall be reported in degrees Fahrenheit or Celsius, rounded to the nearest tenth of a degree.

d. Barometric pressure data may be in any unit of pressure.

8. Air Pollutant Monitoring Stations: Equipment and Pollutant Measurement Capability. MarkWest shall install continuous auto-gas chromatographs for VOCs and separate continuous instruments for reduced sulfur compounds at each upwind and downwind monitoring station so that each station has each of the following:

a. Instruments capable of measuring and recording the concentrations of the following compounds in the air at a minimum detection level of 1.0 part per billion by volume (ppbV): propane, butane, pentane, hexane, benzene, toluene ethylbenzene, xylene and all of its isomers, and total VOCs. The data will be recorded as hourly block averages.

b. Instruments capable of measuring and recording the concentrations of reduced sulfur compounds at a minimum detection level of 1.0 ppbV. The data will be recorded as hourly block averages.

c. The continuous measurement of the compounds listed in Subparagraph 8.a. above, shall be accomplished using an auto-Gas Chromatograph ("GC"). The automated GCs shall be operated and maintained in accordance with the manufacturer's recommendations and shall have a measurement range of 1.0 to 500 ppbV for all gases.

d. The continuous measurement of reduced sulfur compounds, listed in Subparagraph 8.b. above, shall be accomplished using Teledyne API T102 Total Reduced Sulfur (TRS) analyzers. The instruments shall be operated and maintained in accordance with the manufacturer's recommendations, shall be operated in high sensitivity mode, and shall have a measurement range of 1.0 to 50 ppbV.

9. Air Pollutant Monitoring Stations: Temperature-Controlled Shelter: Each air pollutant monitoring station shall be operated inside a temperature-controlled equipment shelter.

a. The temperature within each shelter shall be continuously monitored and recorded using a calibrated resistance temperature detector ("RTD") and microprocessor or PC-based data acquisition system.

b. The climate control system for each monitoring shelter will be capable of maintaining a stable temperature within the range of 20ºC to 30ºC.

c. The monitoring shelters shall measure approximately 8 feet wide by 12 feet

long by 8 feet high.

d. Each shelter shall be anchored to the ground and be electrically grounded for safety.

e. The shelter walls and roofs will have a minimum insulation rating of R11.

f. Each shelter will be equipped with electrical service panels, interior electrical distribution circuits, lighting, workbench and sufficient space for housing, operating, and maintaining the monitoring instruments. All electrical wiring and appurtenances will conform to the National Electric Code (NEC).

10. Air Pollutant Monitoring Station Locations. The air pollutant monitoring stations shall be located at the following coordinates and identified as follows:

a. Humphreys Facility Upwind: Latitude: Longitude

b. Humphreys Facility Downwind: Latitude: Longitude

11. Air Pollutant Monitoring Systems Sampler Inlet Requirements. The sampler inlets for each monitoring station shall comply with the following requirements:

a. The sampler inlets should be 2 to 5 meters above ground and have unrestricted airflow 270 degrees around the sample inlet or 180 degrees if the sampler is on the side of a building.

b. The sampler inlets should be >20 meters from the dripline of any tree(s).

c. The sampler inlets should be >1 meter away from supporting structures and walls.

d. The distance from a sampler probe to an obstacle, such as a building, should be at least twice the height the obstacle protrudes above the sampler, probe, or monitoring path.

e. The sampler inlets should be away from minor sources, to avoid undue influences from minor sources. The separation distance is dependent on the height of the minor source's emission point, the type of fuel or waste burned, and the quality of the fuel.

12. Air Pollutant Monitoring Stations – Prohibition on Moving. MarkWest shall not move the pollutant monitoring stations to a new location without prior written approval by EPA. Movement of the pollutant monitoring station components for maintenance shall not be restricted by this Paragraph.

13. Data Acquisition System (DAS). A DAS will be used to log all numerical data generated by the air pollutant analyzers and weather instruments using a common time-stamp. The DAS also will be programmed to correct pollutant concentration data to standard temperature and pressure, and to automatically correlate pollutant data with wind direction. The DAS outputs shall be in a file format that can be used in common spreadsheet programs.

14. Nothing in this Appendix shall preclude the use of any other, additional fence line monitoring equipment and/or of monitoring other, additional pollutants at the fence line.

C. Operation of AAMS

15. MarkWest shall comply with all terms of this Appendix and the Humphreys Monitoring Plan, including but not limited to operating and maintaining the monitors, equipment, and systems described herein, for a period of no less than a total of 720 days.

16. Quality Assurance/Quality Control (QA/QC). MarkWest shall ensure that all data collected by the AAMS are subjected to the approved QA/QC procedures on a quarterly basis. The QA/QC procedures for a given quarter's data shall be completed by no later than the end of the quarter following the quarter within which the data were collected.

17. Data Submission. MarkWest shall provide Relevant Data on a quarterly basis, within 45 days of the end of each calendar quarter. For purposes of this Paragraph, "Relevant Data" shall mean the hourly block averages of propane, butane, pentane, hexane, benzene, toluene ethylbenzene, xylene and all of its isomers, total VOCs, and reduced sulfur compounds, wind speed, and wind direction that are collected during periods at all times. MarkWest shall submit the data in a manner that allows pollutant concentrations, wind speed, and wind direction to be viewed concurrently and indicate that these data meet the QA/QC procedures in Subparagraph C.16 of this Appendix. All numerical data shall be presented in a format that can be used in common spreadsheet programs. MarkWest shall maintain the Relevant Data collected through the AAMS as required by the Consent Decree.

18. Annual Reports. MarkWest shall prepare and submit at least two annual reports. These reports will detail the operation of the VOC, RSC, and meteorological equipment as well as any maintenance and service work performed at each monitoring location. These reports will contain data summaries, a summary of any problems encountered in the monitoring project and the status of any current problems and corrective actions performed, a summary of any meetings or correspondence addressing the monitoring program, a synopsis of percent recovery including brief explanations of missing data, overall data recovery, quality control, and all quality assurance documentation. Each report will include a fully quality□ assured hourly data file in Excel format and an Adobe Acrobat PDF copy of the

formalized report. Each report will be provided within 45 days of the end of each year-long monitoring period.

APPENDIX 8

AMBIENT AIR MONITORING SEP FOR THE HARMON CREEK GAS PROCESSING PLANT IN THE VICINITY OF SMITH TOWNSHIP, WASHINGTON COUNTY, PENNSYLVANIA

A. General Requirements

1. Pursuant to Section VI of the Consent Decree, and in accordance with the specifications and provisions in this Appendix, MarkWest will install, operate, and maintain an ambient air monitoring system in the vicinity of the proposed Harmon Creek Gas Processing Plant ("HC") in Smith Township, Washington County, Pennsylvania and provide data as required by this Appendix and the Consent Decree (hereinafter the "Harmon Creek Monitoring System").

2. Within 120 Days of the Effective Date, MarkWest shall submit to EPA and PADEP for review and, following consultation with PADEP, approval by EPA a plan (the "Harmon Creek Monitoring Plan") that shall include, at a minimum:

   a. The proposed location of the meteorological station required by this Appendix, a discussion of how the location meets the siting criteria discussed below, the specifications of the station, a discussion of how these specifications meet the data measurement criteria discussed below, and the proposed date for installation and operation. Before submitting the complete Harmon Creek Monitoring Plan, MarkWest may submit a separate plan for installing the meteorological station in order to speed installation and operation of the station.

   b. A description of the three VOC monitors to be installed, how this monitoring equipment meets the criteria discussed below, and a schedule for proposing the specific locations of this monitoring equipment.

   c. Compliance with the monitoring requirements in 40 C.F.R. Part 58, Appendix E, and in accordance with the NATTS guidance document available at https://www3.epa.gov/ttnamti1/files/ambient/airtox/NATTS%20TAD%20Revision%203_FINAL%20October%202016.pdf

   d. A Quality Assurance Project Plan ("QAPP") that describes the Quality Assurance/Quality Control procedures, specifications, and other technical activities to be implemented to ensure: (i) that the results of this SEP meet project specifications; and (ii) the accuracy, validity, representativeness, and usability of the data obtained by all monitoring equipment, including the stationary equipment and systems identified in Section B of this Appendix (Stationary Equipment Requirements). The QAPP shall follow the outline and guidance in the EPA publication entitled "QA Handbook for Air

Pollution Measurement Systems, Volume II, Ambient Air Quality Monitoring Program," EPA-454/B-13-003, May 2013.

e. A description of the implementation of Data Availability (Paragraph 17) requirements of this Appendix.

f. A schedule, with a start date contingent upon approval of the Harmon Creek Monitoring Plan, for (i) expeditiously purchasing, installing, upgrading, and commencing operation of specifically-identified systems and equipment that meet all requirements of this Appendix and (ii) completing the monitoring and submitting a final report to EPA and PADEP.

3. Upon EPA approval, after consultation with PADEP, of the Harmon Creek Monitoring Plan, MarkWest shall purchase all equipment specified in the plan, shall complete the installation of all such equipment, and shall upgrade all systems or stations as set forth in the schedule in the approved plan.

4. MarkWest shall promptly correct deficient implementation of its Harmon Creek Monitoring Plan. Any disputes related to the plan or this Appendix shall be resolved pursuant to the procedures set forth in Section XIII (Dispute Resolution) of the Consent Decree.

5. MarkWest may seek EPA approval to modify the Harmon Creek Monitoring Plan at any time during the effective period of this Consent Decree. EPA will consult with PADEP on any such request.

B. Stationary Equipment Requirements

6. Overview. The Harmon Creek Monitoring System shall include:

a. A meteorological station to monitor meteorological parameters (Paragraph 7);

b. Three air pollutant monitoring stations: one located a short distance upwind of HC ("Upwind Station"), one located a short distance downwind of HC ("Near Downwind Station"), and one located further downwind (approximately 1 – 3 km) of HC ("Far Downwind Station") (collectively referred to as "Air Pollutant Monitoring Stations") (Paragraphs 8-12); and

c. A Data Acquisition System for all Air Pollutant Monitoring Stations and the meteorological station (Paragraph 13).

7. Instruments for Measuring and Recording Wind Speed, Wind Direction, Ambient Temperature, and Barometric Pressure. Specific meteorological parameters will be continuously monitored to obtain data representative of the meteorological conditions at HC. The data set produced shall be adequate to correlate hourly block

average conditions and thirty-minute rolling average conditions (collected on a five-minute basis) with pollutant measurements and transport.

a. Continuously measured meteorological parameters shall include hourly block average and thirty-minute rolling average horizontal wind speed and wind direction, the standard deviation of horizontal wind direction (sigma theta), air temperature, and barometric pressure. Wind speed and direction shall be measured at a height of approximately 10 meters. Temperature and barometric pressure shall be measured at a height of 2 to 3 meters. The sensors shall, to the extent practicable, be positioned away from, or above, obstructions such as buildings, trees, and process units that may interfere with wind direction measurements.

b. Wind direction and sigma theta measurement data shall be auto-corrected to True North, rounded to the nearest whole degree. Wind speed data shall be reported in meters per second, rounded to the nearest tenth.

c. Air temperature data shall be reported in degrees Fahrenheit or Celsius, rounded to the nearest tenth of a degree.

d. Barometric pressure data may be in any unit of pressure.

8. Air Pollutant Monitoring Stations: Equipment and Pollutant Measurement Capability. MarkWest shall install the following equipment at each of the Air Pollutant Monitoring Stations:

a. Instruments capable of measuring and recording the concentrations of the following compounds in the air at a minimum detection level of 1.0 part per billion by volume (ppbV): C_2 to C_6 (i.e. from ethane through 1,3-butadiene up to benzene) and up to 32 compounds from C_6 to C_{12} (hexane, dimethylbutane, diethylbenzene, naphthalene, dodecane, BTEX, and halogen compounds), and total VOCs. The VOC data will be recorded as hourly averages.

b. An auto gas chromatograph ("GC") shall be employed to accomplish the continuous measurement of the compounds listed in Subparagraph 8.a. above. The automated GC shall be operated and maintained in accordance with the manufacturer's recommendations and shall have a measurement range of 1.0 to 500 ppbV for all gases.

9. Air Pollutant Monitoring Stations: Temperature-Controlled Shelter: Each air pollutant monitoring station shall be operated inside a temperature-controlled equipment shelter.

a. The temperature within each shelter shall be continuously monitored and recorded using a calibrated resistance temperature detector ("RTD") and

microprocessor or PC-based data acquisition system.

b. The climate control system for each monitoring shelter will be capable of maintaining a stable temperature within the range of 20ºC to 30ºC.

c. The monitoring shelters shall measure approximately 8 feet wide by 8 feet long by 8 feet high.

d. Each shelter shall be anchored to the ground and be electrically grounded for safety.

e. The shelter walls and roofs will have a minimum insulation rating of R11.

f. Each shelter will be equipped with electrical service panels, interior electrical distribution circuits, lighting, workbench and sufficient space for housing, operating, and maintaining the monitoring instruments. All electrical wiring and appurtenances will conform to the National Electric Code (NEC).

10. Air Pollutant Monitoring Systems Sampler Inlet Requirements. The sampler inlets for each monitoring station shall comply with the following requirements:

a. The sampler inlets should be 2 to 5 meters above ground and have unrestricted airflow 270 degrees around the sample inlet or 180 degrees if the sampler is on the side of a building.

b. The sampler inlets should be >20 meters from the dripline of any tree(s).

c. The sampler inlets should be >1 meter away from supporting structures and walls.

d. The distance from a sampler probe to an obstacle, such as a building, should be at least twice the height the obstacle protrudes above the sampler, probe, or monitoring path.

e. The sampler inlets should be away from minor sources, to avoid undue influences from minor sources. The separation distance is dependent on the height of the minor source's emission point, the type of fuel or waste burned, and the quality of the fuel.

f. Each Air Pollutant Monitoring System shall be housed in a climate controlled monitoring shelter and shall draw air through a sampling tube that meets the criteria at https://www3.epa.gov/ttn/amtic/files/ambient/pams/newtad.pd.

11. Air Pollutant Monitoring Stations – Prohibition on Moving. MarkWest shall not

move the pollutant monitoring stations to a new location without prior written approval by EPA, following consultation with PADEP. Movement of the pollutant monitoring station components for maintenance shall not be restricted by this Paragraph.

12. Data Acquisition System ("DAS"). A DAS will be used to log all numerical data generated by the air pollutant analyzers and weather instruments using a common time-stamp. The DAS also will be programmed to correct pollutant concentration data to standard temperature and pressure, and to automatically correlate pollutant data with wind direction. The DAS outputs shall be in a file format that can be used in common spreadsheet programs.

13. Nothing in this Appendix shall preclude the use of any other, additional fence line monitoring equipment and/or of monitoring other, additional pollutants at the fence line.

C. Operation of Harmon Creek Monitoring System

14. MarkWest shall comply with all terms of this Appendix and the Harmon Creek Monitoring Plan, including but not limited to operating and maintaining the monitors, equipment, and systems described herein, for a period of no less than a total of 720 days.

15. Quality Assurance/Quality Control ("QA/QC"). MarkWest shall ensure that all data collected by the Harmon Creek Monitoring System are subjected to the approved QA/QC procedures on a quarterly basis. The QA/QC procedures for a given quarter's data shall be completed by no later than 45 days following the end of the quarter in which the data were collected.

16. Quarterly Submissions. MarkWest shall provide Relevant Data on a quarterly basis, within 45 days of the end of each calendar quarter. For purposes of this Paragraph, "Relevant Data" shall mean the quality assured hourly block averages of compounds identified in Table A, attached, and all meteorological data collected (see Paragraph 7). MarkWest shall submit the data in a manner that allows pollutant concentrations and meteorological data to be viewed concurrently and indicate that these data meet the QA/QC procedures in Paragraph 15 of this Appendix. All numerical data shall be presented in a format that can be used in common spreadsheet programs. MarkWest shall maintain and retain the Relevant Data collected through the Harmon Creek Monitoring System as required by the Consent Decree. In addition to the Relevant Data, MarkWest shall provide the following information on a quarterly basis: a summary of any problems encountered in the monitoring project and the status of any current problems and corrective actions performed, a summary of any meetings or correspondence addressing the monitoring program, a synopsis of percent recovery including brief explanations of missing data, overall data recovery, quality control, and all quality assurance documentation, as well the results of any Performance Audits performed during the

quarter.

17. Final Report. Within 90 days of the conclusion of the monitoring period, MarkWest shall prepare and submit a Final Report. The Final Report shall describe the Harmon Creek Monitoring System sampling, compile all data collected, including meteorology, chemical compounds, and QA/QC, and interpret and analyze the data collected by the Harmon Creek Monitoring System.

TABLE A

Compound	Parameter Code
Carbon disulfide	42153
Dodecane	43141
Ethane	43202
Ethene	43203
Propane	43204
Propene	43205
Ethyne	43206
Butane	43212
Isobutane	43214
trans-2-Butene	43216
cis-2-Butene	43217
Pentane	43220
Isopentane	43221
1-Pentene	43224
trans-2-Pentene	43226
cis-2-Pentene	43227
3-methylpentane	43230
n-hexane	43231
n-heptane	43232
Octane	43233
Nonane	43235
Decane	43238
Cyclopentane	43242
Isoprene	43243
2,2,-Dimethylbutane	43244
1-Hexene	43245
2,4-Dimethylpentane	43247
Cyclohexane	43248
3-Methylhexane	43249
2,2,4-Trimethylpentane	43250
2,3,4-Trimethylpentane	43252
3-Methylheptane	43253
Methylcyclohexane	43261
Methylcyclopentane	43262
2-methylhexane	43263

Compound	Parameter Code
1-Butene	43280
2,3-Dimethylbutane	43284
2-methylpentane	43285
2,3-Dimethylpentane	43291
Acrolein	43505
Acetone	43551
2-Butanone (MEK)	43552
2-Hexanone	43559
Chloromethane	43801
Chloroform	43803
Carbon tetrachloride	43804
Trichlorofluoromethane	43811
1,1,1-Trichloroethane	43814
Tetrachloroethene (PERC)	43817
1,1,2-Trichloro-1,2,2-trifluoroethane	43821
Dichlorodifluoromethane	43823
Trichloroethylene (TCE)	43824
Methylene chloride	43860
Undecane	43954
2-Methylheptane	43960
m&p-Xylene	45109
Benzene	45201
Toluene	45202
Ethylbenzene	45203
o-Xylene	45204
1,3,5-Trimethylbenzene	45207
1,2,4-Trimethylbenzene	45208
Propylbenzene	45209
Isopropylbenzene	45210
1-Ethyl-2-Methylbenzene	45211
1-Ethyl-3-Methylbenzene	45212
1-Ethyl-4-methylbenzene	45213
m-Diethylbenzene	45218
p-Diethylebenzene	45219
Styrene	45220
1,2,3-Trimethylbenzene	45225

Compound	Parameter Code
Tetrahydrofuran (THF)	46401

GENERAL PERMIT 21.1 TEMPLATE

PIGGING OPERATION

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTI to be issued to a **Title V** facility

1. All the facility-wide terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

   a) B.2.

2. Modeling to demonstrate compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F)(4)(b), is not necessary if/when the maximum annual emissions for each toxic air contaminant, as defined in OAC rule 3745-114-01, from all sources in the project, is less than 1.0 ton per year (or are subject to a standard under 40 CFR Part 63). OAC Chapter 3745-31 requires permittees to apply for and obtain a new or modified PTIO prior to making a "modification" as defined by OAC rule 3745-31-01. The permittee is hereby advised that changes in the composition of the materials or use of new materials that would cause the emissions of any toxic air contaminant to increase to above 1.0 ton per year may require the permittee to apply for and obtain a new PTIO.

3. Records related to this permit may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

1. Emissions Unit: Pigging Operation: P020

Operations, Property and/or Equipment Description:

One discrete pig launcher or receiver.

a) The following emissions unit terms and conditions are federally enforceable with the exception of those listed below which are enforceable under state law only.

(1) b)(1)b., b)(1)c., and b)(2)b.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	Volatile organic compound (VOC) emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit. See b)(2)a., b)(2)c. and c) below.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the VOC emissions from this air contaminant source since the calculated annual emissions rate is less than 10 tons/year, taking into account the voluntary restrictions from OAC rule 3745-31-05(E). See b)(2)b. below.
c.	OAC rule 3745-31-05(E) June 30, 2008	VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
		See b)(2)b., b)(2)c. and c) below.

(2) Additional Terms and Conditions

a. This Best Available Technology (BAT) emissions limit applies until U.S. EPA approves OAC rule 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio SIP.

b. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

c) Operational Restrictions

(1) Access openings to the receivers shall be kept closed at all times, except when a pig is being placed into or removed from the receiver, or during active maintenance operations.

(2) The permittee shall install and operate add-on control (vapor recovery, flare/combustor or equivalent) for the control of VOC emissions as needed to comply with this permit's emission limits.

(3) In the event any needed add-on control is not operating in accordance with the manufacturer's recommendations, instructions, or operating manual, with any modifications deemed necessary by the permittee, add-on control shall be expeditiously repaired or otherwise returned to these documented operating conditions.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall collect the following information for each pigging event venting:

a. Date and time of the venting;

b. The calculated mass of the resulting VOC emissions where the mass is calculated using the following equation[1]:

VOC Mass = [(mw*PV/(RTZ)) * VOC Wt% + L + C] * (1 - capture efficiency * control efficiency) * (1 ton/2000 pounds)

Where:

mw = the molecular weight of the gas vented;

P = the absolute gas pressure of the gas in the pigging vessel prior to venting;

V = the actual volume of the pigging vessel and piping vented;

T = the temperature of the vented gas;

[1] Representative values may be used for this calculation as long as the values are updated with actual data at least on an annual basis.

Z = the gas compressibility factor of the vented gas;

R = the gas constant;

L = the chamber liquid phase released and volatilized (flash) as VOCs; and

C = the VOCs emitted in the re-sealed chamber purge gas flush.

(2) The permittee shall maintain monthly records of the following information:

a. the ton of VOC per month emitted from the pigging events (using the calculation provided in d)(1)), and

b. the ton of VOC per month emitted from all pigging events, averaged over a rolling, 12-month period (using the calculation provided in d)(1) and summing the current month with the previous 11 months and then dividing by 12 months).

(3) The permittee shall maintain documentation of the manufacturer's recommendations, instructions, or operating manuals for add-on control, along with documentation of any modifications deemed necessary by the permittee. These documents shall be maintained at the facility and shall be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(4) The permittee shall conduct periodic inspections of the add-on control to determine whether it is operating in accordance with the manufacturer's recommendations, instructions, or operating manuals with any modifications deemed necessary by the permittee or operator.

(5) The permittee shall document each inspection (periodic and annual) of the add-on control and shall maintain the following information:

a. the date of the inspection;

b. a description of each/any problem identified and the date it was corrected;

c. a description of any maintenance and repairs performed; and

d. the name of person who performed the inspection.

These records shall be maintained at the facility for not less than five years from the date the inspection and any necessary maintenance or repairs were completed and shall be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(6) The permittee shall maintain records that document any time periods when the add-on control was not in service when the emissions unit(s) was/were in operation, as well as, a record of all operations during which add-on control was not operated according to the manufacturer's recommendations with any documented modifications made by the permittee. These records shall be maintained for a period of not less than five years and shall be made available to the Ohio EPA upon request.

e) Reporting Requirements

(1) The permittee shall submit deviation reports that identify any of the following occurrences:

a. All exceedances of the ton of VOC per month, averaged over a rolling, 12-month period, and the other requirements under sections c)(1) through (3) and d)(1) through (6).

(2) The deviation reports shall be submitted in accordance with the reporting requirements of the Standard Terms and Conditions of this permit.

(3) Unless other arrangements have been approved by the Director, all notifications and reports shall be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

Emission Limitation:

VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period.

Applicable Compliance Method:

Compliance shall be determined based on the records found in terms d)(1) and d)(2) above.

g) Miscellaneous Requirements

(1) None.

GENERAL PERMIT 21.1 TEMPLATE

PIGGING OPERATION

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTIO to be issued to a **non-Title V** facility

1. This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

   a) For the purpose of a permit-to-install document, the facility-wide terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

      (1) B.2.

   b) For the purpose of a permit-to-operate document, the facility-wide terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

      (2) None.

2. Modeling to demonstrate compliance with the “Toxic Air Contaminant Statute”, ORC 3704.03(F)(4)(b), is not necessary if/when the maximum annual emissions for each toxic air contaminant, as defined in OAC rule 3745-114-01, from all sources in the project, is less than 1.0 ton per year (or are subject to a standard under 40 CFR Part 63). OAC Chapter 3745-31 requires permittees to apply for and obtain a new or modified PTIO prior to making a "modification" as defined by OAC rule 3745-31-01. The permittee is hereby advised that changes in the composition of the materials or use of new materials that would cause the emissions of any toxic air contaminant to increase to above 1.0 ton per year may require the permittee to apply for and obtain a new PTIO.

3. Records related to this permit may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

1. Emissions Unit: Pigging Operation: P020

Operations, Property and/or Equipment Description:

One discrete pig launcher or receiver.

a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).

(1) For the purpose of a permit-to-install document, the emissions unit terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.

a. b)(1)b., b)(1)c., and b)(2)b.

(2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.

a. None.

b) Applicable Emissions Limitations and/or Control Requirements

(1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	Volatile organic compound (VOC) emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit. See b)(2)a., b)(2)c. and c) below.
b.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply to the VOC emissions from this air contaminant source since the calculated annual emissions rate is less than 10 tons/year, taking into account the voluntary restrictions from OAC rule 3745-31-05(E). See b)(2)b. below.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
c.	OAC rule 3745-31-05(E) June 30, 2008	VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period. Use of add-on control (vapor recovery, flare/combustor or equivalent) to control emissions as needed to comply with the VOC emission limitations. If a flare is used, it must meet the requirements detailed in the permit for the flare emissions unit. See b)(2)b., b)(2)c. and c) below.

(2) Additional Terms and Conditions

a. This Best Available Technology (BAT) emissions limit applies until U.S. EPA approves OAC rule 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio SIP.

b. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

c) Operational Restrictions

(1) Access openings to the receivers shall be kept closed at all times, except when a pig is being placed into or removed from the receiver, or during active maintenance operations.

(2) The permittee shall install and operate add-on control (vapor recovery, flare/combustor or equivalent) for the control of VOC emissions as needed to comply with this permit's emission limits.

(3) In the event any needed add-on control is not operating in accordance with the manufacturer's recommendations, instructions, or operating manual, with any modifications deemed necessary by the permittee, add-on control shall be expeditiously repaired or otherwise returned to these documented operating conditions.

d) Monitoring and/or Recordkeeping Requirements

(1) The permittee shall collect the following information for each pigging event venting:

a. Date and time of the venting;

b. The calculated mass of the resulting VOC emissions where the mass is calculated using the following equation[1]:

[1] Representative values may be used for this calculation as long as the values are updated with actual data at least on an annual basis.

VOC Mass = [(mw*PV/(RTZ)) * VOC Wt% + L + C] * (1 - capture efficiency * control efficiency) * (1 ton/2000 pounds)

Where:

mw = the molecular weight of the gas vented;

P = the absolute gas pressure of the gas in the pigging vessel prior to venting;

V = the actual volume of the pigging vessel and piping vented;

T = the temperature of the vented gas;

Z = the gas compressibility factor of the vented gas;

R = the gas constant;

L = the chamber liquid phase released and volatilized (flash) as VOCs; and

C = the VOCs emitted in the re-sealed chamber purge gas flush.

(2) The permittee shall maintain monthly records of the following information:

a. the ton of VOC per month emitted from the pigging events (using the calculation provided in d)(1)), and

b. the ton of VOC per month emitted from all pigging events, averaged over a rolling, 12-month period (using the calculation provided in d)(1) and summing the current month with the previous 11 months and then dividing by 12 months).

(3) The permittee shall maintain documentation of the manufacturer's recommendations, instructions, or operating manuals for add-on control, along with documentation of any modifications deemed necessary by the permittee. These documents shall be maintained at the facility and shall be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(4) The permittee shall conduct periodic inspections of the add-on control to determine whether it is operating in accordance with the manufacturer’s recommendations, instructions, or operating manuals with any modifications deemed necessary by the permittee or operator.

(5) The permittee shall document each inspection (periodic and annual) of the add-on control and shall maintain the following information:

a. the date of the inspection;

b. a description of each/any problem identified and the date it was corrected;

c. a description of any maintenance and repairs performed; and

d. the name of person who performed the inspection.

These records shall be maintained at the facility for not less than five years from the date the inspection and any necessary maintenance or repairs were completed and shall

be made available to the appropriate Ohio EPA District Office or local air agency upon request.

(6) The permittee shall maintain records that document any time periods when the add-on control was not in service when the emissions unit(s) was/were in operation, as well as, a record of all operations during which add-on control was not operated according to the manufacturer's recommendations with any documented modifications made by the permittee. These records shall be maintained for a period of not less than five years and shall be made available to the Ohio EPA upon request.

e) Reporting Requirements

(1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit.

(2) The reports required by this permit may be submitted through the Ohio EPA's eBusiness Center: Air Services online web portal; or they may be mailed as a hard copy to the appropriate district office or local air agency.

f) Testing Requirements

(1) Compliance with the Emissions Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

Emission Limitation:

VOC emissions shall not exceed 0.27 ton per month, averaged over a rolling 12-month period.

Applicable Compliance Method:

Compliance shall be determined based on the records found in terms d)(1) and d)(2) above.

g) Miscellaneous Requirements

(1) None.

Recover Gas from Pipeline Pigging Operations



Technology/Practice Overview

Description

Gases rich in recoverable hydrocarbons tend to condense liquids in gathering systems upstream of gas gathering and processing plants. These systems are frequently pigged with spherical or bullet-shaped pigs to remove accumulated liquids and reduce the gathering system pressure drop. This improves gas flow and pipeline efficiency. The pigged liquids are separated from the gas ahead of the processing plant compressors, stored temporarily at gathering system pressure, and then sent to a low pressure storage tank. The liquids, recovered at pipeline pressure, flash and vent light hydrocarbon gases from the storage tanks.

Much of the gas that is vented can be recovered by installing a dedicated vapor recovery system. Recovering the flash gas resulting from the pressure drop between the pressurized liquid storage tanks and the atmospheric storage tanks can reduce emissions and add more gas to the sales line.

Operating Requirements

The required equipment to be installed includes an electric or a gas engine driven vapor recovery compressor. A liquid/vapor flash vessel and low pressure liquid pump may also be required depending on system design and/or ambient temperature and pressure. It is assumed that a pig launcher and receiver on gathering lines, vapor/liquid separation and pressurized liquid storage vessels, and low pressure liquid storage tanks would already be

- ☐ Compressors/Engines
- ☐ Dehydrators
- ☐ Directed Inspection & Maintenance
- ■ Pipelines
- ☐ Pneumatics/Controls
- ■ Tanks
- ☐ Valves
- ☐ Wells
- ☐ Other

Applicable Sector(s)

- ■ Production
- ■ Processing
- ■ Transmission
- ☐ Distribution

Other Related PROs:

Use Inert Gases and Pigs to Perform Pipeline Purges, PRO No. 403

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*21,400 Mcf per year*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	21,400 Mcf	$159,400	$24,000	$1,000	2 Month
$5.00/Mcf	21,400 Mcf	$113,800	$24,000	$1,000	3 Month
$3.00/Mcf	21,400 Mcf	$68,300	$24,000	$1,000	5 Months

** Whole gas savings are calculated using a conversion factor of 94% methane in pipeline quality natural gas.*

Additional Benefits

- Addition of gas to the sales line (or plant fuel system)
- Recovery of valuable hydrocarbon liquids
- Safer operations

Recover Gas from Pipeline Pigging Operations (Cont'd)

present on site. Vapor recovery compressor sizing is affected by the variance of pigging operations; colder temperatures in the winter can require extra capacity that is not necessary in the summer months. This is because colder temperatures result in more condensation at constant pressure. Pipelines would therefore have to be pigged more often. In general, gathering lines that must be pigged frequently and recover a large volume of liquid at moderate to high pressure (150 to 300 psig or greater) are best suited for vapor recovery.

Applicability

Gas and condensate recovery is possible at any gas gathering station and processing plant that frequently must remove condensed liquids from its upstream gathering lines.

Methane Emissions

The methane emission savings are based on the design flow rate and operating time of a single vapor recovery compressor dedicated to the compression of the flash vapor from the pigged liquid (pressurized) storage tanks.

Economic Analysis

Basis for Costs and Emissions Savings

For example reported savings are based on a gathering system at 200-300 psig (pounds per square-inch, gage) that is pigged 30-40 times per year and collects approximately 3,000 barrels of condensate per year. A small vapor recovery system was installed with an electric compressor for $24,000 and has an annual operating and maintenance cost in excess of $1,000 per year.

Discussion

Gathering system pigging frequency depends on the gas composition as well as the ambient temperature conditions, and can vary greatly from one location to another and from season to season. The economics of recovering gas from pigging operations are dependent upon the methane through butane composition of the hydrocarbon liquid, which directly impact the energy content and value of the gas, and the amount of liquid collected.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

NMED Exhibit 87 - 0002

EPA United States Environmental Protection Agency

Office of Enforcement and Compliance Assurance

Enforcement Alert

Publication no. EPA 325-F-19-001

SEPTEMBER 2019

EPA Observes Air Emissions from Natural Gas Gathering Operations in Violation of the Clean Air Act

Purpose

EPA and state investigations have identified Clean Air Act (CAA) non compliance caused by unauthorized and/or excess emissions from depressurizing pig launchers and receivers in natural gas gathering operations. For example, EPA and Pennsylvania resolved CAA violations by MarkWest (described at the end of this Alert) in a consent decree in April 2018. The settlement provides an example of potential compliance issues that operators may experience if Volatile Organic Compound (VOC) emissions from depressurizing pig launchers and receivers in natural gas gathering operations are not properly controlled. This Alert discusses engineering, design, operations, and maintenance practices that EPA and state inspectors have found that can cause non-compliance and summarizes engineering solutions to reduce emissions and help alleviate potential safety issues. While this Alert provides information intended to help operators and state regulators identify and address compliance concerns, the solutions discussed in this Alert do not guarantee compliance with federal and state regulations, including, but not limited to requirements to obtain an air permit, keep records, and/or control emissions.

Non-Compliance Concerns

State and federal laws require owners and operators of certain facilities to register air emission sources, obtain authorization to emit from a registered source, including natural gas gathering operations, and design, install, operate, and maintain effective emission control measures. Such laws include state permitting and air pollution regulations—many of which are federally-enforceable and collectively referred to as the State Implementation Plan or "SIP"—and the federal New Source Review (NSR) air permitting regulations including the Prevention of Significant Deterioration (PSD) requirements.



Infrared Image of Compressor Station Pig Receiver Depressurization Event

EPA and state inspectors have observed numerous instances where depressurizing pig launchers and receivers in natural gas gathering operations emit unauthorized or excess VOC emissions, due to the company's failure to obtain an air permit for the pigging

NMED Exhibit 88 - 0001

equipment, to address deficiencies in the design of the pigging equipment, or to operate the pigging equipment in accordance with an air permit, air permit application or air permit registration.

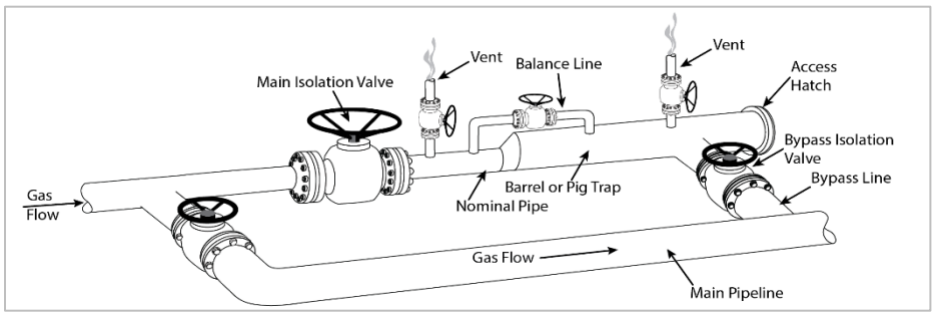


Figure 1. Conventional pig receiver.

In most jurisdictions, a company must determine the mass emissions of pollutants when registering a source, applying for an air permit, and/or claiming an air permit exemption; which are prerequisites to constructing a source. Failing to calculate the potential for VOC or HAP emissions from pigging operations or otherwise underestimating the mass of the pollutants released may result in a misrepresentation to the permit authority when the company applies for a permit or permit exemption. Depending on the state and local air permitting rules and regulations, a company's misrepresentation to the permit authority may mean that the emissions from the pigging operations are considered unauthorized or excess. In this situation, the non-compliance is caused by a company's failure to comply with federal and state permitting requirements, including, but not limited to: failure to register an air emission source, failure to obtain an air permit or obtain the correct air permit, or failure to adhere to representations in the air permit registration, failure to maintain records, and/or failure to control emissions. *See, e.g.,* 40 C.F.R. §§ 51.165 and 70.7(b); 25 Pa. Code §§ 127.11 and 127.402(a); Ohio Admin. Code 3745-31-02(A)(1)(a)-(b) and 3745-15-05(B), (D) and (E).

Emissions from Pigging Operations

Raw natural gas is transported from production wells to processing plants through networks of gathering pipelines. Although liquid separation may occur at the well pad, much of the raw natural gas passing through the gathering pipelines is saturated with hydrocarbons other than methane and may contain other components such as water, carbon dioxide, and hydrogen sulfide. During the transportation of this gas through gathering pipeline systems, the gas often experiences a temperature drop and pressure change that causes the hydrocarbons and other components to condense to a liquid phase. These natural gas condensates can accumulate in low elevation segments of the gathering pipelines, impeding the flow of natural gas. To maintain gas flow and operational integrity of the gathering pipelines, operators mechanically push these condensates out of the low elevations and down the pipeline by an operation called "pigging," which involves first inserting a device called a pig into a pig launcher upstream of the pipeline segment where condensates have accumulated. The gas flowing through the pipeline then pushes the pig through the pipeline, allowing the pig to sweep along the accumulated condensates. The pig is removed from the pipeline segment when it is caught in a pig receiver.

A conventional pig receiver is shown in Figure 1. Pig launchers are very similar in design. The pipeline at the rear of the barrel is called a "kicker line" on pig launchers and a "bypass line" on pig receivers; these lines direct the main gas flow through the barrel to launch or receive a pig, respectively.

Before a pig can be inserted or removed through the hatch of a pig launcher or a pig receiver, the pipeline gas in the launcher or receiver barrel must be removed, leading to potential emissions. This gas is under the same pressure as the pipeline and contains methane, ethane, and VOCs including benzene, toluene, ethylbenzene, and xylene. Pig receivers can also contain collected condensate liquid that had accumulated in the pipeline.

When the launcher and receiver barrels are depressurized (via a vent as shown in Figure 1) prior to opening the hatch for pig insertion or removal, the depressurization gases contain mixtures of methane, ethane, VOCs and hazardous air pollutants (HAPs). The barrel depressurization gases are often vented to the atmosphere but can be controlled or recovered to reduce emissions. When the hatch is opened, additional gas is released, and any liquids collected in a pig receiver that did not volatilize in the depressurization process may be spilled from the open hatch as the pig is withdrawn. These spilled liquids can fall to the ground or be collected in an open tub, either of which allow for further evaporation that contributes to emissions.

The amount of potential emissions from pigging operations depends on several factors including the launcher or receiver volume, pipeline pressure (higher pressure correlating with higher potential emissions), amount of liquid trapped in the pig receiver barrel prior to depressurization, frequency of pigging, and gas composition.

Depending on these system characteristics, the pigging operation may emit VOCs or HAPs in excess of federal or state limits.

Engineering Solutions

EPA inspectors have identified general characteristics of a pig launcher and receiver system that control and reduce emissions of air pollutants and may require less management. These systems: (1) minimize the total volume between the kicker and/or bypass isolation valves and the main isolation valve, so that less gas is trapped in the barrel; and (2) minimize the potential for liquid accumulation or hold-up in the receiver, and include features such as sloped receiver barrels and piping so that liquids collected in the barrel are gravity-drained through the bypass piping into the main pipeline for collection downstream. However, depending on the quantity of emissions released, a company may be required to implement additional design measures, and emissions capture and control approaches to comply with federal and state regulations.

The following sections discuss design alternatives to the conventional launcher/receiver system (i.e., pig ball valves and multi-pig launcher systems), considerations for receiver barrel design (i.e., condensate drains and pig ramps), and additional site modifications to capture or control emissions (i.e., jumper lines, combustion devices, rerouting low pressure systems, barrel pump-down systems, and enhanced liquid containment). In addition to reducing potential VOC emissions to alleviate potential non-compliance, application of these solutions reduces methane (a potent greenhouse gas) and generally improves safety of the pigging operation. The applicability and effectiveness of these engineering solutions are site-specific; solutions can generally be combined to effectively reduce emissions.

Install Pig Ball Valves

Pig ball valves are a design alternative to conventional launcher/receiver systems that result in fewer emissions

NMED Exhibit 88 - 0003

from pigging operations due to a smaller sized barrel (or chamber) that launches and receives the pig. A conventional pig launcher or receiver system can be retrofitted by replacing the conventional launcher and receiver barrels with special ball valves used to insert and remove the pig directly from the main pipeline. Figure 2 shows a pig ball valve installed in a pipeline, with a bypass loop around the pig ball valve for use when the pig ball valve is closed. By replacing the large volume barrel with the much smaller volume ball valve, the volume of gas vented during each pigging operation can be reduced by as much as 80% to 95% with a corresponding reduction in emissions and other risks associated with pipeline pigging operations.

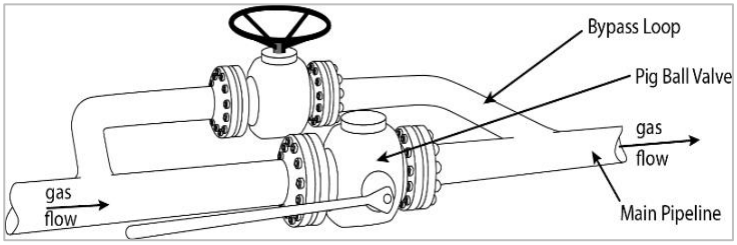


Figure 2. Pig Ball Valve Installation

Install Multi-Pig Launcher Systems

Multi-pig launcher systems are a design alternative to conventional launcher/receiver systems and reduce pigging emissions by reducing the frequency that launchers and receivers must be vented prior to pig insertion and removal. An example manufacturer design for a multi-pig launcher system is shown in Figure 3. The launcher barrel is designed to hold multiple spherical pigs, which are each held in place by gates or pins prior to release. Emission reductions are approximately proportional to the reduction in frequency of opening the launcher and receiver hatch.

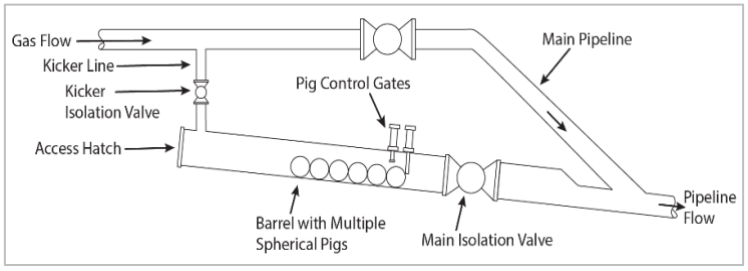


Figure 3. Multi-Pig Launcher System

Receiver Barrel Design: Condensate Drains

Drains can be installed in the bottom of receiver barrels and pig ball valves to ensure that all condensate is drained from the system prior to depressurization. These drains generally route the condensate back into the main pipelines, to onsite storage tanks, or to onsite processes via enclosed piping. Two drains are shown in Figure 4 which depicts a conventional receiver design, but additional drains can be used. These drains can be retrofitted to existing systems.

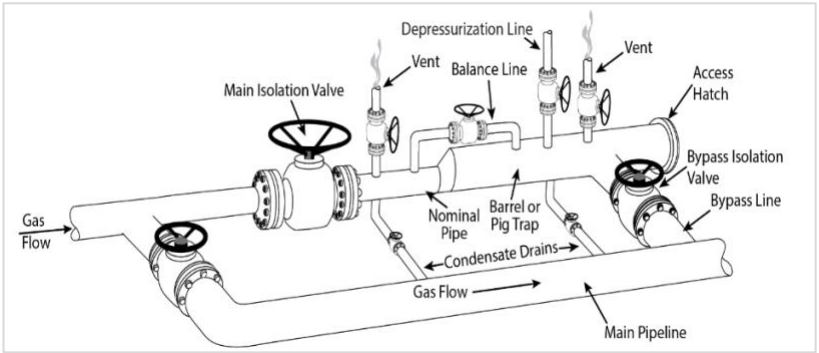


Figure 4. Conventional Pig Receiver with Condensate and Vapor Recovery

The effectiveness of condensate drains in controlling pigging emissions is based on the quantity of condensate trapped in the receiver system, and the subsequent ability of the drain to recover the full quantity of this condensate during each pigging operation, thereby preventing its volatilization during pig receiver depressurization or hatch opening.

NMED Exhibit 88 - 0004

Receiver Barrel Design: Pig Ramps

A pig ramp is a device that can be installed inside a receiver barrel to minimize the accumulation of condensate, or VOCs in the condensed liquid phase, in the receiver by directing the movement of the pig and liquid in the barrel. The pig ramp promotes the flow of liquid through the barrel and into the bypass line by preventing the pig from creating blockages in the receiver. By promoting the flow of liquid back into the pipeline system while the receiver is under pressure, pig ramps reduce the amount of condensed VOCs trapped in the barrel prior to depressurization which reduces the air emission that occur during depressurization and removal of the pig from the receiver. As part of MarkWest's recent settlement with EPA, pig ramps were installed at hundreds of barrels in its wet gas midstream pipeline systems. As discussed below, MarkWest will provide a royalty-free license to others interested in using their proprietary pig ramp design.

Route High Pressure Systems to Lower Pressure Lines (Install Jumper Lines)

The depressurization emissions from high pressure launchers and receivers can be reduced by routing the gases to a lower pressure system before venting the remaining gases to the atmosphere or to control equipment. Routing to a lower pressure system is achieved with a depressurization line (or, "jumper line") exiting the top of the barrel, as shown in Figure 4, or exiting the top of the pig ball valve. Compressor stations and gas plants have low pressure lines on the site that can receive these depressurization gases and recycle them through the process. Similarly, launchers and receivers along high pressure pipelines are occasionally located near low pressure pipelines that can receive depressurization gases exiting the barrel or pig ball valve.

Route Depressurization Gases to Combustion Devices

Depressurization gases from barrels and pig ball valves can be routed through the depressurization line (see Figure 4) to onsite combustion devices. Well-designed and operated combustion devices can achieve vapor destruction efficiencies as high as 95% to 98%. Combustion devices can be used in conjunction with engineering solutions discussed above that first reduce accumulation of or recover as much natural gas and condensate as possible before destroying the remaining vapors in the combustion device. An example would be to route high pressure systems to low pressure lines and drain barrel condensate, then route the remaining vapors to a combustion device. Large, high capacity combustion devices are typically available at compressor stations and processing plants and can be used to control pigging gases while meeting the other flaring needs of the facility. There are also numerous low capacity combustion devices available for serving remote launcher/receiver sites.

Route Low-Pressure Systems into Fuel Gas Systems or Vapor Recovery Unit (VRU)

Gases that remain in high pressure barrels after venting to low pressure systems and gases in low pressure barrels can be recovered during depressurization by discharging the gases to very low-pressure systems at the site (e.g., 10-15 psig). Two examples of very low-pressure systems at compressor stations are a fuel gas system and a condensate tank vapor recovery unit (VRU). Applying such an approach can reduce the gas pressure in the barrels to the pressure of the very low-pressure system (e.g., 10 psig), with a corresponding reduction in depressurization emissions.

NMED Exhibit 88 - 0005

Barrel Pump-down Systems

In barrel pump-down systems, small fixed or portable compressors are used to pump vapors in the receiver or a launcher barrel back into the main pipeline prior to venting and opening the barrel hatch. In barrel pump-down systems, the inlet of a gas compressor is connected to the receiver or launcher depressurization line, and the compressor discharge is connected into the main pipeline. Vapors exiting the depressurization line are pulled into the compression system and recovered back into the pipeline at system pressure. These control systems can recover greater than 99% of the depressurization vapors from pig launchers and receivers.

Enhanced Liquid Containment

Covering containers that collect liquids remaining in a receiver barrel after depressurization with a fitted impermeable material will reduce emissions from evaporation. Use of grounded steel receptacles additionally helps ensure safety.

Estimating Potential Emissions from Pigging Activities in Natural Gas Gathering Operations

The Real Gas Law has been used to estimate the emissions from depressurizing launcher and receiver barrels, where a gas compressibility factor is applied to account for non-ideal gas initial conditions (e.g., high pressure).

However, the fundamental assumption of the methodology guiding this approach is that the average pipeline gas profile accurately characterizes the contents of the barrel prior to depressurization. This assumption neglects changes in physical conditions along the pipeline which lead to compositional changes and potential formation of condensate liquid that can accumulate in and/or is swept into the pig receiver during pigging.

Therefore, when considering emissions from pig receivers, the Real Gas Law methodology accounts for depressurizing the natural gas mixture from pressurized conditions to atmospheric; however, the equation does not address the potential flash emissions from volatilization of condensates during depressurization. Using the Real Gas Law alone in circumstances with liquid accumulation can result in an underestimation of the calculated VOC emissions from the receiver.

A complete emissions estimation methodology for receivers would account for the impact of any liquid accumulation in receivers, as a supplement to estimates based on the Real Gas Law.

Enforcement Settlement with MarkWest

On April 24, 2018, the U.S. EPA, the U.S. Department of Justice, and the Pennsylvania Department of Environmental Protection announced a settlement with MarkWest that requires innovative solutions designed to evaluate and address VOC emissions from pigging operations at gathering compressor stations and stand-alone pigging stations. This settlement resulted from joint inspections conducted by the EPA and the Commonwealth of Pennsylvania. MarkWest failed to apply for, and comply with, the required permits and/or recordkeeping requirements under the Nonattainment New Source Review, Prevention of Significant Deterioration and Title V programs, and the Pennsylvania and Ohio State Implementation Plans, for natural gas pigging and venting activities that released excess VOC emissions. MarkWest is undertaking measures to help

NMED Exhibit 88 - 0006

ensure compliance with federal and state regulations and reduce emissions including:

- Operating jumper lines to depressurize launchers and receivers.
- Installing pig ramps in receivers.
- Using a mobile flare to control emissions during depressurization.
- Using shorter (smaller volume) barrels than those presently used in the system.
- Using liquid containers with grounded steel receptacles that are covered at all times when not in use.
- Using an estimation methodology that accounts for the flash emissions from condensates that accumulate in the pig barrel.

MarkWest additionally is performing the following environmental projects to further EPA's goal of protecting and enhancing the public health and the environment:

- Innovation transfer and emission control education: MarkWest will provide a royalty-free license and public educational sessions to promote rapid adoption of its proprietary pig ramp design. This project is aimed at increasing awareness of the emissions from pigging operations and sharing cost-effective methods to reduce these emissions. The adoption of this technology by other midstream operators will further benefit the environment by reducing emissions from pigging operations.
- Ambient air monitoring: MarkWest will install and operate air sampling stations to analyze VOCs downstream of two compressor stations over a period of at least two years. Air monitoring at these facilities is not required by law, but MarkWest agreed to conduct these supplemental environmental projects as part of the settlement to provide local communities, industry, regulators, and other stakeholders valuable information about air emissions generated during midstream operation and maintenance activities, and their impacts on local air quality.

For more information, visit https://www.epa.gov/enforcement/markwest-clean-air-act-settlement-information-sheet

DISCLAIMER: This document aims to explain the application of certain EPA regulatory provisions using plain language. Nothing in this Alert revises or replaces any regulatory provisions, any other part of the Code of Federal Regulations, the Federal Register, or the Clean Air Act. Following the approaches as discussed in this Alert do not equate to or guarantee compliance with the Clean Air Act, its implementing regulations, and associated state/local requirements. For more information, visit: www.epa.gov/compliance.

NMED Exhibit 88 - 0007

Vapor Recovery and Gathering Pipeline Pigging

Lessons Learned from Natural Gas STAR

Chevron Corporation,
New Mexico Oil and Gas Association,
Texas Oil and Gas Association

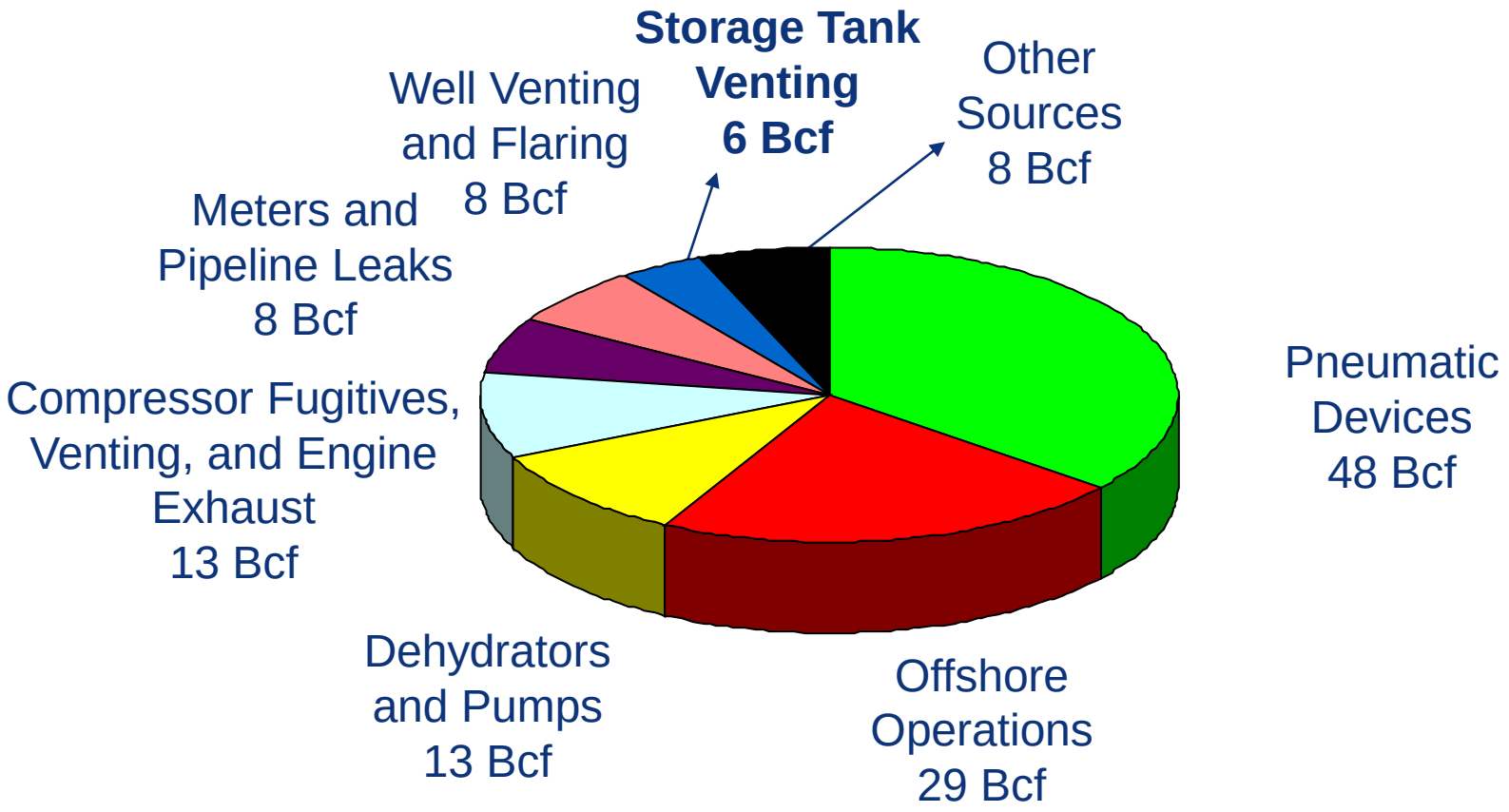
Producers and Processors Technology Transfer Workshop
Midland, Texas
July 23, 2008

epa.gov/gasstar

Reduction Opportunities: Agenda

- Industry Emissions
- Selected Methane Saving Opportunities
  - Vapor Recovery Units
  - Pipeline Pigging
- Discussion

Industry Emissions: Production, Gathering, and Boosting



Source: EPA. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990 – 2006.* April, 2008. Available on the web at: epa.gov/climatechange/emissions/usinventoryreport.html

Note: Natural Gas STAR reductions from gathering and boosting operations are reflected in the production sector.

Vapor Recovery Units

- Methane Losses
- Methane Savings
- Is Recovery Profitable?
- Industry Experience
- Lessons Learned

Sources of Methane Losses

- A storage tank battery can vent 5,000 to 500,000 thousand cubic feet (Mcf) of natural gas and light hydrocarbon vapors to the atmosphere each year
  - Vapor losses are primarily a function of oil or condensate throughput, gravity, and gas-oil separator pressure
- Flash losses
  - Occur when crude oil or condensate is transferred from a gas-oil separator at higher pressure to a storage tank at atmospheric pressure
- Working losses
  - Occur when crude or condensate levels change and when liquid in tank is agitated
- Standing losses
  - Occur with daily and seasonal temperature and barometric pressure changes

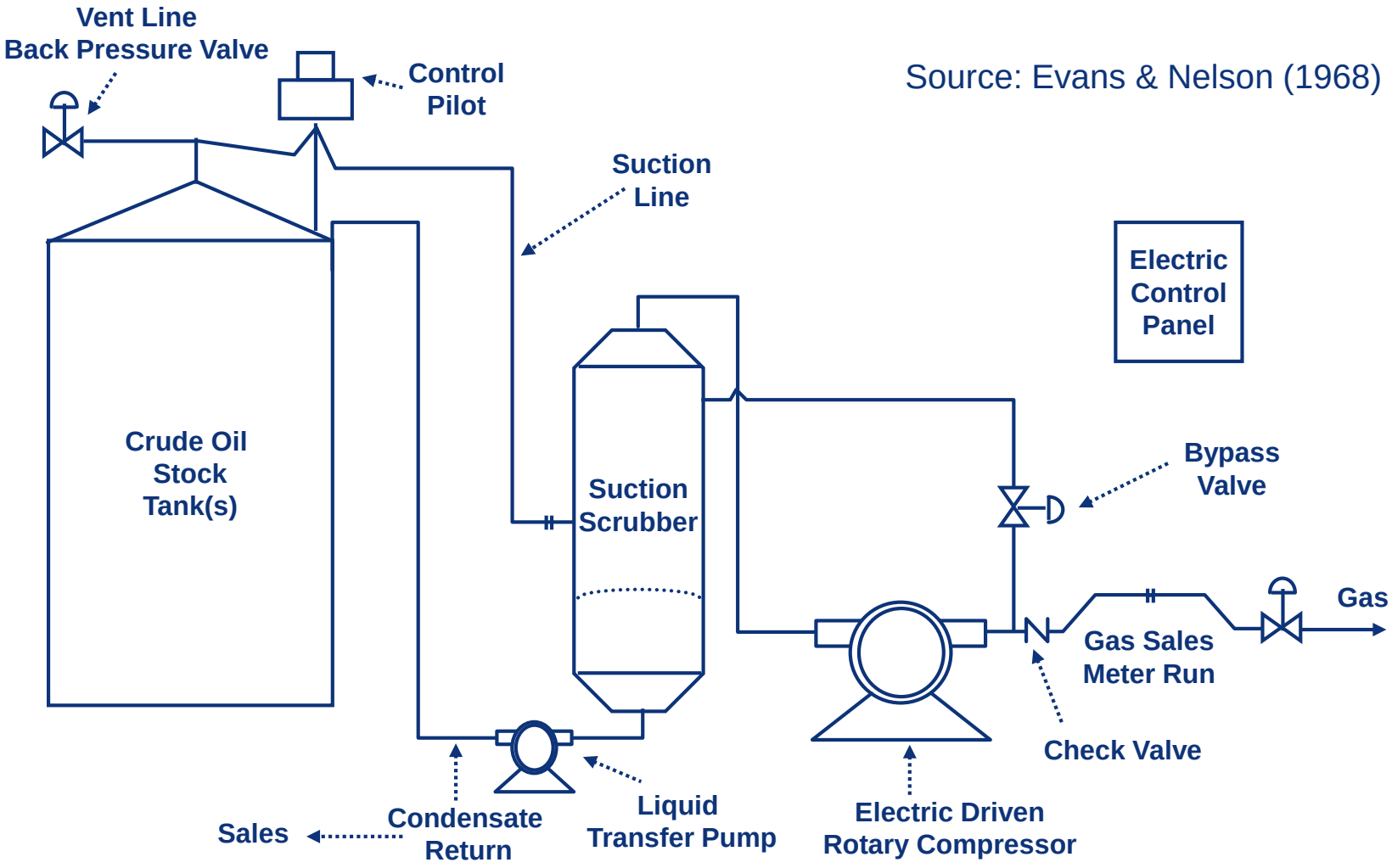
Methane Savings: Vapor Recovery

- Vapor recovery can capture up to 95% of hydrocarbon vapors from tanks
- Recovered vapors have higher heat content than pipeline quality natural gas
- Recovered vapors are more valuable than natural gas and have multiple uses
  - Re-inject into sales pipeline
  - Use as on-site fuel
  - Send to processing plants for recovering valuable natural gas liquids

Types of Vapor Recovery Units

- Conventional vapor recovery units (VRUs)
  - Use screw or vane compressor to suck vapors out of atmospheric pressure storage tanks
  - Scroll compressors are new to this market
  - Require electrical power or engine driver
- Venturi ejector vapor recovery units (EVRU™) or Vapor Jet
  - Use Venturi jet ejectors in place of rotary compressors
  - Contain no moving parts
  - EVRU™ requires a source of high pressure motive gas and intermediate pressure discharge system
  - Vapor Jet requires a high pressure water motive

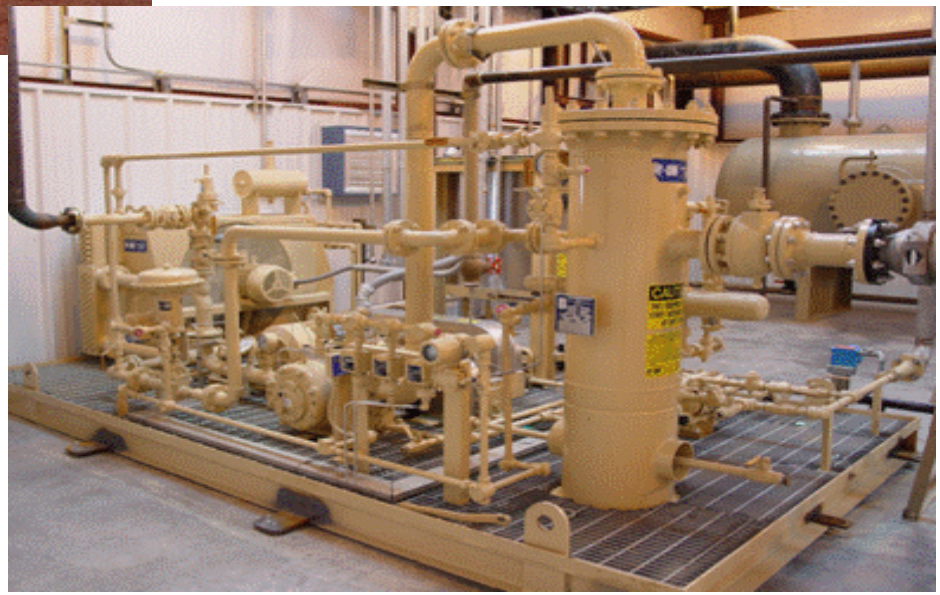
Conventional Vapor Recovery Unit



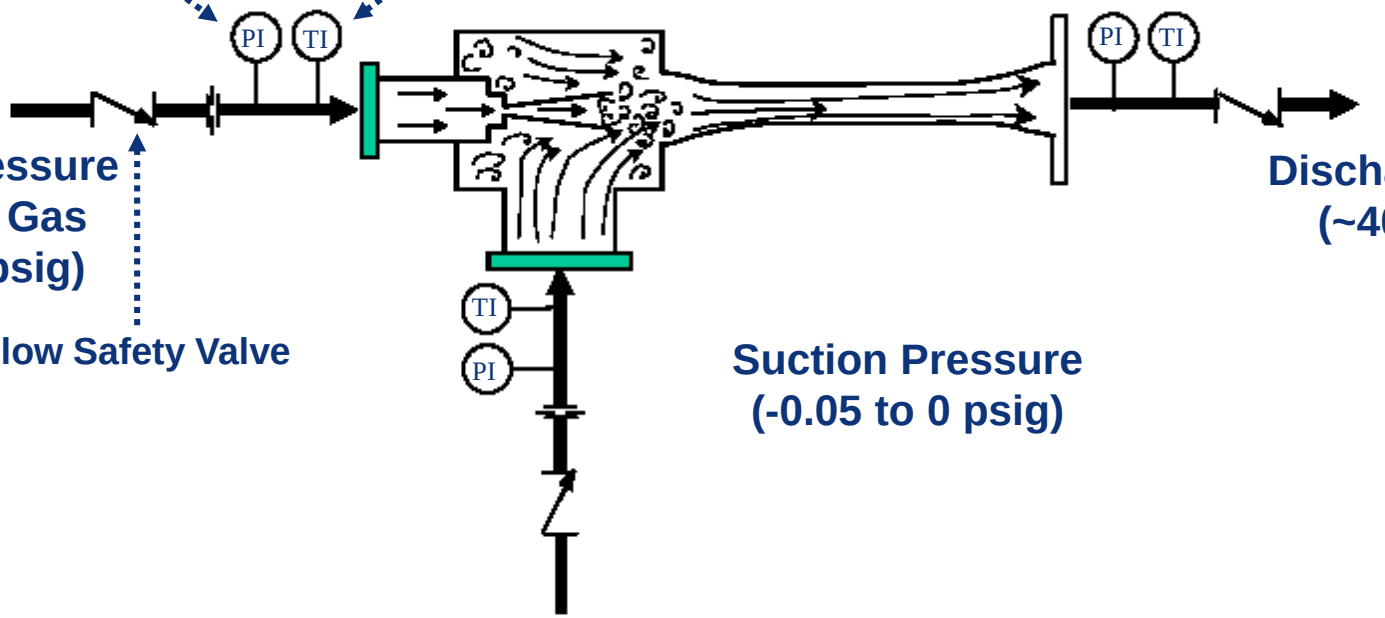
Source: Evans & Nelson (1968)

Vapor Recovery Installations





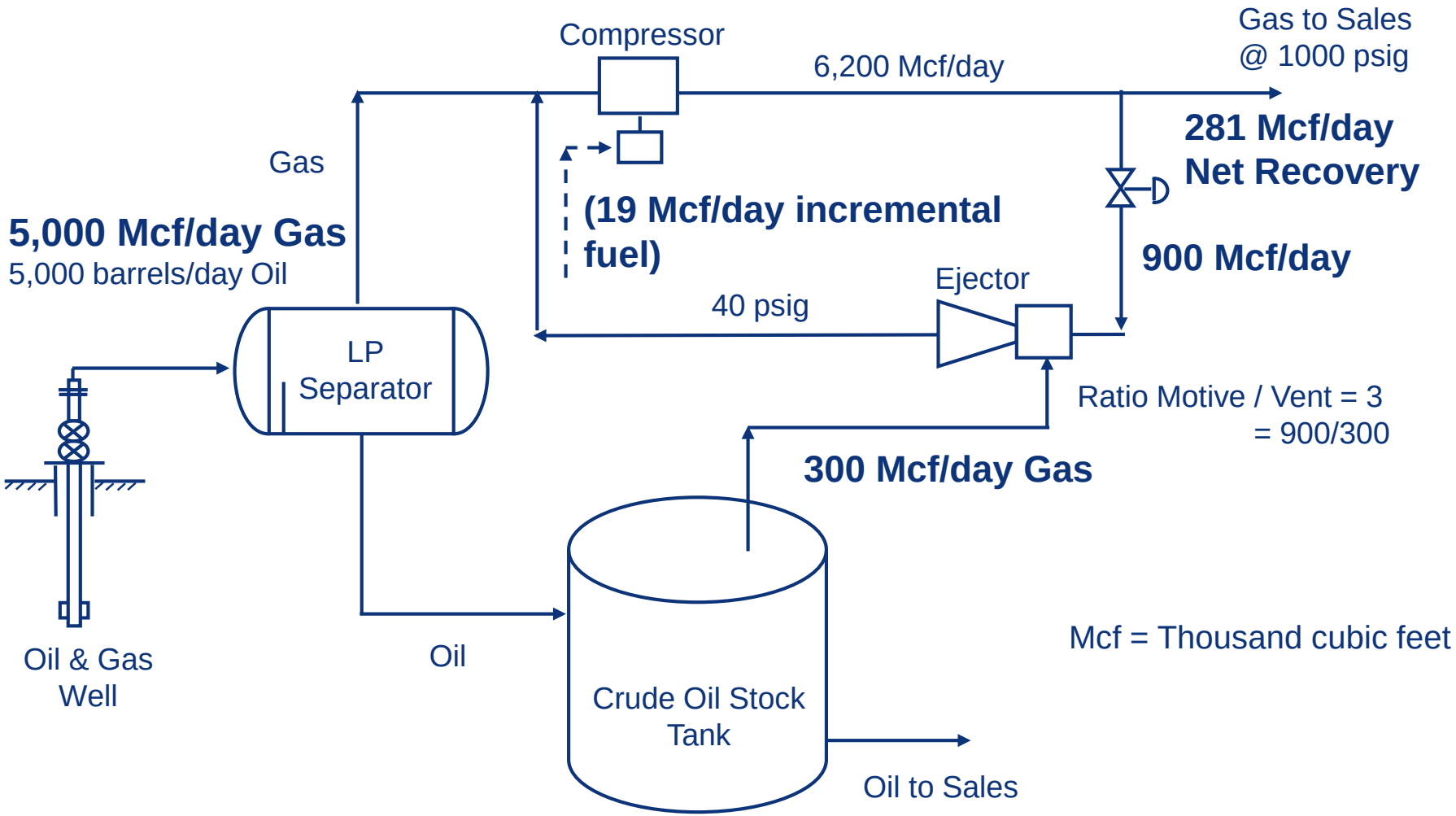
Venturi Jet Ejector*



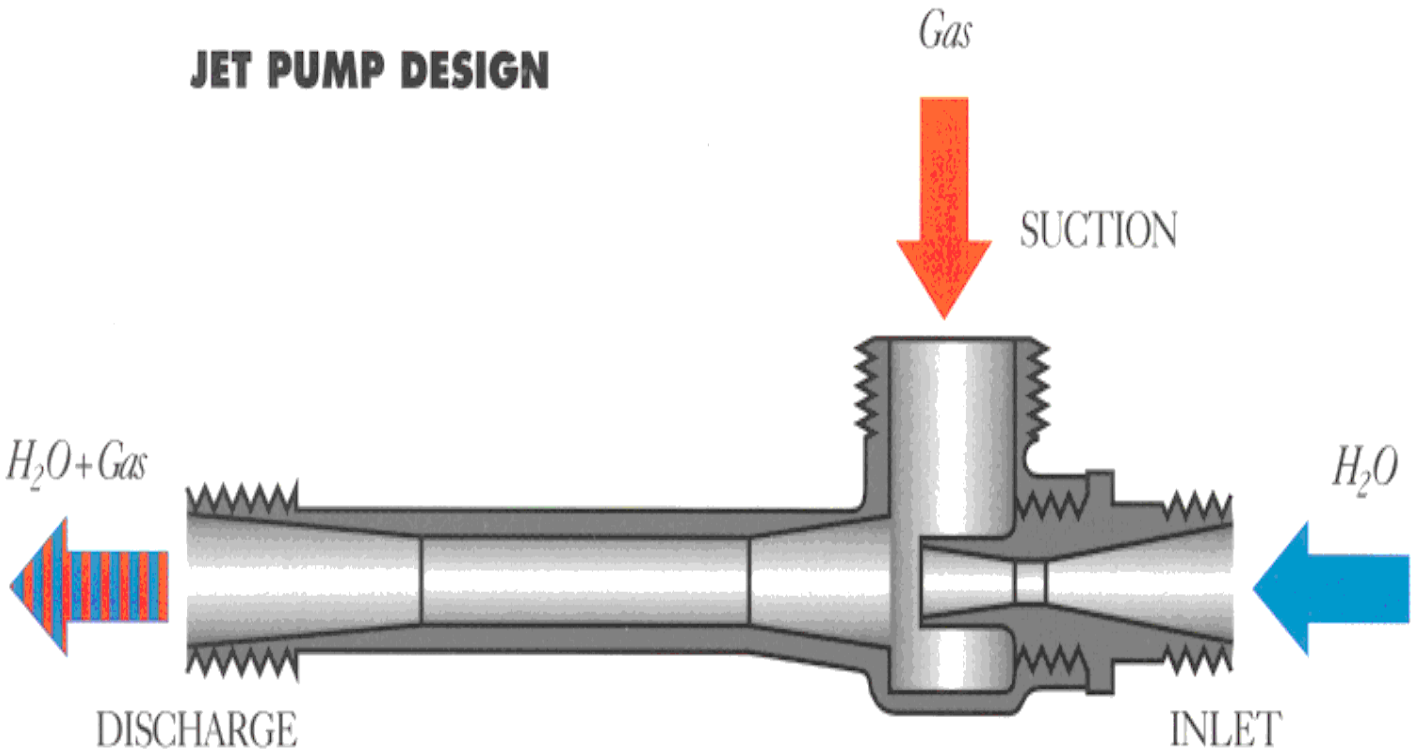
*EVRU™ Patented by COMM Engineering

Adapted from SRI/USEPA-GHG-VR-19
psig = pound per square inch, gauge
psia = pounds per square inch, absolute

Vapor Recovery with Ejector

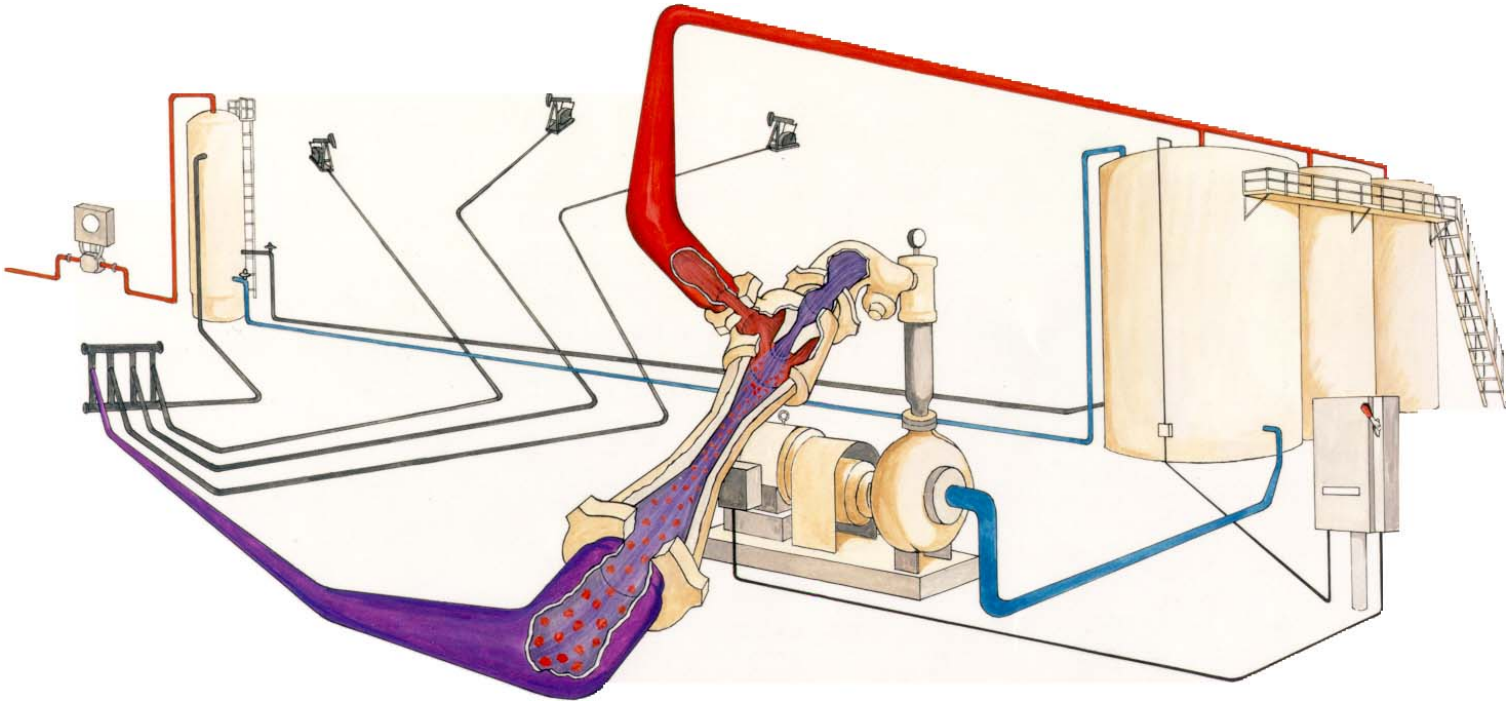


Vapor Jet System*



*Patented by Hy-Bon Engineering

Vapor Jet System*



- Utilizes produced water in closed loop system to effect gas gathering from tanks
- Small centrifugal pump forces water into Venturi jet, creating vacuum effect
- Limited to gas volumes of 77 Mcf/day and discharge pressure of 40 psig

*Patented by Hy-Bon Engineering

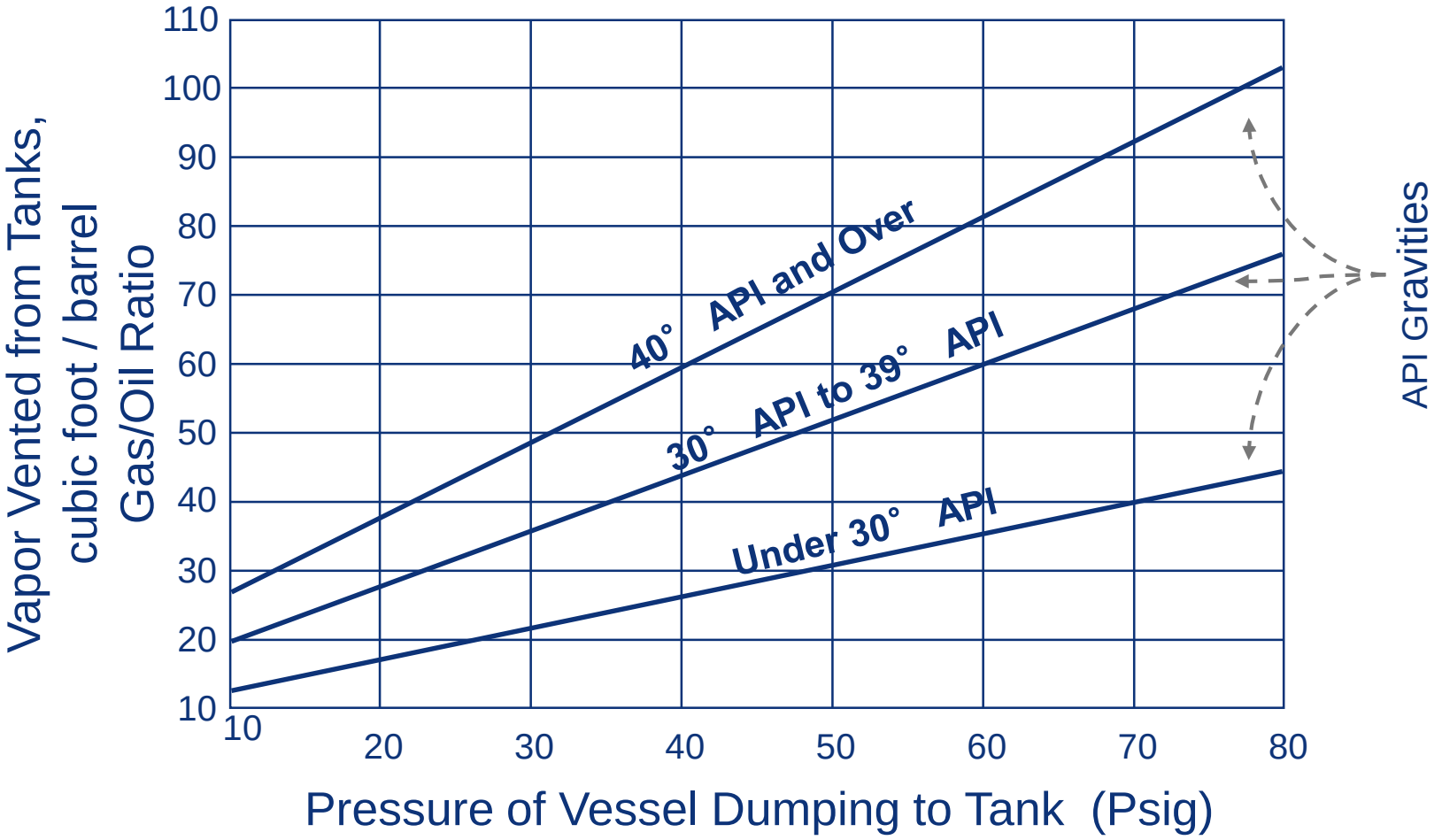
Criteria for Vapor Recovery Unit Locations

- Steady source and sufficient quantity of losses
  - Crude oil stock tank
  - Flash tank, heater/treater, water skimmer vents
  - Gas pneumatic controllers and pumps
  - Dehydrator still vent
  - Pig trap vent
- Outlet for recovered gas
  - Access to low pressure gas pipeline, compressor suction, or on-site fuel system
- Tank batteries not subject to air regulations

Quantify Volume of Losses

- Estimate losses from chart based on oil characteristics, pressure, and temperature at each location (± 50%)
- Estimate emissions using the E&P Tank Model (± 20%)
- Engineering Equations – Vasquez Beggs (± 20%)
- Measure losses using recording manometer and well tester or ultrasonic meter over several cycles (± 5%)
  - This is the best approach for facility design

Estimated Volume of Tank Vapors



° API = API gravity

Estimated Volume of Tank Vapors

- Atmospheric tanks may emit large amounts of tank vapors at relatively low separator pressure

Vasquez-Beggs Equation

$$GOR = A \times (G_{flash\ gas}) \times (P_{sep} + 14.7)^{B} \times \exp\left(\frac{C \times G_{oil}}{T_{sep} + 460}\right)$$

where,

GOR	=	Ratio of flash gas production to standard stock tank barrels of oil produced, in scf/bbl oil (barrels of oil corrected to 60°F)
$G_{flash\ gas}$	=	Specific gravity of the tank flash gas, where air = 1. A suggested default value for $G_{flash\ gas}$ is 1.22 (TNRCC; Vasquez, 1980)
G_{oil}	=	API gravity of stock tank oil at 60°F
P_{sep}	=	Pressure in separator, in psig
T_{sep}	=	Temperature in separator, °F

For $G_{oil} \leq 30$°API: A = 0.0362; B = 1.0937; and C = 25.724

For $G_{oil} > 30$°API: A = 0.0178; B = 1.187; and C = 23.931

psig – pounds per square inch, gauge
scf – standard cubic feet
bbl – barrels

What is the Recovered Gas Worth?

- Value depends on heat content of gas
- Value depends on how gas is used
  - On-site fuel
    - Valued in terms of fuel that is replaced
  - Natural gas pipeline
    - Measured by the higher price for rich (higher heat content) gas
  - Gas processing plant
    - Measured by value of natural gas liquids and methane, which can be separated
- Gross revenue per year = (Q x P x 365) + NGL
  - Q = Rate of vapor recovery (Mcf per day)
  - P = Price of natural gas
  - NGL = Value of natural gas liquids

Value of Natural Gas Liquids

	1 Btu/gallon	2 MMBtu/ gallon	3 $/gallon	4 $/MMBtu[1,2] (=3/2)
Methane	59,755	0.06	0.43	7.15
Ethane	74,010	0.07	1.51	21.57
Propane	91,740	0.09	1.99	22.11
n Butane	103,787	0.10	2.48	24.80
iso Butane	100,176	0.10	2.49	24.90
Pentanes+*	105,000	0.11	3.08	28.00

	5 Btu/cf	6 MMBtu/Mcf	7 $/Mcf (=4*6)	8 $/MMBtu	9 Vapor Composition	10 Mixture (MMBtu/Mcf)	11 Value ($/Mcf) (=8*10)
Methane	1,012	1.01	$7.22	7.15	82%	0.83	$5.93
Ethane	1,773	1.77	$38.18	21.57	8%	0.14	$3.05
Propane	2,524	2.52	$55.71	22.11	4%	0.10	$2.23
n Butane	3,271	3.27	$81.09	24.80	3%	0.10	$2.43
iso Butane	3,261	3.26	$80.90	24.90	1%	0.03	$0.81
Pentanes+	4,380	4.38	$122.64	28.00	2%	0.09	$2.45
Total						1.289	$16.90

1 – Natural Gas Price assumed at $7.15/MMBtu as on Mar 16, 2006 at Henry Hub
2 – Prices of Individual NGL components are from Platts Oilgram for Mont Belvieu, TX July 11, 2008

Cost of a Conventional VRU

Vapor Recovery Unit Sizes and Costs				
Capacity (Mcf/day)	Compressor Horsepower	Capital Costs ($)	Installation Costs ($)	O&M Costs ($/year)
25	5 to 10	20,421	10,207 to 20,421	7,367
50	10 to 15	26,327	13,164 to 26,327	8,419
100	15 to 25	31,728	15,864 to 31,728	10,103
200	30 to 50	42,529	21,264 to 42,529	11,787
500	60 to 80	59,405	29,703 to 59,405	16,839
Cost information provided by United States Natural Gas STAR companies and VRU manufacturers, 2006 basis.				

Is Recovery Profitable?

Financial Analysis for a Conventional VRU Project						
Peak Capacity (Mcf/day)	Installation & Capital Costs[1] ($)	O&M Costs ($/year)	Value of Gas[2] ($/year)	Annual Savings ($)	Simple Payback (months)	Internal Rate of Return
25	$35,738	$7,367	$77,106	$69,739	10	121%
50	$46,073	$8,419	$154,213	$145,794	6	204%
100	$55,524	$10,103	$308,425	$298,322	4	352%
200	$74,425	$11,787	$616,850	$605,063	3	537%
500	$103,959	$16,839	$1,542,125	$1,525,286	2	974%

1 – Unit cost plus estimated installation of 75% of unit cost
2 – $16.90 x ½ peak capacity x 365, Assumed price includes Btu enriched gas (1.289 MMBtu/Mcf)

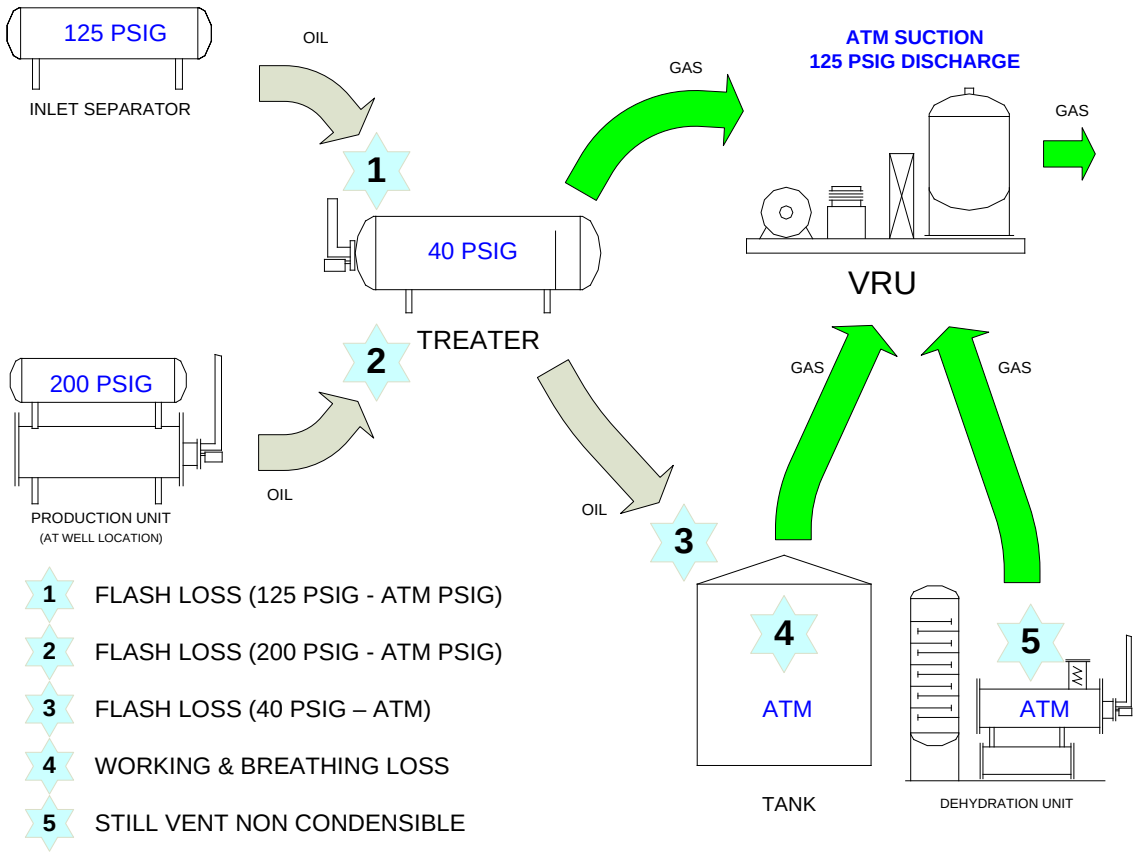
Industry Experience: EnCana Oil & Gas

- Vapor recovery unit installed in Frenchie Draw, WY
- Captures vapors from
  - Separators
  - Crude oil storage tank
  - Non-condensable dehydrator still gas
- VRU designed to handle 500 Mcf/day
  - Additional capacity over the estimated 284 Mcf/day of total gas from all emission sources

Industry Experience: EnCana Oil & Gas

- Quantify the volume of vapor emissions

Total Emissions-
284 MSCFD



Source: EnCana Oil & Gas (USA) Inc.

EnCana Oil & Gas: Project Costs

- Determine the cost of VRU project

Installation

VRU Unit (500 Mcfd) -	$90,000
Generator-	$85,000
Vent Header-	$25,000
Labor-	$200,000
TOTAL	$400,000

O & M

VRU Unit (500 Mcfd) -	$15,000
Generator-	$18,000
Fuel-	$73,000
TOTAL	$106,000

EnCana Oil & Gas: Project Economics

- Evaluate VRU economics

Capacity–	500 Mcfd
Installation Cost -	$400,000
O&M-	$106,000/year
Value of Gas*-	$788,400/year
Payback-	7 months
Return on Investment-	170%

*Gas price assumed to be $ 7.60 by Encana

Industry Experience: Anadarko

- Vapor Recover Tower (VRT)
  - Add separation vessel between heater treater or low pressure separator and storage tanks that operates at or near atmospheric pressure
    - Operating pressure range: 1 psi to 5 psi
  - Compressor (VRU) is used to capture gas from VRT
  - Oil/Condensate gravity flows from VRT to storage tanks
    - VRT insulates the VRU from gas surges with stock tank level changes
    - VRT more tolerant to higher and lower pressures
    - Stable pressure allows better operating factor for VRU

Industry Experience: Anadarko

- VRT reduces pressure drop from approximately 50 psig to 1-5 psig
  - Reduces flashing losses
  - Captures more product for sales
  - Anadarko netted between $7 to $8 million from 1993 to 1999 by utilizing VRT/VRU configuration
- Equipment Capital Cost: $11,000
- Standard size VRTs available based on oil production rate
  - 20” x 35’
  - 48” x 35’
- Anadarko has installed over 300 VRT/VRUs since 1993 and continues on an as needed basis

VRT/VRU Photos





Courtesy of Anadarko

Lessons Learned

- Vapor recovery can yield generous returns when there are market outlets for recovered gas
  - Recovered high heat content gas has extra value
  - Vapor recovery technology can be highly cost-effective in most general applications
  - Venturi jet models work well in certain niche applications, with reduced operating and maintenance costs
- Potential for reduced compliance costs can be considered when evaluating economics of VRU, EVRU™, or Vapor Jet

Lessons Learned (continued)

- VRU should be sized for maximum volume expected from storage tanks (rule-of-thumb is to double daily average volume)
- Rotary vane, screw or scroll type compressors recommended for VRUs where Venturi ejector jet designs are not applicable
- EVRU™ recommended where there is a high pressure gas compressor with excess capacity
- Vapor Jet recommended where there is produced water, less than 75 Mcf per day gas and discharge pressures below 40 psig

Methane Losses from Pipeline Pigging

- Gas lost when launching and receiving a pig
- Fugitive emissions from pig launcher/receiver valves
- Gas lost from storage tanks receiving condensate removed by pigging
- Gas vented from pipeline blowdowns

Pigging Pipelines

- Hydrocarbons and water condense inside pipelines, causing pressure drop and reducing gas flow
- Periodic line pigging removes liquids and debris to improve gas flow
  - Also inspect pipeline integrity
- Efficient pigging:
  - Keeps pipeline running continuously
  - Keeps pipeline near maximum throughput by removing debris
  - Minimizes product losses during launch/capture

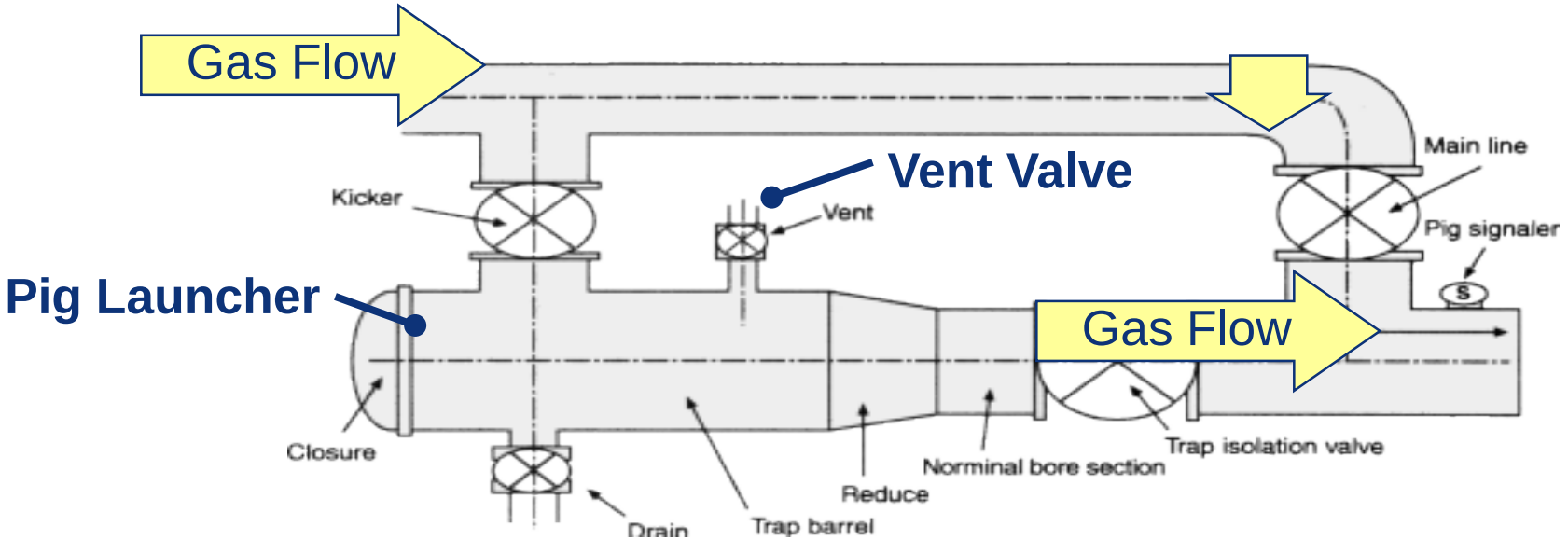




Source: www.girardind.com/

How Does Pigging Vent Methane?

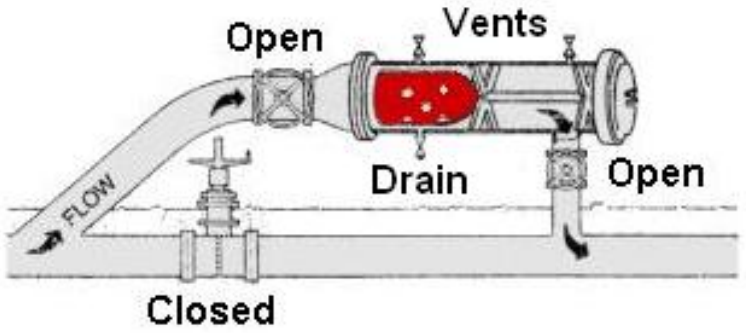
- Pig launchers have isolation valves for loading pigs, pressurizing pigs, and launching pigs with gas bypassed from the pipeline
- Launcher pressuring/depressuring loses methane out the vent valve



Source: www.girardind.com/

Pigging Vents Methane Twice

- Methane lost through vent valve on the launcher and again through vent valve on the receiver
  - Once receiver is isolated from the line, it must be depressured to remove the pig
  - Liquids ahead of the pig drain to a vessel or tank
- *MORE than twice:* isolation valve leaks may cause excessive venting to depressure



Source: www.girardind.com/

Methane Recovery

- Pipeline maintenance requires pipe section blowdown before work can begin
- Gas in pipeline is usually vented to the atmosphere
- Use inert gas and pig
- Route vent to vapor recovery system or fuel gas
  - One Partner reported connecting pig receiver vent to fuel gas to recover gas while working a tight isolation

Is Recovery Profitable?

- One partner pigged gathering lines 30 to 40 times per year, collecting several thousand barrels of condensate per application
- Partner reported saving 21,400 Mcf/year from recovering flash gases
- Dedicated vapor recovery unit (VRU) was installed with an electric compressor at an installation cost of $24,000 and an annual operating cost of $40,000 mostly for electricity
- Large gas savings and increasing gas prices will offset costs

Gas Price ($/Mcf)	$7.00
Gas Saved (Mcf/year)	21,400
Annual Savings ($/year)	$149,800
Installed Cost	$24,000
Operating Cost	$40,000
Payback Period (years)	0.3

Discussion

- Industry experience applying these technologies and practices
- Limitations on application of these technologies an practices
- Actual costs and benefits

Install Flares



Technology/Practice Overview

Description

Remote, unmanned production sites and compressor stations may vent low-pressure natural gas and vapors from storage tanks and other onsite equipment to the atmosphere. These gases, which contain methane and often volatile organic compounds (VOC), hydrogen sulfide, and hazardous air pollutants (HAP), can pose an environmental, health, and safety hazard. In order to reduce these emissions, Partners have reported installing flares to combust these gases instead of venting them to the atmosphere.

Partners have applied flaring technology typically consisting of a small flare stack with one or two pilots. Emissions sources, such as tank vents, compressor blowdown lines, low-pressure separator vents, overpressure relief valves, and other vent streams are piped directly to the flare.

Operating Requirements

If the heat content of the stream is below 300 Btu per scf, auxiliary fuel is needed. The average pilot gas consumption is 70 scf per hour per pilot burner.

Applicability

Flares can be applied to all point source vented emissions of combustible gas with minimal sulfur content.

Methane Emissions

The methane emissions reduction is uniquely dependent on the types and sizes of sources and the methane content of the flared gas. Wellhead gas may range from 70 to 90 percent methane while crude oil production tank vapors

- ☐ Compressors/Engines
- ☐ Dehydrators
- ☐ Directed Inspection & Maintenance
- ☐ Pipelines
- ☐ Pneumatics/Controls
- ☐ Tanks
- ☐ Valves
- ☐ Wells
- ■ Other

Applicable Sector(s)

- ■ Production
- ☐ Processing
- ■ Transmission
- ☐ Distribution

Other Related PROs:

Install Electronic Flare Ignition Devices, PRO No. 903

Economic and Environmental Benefits

Methane Savings

Estimated annual methane emission reductions	*2,000 Mcf per flare (with a single pilot)*

Economic Evaluation

Estimated Gas Price	Annual Methane Savings	Value of Annual Gas Savings*	Estimated Implementation Cost	Incremental Operating Cost	Payback (months)
$7.00/Mcf	2,000 Mcf	N/A	$21,000	$4,200	None
$5.00/Mcf	2,000 Mcf	N/A	$21,000	$3,000	None
$3.00/Mcf	2,000 Mcf	N/A	$21,000	$1,800	None

** Because the natural gas is flared, there are no economic gas savings associated with this activity.*

Additional Benefits

- Safer operations

Install Flares (Cont'd)

may be as low as 50 percent methane. Partners have reported production site application for tank vents, relief valves, and compressor blow-down at 2,000 Mcf per year, low-pressure separators at 4,000 Mcf per year, and condensate tanks at 36,000 Mcf per year.

Economic Analysis

Basis for Costs and Emissions Savings

Methane emissions reductions of 2,000 Mcf per year apply to a single flare with a single pilot. Costs for a flare are estimated to be $3,000 based on partner experiences (which vary significantly and are often between $1,000 and $5,000). In addition, and there is a fuel cost of $1,800 per year for each pilot (at $3 per Mcf of gas).

Discussion

Flares are commonly installed on higher-pressure blowdown or emergency pressure relief valves for safety reasons. Low-pressure gas installations have been justified by environmental emissions control. There are no revenues from the gas as it is destroyed through combustion.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

Oil and Natural Gas Sector Pneumatic Devices

Report for Oil and Natural Gas Sector Pneumatic Devices

Review Panel

April 2014

Prepared by

U.S. EPA Office of Air Quality Planning and Standards (OAQPS)

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NMED Exhibit 91

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Table of Contents

PREFACE 1

1.0 INTRODUCTION 2

1.1 Definition of the Source 2

1.1.1 Pneumatic Controllers 2

1.1.2 Pneumatic Pumps 4

1.2 Background 4

1.2.1 Pneumatic Controllers 4

1.2.2 Pneumatic Pumps 5

1.3 Purpose of the White Paper 6

2.0 AVAILABLE EMISSIONS DATA AND ESTIMATES 6

2.1 Discussion of Data Sources for Pneumatic Controllers 7

2.1.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c) 8

2.1.2 Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999) 12

2.1.3 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014) 13

2.1.4 Greenhouse Gas Reporting Program (U.S. EPA, 2013) 18

2.1.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013) 20

2.1.6 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013) 23

2.1.7 Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014) 25

2.1.8 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014) 26

2.2 Discussion of Data Sources for Pneumatic Pumps 28

NMED Exhibit 91

2.2.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c) (GRI/EPA, 1996e) 28

2.2.1.1 Methane Emissions from the Natural Gas Industry – Chemical Injection Pumps (GRI/EPA, 1996c) 28

2.2.1.2 Methane Emissions from the Natural Gas Industry – Gas-Assisted Glycol Pumps (GRI/EPA, 1996e) 31

2.2.2 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014) 32

2.2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013) 35

2.2.4 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013) 35

2.2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014) 36

3.0 AVAILABLE PNEUMATIC DEVICE EMISSIONS MITIGATION TECHNIQUES 36

3.1 Available Pneumatic Controller Emissions Mitigation Techniques 36

3.1.1 Zero Bleed Pneumatic Controllers 41

3.1.2 Low Bleed Pneumatic Controllers 41

3.1.3 Instrument Air Systems 44

3.1.4 Mechanical and Solar-Powered Systems in Place of Bleed Controller 48

3.1.5 Maintenance of Natural Gas-Driven Pneumatic Controllers 50

3.2 Available Pneumatic Pump Emissions Mitigation Techniques 50

3.2.1 Instrument Air Pump 51

3.2.2 Solar Power Pump 54

3.2.3 Electric Power Pumps 55

4.0 SUMMARY 56

4.1 Pneumatic Controllers 56

4.2 Pneumatic Pumps 57

NMED Exhibit 91

5.0 CHARGE QUESTIONS FOR REVIEWERS 57

6.0 REFERENCES 58

NMED Exhibit 91

PREFACE

On March 28, 2014 the Obama Administration released a key element called for in the President's Climate Action Plan: a Strategy to Reduce Methane Emissions. The strategy summarizes the sources of methane emissions, commits to new steps to cut emissions of this potent greenhouse gas, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut methane emissions from several sectors, including the oil and natural gas sector.

This technical white paper is one of those steps. The paper, along with four others, focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. The Agency is seeking input from independent experts, along with data and technical information from the public. The EPA will use these technical documents to solidify our understanding of these potentially significant sources, which will allow us to fully evaluate the range of options for cost-effectively cutting VOC and methane waste and emissions.

The white papers are available at:

www.epa.gov/airquality/oilandgas/whitepapers.html

NMED Exhibit 91

1.0 INTRODUCTION

The oil and natural gas exploration and production industry in the U.S. is highly dynamic and growing rapidly. Consequently, the number of wells in service and the potential for greater emissions from oil and natural gas sources is also growing. There were an estimated 504,000 producing gas wells in the U.S. in 2011 (U.S. EIA, 2012a), and an estimated 536,000 producing oil wells in the U.S. in 2011 (U.S. EIA, 2012b). It is anticipated that the number of gas and oil wells will continue to increase substantially in the future because of the continued and expanding use of horizontal drilling combined with hydraulic fracturing (referred to here as simply hydraulic fracturing).

Due to the growth of this sector and the potential for increased air emissions, it is important that the U.S. Environmental Protection Agency (EPA) obtain a clear and accurate understanding of emerging data on emissions and available mitigation techniques. This paper presents the Agency's understanding of emissions and available emissions mitigation techniques from a potentially significant source of emissions in the oil and natural gas sector.

1.1 Definition of the Source

The focus of this white paper is natural gas-driven pneumatic controllers and natural gas-driven pneumatic pumps. Such pneumatic controllers and pumps are widespread in the oil and natural gas industry and emit natural gas, which contains methane and VOCs. In some applications, pneumatic controllers and pumps used in this industry may be driven by gases other than natural gas and, therefore, do not emit methane or VOCs.

1.1.1 Pneumatic Controllers

For the purposes of this white paper, a *pneumatic controller* means an automated instrument used for maintaining a process condition such as liquid level, pressure, pressure difference and temperature. Based on the source of power, two types of pneumatic controllers are defined for this paper:

NMED Exhibit 91

- *Natural gas-driven pneumatic controller* means a pneumatic controller powered by pressurized natural gas.
- *Non-natural gas-driven pneumatic controller* means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Natural gas-driven pneumatic controllers come in a variety of designs for a variety of uses. For the purposes of this white paper, they are characterized primarily by their emissions characteristics:

- *Continuous bleed pneumatic controllers* are those with a continuous flow of pneumatic supply natural gas to the process control device (e.g., level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator. For the purposes of this paper, continuous bleed controllers are further subdivided into two types based on their bleed rate:
    - *Low bleed*, having a bleed rate of less than or equal to 6 standard cubic feet per hour (scfh).
    - *High bleed*, having a bleed rate of greater than 6 scfh.
- *Intermittent pneumatic controller* means a pneumatic controller that vents non-continuously. These natural gas-driven pneumatic controllers do not have a continuous bleed, but are actuated using pressurized natural gas.
- *Zero bleed pneumatic controller* means a pneumatic controller that does not bleed natural gas to the atmosphere. These natural gas-driven pneumatic controllers are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere.

NMED Exhibit 91

1.1.2 Pneumatic Pumps

Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available (GRI/EPA, 1996d). The supply gas for these pumps can be compressed air, but most often these pumps use natural gas from the production stream (GRI/EPA, 1996e).

1.2 Background

1.2.1 Pneumatic Controllers

Pneumatic controllers are automated instruments used for maintaining a process condition such as liquid level, pressure, pressure differential, and temperature. In many situations, across all segments of the oil and gas industry, pneumatic controllers make use of the available high-pressure natural gas to operate control of a valve. In these natural gas-driven pneumatic controllers, natural gas is released with every actuation of the valve, i.e., valve movement. In some designs, natural gas is also released continuously from the valve control pilot. The rate at which the continuous release occurs is referred to as the bleed rate. Bleed rates are dependent on the design and operating characteristics of the device. Similar designs will have similar steady-state rates when operated under similar conditions. There are three basic designs of natural gas-driven pneumatic controllers: (1) continuous bleed controllers are used to modulate flow, liquid level, or pressure, and gas is vented continuously at a rate that may vary over time; (2) intermittent controllers release gas only when they open or close a valve or as they throttle the gas flow; and (3) zero bleed controllers, which are self-contained devices that release gas to a downstream pipeline instead of to the atmosphere (EPA, 2011a).

As noted above, intermittent controllers are devices that only emit gas during actuation and do not have a continuous bleed rate. Thus, the actual amount of emissions from an intermittent controller is dependent on the amount of natural gas vented per actuation and how often it is actuated. Continuous bleed controllers also vent an additional volume of gas during

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actuation, in addition to the device's continuous bleed stream. Thus, actual emissions from a continuous bleed device also depend, in part, on the frequency of activation and the amount of gas vented during activation. As the name implies, zero bleed controllers are considered to emit no natural gas to the atmosphere (EPA, 2011a).

In general, intermittent controllers serve functionally different purposes than bleed controllers and, therefore, cannot replace bleed controllers in most (but not all) applications. Furthermore, zero bleed controllers are "closed loop" systems that can be used only in applications with very low pressure and therefore may not be suitable to replace continuous bleed pneumatic controllers in many applications.

Non-natural gas-driven pneumatic controllers can be used in some applications. These controllers can be mechanically operated or use sources of power other than pressurized natural gas, such as compressed "instrument air." Instrument air systems are feasible only at oil and natural gas locations that have electrical service sufficient to power an air compressor. At sites without electrical service sufficient to power an instrument air compressor, mechanical or electrically powered pneumatic controllers can be used. Non-natural gas-driven controllers do not directly release methane or VOCs, but may have secondary impacts related to generation of required electrical power (EPA, 2011a).

1.2.2 Pneumatic Pumps

There are two types of pneumatic pumps that are commonly used in the oil and natural gas sector: piston and diaphragm (GRI/EPA, 1996d). These pumps have two major components, a driver side and a motive side, which operate in the same manner but with different reciprocating mechanisms. Pressurized gas provides energy to the driver side of the pump, which operates a piston or flexible diaphragm to draw fluid into the pump. The motive side of the pump delivers the energy to the fluid being moved in order to discharge the fluid from the pump. The natural gas leaving the exhaust port of the pump is either directly discharged into the atmosphere or is recovered and used as a fuel gas or stripping gas (GRI/EPA, 1996d).

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The majority of pneumatic pumps used in oil and natural gas production are used for chemical injection or glycol circulation (GRI/EPA, 1996d). Pneumatic pumps used for chemical injection are needed in oil and natural gas production to inject small amounts of chemicals to limit processing problems and protect equipment. Typical chemicals that are injected into the process include: biocides, demulsifiers, clarifiers, corrosion inhibitors, scale inhibitors, hydrate inhibitors, paraffin dewaxers, surfactants, oxygen scavengers and hydrogen sulfide scavengers (GRI/EPA, 1996d). These chemicals are normally injected using pneumatic pumps at the wellhead, and into gathering lines or at production separation facilities (GRI/EPA, 1996d). Pneumatic pumps, commonly referred to as "Kimray" pumps, used for glycol circulation recover energy from the high-pressure rich glycol/gas mixture leaving the absorber and use that energy to pump the low-pressure lean glycol back into the absorber (GRI/EPA, 1996e).

1.3 Purpose of the White Paper

This white paper provides a summary of the EPA's understanding of the emissions from natural gas-driven pneumatic controllers and pumps in the oil and natural gas sector, the mitigation techniques available to reduce these emissions, the efficacy of these techniques and the prevalence of these techniques in the field. Section 2 of this document provides the EPA's understanding of emissions from pneumatic controllers and pumps, and Section 3 provides our understanding of available mitigation techniques. Section 4 summarizes the EPA's understanding based on the information presented in Sections 2 and 3, and Section 5 presents a list of charge questions for reviewers to assist the EPA with obtaining a more comprehensive understanding of pneumatic controller and pump VOC and methane emissions and emission mitigation techniques.

2.0 AVAILABLE EMISSIONS DATA AND ESTIMATES

There are a number of studies that have been published that have estimated VOC and methane emissions from pneumatic controllers and pneumatic pumps in the oil and natural gas sector. These studies have used different methodologies to estimate these emissions including the use of equipment counts and emission factors and direct measurement of emissions. Section 2.1 discusses the studies relevant to pneumatic controllers, and Section 2.2 discusses the studies

NMED Exhibit 91

relevant to pneumatic pumps. These studies are listed in Table 2-1, along with an indication of the type of information contained in the study.

Table 2-1. Summary of Major Sources of Pneumatic Controller and Pump Information

Report Name	Affiliation	Year of Report	Activity Factor	Pneumatic Controllers	Pneumatic Pumps
Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)	Gas Research Institute / EPA	1996	Nationwide	X	X
Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)	EPA	1999	Nationwide	X	
Inventory of Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)	EPA	2014	Nationwide/ Regional	X	X
Greenhouse Gas Reporting Program (U.S. EPA, 2013)	EPA	2013	Basin	X	X
Measurements of Methane Emissions from Natural Gas Production Sites in the United States (Allen et al., 2013)	Multiple Affiliations, Academic and Private	2013	Nationwide	X	
Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino, 2013)	The Prasino Group	2013	British Columbia	X	
Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)	Carnegie Mellon University	2014	Regional (Marcellus Shale)	X	
Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)	ICF International	2014	Nationwide	X	X

2.1 Discussion of Data Sources for Pneumatic Controllers

This section presents and discusses pertinent studies and data sources that estimate emissions from pneumatic controllers.

NMED Exhibit 91

2.1.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c)

This report's main objective was to quantify annual methane emissions from pneumatic controllers from the natural gas production, processing, transmission, and distribution sectors. The methane emissions were determined by developing average annual emissions factors for the various types of pneumatic controllers used in each of the natural gas segments. The annual emission factors were then extrapolated to a national estimate using activity factors for each of the natural gas segments.

Production

The data used to develop emission factors for pneumatic controllers in the natural gas production sector were obtained from a study performed by the Canadian Petroleum Association (CPA)[1], manufacturers' data, measured emission rates[2], data collected from site visits, and literature data for methane composition.

The CPA study consisted of methane and VOC emission measurements from pneumatic controllers in two types of service: 19 in on/off service and 16 in throttling service.[3] The CPA study determined the average natural gas emission rate for on/off controllers was 213 standard cubic feet per day per device (scfd/device), and the average natural gas emission rate for throttling controllers was 94 scfd/device. For throttling controllers, the CPA study did not distinguish between the throttling controllers with intermittent bleed rates and throttling controllers with continuous bleed rates. In addition, only one throttling controller actuated during the emission measurement. Therefore, these measurements are lower in comparison to field measurements of similar devices in the U.S. (GRI/EPA, 1996c).

---

[1] Picard, D.J., B.D. Ross, and D.W.H. Koon, *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta*. Canadian Petroleum Association, Calgary, Alberta, 1992.

[2] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

[3] Controllers in on/off service wait until a specific set point is reached before actuating (e.g., a high or low liquid level). Controllers in throttling service maintain a desired set point (e.g., pressure).

NMED Exhibit 91

The manufacturers' data were obtained from four manufacturers of pneumatic controllers and were based on laboratory testing of new controllers. The manufacturers' noted that emissions in the field can be higher due to operating condition, age, and wear of the device. The gas consumption rates for the manufacturers' pneumatic controllers ranged from 0 to 2,150 scfd. The manufacturers noted that the emissions from these controllers in the field may be higher than the reported maximum value (GRI/EPA, 1996c).

The measured emissions data[4] were collected by connecting a flow meter to the supply line between the pressure regulator and the controller to measure the gas consumption of the controller. The duration of the test depended on the operating conditions. For steady operating conditions, one data point was measured for 15-20 minutes. For variable operating conditions, several one-hour measurements were taken. The data set contained a total of 41 measurements from a combination of continuous bleed controllers from offshore and onshore production sites and transmission stations. The average gas emissions rates for continuous bleed controllers were determined to be 872 scfd/device for onshore and offshore production sites and 1,363 scfd/device for transmission stations.

The measured emission data[5] also provided data for intermittent bleed controllers that were measured using the same techniques that were used for the continuous bleed pneumatic controllers. A total of seven measurements were performed on intermittent bleed controllers located at onshore natural gas production sites. No measurements were available for intermittent bleed controllers in the offshore or transmission segments. The average natural gas emission rate for the intermittent pneumatic controllers was determined to be 511 scfd/device.

Site visit data were collected from a total of 22 sites to determine the number of pneumatic controllers located at natural gas production sites, and to determine the fraction of these controllers that were intermittent or continuous bleed. The study determined that 65% of

[4] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.
[5] Controller survey data provided by Tenneco Gas Transportation, 1994 and Chevron, 1995.

the pneumatic controllers were intermittent bleed and 35% of the pneumatic controllers were continuous bleed.

The measured emission data, the CPA study emissions data, and the pneumatic controller counts were used to develop a single emission factor for a "generic" pneumatic device. For the production segment, the "generic" pneumatic controller emission factor was calculated using:

- 323 scfd/device for intermittent bleed controllers,
- 654 scfd/device for continuous bleed controllers,
- a methane content of 78.8%, and
- the ratio of intermittent bleed to continuous bleed controllers at natural gas production sites.

The "generic" emission factor was determined to be 345 scfd/device of methane for a pneumatic controller at natural gas production sites.

Transmission

The transmission "generic" emission factor was calculated using data from three types of gas-operated pneumatic controllers: continuous bleed controllers and two types of intermittent bleed controllers used to operate isolation valves[6] (isolation valves with turbine operators and isolation valves with displacement-type pneumatic/hydraulic operators). The continuous bleed emission factor was obtained from the transmission station measured emission data, which was determined to be 1,363 scfd/device. The isolation valve with displacement-type pneumatic/hydraulic operators emission factor was determined using data provided by Shafer Valve Operating Systems[7,8] and the count of the isolation valves at four sites. Using these data,

[6] Isolation valves at transmission stations are very large and are most often actuated either pneumatically or by electric motor. Isolation valve pneumatic controllers only discharge gas when they are actuated and are considered to be intermittent.

[7] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-00693. June 1993.

the average annual emission factor was determined to be 5,627 standard cubic feet per year per device (scfy/device). For turbine-operated isolation valves, the natural gas emissions were estimated using information provided by Limitorque Corporation[9] and information from two transmission sites. This information was used to calculate an emission factor of 67,599 scfy/device. The above emission factors, a methane content of 93.4% and proportions of each of these controllers at transmission sites was used to calculate a "generic" emission factor of 162,197 scfy/device of methane for pneumatic controllers at transmission stations.

Processing

The site visit information from nine natural gas processing plants found that plants used compressed air to operate the majority of pneumatic controllers at the plants. Only one of the plants used natural gas-powered continuous bleed controllers, and five had natural gas-driven pneumatic controllers for the isolation valves on the main pipeline emergency shutdown system or isolation valves used for maintenance. The same type of pneumatic controllers used in the transmission sector are used at natural gas processing sites; therefore, the same emission factors were used to calculate a facility pneumatic emission factor. Using the survey data and the transmission sector pneumatic controller emission factors, the annual methane emissions were determined to be 165 thousand standard cubic feet per facility (Mscfy/facility).

Summary

A summary of the pneumatic controller emission factors, activity factors, and annual methane emission rates estimated by this report are provided in Table 2-2 for the natural gas production, processing and transmission segments. The total methane emissions from pneumatic controllers was estimated to be 45,634 million standard cubic feet per year (MMscfy) or 861,704 metric tons (MT).

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[8] Shafer Valve Operating Systems. Gas Consumption Calculation Method for Rotary Vane, Gas/Hydraulic Actuators. Technical Bulletin Data, Bulletin GC-2-00394. March 1994.

[9] Personal correspondence with Belva Short of Limitorque Corporation, Lynchburg, VA, April 5, 1994.

Table 2-2 GRI Nationwide Pneumatic Controller Methane Emissions in the United States (1992 Base Year)

Natural gas Segment	Methane Emission Factor	Activity Factor	Annual Methane Emission Rate (MMscf/yr)	Annual Methane Emission Rate (MT)
Production	125,925 scfy/device	249,111 controllers	31,369	592,349
Processing	165,000 scfy/facility	726 facilities	120	2,262
Transmission	162,197 scfy/device	87,206 controllers	14,145	267,093
Total			45,634	861,704

2.1.2 Estimates of Methane Emissions from the U.S. Oil Industry (ICF Consulting, 1999)

ICF Consulting (ICF Consulting, 1999) prepared a report for the EPA that estimated methane emissions from crude oil production, transportation and refining, identified potential methane mitigation techniques and provided an analysis of the economics of reducing methane emissions. The report estimated that 97% of the annual methane emissions occur during crude oil production (59.1 billion cubic feet, Bcf or 1,116,000 MT) in 1995. The transportation and refining sectors generate 0.3 Bcf (5,700 MT) and 1.3 Bcf (24,500 MT) of the annual methane emissions, respectively. The annual methane emissions were estimated using methane emission factors and activity factors to calculate the annual methane emissions from the oil industry.

In the production segment, annual vented methane emissions from 13 sources account for 91% (53.8 Bcf or 1,016,000 MT) of the total 1995 methane emissions from crude oil production. Two of these sources: high bleed pneumatic controllers and low bleed pneumatic controllers account for 37% (19.9 Bcf or 376,000 MT) and 7% (3.7 Bcf or 69,900 MT) of the annual vented methane emissions, respectively.

The high bleed pneumatic controller methane emissions were calculated using an emission factor of 345 scfd (GRI/EPA, 1996c). The activity factor for high bleed pneumatic controllers was determined to be 157,581 and assumes that tank batteries with heater treaters have four pneumatic controllers (three level controllers and one pressure controller). Tank batteries without heater treaters were assumed to have three pneumatic controllers. In addition, it was assumed that 35% of the total pneumatic controllers were high bleed, which is based on the percentage of continuous bleed pneumatic controllers determined in the GRI/EPA study (GRI/EPA, 1996c).

The low bleed pneumatic controller methane emission factor was estimated to be 10% of the high bleed methane emission factor or 35 scfd.[10] The activity factor for low bleed controllers was calculated to be 292,650 controllers and was determined using the assumption that 65% of the total pneumatic controllers are intermittent bleed (GRI/EPA, 1996c), which this report assumed to be low bleed pneumatic devices.

No methane emissions from pneumatic controllers were estimated in this report for the transportation and refining segments of the oil industry.

2.1.3 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

The EPA leads the development of the annual Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHG Inventory). This report tracks total U.S. greenhouse gas (GHG) emissions and removals by source and by economic sector over a time series, beginning with 1990.

The U.S. submits the GHG Inventory to the United Nations Framework Convention on Climate Change (UNFCCC) as an annual reporting requirement. The GHG Inventory includes estimates of methane and carbon dioxide for natural gas systems (production through distribution) and petroleum systems (production through refining).

[10] EPA Natural Gas STAR default value for low bleed pneumatic controllers.

Table 2-3 summarizes the 2014 GHG Inventory's (published in 2014; containing emissions data for 1990-2012) estimates of 2012 national methane emissions from pneumatic controllers in the natural gas production, processing, transmission and storage segments and the petroleum production segment. Where presented in the GHG Inventory, the table includes potential emissions (i.e., emissions that would be released in the absence of controls), emission reductions and net emissions. For pneumatic controllers, the emission reductions reported to the Natural Gas STAR program are deducted from potential emission to calculate net emissions. In future years, the GHG Inventory will also account for regulatory reductions impacting emissions from pneumatic controllers that result from subpart OOOO.

Table 2-3. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Controllers

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas and petroleum production[a]	1,642,622	873,100	769,522
Natural gas processing	1,923	[b]	[b]
Natural gas transmission and storage	263,561	14,078	249,483

[a] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

[b] The GHG Inventory does not include a specific emission reduction for pneumatic controllers in the natural gas processing sector resulting from the Natural Gas STAR program although it is likely non-zero.

The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors. The following sections provide greater detail on the estimates given in Table 2-3.

2.1.3.1 Natural gas and petroleum production industry segment

Table 2-4 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas and petroleum production industry segment. The table

NMED Exhibit 91

presents the population of pneumatic controllers, methane emission factors, potential methane emissions, and the estimated national total of pneumatic controllers and potential methane emissions. The natural gas production data are broken down by the Energy Information Agency's (EIA's) National Energy Modeling System (NEMS) regions. The table also presents the national total of methane emission reductions compiled from Natural Gas STAR reports and the resulting estimated national net methane emissions from pneumatic controllers.

Table 2-4. Estimated 2012 National and Regional Methane Emissions from Pneumatic Controllers in the Natural Gas and Petroleum Production Segment

NEMS Region	Population of Pneumatic Controllers[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Potential Emissions-Natural Gas Systems			
North East	77,261	373	202,696
Midcontinent	167,589	362	426,133
Rocky Mountain	122,127	339	291,166
South West	55,095	353	136,534
West Coast	2,098	402	5,933
Gulf Coast	53,436	386	145,057
Total	477,606		1,207,519
Potential Emissions-Petroleum Systems			
High Bleed	145,179	330	336,692
Low Bleed	269,618	52	98,411
Total	414,797		435,103
Combined Natural Gas and Petroleum Systems			
Total	892,403		1,642,622
Voluntary Emission Reductions-Natural Gas and Petroleum			873,100
Net Emissions-Natural Gas and Petroleum[b]			769,522

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
[b] In the GHG Inventory, all Natural Gas STAR reductions for pneumatic devices are removed from the natural gas systems estimate. As some of these reductions likely occur in petroleum systems, a combined number for production segment pneumatic devices in natural gas and petroleum systems is presented here.

Recent national activity data on pneumatic controllers are not available. To calculate national emissions for these sources for the GHG Inventory, a set of industry activity data drivers was developed and used to update activity data. For the natural gas production segment, pneumatic controllers were estimated each year by applying a regional factor for the number of pneumatic controllers per well to annual regional data on gas well population. These factors ranged from 0.5 to 1.6 pneumatic controllers per well. For the petroleum production segment, pneumatic controllers were estimated each year by applying a factor for the number of pneumatic controllers per heater/treater (4), and pneumatic controller per battery without a heater/treater (3).

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas and petroleum production industry segment is the 1996 GRI/EPA report. The factor for natural gas systems represents a mix of the average emissions from continuous bleed and intermittent natural gas-driven pneumatic controllers in the 1996 GRI/EPA report. The region-specific factors are developed using the GRI/EPA factor and regional gas composition data. For petroleum systems, it was then assumed that 65% of pneumatic controllers in the petroleum production segment are low bleed pneumatic controllers, and 35% of controllers are high bleed. The GRI/EPA factors for low and high bleed controllers are applied to these populations

According to the GHG Inventory, the 1996 GRI/EPA report "still represents the best available [emissions] data in many cases, [but] using these emission factors alone to represent actual emissions without adjusting for emissions controls would in many cases overestimate emissions. For this reason, 'potential emissions' are calculated using the [1996 GRI/EPA report] data, and then current data on voluntary and regulatory emission reduction activities are deducted to calculate actual emissions."

In the case of pneumatic controllers in the natural gas production industry segment, the GHG Inventory reduces the calculated potential emissions using voluntary emission reductions reported by industry partners to the Natural Gas STAR Program. The reductions undergo quality assurance and quality control checks to identify errors, inconsistencies, or irregular data before

being incorporated into the GHG Inventory. Future inventories are expected to reflect the subpart OOOO requirements for pneumatic controllers as they are implemented.

2.1.3.2 Natural gas processing industry segment

Table 2-5 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas processing industry segment.

Table 2-5. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Processing Segment

Activity Factor	CH_4 Potential Emission Factor (scfy/plant)[b]	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
606 gas plants[a]	164,721	1,923	[c]	[c]

[a] *Oil and Gas Journal*, with available 2012 activity data.
[b] 1996 GRI/EPA report.
[c] Although voluntary Natural Gas STAR emission reductions are reported for this industry segment in the aggregate, no value is given specifically for pneumatic controllers.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas processing segment is the 1996 GRI/EPA report. This potential emission factor is expressed in terms of standard cubic feet per year per processing plant (scfy/plant). The associated activity factor is the number of U.S. gas plants, which comes from the *Oil and Gas Journal*.

The GHG Inventory does not report emissions reductions specific to pneumatic controllers in this industry segment and, thus, there is no reported net emissions figure.

2.1.3.3 Natural gas transmission and storage segment

Table 2-6 shows the 2014 GHG Inventory's estimates of 2012 methane emissions from pneumatic controllers in the natural gas transmission and storage industry segment.

NMED Exhibit 91

Table 2-6. Estimated 2012 National Methane Emissions from Pneumatic Controllers in the Natural Gas Transmission and Storage Segment

Subsegment	Activity Factor (# of controllers)	CH_4 Potential Emission Factor (scfy/device)	CH_4 Potential Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Transmission	70,827	162,197[a]	221,257		
Storage	13,542	162,197[a]	42,304		
Total	84,369		263,561	-14,078[b]	249,483

[a] 1996 GRI/EPA report.
[b] Voluntary Natural Gas STAR emission reductions are reported for all pneumatic controllers in this industry segment, not split out by transmission and storage.

The basis for the GHG Inventory's potential methane emission factors for pneumatic controllers in the natural gas transmission and storage segment is the 1996 GRI/EPA report. In this case, the potential emission factor is expressed in terms of scfy/device. The associated activity factor is the number of pneumatic controllers. For transmission, the number of pneumatic controllers is calculated based on transmission pipeline length. For storage, the number of pneumatic controllers is calculated based on number of compressor stations in the storage segment.

The 2014 GHG Inventory includes voluntary emission reductions reported by industry partners to the Natural Gas STAR Program for pneumatic controllers in the natural gas transmission and storage industry segment.

2.1.4 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

In October 2013, the EPA released 2012 GHG data for Petroleum and Natural Gas Systems collected under the Greenhouse Gas Reporting Program (GHGRP). The GHGRP, which was required by Congress in the FY2008 Consolidated Appropriations Act, requires facilities to report data from large emission sources across a range of industry sectors, as well as suppliers of certain GHGs and products that would emit GHGs if released or combusted.

When reviewing this data and comparing it to other data sets or published literature, it is important to understand the GHGRP reporting requirements and the impacts of these requirements on the reported data. The GHGRP covers a subset of national emissions from Petroleum and Natural Gas Systems; a facility in the Petroleum and Natural Gas Systems source category is required to submit annual reports if total emissions are 25,000 MT of CO_2 equivalent (MT CO_2e) or more. Facilities use uniform methods prescribed by the EPA to calculate GHG emissions, such as direct measurement, engineering calculations, or emission factors derived from direct measurement. In some cases, facilities have a choice of calculation methods for an emission source.

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rules define three segments of the oil and natural gas industry sector that are required to report GHG emissions from pneumatic controllers: (1) onshore petroleum and natural gas production, (2) onshore natural gas transmission compression, and (3) underground natural gas storage. Facilities calculate emissions from pneumatic controllers by determining the number of each type of controller at the facility and applying emission factors. In the petroleum and natural gas production segment, facilities must apply facility-specific gas composition factors for methane and CO_2. In the natural gas transmission and storage segments, default gas composition factors are used. Subpart W emission factors for pneumatic controllers are located at 40 CFR Part 98, subpart W, Table W-1A (Onshore Petroleum and Natural Gas Production), Table W-3 (Onshore Natural Gas Transmission Compression), and Table W-4 (Underground Natural Gas Storage). These emission factors are based on the 2009 document *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* published by the American Petroleum Institute (API), which in turn is based on the 1996 GRI/EPA report.

Table 2-7 shows the number of reporting facilities[11] in each of the three industry segments, along with reported pneumatic controller methane emissions.

Table 2-7. Facilities and Reported Emissions from Pneumatic Controllers, 2012

Segment	Number of Reporting Facilities	Reported Methane Emissions (MT)[a]
Petroleum and NG Production	417	861,224
Transmission	330	7,582
Storage	38	4,493

[a] The reported methane MT CO2e emissions were converted to methane emissions in MT by dividing by a global warming potential (GWP) of methane (21).

2.1.5 Measurements of Methane Emissions at Natural Gas Production Sites in the United States (Allen et al., 2013)

A study completed by multiple academic institutions and consulting firms was conducted to gather methane emissions data at onshore natural gas sites in the U.S. and compare those emission estimates to the 2011 estimates reported in the 2013 GHG Inventory. The sources or operations tested included 305 pneumatic controllers located at 150 distinct natural gas production sites in four production regions (Appalachian, Gulf Coast, Midcontinent, and Rocky Mountain).

Testing was carried out using a Hi-Flow Sampler, which is a portable, battery-powered instrument designed to determine the rate of gas leakage around various pipe fittings, valve packings and compressor seals found in natural gas production, transmission, storage and processing facilities. To allow the quantity of methane to be separated out from other chemical

[11] In general, a "facility" for purposes of the GHGRP means all co-located emission sources that are commonly owned or operated. However, the GHGRP has developed a specialized facility definition for onshore production. For onshore production, the "facility" includes all emissions associated with wells owned or operated by a single company in a specific hydrocarbon-producing basin (as defined by the geologic provinces published by the American Association of Petroleum Geologists).

species, gas composition data were collected for each natural gas production site, typically provided by the site owner. The 305 sampled pneumatic controllers represented an estimated 41% of all the controllers associated with the wells that were sampled. The sampling time for each controller was not specified in the study. Table 2-8 shows the emission rates determined by the testing.

Table 2-8. Pneumatic Controller Methane Emission Rates Reported in the Allen Study

	Methane Emissions per Pneumatic Controller				
	Appalachian	Gulf Coast	Midcontinent	Rocky Mtn.	Total
Number sampled[a]	133	106	51	15	305
Emissions rate (scf methane/min/device)[b]	0.126 ± 0.043	0.268 ± 0.068	0.157 ± 0.083	0.015 ± 0.016	0.175 ± 0.034
Emissions rate (scf whole gas/min/device, based on site-specific gas composition)[b]	0.130 ± 0.044	0.289 ± 0.071	0.172 ± 0.086	0.021 ± 0.022	0.187 ± 0.036

[a] Intermittent and low bleed controllers are included in the total; no high bleed controllers were reported by companies providing controller type information

[b] Uncertainty characterizes the variability in the mean of the data set, rather than an instrumental uncertainty in a single measurement

The Allen study reports that the average whole gas emission rate was 11.2 scfh per pneumatic controller for the tested population, which consisted of a mix of intermittent and low bleed controllers. No high bleed controllers were reported by the companies that provided controller type information. The study also reports whole gas emission factors of 5.1 scfh for low bleed controllers and 17.4 scfh for intermittent controllers. These emission factors are based on measured emissions at the 24 sites where the site operators reported only low bleed controllers and the 55 sites reporting only intermittent controllers, where potential misidentification of controller type is less likely to be a confounding factor.

The study notes that there is significant geographical variability in the emissions rate from pneumatic controllers between production regions. Emissions per controller from the Gulf Coast are highest and are statistically different than emissions from controllers in the Rocky Mountain and Appalachian regions. The difference in average values is more than a factor of 10

between Rocky Mountain and Gulf Coast regions. The study provided the following discussion of these differences:

> Some of the regional differences in emissions may be explained by differences in practices for utilizing low bleed and intermittent controllers. For example, new controllers installed after February 1, 2009 in regions in Colorado that do not meet ozone standards, where most of the Rocky Mountain controllers were sampled, are required to be low bleed (or equivalent) where technically feasible (Colorado Air Regulation XVIII.C.1; XVIII.C.2; technical feasibility criterion under review as this is being written). However, observed differences in emission rates between intermittent and low bleed devices (roughly a factor of 3) are not sufficient to explain all of the regional differences. A number of additional hypotheses were examined to attempt to explain the differences in emissions. For datasets consisting entirely of intermittent or entirely of low-bleed devices, the volume of oil produced was not a good predictor of emissions. Wellhead and separator pressure were also not good predictors of emissions. The definition of low-bleed controllers may be [an] issue, however. All low bleed devices are required to have emissions below 6 scf/hr (0.1 scf/m), but there is not currently a clear definition of which specific controller designs should be classified as low bleed and reporting practices among companies can vary. Other possibilities for explaining the low-bleed emission rates observed in this work, that have not yet been investigated, but that may be pursued in follow-up work, include operating practices for the use of the controllers.

The study estimated 2011 national methane emissions from pneumatic controllers in the natural gas production industry segment at 570,000 MT (with a range of 510,000 – 812,000 MT based on the 95% confidence bounds of the emission factor) using the same number of controllers (447,379) used in the 2013 GHG Inventory for 2011. This estimate was computed using a regionally weighted emission factor of 67,400 scfy methane/device.

2.1.6 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

A study completed by the Prasino Group was conducted to determine the average bleed rate of pneumatic controllers when operating under field conditions in British Columbia (BC). Bleed rates were sampled from pneumatic controllers using a positive displacement bellows meter at upstream oil and gas facilities across a variety of producing fields in the Fort St. John, BC and surrounding areas. For this study, bleed rate was defined as "the amount of fuel gas released to the atmosphere per hour," including both continuous bleed (where applicable) and emissions during activation. The study centered on high bleed controllers, including both continuous bleed and intermittent controllers with emissions greater than 0.17 cubic meters per hour ($m^{3/}$hr) (e.g, > 6 scfh).[12] The study aimed to identify the most common high bleed pneumatic controllers in the field and test emissions from at least 30 units of each model. In identifying controllers to test, the study used a manufacturer-supplied emission rate of 0.119 m^3/hr as a cutoff to explore whether some models identified by manufacturers as low bleed perform at that level in the field.

Field measurements were carried out with a Calscan Hawk 9000 Vent Gas Meter, which uses a positive displacement diaphragm meter that detects flow rates down to zero, and can also effectively measure any type of vent gas (methane, air, or propane). (A few sampled devices ran on air at large sites using compressed air, or propane at sour sites using compressed propane; such samples were corrected using a density ratio to equivalent natural gas emissions rates.) This device uses "a precision pressure sensor, an external temperature probe, and industry standard gas flow measurement algorithms to accurately measure the gas rates and correct for pressure and temperature differences." The report notes that metering a device can affect the operation of the device when hooked up due to back pressure, adding that it is possible that certain controllers did not produce enough pressure when hooked up to overcome the back pressure, resulting in a

[12] This definition of "high bleed" is slightly different than the definition presented in Section 1.1.1 of this paper, because "intermittent bleed controllers" are included as "high bleed controllers" if their emissions are above the specified threshold. The definition presented in Section 1.1.1 places "intermittent bleed controllers" in their own category.

zero reading. The sample time for each controller was 30 minutes, so there was variability in the number of actuation events captured for each controller depending on operating conditions.

In addition to emission factors for individual models of pneumatic controllers, the study generated emission factors for "generic high bleed controllers" and "generic high bleed intermittent controllers." The study also included a regression analysis of the relationship between bleed rate and the pressure of the supply gas routed to the controller. Based on the analysis, the study found that the positive relationship between these parameters was strong enough to recommend use of a supply pressure coefficient to calculate the bleed rate for several controller models and for generic controllers. The generic emission factors and supply pressure coefficients are shown in Table 2-9.

Table 2-9. Generic Natural Gas Emission Factors and Supply Pressure Coefficients for High Bleed Pneumatic Controllers

Type of Pneumatic Controller	Average Bleed Rate (m^3/hr)[a]	Average Bleed Rate (scfh)[b]	Coefficient Related to Supply Pressure[c]
Generic High Bleed Controller	0.2605	9.199	0.0012
Generic High Bleed Intermittent Controller	0.2476	8.744	0.0012

[a] "Bleed rate" defined to include actuation emissions as well as continuous bleed.
[b] Calculated.
[c] Supply pressure apparently in kPa, although not clearly stated in the report.

Based on what it termed a "positive correlation," the Prasino study recommended the use of the supply pressure coefficients above for calculating emission rates for generic high bleed controllers and generic high bleed intermittent controllers. It should be noted that the coefficients of determination (R^2 values) for these supply pressure coefficients are 0.41 and 0.35 for high bleed and high bleed intermittent controllers, respectively.

2.1.7 Air Pollutant Emissions from the Development, Production, and Processing of Marcellus Shale Natural Gas (Roy et al., 2014)

A study by the Center for Atmospheric Particle Studies at Carnegie Mellon University was conducted to develop an emission inventory for the development, production, and processing of natural gas in the Marcellus Shale region for 2009 and 2020. (Note: The focus of this white paper is current emissions, therefore, the 2020 projections are not discussed further.) The inventory includes estimates for emissions of nitrogen oxides, VOC, and particulate matter less than 2.5 micrometers in diameter from major activities, including VOC emissions from pneumatic controllers associated with "wet" and "dry" gas wells. The study estimated VOC emissions from pneumatic controllers associated with Marcellus Shale natural gas wells to be on the order of 10 tons/day in 2009.

This study developed these emissions estimates by estimating the number of wet and dry wells in the region and establishing per-well emission factors for 2009. The per-well emission factors are shown in Table 2-10.

Table 2-10. Per-Well VOC Emissions from Pneumatic Controllers in 2009 (95% confidence interval)

Type of Well	VOC Emissions, 2009 (tons/producing well)
Dry Gas	0.5 (0.08 – 0.8)
Wet Gas	3.5 (2.4 – 4.4)

The per-well emission factors were based on assumptions regarding the type, number, and emission factors for pneumatic controllers associated with each natural gas well, which were drawn primarily from a 2008 ENVIRON report.[13] Table 2-11 shows these assumptions.

[13] Bar-Ilan, Amnon et al., ENVIRON International Corporation. *Recommendations for Improvement to the CENRAP States' Oil and Gas Emissions Inventories*. Prepared for the Central States Regional Air Partnership. November 13, 2008. This report also includes emission factors for positioners (15.2 scfh) and transducers

Table 2-11. Assumed Type, Number, and Emission Factors for Pneumatic Controllers Associated with Each Natural Gas Well

Type of Device	Number of Controllers	Emission Factor (scfh)[a]
Liquid Level Controller	2	31 (2009)
Pressure Controller	1	17 (2009)

[a] 2009 emission factors are from the 2008 ENVIRON report.

The emission factors from this study and the ENVIRON report are not comparable to the emission factors discussed above because they are provided for different classifications of pneumatic controllers. In addition, these emission factors differ from those discussed previously in that they are based on bleed rates provided by manufacturers rather than measured emissions.

2.1.8 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The Environmental Defense Fund (EDF) commissioned ICF International (ICF) to conduct an economic analysis of methane emission reduction opportunities from the oil and natural gas industry to identify the most cost-effective approach to reduce methane emissions from the industry. The study projects the estimated growth of methane emissions through 2018 and focuses its analysis on 22 methane emission sources in the oil and natural gas industry (referred to as the targeted emission sources). These targeted emission sources represent 80% of their projected 2018 methane emissions from onshore oil and gas industry sources. Pneumatic devices are several of the 22 emission sources that are included in the study and include: high bleed pneumatic controllers, intermittent bleed pneumatic controllers, Kimray pumps, intermittent bleed pneumatic controllers – dump valves, and chemical injection pumps. The

(13.6 scfh). The emission factors in the report "were obtained from data gathered as part of the EPA's Natural Gas STAR program." Examination of Natural Gas STAR program materials clearly shows that these emission factors were derived from the manufacturer-supplied natural gas bleed rates for high bleed pneumatic controllers listed in Appendix A to *Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*. The ENVIRON report also includes the number of controllers of each type associated with each gas well, said to be drawn from survey data in the CENRAP states. The numbers for liquid level controllers and pressure controllers are reflected in Table 2-15; the report found zero positioners and transducers per well.

methodology that was used for this analysis is based on the 2013 GHG Inventory and uses data from the GHGRP and the University of Texas/EDF gas production measurement study (Allen et al., 2013).

The study relied on the 2013 GHG Inventory for 1990-2011 for methane emissions data for the oil and natural gas sector. These emissions data were revised to include updated information from the GHG Inventory and the *Measurements of Methane Emissions at Natural Gas Production Sites in the United States* study (Allen et al., 2013). The revised 2011 baseline methane emissions estimate was used as the basis for projecting onshore methane emissions to 2018. (Note: The focus of this white paper is current emissions, therefore, the 2018 projections are not discussed further.)

The study used the 2013 GHG Inventory estimates for 2011 to develop new activity and emission factors for pneumatic controllers. The count of pneumatic controllers was calculated using the well counts and assuming 0.94 pneumatic controllers per well. The study did find that there are an additional 8.6 pneumatic controllers per gathering/boosting station that were not accounted for in the 2013 GHG Inventory. The study also used emission factors from subpart W, which reported pneumatic controllers in three categories: low bleed, intermittent bleed and high bleed controllers. To break out the number of pneumatic controllers in each of these categories, the emission data from subpart W were analyzed, and the study determined that the percentage of pneumatic controllers were 10% high bleed, 50% intermittent bleed and 40% low bleed. These percentages were applied to the pneumatic controller counts and the respective emission factor was used to calculate the emissions from these controllers. Intermittent pneumatic controllers were further segregated into two categories: dump valves and non-dump valve intermittent controllers. The dump valves represent intermittent controllers that do not continuously bleed and only emit during actuation. The study estimated that 75% of the total intermittent pneumatic controllers were dump valves. Based on the subpart W data and the assumptions above, the study used the following emission factors for each of the controllers: 320 Mcf/yr/device for high bleed, 120 Mcf/yr/device for non-dump intermittent, 20 Mcf/yr/device for dump intermittent and 11 Mcf/yr/device for low bleed pneumatic controllers. Using these factors, the study estimated an

NMED Exhibit 91

increase of 41% (26 Bcf or 491,000 MT) in methane emissions in comparison to the 2013 GHG Inventory.

Further information included in this study on the replacement of high bleed and intermittent bleed pneumatic controllers with low bleed pneumatic controllers, and the replacement of pneumatic pumps with electric pumps as mitigation or emission reduction techniques, methane control costs, and their estimates for the potential for VOC emissions co-control benefits from the replacement of these pneumatic controllers are presented in Section 3 of this document.

2.2 Discussion of Data Sources for Pneumatic Pumps

Many of the data sources for pneumatic pumps are the same as those for pneumatic controllers, therefore, the overall descriptions of these data sources are not repeated in this section and only the information relevant to pneumatic pumps is discussed.

2.2.1 Methane Emissions from the Natural Gas Industry (GRI/EPA, 1996c) (GRI/EPA, 1996e)

The methane emission estimates for pneumatic pumps are separated into two categories for the GRI/EPA reports; chemical injection pumps (GRI/EPA, 1996d) and gas-assisted glycol pumps (GRI/EPA, 1996f). A summary of each of these reports and the methane calculation methodologies are provided in the following sections.

2.2.1.1 Methane Emissions from the Natural Gas Industry – Chemical Injection Pumps (GRI/EPA, 1996c)

This report estimates emissions from two types of pumps that the oil and natural gas industry uses for chemical injection into process streams: piston pumps and diaphragm pumps. Four sources of information were used to develop an emission factor for chemical injection

pumps: a study by the CPA[14], data collected from site visits, literature data for methane composition, and data from pump manufacturers.

The CPA study provided natural gas emissions from five diaphragm chemical injection pumps using the "bagging" method. This method involves enclosing the pump and measuring the flow rate and concentration of the natural gas emissions from the pump. The measurements from this study reported natural gas emissions ranging from 254 to 499 standard cubic feet per day per pump (scfd/pump) with an average of 334 scfd/pump.

Data from site visits included: the total number of chemical injection pumps for a particular site, number of chemical injection pumps used in natural gas production, the energy source for the pump (e.g., natural gas, instrument air, electricity), frequency of operation (e.g., pumping rate in strokes per minute), number of pumps that are active or idle, pump operation schedule, size of the unit (e.g., volume displacement of the motive chamber), manufacturer and model number of the pump, and supply gas pressure. Table 2-12 provides a summary of the site visit data. The methane emission factor in Table 2-12 was calculated using a methane composition of 78.8% (GRI/EPA, 1996d).

Table 2-12. Summary of Chemical Injection Pump Site Visit Data

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Percent of Total Pumps	49.8 ± 38%	50.2 ± 38%	4.5 ± 678%	95.5 ± 32%
Pump Actuation Rate (strokes/min)	26.32 ± 29%	13.64 ± 49%	3.57 ± 42%	14.75 ± 61%
Number of Pump Actuation Measurements	32	8	15	5
Number of Sites with	7	5	2	4

[14] Canadian Petroleum Association. A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations in Alberta, March 1992.

NMED Exhibit 91

Chemical Injection Pump Data	All Data		Natural Gas Industry Data	
	Piston Pumps	Diaphragm Pumps	Piston Pumps	Diaphragm Pumps
Pump Actuation Measurements				
Percent of Pumps Operating	44.6 ± 62%	40.0 ± 52%	77.5 ± 148%	58.0 ± 39%
Number of Sites with Pumps Operating	7	10	4	6
Methane Emissions Factor (scfd/pump)	248 ± 83%		668 ± 88%	

Manufacturers' data and the CPA data were used to determine the volume of gas released per pump stroke. This was done by using the natural gas usage data (amount of natural gas required to pump one gallon of liquid), stroke length, and stoke diameter to calculate volume of natural gas per pump stoke. For diaphragm pumps, the average natural gas usage was calculated to be 0.0719 standard cubic feet per stroke (scf/stroke). The piston pump average natural gas usage was calculated to be 0.0037 scf/stroke. These averages were then used to determine the emission factor for each of the pump types by multiplying the average frequency (strokes per day) by the operating time percentage. Note that the report uses the "all data" frequency and operating percentage to calculate the emission factor for each type of pump. The emission factor for diaphragm pumps was calculated to be 446 scfd/pump and the emission factor for piston pumps was calculated to be 48.9 scfd/pump.

The percentage of piston and diaphragm pumps and their respective emission factors were then used to calculate an average emission factor for chemical injection pumps. The average emission factor was determined to be 248 scfd/pump. The 1992 national emissions were then calculated using the average chemical injection pump emission factor (248 scfd/pump) and the activity factor for chemical injection pumps of 16,971 (GRI/EPA, 1996a). The resulting 1992 national emissions from chemical injection pumps for the natural gas production segment was calculated to be 1,536 MMscf/yr (29,008 MT).

2.2.1.2 Methane Emissions from the Natural Gas Industry – Gas-Assisted Glycol Pumps (GRI/EPA, 1996e)

For many glycol dehydrators in the natural gas industry, small gas-assisted pumps are used to circulate the glycol. These pumps use energy from the high-pressure rich glycol/gas mixture leaving the absorber to pump the low-pressure lean glycol back to the absorber. Natural gas is entrained in the rich glycol stream feeding the pump and is discharged from the pump at a lower pressure to the regenerator. If the glycol unit has a flash tank, most of the natural gas in the low-pressure stream can be recovered and used as a fuel or stripping gas. If the natural gas from the pump is used as a stripping gas, or if there is no flash tank, all of the pump exhaust gas will be vented through the regenerator's atmospheric vent stack (GRI/EPA, 1996e).

Methane emissions from these gas-assisted pumps were calculated using technical information from Kimray, a manufacturer of gas-assisted pumps. No direct measurements of pump gas usage were used in the calculations. Kimray reported that the natural gas usage ranges from 0.081 actual cubic feet per gallon of glycol pumped (acf/gal) for high-pressure pumps (>400 psig) to 0.130 acf/gal for low-pressure pumps (< 400 psig). These values convert to 3.73 standard cubic feet per gallon (scf/gal) at an operating pressure of 800 psig and 83 mole percent methane for high-pressure pumps and 2.31 scf/gal at an operating pressure of 300 psig and 83 mole percent methane for low-pressure pumps.

The gas usage rates were then converted to an amount of natural gas treated by assuming a typical high-pressure dehydrator would remove 53 pounds of water per million cubic feet of gas (lbs/MMscf), and a typical low-pressure dehydrator would remove 127 lbs/MMscf. The design glycol-to-gas ratio was assumed to be three gallons of glycol per pound of water removed and an overcirculation ratio of 2.1 was used to determine the emission factors for the pumps for the natural gas production segment. Using these factors and the fraction of dehydrators without flash tanks (0.735) and the fraction of dehydrators without combustion vent controls (0.988), the emission factor for the gas-assisted pumps in the natural gas production segment were calculated to be 904.5 standard cubic feet of methane per million standard cubic feet of natural gas treated (scf/MMscf) for high-pressure pumps, and 1342.2 scf/MMscf for low-pressure pumps. The final

emission factor for methane from an average gas-assisted glycol pump was determined assuming that 80% of these pumps are high-pressure and 20% are low-pressure. The average emission factor was calculated to be 992.0 scf/MMscf and was used to estimate methane emissions from the natural gas production segment.

For natural gas processing, the study assumed that only high-pressure gas-assisted glycol pumps are used. The emission factor was calculated using the high-pressure pump gas usage (3.73 scf/gal), the design glycol-to-gas ratio (3 gal glycol/lb water), the water removal rate for a high-pressure system (53 lbs/MMcsf), an overcirculation ratio of 1.0, the fraction of dehydrators without flash tanks (0.333) and the fraction of dehydrators without combustion vent controls (0.900). These values were used to calculate a methane emission factor of 177.8 scf/MMscf for gas-assisted pumps for the natural gas processing segment. The natural gas transmission and storage segments do not use gas-assisted glycol pumps.

The 1992 national methane emissions were calculated using data from site surveys to determine the natural gas throughput of dehydrators with gas-assisted pumps. The natural gas throughput of dehydrators with gas-assisted pumps was estimated to be 11.1 trillion standard cubic feet per year (Tscf/yr) for the natural gas production segment and 0.958 Tscf/yr for the natural gas processing segment. The 1992 national methane emissions from gas-assisted pumps were calculated to be 10,962 MMscf/yr (206,989 MT) for the natural gas production segment and 170 MMscf/yr (3,215 MT) for the natural gas processing segment.

2.2.2 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012 (U.S. EPA, 2014)

Table 2-13 summarizes the 2014 GHG Inventory estimates of 2012 national methane emissions from pneumatic pumps in the natural gas production and processing segments. (Note: The GHG inventory does not include estimates of emissions from pneumatic pumps in the natural gas transmission and storage segments.) The pneumatic pumps described in the GHG Inventory include: chemical injection pumps and Kimray pumps. The table includes potential emissions, emission reductions and net emissions. For pneumatic pumps, the emission reductions

NMED Exhibit 91

in this report are voluntary reductions through the Natural Gas STAR program. In future years, the GHG Inventory will also account for regulatory reductions that result from subpart OOOO.

Table 2-13. Summary of GHG Inventory 2012 Nationwide Emissions from Pneumatic Pumps

Industry Segment	Potential CH_4 Emissions (MT)	CH_4 Emission Reductions (MT)	Net CH_4 Emissions (MT)
Natural gas production	455,719	2,771	452,948
Petroleum Production	49,973	N/A	
Natural gas processing	5,011	N/A	

The 2014 GHG Inventory data estimates that pneumatic pump emissions are around 16% of overall methane emissions from the natural gas production and processing sectors.

Tables 2-14 and 2-15 show the 2014 GHG Inventory's estimates of 2012 methane emissions from chemical injection pumps and gas-assisted pumps (Kimray pumps) in the natural gas and petroleum production and processing industry segments. The tables present population of chemical injection and Kimray pumps, methane emission factors and potential methane emissions from these devices in each of the EIA's NEMS regions, and the estimated national total of chemical injection pumps, Kimray pumps and potential methane emissions. The activity factors for chemical injection pumps are based on the estimated count of chemical injection pumps in operation. For the production sector, a regional factor for pumps per well (ranging from 0.01 to 0.68) is applied to annual regional well counts to calculate chemical injection pumps each year for natural gas, and for petroleum systems it is estimated that around 20% of wells have pumps (based on 1996 GRI/EPA) and that 25% of pumps use gas. For the production sector, the activity factors for Kimray pumps are based on the total throughput of natural gas multiplied by the fraction of dehydrators using gas-driven pumps (0.9 for the production segment). For the processing segment, the activity factor for Kimray pumps is based the total processing plant throughput multiplied by the fraction of natural gas treated by dehydrators at

NMED Exhibit 91

gas plants (0.5) and then multiplied by the fraction of dehydrators that use a gas-driven pump (0.1 for the processing segment).

Table 2-14. Estimated 2012 National and Regional Methane Emissions from Chemical Injection Pumps in the Natural Gas Production Segment

NEMS Region	Population of Chemical Injection Pumps[a]	CH_4 Potential Emission Factor (scfd/device)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	795	268	1,499
Midcontinent	15,343	260	28,045
Rocky Mountain	14,849	244	25,448
South West	2,531	253	4,508
West Coast	1,422	289	2,890
Gulf Coast	2,537	278	4,951
Total Natural Gas	37,477		67,341
Voluntary Emission Reductions			-2,771
Net Emissions-Natural Gas			64,570
Petroleum Production	28,702	248	49,973

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.

Table 2-15. Estimated 2012 National and Regional Methane Emissions from Kimray Pumps in the Natural Gas Production and Processing Segments

NEMS Region	Total Natural Gas using Kimray Pumps[a]	CH_4 Potential Emission Factor (scfd/MMscf)[a]	CH_4 Emissions (MT)
Natural Gas Production			
North East	6,487,241	1,073	134,073
Midcontinent	4,409,271	1,040	88,322
Rocky Mountain	3,404,114	975	63,934
South West	1,692,957	1,014	33,050
West Coast	85,450	1,157	1,904
Gulf Coast	3,137,482	1,110	67,095
Production Total	19,216,515		388,378
Natural Gas Processing			

All Regions	1,463,675	178	5,011
Total Potential Emissions			393,389

[a] 1996 GRI/EPA report, extrapolated using ratios relating other factors for which activity data are available.
Note: The GHG Inventory did not list any Kimray pumps in the natural gas transmission or distribution sectors.

The basis for the GHG Inventory's potential methane emission factors for pneumatic pumps in the natural gas production and processing segments is the 1996 GRI/EPA report.

The region-specific factors used in the production segment are developed using the GRI/EPA factor and regional gas composition data.

2.2.3 Greenhouse Gas Reporting Program (U.S. EPA, 2013)

The GHGRP addresses petroleum and natural gas systems with implementing regulations at 40 CFR part 98, subpart W. The rule requires facilities in the onshore petroleum and natural gas production segment to report GHG emissions from pneumatic pumps. Facilities calculate emissions from pneumatic pumps by determining the number of pneumatic pumps at the facility and applying an emission factor of 13.3 scf/hour/pump. Facilities also apply a facility-specific gas composition factor for calculating emissions. For 2012, 343 facilities in the onshore petroleum and natural gas production industry segment reported emissions from pneumatic pumps, with total methane emissions of 135,227 metric tons.

2.2.4 Determining Bleed Rates for Pneumatic Devices in British Columbia (Prasino Group 2013)

The study used data from the Canadian Association of Petroleum Producers (2008), Pacific Carbon Trust (2011), Cap-Op Energy's Distributed Energy Efficiency Project Platform (DEEPP) database to compile a list of pneumatic pumps. The study notes that the total number of pneumatic pumps is unknown and the list only comprises a subset of the total population. In total, 184 samples were taken from chemical injection pumps. From the data collected, the study determined the average bleed rate for a piston-type pneumatic pumps to be 0.5917 m^3/hr

(approximately 20.9 scfh). For diaphragm-type pneumatic pumps, the bleed rate was calculated to be 1.0542 m^3/hr (approximately 37.2 scfh).

2.2.5 Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF, 2014)

The analysis developed by ICF includes an inventory of methane emissions for 2011 using data from the 2013 GHG Inventory and the GHGRP (U.S. EPA, 2013), in addition to data from the EIA and GRI.

For pneumatic chemical injection pumps in the natural gas production segment, the 2011 ICF inventory updated the count of chemical injection pumps to reflect changes made to the well counts and applied the Natural Gas STAR estimated reductions associated with pneumatic pumps. These changes resulted in a 2011 methane estimate of 3 Bcf (56,600 MT) from chemical injection pumps in the natural production segment. Kimray pumps (gas-assisted glycol pumps) were estimated to be 17 Bcf (321,000 MT).

3.0 AVAILABLE PNEUMATIC DEVICE EMISSIONS MITIGATION TECHNIQUES

The following sections describe the different available emissions mitigations techniques that the EPA is aware of for pneumatic controllers and pneumatic pumps. The primary sources of information for mitigations techniques was the EPA's Natural Gas STAR Lessons Learned documents and the ICF economic analysis (ICF, 2014).

3.1 Available Pneumatic Controller Emissions Mitigation Techniques

Several techniques to reduce emissions from pneumatic controllers have been developed over the years. Table 3-1 provides a summary of these techniques for reducing emissions from pneumatic controllers including replacing high bleed controllers with low bleed or zero bleed

models, driving controllers with instrument air rather than natural gas, using non-gas-driven controllers, and enhanced maintenance.

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Install Zero Bleed Controller in Place of Continuous Bleed Controller (U.S. EPA, 2011a, GE Energy Services, 2012)	Zero bleed controllers are self-contained natural gas-driven devices that vent to the downstream pipeline, not the atmosphere. Provide the same functional control as continuous bleed controllers, where applicable (U.S. EPA, 2011a, GE Energy Services, 2012).	Applicable only for relatively low-pressure control valves, e.g., in gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution applications (U.S. EPA, 2011a).	The EPA does not have cost information on this technology.	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field, however, it is the EPA's understanding that applicability is limited.
Install Low Bleed Controller in Place of High Bleed Controller (U.S. EPA, 2006b)	Low bleed controllers provide the same functional control as a high bleed devices, while emitting less continuous bleed emissions (U.S. EPA, 2006b).	Applicability depends on the function of instrumentation for an individual device and whether the device is a level, pressure, or temperature controller. Not recommended for control of very large valves that require fast and/or precise response to process changes. These are found most frequently on large compressor discharge and bypass pressure controllers (U.S. EPA, 2006b).	Based on information from Natural Gas STAR (U.S. EPA, 2006b) and supplemental research conducted for subpart OOOO, low bleed devices cost, on average, around $165 more than high bleed versions. ICF report assumed a cost of $3,000 per replacement based on industry comments (ICF, 2014).	Estimated average reductions (U.S. EPA, 2011a): *Production segment:* 6.6 tpy methane *Transmission:* 3.7 tpy methane The EPA does not have information on the prevalence of this technology in the field.

NMED Exhibit 91

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Convert to Instrument Air (U.S. EPA, 2006c)	Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. In this type of system, atmospheric air is compressed, stored in a tank, filtered and then dried for instrument use. Instrument air conversion requires additional equipment to properly compress and control the pressured air. This equipment includes a compressor, power source, air dehydrator and air storage vessel (U.S. EPA, 2006c).	Most applicable at facilities where there are a high concentration of pneumatic control valves and an operator present. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2006c).	System costs are dependent on size of compressor, power supply needs, labor and other equipment (U.S. EPA, 2006c). A cost analysis is provided in Section 3.1.3 below.	100% emission reduction, where applicable. There are secondary emissions associated with electrical power generation. The EPA does not have information on the prevalence of this technology in the field.
Mechanical and Solar-Powered Systems in Place of Bleed Controller (U.S. EPA, 2006a, U.S. EPA, 2006b)	Mechanical controls operate using a simple design comprised of levers, hand wheels, springs and flow channels. The most common mechanical control device is the liquid-level float to the drain valve position with mechanical linkages. Electricity or small electrical motors (including solar-powered) have been used to operate valves. Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability (U.S. EPA, 2006a).	Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations. Electric-powered valves are only reliable with a constant supply of electricity (U.S. EPA, 2006a).	Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).	100% emission reduction, where applicable. The EPA does not have information on the prevalence of this technology in the field.

NMED Exhibit 91

Table 3-1. Summary of Alternative Mitigation Techniques for Pneumatic Controllers

Option	Description	Applicability	Costs	Efficacy and Prevalence
Enhanced Maintenance (U.S. EPA, 2006a)	Instrumentation in poor condition typically bleeds 5 to 10 scfh more than representative conditions due to worn seals, gaskets, diaphragms; nozzle corrosion or wear; or loose control tube fittings. This may not impact operations but does increase emissions. Proper methods of maintaining a device are highly variable (U.S. EPA, 2006a).	Enhanced maintenance to repair and maintain pneumatic controllers periodically can reduce emissions at many controllers (U.S. EPA, 2006a).	Variable based on labor, time, and fuel required to travel to many remote locations.	Natural gas emission reductions of 5 to 10 scfh (U.S. EPA, 2006a). The EPA does not have information on the prevalence of this practice in the field.

NMED Exhibit 91

The mitigation techniques summarized in Table 3-1 are discussed in more detail in the following sections.

3.1.1 Zero Bleed Pneumatic Controllers

Zero bleed pneumatic controllers are self-contained, "closed loop" natural gas-driven controllers that vent to the downstream pipeline rather than to the atmosphere (U.S. EPA, 2011a). These closed loop devices are considered to emit no natural gas to the atmosphere. However, they can be used only in applications with very low pressure and, therefore, may not be suitable to replace continuous bleed pneumatic controllers in many applications. Some applications where they may suitable include gathering, metering and regulation stations, power plant and industrial feed, and city gate stations/distribution (U.S. EPA, 2011a). To date, the EPA has not obtained any information on the cost of zero bleed controllers or their prevalence in the field.

3.1.2 Low Bleed Pneumatic Controllers

Description

Low bleed controllers provide similar functional control as high bleed controllers, but have lower continuous bleed emissions. It has been estimated on average that 6.6 tons of methane and 1.8 tons of VOC will be reduced annually in the production segment from installing a low bleed device in place of a high bleed device (U.S. EPA, 2011a). In the transmission segment, the average achievable reductions per device are estimated around 3.7 tons and 0.08 tons for methane and VOC, respectively (U.S. EPA, 2011a). As defined in this white paper, a low bleed controller can emit up to 6 scfh, but this is higher than the expected emissions from the typical low bleed controllers available on the current market.

NMED Exhibit 91

Applicability

There are certain situations in which replacing and retrofitting are not feasible, such as instances where a minimal response time is needed, cases where large valves require a high bleed rate to actuate, or a safety isolation valve is involved.

Replacing high bleed pneumatic with low bleed controllers is infeasible in situations where a process condition may require a fast or precise control response so that it does not stray too far from the desired set point (U.S. EPA, 2011a). A slower-acting controller could potentially result in damage to equipment and/or become a safety issue. An example of this is on a compressor where pneumatic controllers monitor the suction and discharge pressure and actuate a recycle when one or the other is out of the specified target range. Another scenario where fast and precise control is necessary includes transient (non-steady) situations where a gas flow rate may fluctuate widely or unpredictably (U.S. EPA, 2011a). In this case, a responsive high bleed device may be required to ensure that the gas flow can be controlled in all situations. Temperature and level controllers are typically present in control situations that are not prone to fluctuate as widely or where the fluctuation can be readily and safely accommodated by the equipment. Therefore, such processes may be appropriate for control from a low bleed device, which is slower acting and less precise.

Safety concerns can limit the appropriateness of low bleed controllers in specific situations where any amount of bleeding is unacceptable. Emergency valves are often not controlled with bleeding controllers (e.g., neither low bleed nor high bleed), because it may not be acceptable to have any amount of bleeding in emergency situations (U.S. EPA, 2011a). Pneumatic controllers are designed for process control during normal operations and to keep the process in a normal operating state. If an Emergency Shut Down (ESD) or Pressure Relief Valve (PRV) actuation occurs,[15] the equipment in place for such an event is spring-loaded, or otherwise not pneumatically powered. During a safety issue or emergency, it is possible that the pneumatic

[15] ESD valves either close or open in an emergency depending on the fail safe configuration. PRVs always open in an emergency.

NMED Exhibit 91

gas supply will be lost. For this reason, control valves are deliberately selected to either fail open or fail closed, depending on which option is the failsafe.

Costs

The costs described in this section are based on vendor research and information given in the appendices of the Natural Gas STAR Lessons Learned document on pneumatic controllers (U.S. EPA, 2006a). As Table 3-2 indicates, the average cost for a low bleed pneumatic is $2,553, while the average cost for a high bleed is $2,338.[16] Thus, the incremental cost of installing a low bleed device instead of a high bleed device is on the order of $165 per device. (Note: The ICF report assumed a cost of $3,000 to replace an existing high bleed pneumatic controller with a low bleed pneumatic controller based on industry comments (ICF, 2014).)

Table 3-2. Cost Projections for the Representative Pneumatic Controllers[a]

Device	Minimum cost ($)	Maximum cost ($)	Average cost ($)	Low Bleed Incremental Cost ($)
High bleed controller	366	7,000	2,388	$165
Low bleed controller	524	8,852	2,553	

[a] Major pneumatic controllers vendors were surveyed for costs, emission rates and any other pertinent information that would give an accurate picture of the present industry.

Monetary savings associated with additional gas captured to the sales line were estimated based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).[17] The representative low bleed device is estimated to emit 6.65 tons, or 319 Mcf, (using the conversion factor of 0.0208 tons methane per 1 Mcf) of methane less than the average high bleed device per year. Assuming production quality gas is 82.8% methane by volume, this equals 385.5 Mcf natural gas recovered

[16] Costs are estimated in 2008 U.S. Dollars.

[17] The average market price for natural gas in 2010 was approximately $4.16 per Mcf. This is much less compared to the average price in 2008 of $7.96 per Mcf. Due to the volatility in the value, a conservative savings of $4.00 per Mcf estimate was projected for the analysis in order to not overstate savings.

per year (EC/R, 2011). Therefore, the value of recovered natural gas from one pneumatic controller in the production segment equates to approximately $1,500. While the owner of the transmission system is generally not the owner of the natural gas, the potentially lost gas still has value. The total value of the recovered gas from one pneumatic controller in the transmission segment is $1,375 assuming a natural gas value of $4.00 per Mscf and transmission natural gas is 92.8% methane by volume (EC/R, 2011).

3.1.3 Instrument Air Systems

Description

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following is a description of each component as described in the Natural Gas STAR document (U.S. EPA, 2006c), *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air:*

- Compressors used for instrument air delivery are available in various types and sizes, from centrifugal (rotary screw) compressors to reciprocating piston (positive displacement) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed. A minimum amount of electrical service is required to power the compressors.
- A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and in remote locations, however, a reliable source of

electric power can be difficult to ensure. In some instances, solar-powered battery-operated air compressors can be effective for remote locations, which reduce both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- Dehydrators, or air dryers, are also an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices.
- The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high-pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Compressed air may be substituted for natural gas in pneumatic systems without altering any of the parts of the pneumatic control. The use of instrument air eliminates natural gas emissions from natural gas powered pneumatic controllers. All other parts of a gas pneumatic system will operate the same way with instrument air as they do with natural gas. A diagram of a natural gas pneumatic controller is presented in Figure 3-1. A diagram of a compressed instrument air system is presented in Figure 3-2.

Applicability

The use of instrument air eliminates natural gas emissions from the natural gas-driven pneumatic controllers; however, these systems may only be used in locations with access to a sufficient and consistent supply of electrical power. Instrument air systems are also usually installed at facilities where there is a high concentration of pneumatic control valves and the presence of an operator that can ensure the system is properly functioning (U.S. EPA, 2006c).

NMED Exhibit 91

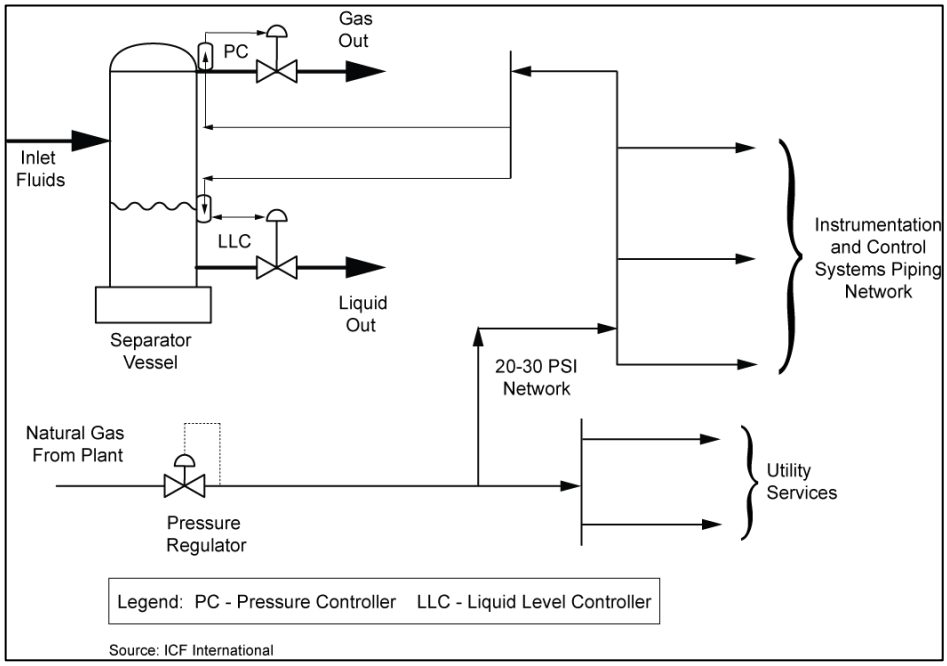


Figure 3-1 Natural Gas Pneumatic Control System

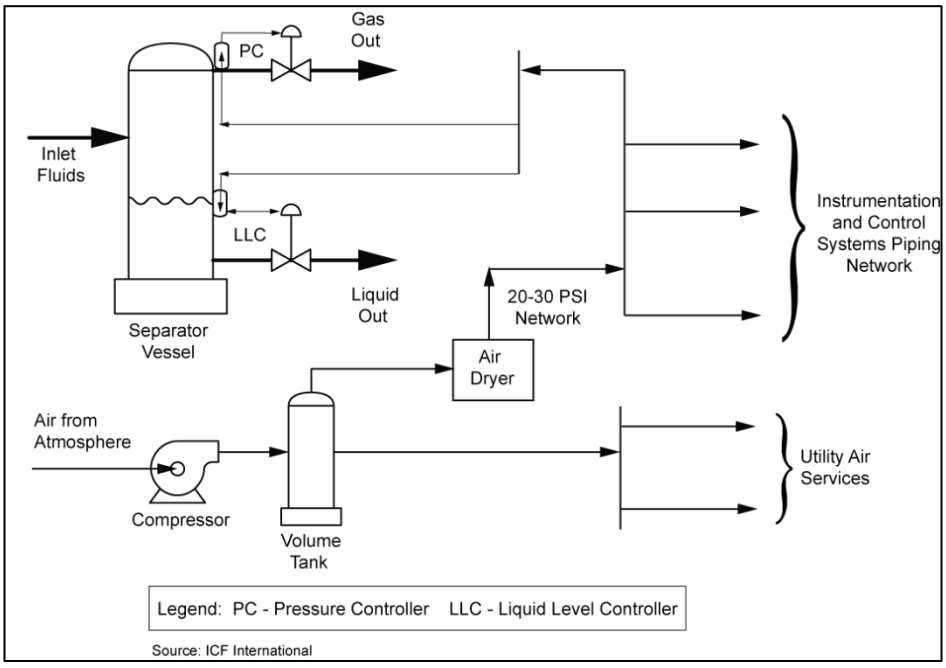


Figure 3-2. Compressed Instrument Air System

Costs

Instrument air conversion requires additional equipment to properly compress and control the pressured air. The size of the compressor will depend on the number of control loops present at a location. A control loop consists of one pneumatic controller and one control valve. The volume of compressed air supply for the pneumatic system is equivalent to the volume of gas used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by direct metering if a meter is installed. Otherwise, an alternative rule of thumb for sizing instrument air systems is 1 cubic foot per minute (cfm) of instrument air for each control loop. As the system is powered by electric compressors, the system requires a constant source of electrical power or a backup pneumatic device. Table 3-3 outlines three different sized instrument air systems including the compressor power requirements, the flow rate provided from the compressor, and the associated number of control loops.

Table 3-3. Compressor Power Requirements and Costs for Various Sized Instrument Air Systems[a]

Compressor Power Requirements[b]			Flow Rate	Control Loops
Size of Unit	Hp	kW	(cfm)	Loops/Compressor
Small	10	13.3	30	15
Medium	30	40	125	63
Large	75	100	350	175

[a] Based on rules of thumb stated in the Natural Gas STAR document, *Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air.*

[b] Power is based on the operation of two compressors operating in parallel (each assumed to be operating at full capacity 50% of the year).

The primary costs associated with conversion to instrument air systems are the initial capital expenditures for installing compressors and related equipment and the operating costs for electrical energy to power the compressor motor. This equipment includes a compressor, a power source, a dehydrator and a storage vessel. It is assumed that in either an instrument air solution or a natural gas pneumatic solution, gas supply piping, control instruments, and valve actuators of the gas pneumatic system are required. The total cost, including installation and labor, of three representative sizes of compressors based on assumptions found in the Natural Gas STAR

NMED Exhibit 91

document, “Lessons Learned: Convert Gas Pneumatic Controls to Instrument Air” are summarized in Table 3-4.

3.1.4 Mechanical and Solar-Powered Systems in Place of Bleed Controller

Description

Mechanical controls have been widely used in the natural gas and petroleum industry. They operate using a combination of levers, hand wheels, springs and flow channels with the most common mechanical control device being a liquid-level float to the drain valve position with mechanical linkages (U.S. EPA, 2006a). Another device that is increasing in use is electronic control instrumentation. Electricity or small electrical motors (including solar-powered) have been used to operate valves and therefore do not bleed natural gas into the atmosphere (U.S. EPA, 2006a). Solar control systems are driven by solar power cells that actuate mechanical devices using electric power. As such, solar cells require some type of backup power or storage to ensure reliability.

Applicability

Application of mechanical controls is limited because the control must be located in close proximity to the process measurement. Mechanical systems are also incapable of handling larger flow fluctuations (U.S. EPA, 2006c). Electric-powered valves are only reliable with a constant supply of electricity. These controllers can achieve 100% reduction in emissions where applicable.

Costs

Depending on supply of power, costs can range from below $1,000 to $10,000 for entire systems (U.S. EPA, 2006a).

NMED Exhibit 91

Table 3-4 Estimated Capital and Annual Costs of Various Sized Representative Instrument Air Systems

Instrument Air System Size	Compressor	Tank	Air Dryer	Total Capital[a]	Annualized Capital[b]	Labor Cost	Total Annual Costs[c]	Annualized Cost of Instrument Air System
Small	$3,772	$754	$2,262	$16,972	$2,416	$1,334	$8,674	$11,090
Medium	$18,855	$2,262	$6,787	$73,531	$10,469	$4,333	$26,408	$36,877
Large	$33,183	$4,525	$15,083	$135,750	$19,328	$5,999	$61,187	$80,515

[a] Total Capital includes the cost for two compressors, tank, an air dryer and installation. Installation costs are assumed to be equal to 1.5 times the cost of capital. Equipment costs were derived from the Natural Gas Star Lessons Learned document and converted to 2008 dollars from 2006 dollars using the Chemical Engineering Cost Index.

[b] The annualized cost was estimated using a 7% interest rate and 10-year equipment life.

[c] Annual Costs include the cost of electrical power as listed in Table 3-3 and labor.

3.1.5 Maintenance of Natural Gas-Driven Pneumatic Controllers

Manufacturers of pneumatic controllers indicate that emissions in the field can be higher than the reported gas consumption due to operating conditions, age, and wear of the device (U.S. EPA, 2006a). Examples of circumstances or factors that can contribute to this increase include:

- Nozzle corrosion resulting in more flow through a larger opening.
- Broken or worn diaphragms, bellows, fittings, and nozzles.
- Corrosives in the gas leading to erosion or corrosion of control loop internals.
- Improper installation.
- Lack of maintenance (maintenance includes replacement of the filter used to remove debris from the supply gas and replacement of O-rings and/or seals).
- Lack of calibration of the controller or adjustment of the distance between the flapper and nozzle.
- Foreign material lodged in the pilot seat.
- Wear in the seal seat.

Maintenance of pneumatics can correct many of these problems and can be an effective method for reducing emissions. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device (U.S. EPA, 2006a).

However, proper methods of maintaining a device are highly variable, thus, costs are variable based on labor, time, and fuel required to travel to many remote locations.

3.2 Available Pneumatic Pump Emissions Mitigation Techniques

There are several techniques that are currently being used to reduce emissions from pneumatic pumps. Table 3-5 provides a summary of these techniques for reducing emissions

NMED Exhibit 91

from pneumatic pumps, which include chemical injection pumps and natural gas-assisted recirculation pumps.

3.2.1 Instrument Air Pump

Description

Circulation pumps in glycol dehydration processes and chemical injection pumps are often powered by pressurized natural gas at remote locations. As a result, these pumps vent natural gas to the atmosphere as part of their normal operation. To mitigate VOC and methane emissions, some companies are using instrument air to power these pumps. These companies have found that the use of instrument air increased operational efficiency, decreased maintenance and decreased costs, while eliminating emissions of methane and VOC (U.S. EPA, 2011b).

Applicability

Converting chemical injection pumps and glycol dehydration circulation pumps to instrument air can be applied to natural gas hydration operations across all gas industry sectors with excess capacity of its instrument air system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic device (U.S. EPA, 2011b).

Costs

The total cost to convert a natural gas pneumatic circulation pump to instrument air includes the installation of piping and an appropriate control system between the existing instrument air system and the glycol pump if the driver is independent of the circulation pump. If the driver is separated from the pump by O-rings, then the pump would need to also be replaced. The implementation capital costs are estimated to be $1,000 to $10,000, and the incremental operating costs are estimated to be $100 to $1,000 (U.S. EPA, 2011b). The potential annual

NMED Exhibit 91

Table 3-5. Summary of Alternative Mitigation Techniques for Pneumatic Pumps

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replace natural gas-assisted pump with instrument air pump (U.S. EPA, 2011b)	Circulation pumps in glycol dehydration units and chemical injection pumps are retrofitted with instrument air to drive the pumps (U.S. EPA, 2011b).	Facilities with excess capacity of instrument air or facilities that can install an air compressor system. Because the systems are powered by electric compressors, they require a constant source of electrical power or a backup natural gas pneumatic pump (U.S. EPA, 2011b).	The installation of the piping from the air compressor system to the pump accounts for the bulk of the capital cost and typically ranges from $100 to $1,000 (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 2,500 Mcf for glycol circulation pumps and 183 Mcf for chemical injection pumps (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.
Replacement of natural gas-assisted pump with solar-charged direct current pump (U.S. EPA, 2011b)	In field settings, low volume natural gas pneumatic pumps can be replaced with solar-charged DC pumps (U.S. EPA, 2011b).	Low volume solar-charged pneumatic pumps are limited to approximately 5 gallons per day discharge at 1,000 psig. Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b).	The reporting partners for Natural Gas STAR stated a replacement cost of $2,000 per pump, including the solar panels, storage batteries and pump (U.S. EPA, 2011b).	100% emission reduction, where applicable. The Natural Gas STAR reports typical annual methane savings to be 182.5 Mcf per chemical injection pump conversion (U.S. EPA, 2011b). The EPA does not have information on the prevalence of this technology in the field.

NMED Exhibit 91

Option	Description	Applicability	Costs	Efficacy and Prevalence
Replacement of natural gas-assisted pump with electric pump (ICF, 2014)	In settings where a constant supply of electricity is available, natural gas pneumatic pumps can be replaced with electric pumps (ICF, 2014).	These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity (U.S. EPA, 2011b).	Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year. (ICF, 2014)	100% emission reduction, where applicable. The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014). The EPA does not have information on the prevalence of this technology in the field.

NMED Exhibit 91

natural gas savings are estimated to be 2,500 Mcf (U.S. EPA, 2011b) or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf per pump conversion (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.2 Solar Power Pump

Description

Solar power can be used to operate pumps located at remote sites where electricity is not available. These solar-powered pumps use electric power captured by solar panels to operate a DC-charged pump. Solar injection pumps can handle a range of throughputs and injection pressures. Low volume solar-charged DC pumps are limited to approximately 5 gallons per day discharge at 1,000 psig (U.S. EPA, 2011b). Large volume solar pumps are available with maximum output of 38 to 100 gallons per day at maximum injection pressures of 1,200 to 3,000 psig (U.S. EPA, 2011b). These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These solar-powered pumps are generally used to replace low volume natural gas pneumatic pumps if sufficient sunlight is available to power the pumps and backup power is not required. These low volume pumps are typically used to inject methanol or corrosion inhibiters into producing wells and other field equipment. These chemical injection pumps are typically sized for 6 to 8 gallons of methanol injection per day. The large volume pumps can be used to replace gas-assisted circulation pumps for glycol dehydrators.

Costs

The Natural Gas STAR program reported the cost of replacing pneumatic pumps with solar-charged electric pumps to be approximately $2,000 per pump (U.S. EPA, 2011b). The solar

NMED Exhibit 91

panels and storage batteries are nearly maintenance free, and the solar panels have a life span of up to 15 years and the electric motors last approximately 5 years in continuous use (U.S. EPA, 2011b). The potential annual natural gas savings are estimated to be 2,500 Mcf or $10,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010) for recirculation pumps (U.S. EPA, 2011b). For chemical injection pumps, the implementation costs are the same, but the potential annual natural gas savings are estimated to be 183 Mcf (U.S. EPA, 2011b) or $732 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010). The ICF report estimates the cost of replacing chemical injection pneumatic pumps with solar-powered pumps to be $5,000 per pump with a natural gas savings of 180 Mcf per year (ICF, 2014) or $720 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

3.2.3 Electric Power Pumps

Description

Electric power pumps are used to replace natural gas-assisted pneumatic used to recirculate glycol in gas dehydrators. These pumps eliminate the methane and VOC emissions that would have resulted from the use of a pneumatic pump.

Applicability

These pumps require a constant source of electricity, thus, they are typically installed at processing plants or large dehydration facilities, which are normally equipped with electricity.

Costs

Electrical pumps are estimated to cost roughly $10,000 per pump and the annual electrical usage cost was estimated to be $2,000 per year (ICF, 2014). The annual methane reduction from replacing pneumatic pumps with electrical pumps is estimated to be 5,000 Mcf (ICF, 2014) or $20,000 based on a natural gas value of $4.00 per Mcf (U.S. EIA, 2010).

NMED Exhibit 91

4.0 SUMMARY

The EPA has used the data sources, analyses and studies discussed in this paper to form the Agency's understanding of emissions from pneumatic controllers and pumps and the emissions mitigation techniques. The following are characteristics the Agency believes are important to understanding these sources of VOC and methane emissions.

4.1 Pneumatic Controllers

- The majority of recent emissions estimates for pneumatic controllers have focused on methane emissions and not VOC emissions.
- The GHG Inventory data estimates that pneumatic controller emissions are 13% of overall methane emissions from the oil and natural gas sectors.
- Recent emission measurement studies have resulted in a wide range of methane emission factors for natural gas-driven pneumatic controllers. The studies all show that emissions can vary depending on sector (e.g., production, transmission, or storage) and the type of gas-driven pneumatic controller.
- Natural gas-driven pneumatic controllers are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Low bleed gas-driven controllers can replace high bleed gas-driven controllers in many, but not all, applications.
- Where a reliable source of electrical power is available, instrument air systems can replace natural gas-driven pneumatic controllers, and result in no methane or VOC emissions.
- Zero bleed, mechanical, and solar-powered controllers can replace continuous bleed controllers in certain applications, but are not broadly applicable to all segments of the oil and natural gas industry.

NMED Exhibit 91

4.2 Pneumatic Pumps

- Pneumatic pumps in the oil and natural gas industry are used as chemical injection pumps and circulation pumps for glycol dehydrators. Pressure from the natural gas line is used to power these pumps and the natural gas is vented to the atmosphere.
- There are several mitigation techniques that can be used to reduce or eliminate emissions from pneumatic pumps and they include: instrument air pumps and electric pumps (both AC and DC powered).
- The 2014 GHG Inventory data estimates that pneumatic pump emissions are 16% of overall methane emissions from the natural gas production and processing sectors. The 2014 GHG Inventory estimated methane emissions from these sources to be 64,570 MT of methane for chemical injection pumps and 393,389 MT of methane for natural gas-assisted Kimray pumps. Chemical injection pumps at petroleum systems emitted 49,973 MT of methane, or around 3% of emissions from petroleum production.
- Natural gas-driven pneumatic pumps are particularly useful in segments of the oil and natural gas industry that involve remote locations where electrical power is not available or reliable.
- Where a reliable source of electrical power is available, instrument air systems are an effective replacement for natural gas-driven pneumatic pumps.

5.0 CHARGE QUESTIONS FOR REVIEWERS

1. Did this paper appropriately characterize the different studies and data sources that quantify emissions from pneumatic controllers and pneumatic pumps in the oil and gas sector?
2. Please discuss explanations for the wide range of emission rates that have been observed in direct measurement studies of pneumatic controller emissions (e.g., Allen et al., 2013 and Prasino 2013). Are these differences driven purely by the design of the monitored controllers or are there operational characteristics, such as supply pressure, that play a crucial role in determining emissions?

NMED Exhibit 91

3. Did this paper capture the full range of technologies available to reduce emissions from pneumatic controllers and pneumatic pumps oil and gas facilities?

4. Please comment on the pros and cons of the different emission reduction technologies. Please discuss efficacy, cost and feasibility for both new and existing pneumatics.

5. Please comment on the prevalence of the different emission control technologies and the different types of pneumatics in the field. What particular activities require high bleed pneumatic controllers and how prevalent are they in the field?

6. What are the barriers to installing instrument air systems for converting natural gas-driven pneumatic pumps and pneumatic controllers to air-driven pumps and controllers?

7. Are there situations where it may be infeasible to use air driven pumps and controllers in place of natural gas-driven pumps and controllers even where it is feasible to install an instrument air system?

8. Did this paper correctly characterize the limitations of electric-powered pneumatic controllers and pneumatic pumps? Are these electric devices applicable to a broader range of the oil and gas sector than this paper suggests?

9. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from pneumatic controllers and pneumatic pumps and available techniques for increased product recovery and emissions reductions?

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NMED Exhibit 91

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Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry



Executive Summary

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector and <1 Bcf per year in the processing sector, are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

Natural Gas STAR Partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. Partners have found that most retrofit investments pay for themselves in little over a year, and replacements in as little as 6 months. To date, Natural Gas STAR Partners have saved 36.4 Bcf by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of $254.8 million worth of gas. Individual savings will vary depending on the design, condition and specific operating conditions of the controller.

Technology Background

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. Control devices can be powered by electricity or compressed air, when available and economic. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

Natural gas powered pneumatic devices perform a variety of functions in all three sectors of the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices are used to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector, about 13,000 gas pneumatic devices are used for compressor and glycol dehydration control in gas gathering/booster stations and isolation valves in processing plants (process control in gas processing plants is predominantly instrument air).

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/year)	Value of Natural Gas Savings ($/year)			Implementation Cost ($)	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Replacement								
Change to low-bleed device at end of life.	50 to 200	$150 to $600	$250 to $1,000	$350 to $1,400	$210 to $340[a]	4 to 27	3 to 17	2 to 12
Early-replacement of high-bleed unit.	260	$780	$1,300	$1,820	$1,850	29	17	13
Retrofit	230	$690	$1,150	$1,610 per year	$675	12	7	5
Maintenance	45 to 260	$135 to $780	$225 to $1,300	$315 to $1,820	Negligible to $500	Immediate to 8	Immediate to 5	Immediate to 4

General Assumptions:
[a] Incremental cost of low-bleed over high-bleed equipment.

NMED Exhibit 92 - 0001

Definition of High-Bleed Pneumatic

Any pneumatic device that bleeds in excess of 6 scfh (over 50 Mcf per year) is considered a high-bleed device by the Natural Gas STAR Program.

In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations for regulating flow, pressure, and temperature.

As part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device.

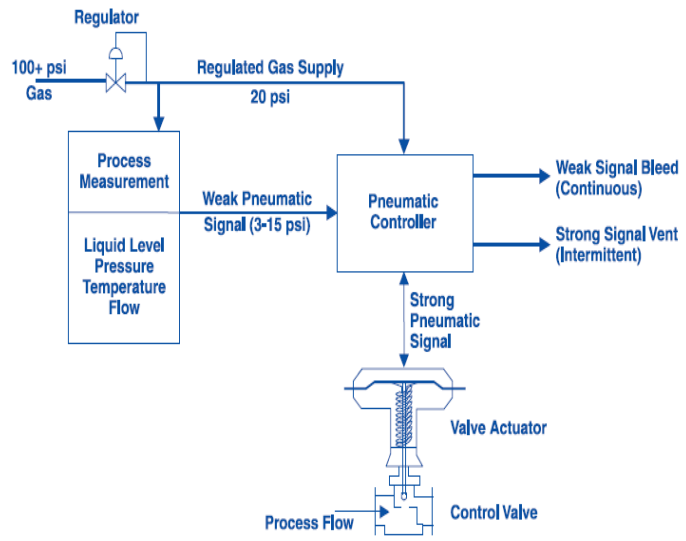
Exhibit 1 shows a schematic of a gas pneumatic control system. Clean, dry, pressurized natural gas is regulated to a constant pressure, usually around 20 psig. This gas supply is used both as a signal and a power supply. A small stream is sent to a device that measures a process condition (liquid level, gas pressure, flow, temperature). This device regulates the pressure of this small gas stream (from 3 to 15 psig) in proportion to the process condition. The stream flows to the pneumatic valve controller, where its variable pressure is used to regulate a valve actuator.

To close the valve pictured in Exhibit 1, 20-psig pneumatic gas is directed to the actuator, pushing the diaphragm down against the spring, which, through the valve stem, pushes the valve plug closed. When gas is vented off the actuator, the spring pushes the valve back open. The weak signal continuously vents (bleeds) to the atmosphere. Electro-pneumatic devices use weak electric current instead of the weak gas stream to signal pneumatic valve actuation.

In general, controllers of similar design usually have similar steady-state bleed rates regardless of brand name. Pneumatic devices come in three basic designs:

- ★ **Continuous** bleed devices are used to modulate flow, liquid level, or pressure and will generally vent gas at a steady rate;
- ★ **Actuating or intermittent** bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows; and

Exhibit 1: Pneumatic Device Schematic



- ★ **Self-contained** devices release gas into the downstream pipeline, not to the atmosphere.

To reduce emissions from pneumatic devices the following options can be pursued, either alone or in combination:

1. Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.
2. Installation of low-bleed retrofit kits on operating devices.
3. Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Exhibit 2 lists the generic options applicable for different controller requirements.

In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.

Exhibit 2: Options for Reducing Gas-Bleed Emissions by Controller Type

Action	Pneumatic Types		
	Level Controllers	Pressure Controllers	Positioners/ Transducers
Replacements			
High-bleed with low-bleed	X	X	X (electro-pneumatic)
Retrofits			
Install retrofit kits	X	X	X
Maintenance			
Lower gas supply pressure/replace springs/re-bench	X	X	X
Repair leaks, clean and tune	X	X	X
Change gain setting	X	X	
Remove unnecessary positioners			X

Economic and Environmental Benefits

Reducing methane emissions from high-bleed pneumatic devices through the options presented above will yield significant benefits, including:

- ★ **Financial return from reducing gas-bleed losses.** Using a natural gas price of $7.00 per thousand cubic feet (Mcf), savings from reduced emissions can range from $315 to $1,820 or more per year per device. In many cases, the cost of implementation is recovered in less than a year.

- ★ **Increased operational efficiency.** The retrofit or complete replacement of worn units can provide better system-wide performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level.

- ★ **Lower methane emissions.** Reductions in methane emissions can range from 45 to 260 Mcf per device per year, depending on the device and the specific application.

Decision Process

Operators can determine the gas-bleed reduction option that is best suited to their situation, by following the decision process laid out below. Depending on the types of devices that are being considered, one or more options for reducing pneumatic gas bleed may be appropriate.

Step 1: Locate and describe the high-bleed devices.

Partners should first identify the high-bleed devices that are candidates for replacement, retrofit, or repair. The identification and description process can occur during normal maintenance or during a system-wide or facility-specific pneumatics survey. For each pneumatic device, record the location, function, make and model, condition, age, estimated remaining useful life, and bleed rate characteristics (volume and whether intermittent or continuous).

The pneumatic device's bleed rate can be determined through direct measurement or from data provided by the manufacturer. Direct measurement might include bagging studies at selected instruments, high-volume sampler measurements (see "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned) or the operator's standard leak measurement approach. Operators will find it unnecessary to measure bleed rates at each device. In most cases, sample measurements of a few devices are sufficient. Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when it can be acquired.

Appendix A lists brand, model, and gas bleed information—as provided by manufacturers—for various pneumatic devices. This is not an exhaustive list, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included.

Step 2: Establish the technical feasibility and costs of alternatives.

Nearly all high-bleed pneumatic devices can be replaced or retrofitted with lower-bleed equipment. Consult your pneumatic device vendor or an instrumentation specialist for availability, specifications and costs of suitable devices. Low-bleed devices can be requested by specifying bleed rates less than 6 standard cubic feet per hour (scfh). It is important to note that not all manufacturers report bleed rates in the same manner, and companies should exercise

Five Steps for Reducing Methane Emissions from Pneumatic Devices:
1. Locate and describe the high-bleed devices;
2. Establish the technical feasibility and costs of alternatives;
3. Estimate the savings;
4. Evaluate the economics; and
5. Develop an implementation plan.

NMED Exhibit 92 - 0003

caution when making purchases of low-bleed devices.

Appendix B lists cost data for many low-bleed pneumatic devices and summarizes the compatibility of retrofit kits with various controllers. This is not an exhaustive list, but it covers the most commonly used devices.

Maintenance of pneumatics is a cost-effective method for reducing emissions. All companies should consider maintenance as an important part of their implementation plan. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device.

Some high-bleed devices, however, should not be replaced with low-bleed devices. Control of very large valves that require fast and/or precise response to process changes often require high-bleed controllers. These are found most frequently on large compressor discharge and bypass pressure controllers. EPA recommends contacting vendors for new fast-acting devices with lower bleed rates.

Step 3: Estimate the savings.

Determine the quantity of gas that can be saved with a low-bleed controller, using field measurement of the high-bleed controller and a similar low-bleed device in service. If these actual bleed rates are not available, use bleed specifications provided by manufacturers.

Gas savings can be monetized to annual savings using $7.00 per Mcf and multiplying bleed reduction, typically specified in scfh, by 8,670 hours per year.

Gas Savings = (High-bleed, scfh) — (Low-bleed, scfh)

Annual Gas Savings = Gas Savings (scfh) * 8,760 hrs/yr * 1 Mcf/1000scf * $7.00/Mcf

Step 4: Evaluate the economics.

The cost-effectiveness of replacement, retrofit, or maintenance of high-bleed pneumatic devices can be evaluated using straightforward economic analysis. A cost-benefit analysis for replacement or retrofit is appropriate unless high-bleed characteristics are required for operational reasons.

Exhibit 3 illustrates a cost-benefit analysis for replacement of a high-bleed liquid level controller. Cash flow over a five-year period is analyzed by showing the magnitude and timing of costs (shown in parenthesis) and benefits. In this example, a $513 initial investment buys a level controller that saves 19 scfh of gas. At $7.00 per Mcf, the low-bleed device saves $1,165 per year. Annual maintenance costs for the new and old controllers are shown. The maintenance cost for the older high-bleed controller is shown as a benefit because it is an avoided cost. Net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. Internal rate of return (IRR) is the discount rate at which the NPV generated by the investment equals zero.

Exhibit 3: Cost-Effectiveness Calculation for Replacement

Type of Costs	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Costs, $ (Capital Costs)[a]	(513)					
Annual Savings, $ (New vs. Old)[b]		1,165	1,165	1,165	1,165	1,165
Maintenance Costs, $ (New Controller)[c]		(34)	(34)	(34)	(34)	(34)
Avoided Maintenance, $ (Replaced Controller)[c]		70	70	70	70	70
Net Benefit	(513)	1,202	1,202	1,202	1,202	1,202
NPV[d] = $4,042 IRR = 234%						

Notes:
[a] Quoted cost of a Fisher 2680 device. Adjusted to 2006 equipment costs. See Appendix B.
[b] Annual savings per device calculated as the change in bleed rate of 19 scfh x 8,760 hrs/hr = 167 Mcf/yr at $7/Mcf.
[c] Maintenance costs are estimated.
[d] Net Present Value (NPV) based on 10% discount rate for 5 years.

Exhibit 4 illustrates the range of savings offered by proven methods for reducing gas bleed emissions. For simplicity, it is assumed that the cost of maintenance of the pneumatic device will be the same before and after the replacement, retrofit, or enhanced maintenance activity.

As seen in Exhibit 4, sometimes more than one option to reduce gas bleed may be appropriate and cost-effective for a given application. For the listed options, please note that the payback period with respect to implementation cost can range from less than one month to two years.

Exhibit 4: Economic Benefits of Reducing Pneumatic Device Emissions

Action	Cost[a] ($)	Bleed Rate Reductions[b] (Mcf/yr/device)	Annual Savings[c] ($/year)	Payback Period (months)	IRR[d] (%)
Replacement					
Level Controllers					
High-bleed to low-bleed	513	166	1,165	6	226
Pressure Controllers					
High-bleed to low-bleed	1,809	228	1,596	14	84
Airset metal to soft-seal	104	219	1,533	<1	>1,400
Retrofit					
Level Controllers					
Mizer	675	219	1,533	6	226
Large orifice to small	41	184	1,288	<1	>3,100
Large nozzle to small	189	131	917	3	>450
Pressure Controllers					
Large orifice to small	41	184	1,288	<1	>3,100
Maintenance					
All types					
Reduce supply pressure	207	175	1,225	3	>500
Repair leaks, retune	31	44	308	2	>900
Level Controllers					
Change gain setting	0	88	616	Immediate	—-
Positioners					
Remove unnecessary	0	158	1,106	Immediate	—-

[a] Implementation costs represent average costs for Fisher brand pneumatic instruments installed.
[b] Bleed rate reduction = change in bleed rate scf/hr x 8,760 hr/yr.
[c] Savings based on $7.00/Mcf cost of gas.
[d] Internal rate of return (IRR) calculated over 5 years.

The case studies in Exhibit 5 on the next page present analyses performed and savings achieved by two Natural Gas STAR Partners who installed retrofit kits at gas production facilities.

Step 5: Develop an implementation plan.

After identifying the pneumatic devices that can be profitably replaced, retrofitted or maintained, devise a systematic plan for implementing the required changes. This can include modifying the current inspection and maintenance schedule and prioritizing replacement or retrofits. It may be most cost-effective to replace all those devices that meet the technical and economic criteria of your analysis at one time to minimize labor costs and disruption of operation.

Where a pneumatic device is at the end of its useful life and is scheduled for replacement, it should be replaced with a low-bleed model instead of a new high-bleed device whenever possible.

When assessing options for replacement of high-bleed pneumatic devices, natural gas price may influence the decision making process. Exhibit 6 shows an economic analysis of early replacement of a high bleed pneumatic device with a lower bleed device at different natural gas prices.

NMED Exhibit 92 - 0005

Exhibit 5: Case Studies on Retrofit To Reduce Gas Leaks at Natural Gas STAR Partner Sites

Study	Implementation Costs ($)	Emissions Reductions (Mcf/yr)	Annual Savings ($/year)	Payback (months)	IRR (%)
Company 1:					
Platform 1	8,988	2,286	16,002	7	177
Platform 2	13,892	3,592	25,144	7	180
Retrofit Liquid-level controllers	5,452	1,717	12,019	6	220
Company 2:					
Per device	702	219	1,533	6	218

Exhibit 6: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$780	$1,300	$1,820	$2,080	$2,600
Payback Period (months)	29	18	13	11	9
Internal Rate of Return (IRR)	31%	64%	95%	110%	139%
Net Present Value (i=10%)	$1,107	$3,078	$5,049	$6,035	$8,006

Other Technologies

Instrument air, nitrogen gas, electric valve controllers, and mechanical control systems are some of the alternatives to gas powered pneumatics implemented by Partners.

★ **Instrument Air.** These systems substitute compressed, dried air in place of natural gas in pneumatic devices, and thus eliminate methane emissions entirely. Instrument air systems are typically installed at facilities where there is a high concentration of pneumatic control valves and fulltime operator presence (for example, most gas processing plants use instrument air for pneumatic devices). The major costs associated with instrument air systems are capital and energy. Instrument air systems are powered by electric compressors, and require the installation of dehydrators and volume tanks to filter, dry and store the air for instrumentation use. Generally, Partners have found that cost-effective implementation of instrument air systems is limited to field sites with available utility or self-generated electrical power. The Lessons Learned study, "Covert Gas Pneumatic Controls to Instrument Air," provides a detailed description of the technical and economic decision process required to evaluate conversion from gas pneumatic devices to instrument air.

★ **Nitrogen Gas.** Unlike instrument air systems that require capital expenditures and electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, that is replaced periodically, and a liquid nitrogen vaporizer. The system uses a pressure regulator to control the expansion of the nitrogen gas (i.e., the gas pressure) as it enters the control system. The primary disadvantage of these systems stems from the cost of liquid nitrogen and the potential safety hazard associated with using cryogenic liquids.

★ **Electric Valve Controllers.** Due to advances in technology, the use of electronic control instrumentation is increasing. These systems use small electrical motors to operate valves and therefore do not bleed natural gas into the atmosphere. While they are reliant on a constant

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

supply of electricity, and have high associated operating costs, they have the advantage of not requiring the utilization of natural gas or a compressor to operate.

★ **Mechanical Control Systems.** These devices have been widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. While they are simple in design and require no natural gas or power supply to operate, their application is limited due to the need for the control valve to be in close proximity to the process measurement. Also, these systems are unable to handle large flow fluctuations and lack the sensitivity of pneumatic systems.

Each of these options has specific advantages and disadvantages. Where Natural Gas STAR Partners do install these systems as replacements to gas powered pneumatic devices, they should report the resulting emissions reductions and recognize the savings.

One Partner's Experience

Union Pacific Resources replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, this Partner has estimated a total reduction of methane emissions of 49,600 Mcf per year. Assuming a gas price of $7 per Mcf, the savings corresponds to $347,200. The costs of replacing and retrofitting all the devices, including materials and labor, is $166,300 at 2006 costs, resulting in a payback period of less than one year.

One Partner's Experience

Marathon Oil Company surveyed 158 pneumatic control devices at 50 production sites using the Hi-Flow Sampler to measure emissions. Half of these controllers were identified as non-bleed devices (e.g., weighted dump valves, spring operated regulators, enclosed capillary temperature controllers, non-bleed pressure switches). High-bleed devices accounted for 35 of 67 level controllers, 5 of 76 pressure controllers, and 1 of 15 temperature controllers. Measured gas emissions were 583 scfh total; 86 percent of emissions came from level controllers, with leaks up to 48 scfh, and averaging 7.6 scfh. Marathon concluded that "control devices with higher emissions can be identified qualitatively by sound prior to leak measurement, making it unnecessary to quantitatively measure methane emissions using technologically advanced equipment."

Lessons Learned

Natural Gas STAR Partners offer the following Lessons Learned:

★ Hear it; feel it; replace it. Where emissions can be heard or felt, this is a sign that emissions are significant enough to warrant corrective action.

★ Control valve cycle frequency is another indicator of excessive emissions. When devices cycle more than once per minute, they can be replaced or retrofitted profitably.

★ Manufacturer bleed rate specifications are not necessarily what users will experience. Actual bleed rates will generally exceed manufacturer's specifications because of operating conditions different from manufacturer's assumptions, installation settings and maintenance.

★ Combine equipment retrofits or replacements with improved maintenance activities. Do not overlook simple solutions such as replacing tubes and fittings or rearranging controllers.

★ The smaller orifices in low-bleed devices and retrofit kits can be subject to clogging from debris in corroded pipes. Therefore, pneumatic supply gas piping and tubing should be flushed out before retrofitting with

NMED Exhibit 92 - 0007

smaller orifice devices, and gas filters should be well maintained.

- ★ When replacing pneumatic control systems powered by pressurized natural gas with instrument air or other systems, do not forget to account for the savings from the resulting methane emission reductions.

- ★ Include methane emission reductions from pneumatics in annual reports submitted as part of the Natural Gas STAR Program.

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Appendix A

The following chart contains manufacturer-reported bleed rates. Actual bleed rates have been included whenever possible. Discrepancies occur due to a variety of reasons, including:

- ★ Maintenance.
- ★ Operating conditions.
- ★ Manufacturer vs. operating assumptions.

It is important to note that manufacturer information has not been verified by any third party and there may be large differences between manufacturer-reported bleed rates and those found during operations. Until a full set of information is available, companies should be careful to compare bleed rates in standard units (CFH) when comparing manufacturers and models. During this study we found that manufacturers reported information in a wide range of different units and operating assumptions.

Gas Bleed Rate for Various Pneumatic Devices

Controller Model	Type	Consumption Rate (CFH)	
		Manufacturer Data	Field Data (where available)
High-Bleed Pneumatic Devices			
**Fisher 4100 Series	Pressure controller (large orifice)	35	
**Fisher 2500 Series	Liquid-level controllers (P.B. in mid range)	10-34	44-72
*Invalco AE-155	Liquid-level controller		44-63
*Moore Products—Model 750P	Positioner	42	
*Invalco CT Series	Liquid-level controllers	40	34-87
**Fisher 4150/4160K	Pressure controller (P.B. 0 or 10)	2.5-29	
**Fisher 546	Transducer	21	
**Fisher 3620J	Electro-pneumatic positioner	18.2	
Foxboro 43AP	Pressure controller	18	
**Fisher 3582i	Electro-pneumatic positioner	17.2	
**Fisher 4100 Series	Pressure controller (small orifice)	15	
**Fisher DVC 6000	Electro-pneumatic positioner	14	
**Fisher 846	Transducer	12	
**Fisher 4160	Pressure controller (P.B. 0.5)	10-34	
**Fisher 2506	Receiver controller (P.B. 0.5)	10	
**Fisher DVC 5000	Electro-pneumatic positioner	10	
**Masoneilan 4700E	Positioners	9	
**Fisher 3661	Electro-pneumatic positioner	8.8	
**Fisher 646	Transducer	7.8	
**Fisher 3660	Pneumatic positioner	6	
**ITT Barton 335P	Pressure controller	6	
*Ametek Series 40	Pressure controllers	6	
Low- or No-Bleed Pneumatic Devices			
**Masoneilan SV	Positioners	4	
**Fisher 4195 Series	Pressure controllers	3.5	
**ITT Barton 273A	Pressure transmitter	3	
**ITT Barton 274A	Pressure transmitter	3	
**ITT Barton 284B	Pressure transmitter	3	
**ITT Barton 285B	Pressure transmitter	3	
**Bristol Babcock Series 5457-70F	Transmitter	3	
**Bristol Babcock Series 5453-Model 624 -II	Liquid-level controllers	3	
**Bristol Babcock Series 5453-Model 10F	Pressure controllers	3	
**Bristol Babcock Series 5455 Model 624 -III	Pressure controllers	3	
**ITT Barton 358	Pressure controller	1.8	

**ITT Barton 359	Pressure controller	1.8	
**Fisher 3610J	Pneumatic positioner	16	
**Bristol Babcock Series 502 A/D	Recording pneumatic controllers	<6	
**Fisher 4660	High-low pressure pilot	<5	
**Bristol Babcock Series 9110-00A	Transducers	0.42	
Fisher 2100 Series	Liquid-level controllers	1	
**Fisher 2680	Liquid-level controllers	<1	
*Norriseal 1001 (A) (snap)	Liquid-level controller	0.2	0.2
*Norriseal 1001 (A) ('Envirosave')	Liquid-level controller	0	0
*Norriseal 1001 (A) (throttle)	Liquid-level controller	0.007	0.007
**Becker VRP-B -CH	Double-acting pilot pressure control system (replaces controllers and positioners)	0-10	
**Becker HPP-5	Pneumatic positioner (Double-acting)	0-10	
**Becker EFP-2.0	Electro-pneumatic positioner	0	
**Becker VRP-SB	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker VRP-SB GAP Controller	Replaces pneumatic "gap" type controllers	0	
**Becker VRP-SB-PID Controller	Single-acting pilot pressure control system specifically designed for power plant type feeds (replaces controllers and positioners)	0	
**Becker VRP-SB-CH	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker HPP-SB	Pneumatic positioner (Single-acting)	0	

Actuator Model	Size	Manufacturer Data	Field Data
*Shafer RV-Series Rotary Vane Valve Actuators	33" x 32"	1,084	
	36" x 26"	768	
	26" x 22"	469	
	25" x 16"	323	
	20" x 16"	201	
	16.5" x 16"	128	
	14.5" x 14"	86	
	12.5" x 12"	49	
	12" x 9"	22	
	11" x 10"	32	
	9" x 7"	12	
	8" x 6.5"	8	
	6.5" x 3.5"	6	
	5" x 3"	6	

Actuator Model	Size	Number of Snap-acting Strokes per CF	Number of Throttling Strokes per CF
**Fisher Valve Actuators	20	21	39
**Fisher Valve Actuators	30	12	22
**Fisher Valve Actuators	34/40	6	10
**Fisher Valve Actuators	45/50	3	5
**Fisher Valve Actuators	46/50	2	3

* Last updated in 1996.
** Last updated in 2001.

Appendix B

Controllers Compatible with MIZER Retrofits	
Type	**Brand/Model Number**
Liquid-level controllers	C.E. Invalco — 215, 402, AE-155
	Norriseal — 1001, 1001A
Pressure controllers	Norriseal — 4300
Suggested Retail Prices for Various Brand Low-Bleed Pneumatic Devices (Estimates Based on Best Information Available at Time of Publication)	
Brand/Model	**Price per Device**
**ITT Barton 335P (pressure controller)	$920
**ITT Barton 273A (pressure transmitter)	$1,010
**ITT Barton 274A (pressure transmitter)	$1,385
**ITT Barton 284B (pressure transmitter)	$1,605
**ITT Barton 285B (pressure transmitter)	$1,990
**ITT Barton 340E (recording pressure controller)	$1,400
**ITT Barton 338E (recorder controller)	$2,800
**Ametek Series 40 (pressure controllers)	$1,100 (average cost)
**Becker VRP-B-CH	$1,575.00
**Becker HPP-5	$1,675.00
**Becker VRP-SB	$1,575.00-$2,000.00
**Becker VRP-SB-CH-PID	$2,075.00
**Becker VRP-SB-CH	$1,575.00
**Becker HPP-SB	$1,675.00
**Mizer Retrofit Kits	$400-$600
**Fisher 67AFR (airset regulators)	$80
**Fisher 2680 (liquid-level controllers)	$380
**Fisher 4195 (pressure controllers)	$1,340
**Bristol Babcock Series 9110-00A (transducers)	$1,535-$1,550
**Bristol Babcock Series 5453 (controllers)	$1,540
**Bristol Babcock 5453 40 G (temperature controllers)	$3,500
**Bristol Babcock Series 5457-624 II (controllers)	$3,140
**Bristol Babcock Series 502 A/D (recording controllers)	$3,000
**Bristol Babcock Series 5455-624 III (pressure controllers)	$1,135
**Bristol Babcock Series 5453-624 II (liquid level controllers)	$2,345
**Bristol Babcock Series 5453-10F (pressure controllers)	$1,440

* Last updated in 1996.
** Last updated in 2001.

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

COLORADO

Air Pollution Control Division

Department of Public Health & Environment

Dedicated to protecting and improving the health and environment of the people of Colorado

Pneumatic Controller Task Force Report to the Air Quality Control Commission

Pneumatic Controller Field Study and Recommendations

June 1, 2020

TABLE OF CONTENTS

1 INTRODUCTION 1

1.1 2017 AQCC REG 7 OIL AND GAS CTG RULEMAKING AND PNEUMATIC INSPECTION PROGRAM 2
1.1.1 Background *2*
1.1.2 PC Find and Fix program *3*
1.1.3 Reassessment Provision *3*
1.1.4 2019 Rulemaking Directives *4*

2 PNEUMATIC CONTROLLERS 5

2.1 WHAT IS A PC, WHAT DOES IT DO? 5
2.2 TYPES OF PCS 5
2.3 IMPROPER OPERATION 6
2.3.1 Causes *6*
2.3.2 Effects and Indicators *6*

3 PC TASK FORCE 7

3.1 PCTF GOALS 7
3.2 IMPLEMENTATION PLAN 7

4 PC FIELD STUDY 7

4.1 PARTICIPATING STAKEHOLDERS 7
4.2 STUDY DESIGN 8
4.2.1 PC Inspection Method Utilized *8*
4.2.2 Field Data Form Development *8*
4.2.3 Facility Selection *8*
4.3 FIELD CAMPAIGN SUMMARY 10
4.3.1 Field Data Compilation *10*
4.3.2 Completeness and Consistency Review *10*
4.4 PCTF STUDY DATA 11
4.4.1 Oil and Gas Production Facility Data *11*
4.4.2 Midstream Data *14*
4.5 PCTF STUDY FINDINGS AND CONCLUSIONS 14
4.5.1 Key Findings *14*
4.5.2 Conclusions *16*
4.6 SEPARATE EPA/CDPHE STUDY ON PCS IN DENVER-JULESBURG BASIN 16
4.6.1 Overview *16*
4.6.2 Study Design *17*
4.6.3 Findings *18*
4.6.4 Conclusions *20*
4.7 COMPARISON OF PCTF STUDY AND EPA/CDPHE STUDY FINDINGS AND CONCLUSIONS 21
4.7.1 Findings *21*
4.7.2 Conclusions *22*

5 INDUSTRY SURVEYS 23

5.1 EFFECTIVENESS AND COSTS OF INSPECTION TECHNIQUES (NAA ONLY) 23
5.2 EFFECTIVENESS AND COSTS OF REPAIRS (NAA ONLY) 24
5.3 USE OF SELF-CONTAINED AND NO-BLEED PCS (STATE-WIDE SURVEY) 25
5.4 ELECTRICAL INFRASTRUCTURE FOR OIL AND GAS DEVELOPMENT 30

6 GOOD ENGINEERING AND MAINTENANCE PRACTICES 32

6.1.1 The Environmental Partnership *32*

NMED Exhibit 93

7 RECOMMENDATIONS 33

7.1 EFFECTIVENESS OF CURRENT PROGRAM (NAA ONLY) 33
7.2 DEFINITION APPROPRIATENESS 35
7.3 NO-BLEED AND SELF-CONTAINED PCS 36
7.3.1 Current applications 36
7.3.2 Effectiveness of devices 38
7.3.3 Costs for new and retrofit facilities 38
7.3.4 Limitations and Barriers to expanded use 39
7.3.5 Opportunities for expanded use 40

8 ACKNOWLEDGMENTS 40

NMED Exhibit 93

1 Introduction

This report was developed in response to a December 2017 rulemaking, in which the Colorado Air Quality Control Commission (AQCC) established a pneumatic controller (PC) 'Find and Fix' program for oil and gas well production facilities and natural gas compressor stations located in the ozone non-attainment area (NAA). The AQCC recognized that continuous bleed and intermittent pneumatic controllers are designed to have emissions but these emissions can be excessive when the controllers are not operating properly. The AQCC adopted the Find and Fix program to reduce excess emissions from such natural gas-driven pneumatic controllers.

As part of the Statement of Basis and Purpose (SBAP), and at the request of industry and other stakeholders, the AQCC adopted a "reassessment" provision for the Find and Fix program. The reassessment was to follow an Air Pollution Control Division (Division) led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also directed that more information on "good engineering and maintenance practices" should be gathered during the pneumatic controller study and implementation of the Find and Fix program to inform the reassessment. As part of the reassessment, industry agreed to participate in a study focused on the Denver-Julesburg (DJ) Basin that would collect data on the types of PCs in service, those PCs determined to be operating improperly, what caused the PCs to not operate properly, and the repairs taken to return the PCs to proper operation across a representative cross section of well production facilities and natural gas compressor stations in the NAA.

The AQCC directed the creation of a Pneumatic Controller Task Force (PCTF) comprised of representatives of the Division, operators and industry trade groups, local governments, and conservation groups. The PCTF was to brief the AQCC annually and make recommendations in this report, and each participant was to have the opportunity to contribute to the briefings and report. The AQCC also recognized that the pneumatic controller study and inspection program might inform the strategies for cost-effective hydrocarbon emission reductions for pneumatic controllers, including zero emission pneumatic controllers, under consideration by the Statewide Hydrocarbon Emission Reduction (SHER) team. The AQCC also established the SHER team through the SBAP for the December 2017 rulemaking.

The PCTF convened for the first time on January 25, 2018. The group held bi-weekly meetings for several months to develop and design the study. Field inspections of production facilities selected for the study started on May 1, 2018. Afterwards, meetings were held bi-monthly to check on the progress of field inspections and updates on data management until the data was submitted to the Division in December 2018. The group met in January 2019 to discuss initial data analysis, finalize the project plan, and revisit goals. The PCTF briefed the AQCC on February 21, 2019 on its progress. Throughout the spring of 2019, industry PCTF members developed and responded to questionnaires to document and assess the effectiveness and costs of inspection techniques as well as to understand opportunities for expanded use of no-bleed PCs. The PCTF and the SHER team held a joint meeting on June 11, 2019, to hear presentations on Canadian regulation of pneumatic controllers.

NMED Exhibit 93

In April 2019, the legislature adopted Senate Bill 19-181, which directs the AQCC to "review its rules for oil and natural gas well production facilities and compressor stations and specifically consider adopting more stringent provisions, including . . . a requirement to reduce emissions from pneumatic devices. The AQCC shall consider requiring oil and gas operators, under appropriate circumstances, to use pneumatic devices that do not vent natural gas." The PCTF was effectively put on hold in the summer of 2019 to allow its members to focus on regulatory proposals to be addressed during the December 2019 SB 19-181 Rulemaking. In that rulemaking, the AQCC adopted the SHER team's proposal to (1) expand the Find and Fix program statewide, (2) include language in the SBAP directing continued work to evaluate the use of zero-bleed pneumatic devices, and (3) provide for a compliance assistance approach for operators outside the nonattainment area while those operators get up to speed on the Find and Fix program. In the SBAP, the AQCC directed the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the AQCC in 2020 their recommendations on the use of zero-bleed pneumatic devices.

Members of the PCTF were requested in April 2020 to review and complete this report.

1.1 2017 AQCC Reg 7 Oil and Gas CTG Rulemaking and Pneumatic Inspection Program

Below is a summary from the Statement of Basis and Purpose prepared for the 2017 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2017 rulemaking and the direction given to the Division to convene a PCTF.

1.1.1 Background

On May 4, 2016, the U.S. Environmental Protection Agency ("EPA") published a final rule that determined that Colorado's Marginal ozone NAA failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard ("NAAQS"). EPA, therefore, reclassified the Denver Metro North Front Range ("DMNFR") area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan ("SIP") to address the Clean Air Act's ("CAA") Moderate NAA requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (*See* 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate NAA, Colorado revised its SIP to include Reasonably Available Control Technology ("RACT") requirements for each category of volatile organic compound ("VOC") sources covered by a Control Technique Guidelines ("CTG") for which Colorado has sources in the DMNFR that EPA finalized prior to a NAA's attainment date. EPA finalized the CTG for the Oil and Natural Gas Industry ("Oil and Gas CTG") on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado needed to further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado had similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions were not currently in Colorado's Ozone SIP. Therefore, on November 16, 2017, the AQCC adopted RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP. In order to make additional progress towards attainment of the NAAQS, the AQCC also adopted State Only revisions to require owners or operators of oil and gas well production facilities and

compressor stations with natural gas-driven PCs in the DMNFR area to inspect and maintain these PCs.

1.1.2 PC Find and Fix program

The AQCC adopted an inspection and enhanced response (*e.g.*, maintenance) program for natural gas-driven PCs. While the Oil and Gas CTG notes the value of PC inspection and maintenance, the Oil and Gas CTG does not specify PC inspection and maintenance as presumptive RACT. The AQCC therefore created a new program that requires that natural gas-driven PCs at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the PC is operating properly. The program requires that owners or operators inspect PCs for proper operation as part of routine LDAR regulatory programs at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

This PC inspection and enhanced response process was intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven PC using an approved instrument monitoring method (AIMM) to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those PCs with detected emissions. Second, the owner or operator must determine whether the PCs with detected emissions are operating properly. Use of an AIMM is not required during this second step; the AQCC did not lay out a process for how owners or operators are to determine if their PCs are operating properly. During this second step, if an owner or operator determines that the PC is operating properly, no further action is necessary. Third, where an owner or operator determines the PC is not operating properly, the owner or operator must take actions to return an improperly operating PC to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those PCs that the owner or operator determined not to be operating properly. Similar to the LDAR records, owners or operators must keep records of the date the PC was returned to proper operation and a description of the types of actions taken.

1.1.3 Reassessment Provision

The reassessment provision is explained as follows in the SBAP for the 2017 Reg 7 CTG rulemaking.

The AQCC adopted a "reassessment" provision for this inspection and enhanced response program following a Division led study of PC emission reduction options, including the rate, type, application, and causes of PCs found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also recognized that owners and operators may have limited information on "good engineering and maintenance practices" for PCs and intended that more information on these practices are gathered during the pneumatic study and implementation to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry's proposal, a task force was directed to convene by January 30, 2018, consisting of

representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection was scheduled to commence no later than by May 1, 2018. The task force *will* brief the AQCC annually and make any recommendations on its findings in a report (this document) to the AQCC due May 1, 2020. The AQCC *intends* that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the AQCC. The AQCC intended that this information be used to reassess the natural gas-driven PC requirements of Regulation Number 7 that will remain in effect until rescinded, superseded, or revised.

1.1.4 2019 Rulemaking Directives

Below is an excerpt from the Statement of Basis and Purpose prepared for the 2019 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2019 rulemaking and the direction given to the PCTF and SHER Team:

> "Pneumatic Controllers (Part D, Section III.)
>
> SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.
>
> The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.
>
> The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

> The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings."

2 Pneumatic Controllers

This section provides some basic information regarding PCs, with a focus on the PCs studied recently in Colorado.

2.1 What is a PC, what does it do?

PCs are found widely on oil and natural gas production facilities in Colorado. PCs are used to automate and regulate process control variables such as temperature, pressure, liquid level, and to maintain critical safety fail-safe functions. PCs operate by sensing a condition and then sending a signal to a valve actuator that in turn controls a valve that controls the process parameter in question. For instance, a liquid level controller will sense liquid levels in a separator and send a signal (in the form of natural gas pressure) to a valve actuator on a dump valve which in turn opens the dump valve and lowers the liquid level in the separator. It is important to note that the PC, the valve actuator, and the valve are all different components of the control system. It is not uncommon for the PC to be located several feet away from the valve actuator and the valve it is controlling. Finally, it is important to realize that the valve being controlled by the PC is a component that is already subject to the LDAR provisions of Regulation Number 7. Similarly, there are many connectors associated with PCs and valve actuators - each of which is also a component subject to the LDAR provisions. As such, it is important to distinguish emissions from leaking components that are routinely found and repaired in an LDAR program, from emissions caused by an improperly operating PC.

2.2 Types of PCs

As part of their normal function, PCs emit natural gas when they actuate, either intermittently or continuously. Continuous and intermittent PCs are the two broad categorizations of PCs that were the focus of the 2018 PCTF field study. The categorization refers to how the PC is expected to emit under normal operation. A continuous PC is designed to emit at a steady rate, commonly referred to as a bleed rate. The bleed rate may change during actuation. Contrastingly, an intermittent PC is only expected to emit above a de minimis level during actuations and hence they do not have a bleed rate per se. Some intermittent PCs actuate very frequently and some only rarely. For instance, a liquid-level

controller on a new high producing well may actuate many times within an hour. There may be significant emissions associated with this normal, intended operation.[1]

There are also non-emitting controllers, often referred to as "no-bleed," "zero-bleed" or "zero-emitting"[2] PCs. These devices do not emit natural gas to the atmosphere during any phase of normal operation. Many of these devices are inherently non-emitting because they are driven by electricity or pressurized air, rather than pressurized natural gas. Since the intent of this field study was to examine emissions associated with natural gas-driven PCs, non-emitting PCs were not included in the scope of the 2018 PCTF field study.

Contained within the continuous PC category are high-bleed and low-bleed PCs. High-bleed PCs are designed to emit over 6 standard cubic feet per hour (scf/hr) of gas between actuations. Low-bleed devices emit less than 6 scf/hr. As of 2020, the Division believes that there are no high-bleed devices in use within the State of Colorado and all continuous-bleed PCs reported during this study were low-bleed.

2.3 Improper operation

Numerous studies have identified that a small number of improperly operating PCs are typically responsible for the majority of emissions from the PC population[3,4,5]. This information is what originally prompted the AQCC to adopt a PC find and fix program. The PCTF took a similar approach with the field study by focusing on "proper" vs "improper" operation.

2.3.1 Causes

Improper operation could be caused by any number of issues affecting a PC. These causes range from small amounts of debris keeping the controller from reseating properly to broken internal parts or defects in the housing for the PC. The causes specifically identified in the field study included: abnormal operation parameters, corrosion, debris, diaphragm failure, seal failure, spring failure, and wet supply gas.

2.3.2 Effects and Indicators

Operator personnel utilize AIMM (typically an OGI camera) to detect emissions from production facilities during LDAR inspections. Identification of a PC that is not operating properly requires additional knowledge regarding the types of PCs and their emission characteristics during normal operation in order to distinguish improper operation with an OGI camera.

Common tell-tale signs of PC improper operation include: loss of or improper control of the process parameter the PC is supposed to control; continuous emissions from an intermittent PC; excess emissions, as compared to normal operation, as identified via audio, visual, and olfactory (AVO) inspections or AIMM, from a controller; or obvious signs of significant staining

[1] Stovern, 2020: Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging, Journal of the Air & Waste Management Association.
[2] Simpson, 2014. Pneumatic controllers in upstream oil and gas. Oil Gas Facil. 3(5):83–96.
[3] Allen, 2014. CH4 emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers. Environ. Sci. Technol. 49 (1):633–40.
[4] Luck, 2019. Multi-day measurements of pneumatic controller emissions reveal frequency of abnormal emissions behavior at natural gas gathering stations. Environ. Sci. Technol. Letters 6:348–52.
[5] Thoma, 2017. Assessment of Uinta basin oil and natural gas well pad pneumatic controller emissions. J. Environ. Prot. 8:394.

or corrosion. A subset of improperly operating PCs may also be able to be identified by field personnel using their AVO senses; however, all inspections in this study used AIMM and did not solely rely on AVO observations.

3 PC Task Force

3.1 PCTF Goals

The PCTF members established the following goals for the PC study:

- Identify and collect natural gas-actuated PC data from a representative subset of well production facilities and compressor stations in the NAA
    - Set parameters of "improper operation" for each type of PC
    - Develop, document, and assess the effectiveness and costs of inspection techniques
    - Document malfunction rates and causes for types, makes, and models of PCs in different types of service
    - Document the effectiveness and costs of repair techniques and preventative maintenance
    - Estimate the number of PCs typically associated with a separator or other grouping of equipment

- Gather information regarding "good engineering and maintenance" practices

- Evaluate the appropriateness of the definitions in Regulation No. 7 for enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller

- Gather information about the current applications, cost, effectiveness, current applications and opportunities for expanded use for no-bleed and self-contained PCs

- Produce timely annual presentations and a report to the AQCC

3.2 Implementation Plan

The PCTF formed three distinct groups to address different elements of designing the field study: a main core group and two subgroups. One subgroup selected representative facilities and the second subgroup developed a field data form. Members of the PCTF provided several technical presentations to grow the shared knowledge base during the study development phase.

Once the field inspection campaign commenced on May 1, 2018, bimonthly meetings were held to check on the progress of field inspection and subsequent data management until the compiled and blinded data was submitted to the Division in December 2018. The two subgroups disbanded once 2018 sampling began while the main core group continued to meet.

4 PC Field Study

4.1 Participating Stakeholders

The field study was designed with the help of all PCTF stakeholders. These stakeholders include: the Division, the American Petroleum Institute (API), the Colorado Oil and Gas

Association (COGA), nine upstream oil and gas well production operators, one midstream operator, the Clean Air Task Force (CATF), Earthjustice (EJ), the Environmental Defense Fund (EDF), Boulder County Public Health (BCPH), Denver Public Health and Environment (DDPHE), Colorado Communities for Climate Action (CC4CA), and the Regional Air Quality Council (RAQC).

The field study was implemented and conducted with the participation of nine upstream oil and gas well production facility operators in the DJ Basin. The study also surveyed PCs at the only two known natural gas compressor stations within the DJ Basin that operate natural gas-actuated PCs.

4.2 Study Design

4.2.1 PC Inspection Method Utilized

All PC inspections conducted at the facilities selected for this field study utilized an OGI camera to monitor and identify improperly operating PCs. Some operators also noted whether an improperly operating PC could have been identified using only AVO methods (e.g. visible staining or corrosion or audible hissing when not actuating).

4.2.2 Field Data Form Development

A subgroup was formed to develop the field data forms (Attachment A) that would be used by operators during PC inspections of the selected facilities to collect consistent metadata across operators and facilities. These forms were based on forms utilized by the Stovern et al (2020) study and amended to reflect the different data collection goals of the PCTF inspection process. The final data forms include general, inventory, inspection, and repair information. The data form options include PC type (including manufacturer and model), function, application, depressurization method, and type of service. The forms determine "improper operation" causes, including description(s). The forms note primary causes of improper operation such as debris, corrosion, equipment failures, broken or missing parts, or abnormal operational parameters; there is also an option for other causes.

Industry representatives provided extensive instructions (Attachment B) for field staff that detailed each item on the form step-by-step. The final data forms were available in paper and electronic form. Operators that utilized paper forms tabulated the data into the electronic form once the paper forms were returned to office staff. All data was submitted to the Division in electronic form.

4.2.3 Facility Selection

The PCTF extensively examined appropriate cross-sectional data for well production facilities and natural gas compressor stations. For well production facilities, the Division initially estimated about 7,000 well production facilities in the NAA counties. The group discussed how to appropriately divide the facilities into cohorts in order to identify which facilities should be sampled for the study. The factors discussed included type of drilling (horizontal vs. vertical), operation size based on production levels, facility age, and separator types. Ultimately, the subgroup decided that production level (barrels/day) was most appropriate and representative of the other variables being considered.

Industry then provided "snapshot" daily average production data from December 2017 for each of the nine participating operators to the Division on February 21, 2018, with subsequent updates based on stakeholder meeting discussions. This snapshot dataset for the nine participating operators represented approximately 80% of all well production facilities located

in the NAA. The original dataset was grouped by level of production (barrels/day), and a 50 percent "Plug and Abandon" (P&A) rate for wells in the 0 - 10 bbls production level cohort was assumed, as these wells were largely older vertical wells likely to be shut-in or scheduled for P&A. This P&A rate assumption is based on multiple factors including, but not limited to, line pressure, economic considerations, lease agreement issues, and land use matters.

Industry updated the dataset on March 21, 2018, with more accurate information from the two largest participating operators, which decreased the P&A rate and provided a conservatively low estimate of the number of PCs to be surveyed at each well production facility, based on its level of production. This analysis was conducted to demonstrate that the study would sample a sufficient number of selected facilities in each production cohort, to provide an adequate data set for the study.

After further meetings and discussion, the PCTF decided on the following cross-sectional sample of well production facilities to be subject to PC inspections starting May 1, 2018, shown in Table 1:

Table 1: Preliminary DMNFR Ozone NAA Well Production Facility Dataset (2018 Sampling Estimate)

Production Buckets	Estimated number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Estimated # of controllers
>250 bbls/day	50	104	13	14	700
10-250 bbls/day	20	553	7	39	780
0-10 bbls/day	5	2,509	5	125	625
TOTAL		**3,166**		**178**	**2,105**

The actual sampling that took place resulted in one extra facility inadvertently being surveyed by one of the operators. Additionally, because operator PC count estimates were intentionally conservative, a significantly higher number of controllers were actually surveyed during the study. The actual final 2018 well sampling facility and PC numbers inspected are shown below in Table 2.

Table 2: Final DMNFR Ozone NAA Well Production Facility Dataset (May - October 2018)

Production Buckets	Average number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Final # of controllers
>250 bbls/day	98	104	13	14	1,378
10-250 bbls/day	34	553	7	39	1,319
0-10 bbls/day	9	2,509	5	126	1,141
TOTAL		**3,166**		**179**	**3,838**

For natural gas compressor stations, the Division initially requested industry feedback on potential data for inclusion in the May 2018 sampling. After further stakeholder discussion, the Division conducted an independent analysis using its databases to determine the number of active natural gas compressor stations in the NAA and gathered industry feedback by facility. The final analysis showed 58 active natural gas compressor stations operated by eight companies. The Division received feedback on 86% of the stations (50 stations) by June 2018 (four out of eight operators). Of these, 48 stations are currently operating or under construction to operate on instrument air, or have been depressurized and are not included in the field inspections. Two natural gas compressor stations were confirmed to use natural gas-driven PCs and were included in the study. These two natural gas compressor stations were sampled in the summer of 2018. Nine compressor stations are operated by non-participating operators and are of an unknown status at the time of the study. It is likely that at least some of these natural gas compressor stations are operated on instrument air since 4% (two out of 50) of the participating stations use natural gas-driven PCs; however, this is assumed and not verified.

4.3 Field Campaign Summary

The PCTF field study began in May 2018 and data collection was finished by October 2018. On August 1, 2018, and September 11, 2018, Patrick Murphy (formerly of Boulder County) and Jeramy Murray (APCD) attended field surveys at four Noble Energy and two PDC Energy facilities to observe how industry field staff were implementing the study design.

4.3.1 Field Data Compilation

Spirit Environmental (Spirit) was retained by COGA to assist with implementation of the PCTF study plan, including facility selection, field data form development, and data validation and compilation. Once the representative cross-section criteria was developed, Spirit generated a randomly selected list of facilities to be inspected by participating operators. If a facility was not available for inspection, Spirit randomly chose a replacement facility that met the original criteria for that operator. Reasons for assigning a designating a site as unavailable included: depressurized, shut-in, P&A, divested sites, sites operating with instrument air, sites with landowner access restrictions, or incorrectly categorized sites.

4.3.2 Completeness and Consistency Review

All data collected by operators was compiled and blinded by Spirit Environmental before electronic submission to the Division. The data also went through a completeness and consistency check performed by Spirit, where operators were consulted to complete missing

data fields and to better account for information provided, thereby improving field data reporting consistency between operators. For transparency, industry provided the compiled field data in both uncorrected and corrected spreadsheets that were made available to all stakeholders in the PCTF.

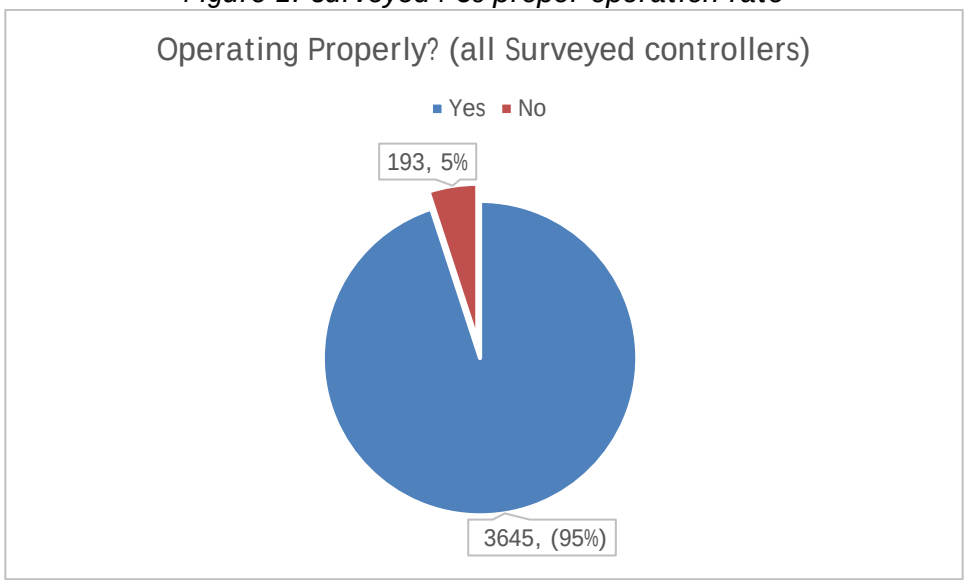
4.4 PCTF Study Data

The following sections contain summaries of key data collected during the PCTF field study. A full spreadsheet with all data collected in the program is available to stakeholders for analysis through the Division.

4.4.1 Oil and Gas Production Facility Data

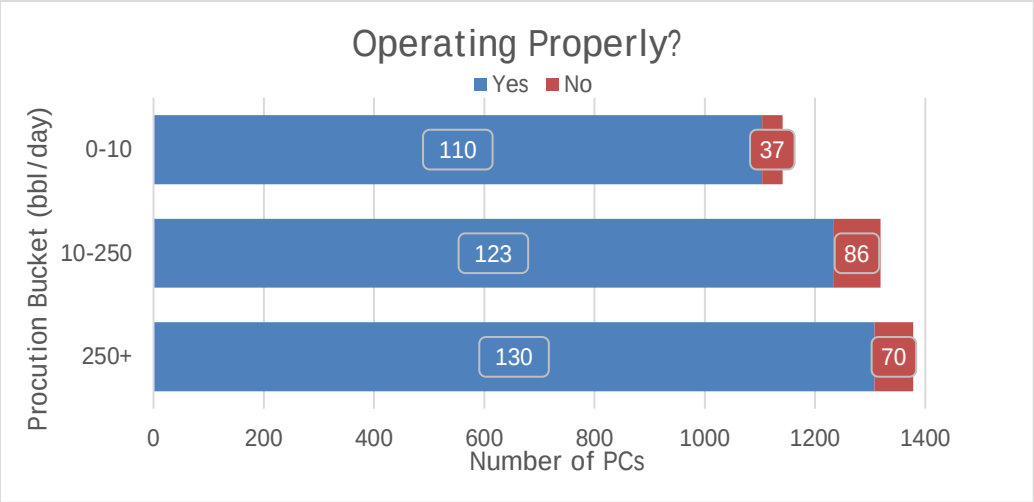
The study resulted in data points based on inspections for over 3800 PCs in the DJ Basin. Of the PCs observed, approximately 5% were observed to be improperly operating.

Figure 1. Surveyed PCs proper operation rate



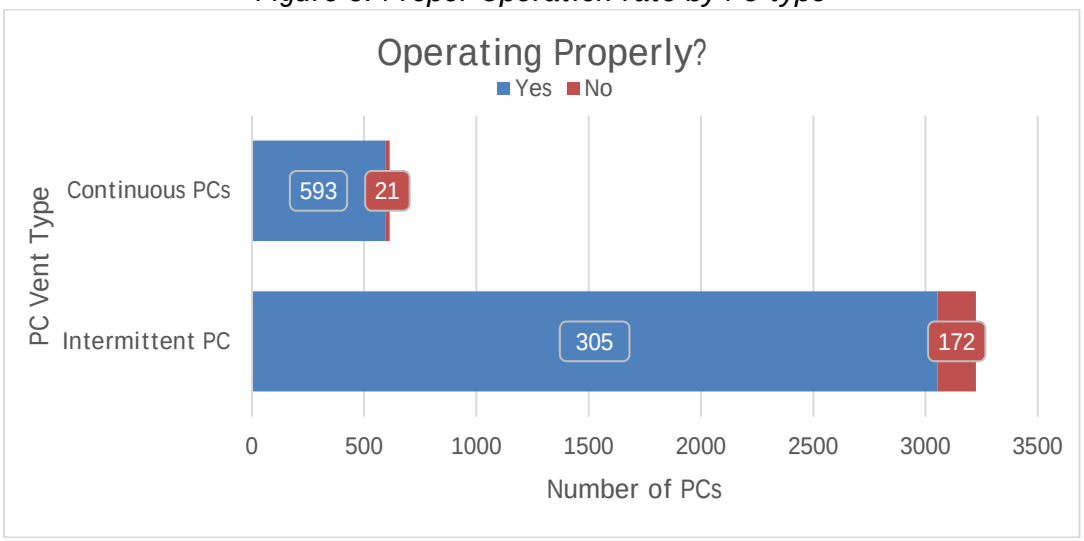
This data was also broken down by the three predetermined inventory production buckets. In the 0-10 bbl/day production bucket, 3.2% of all PCs were improperly operating. In the 10-250 and 250+ bbl/day buckets, 6.5 and 5.1% of PCS respectively were found to be improperly operating.

Figure 2. Proper Operation rate by inventory production bucket



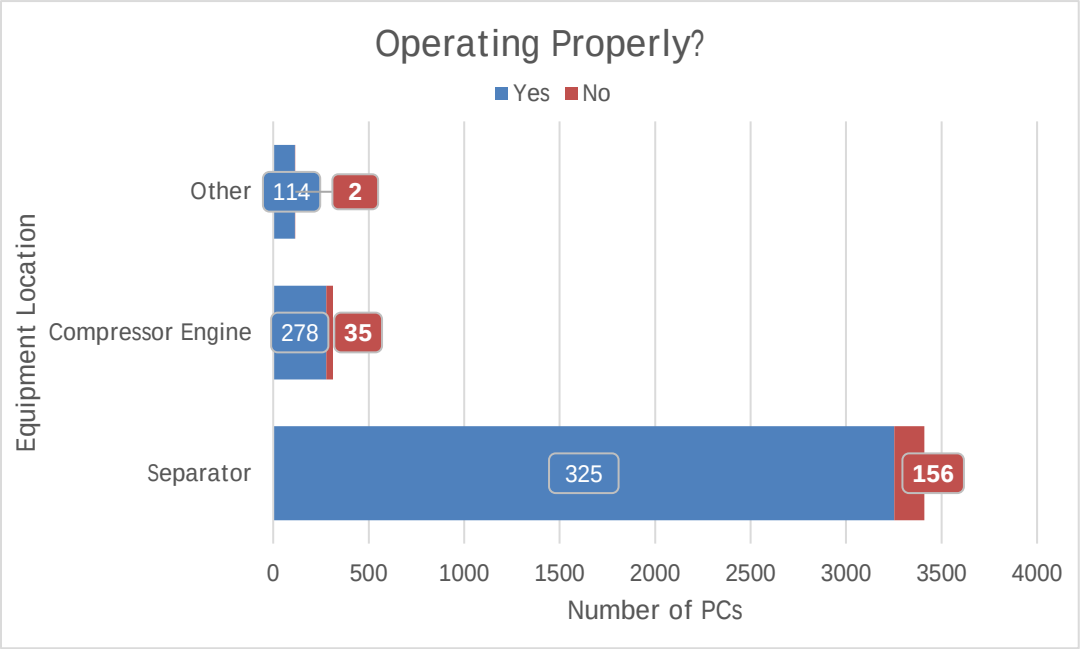
Breaking down the data by PC type (continuous vs. Intermittent) is also a useful way to look at the data. Continuous PCs were found to have an improper operation rate of 3.5% and intermittent controllers had a rate of 5.6%.

Figure 3. Proper Operation rate by PC type



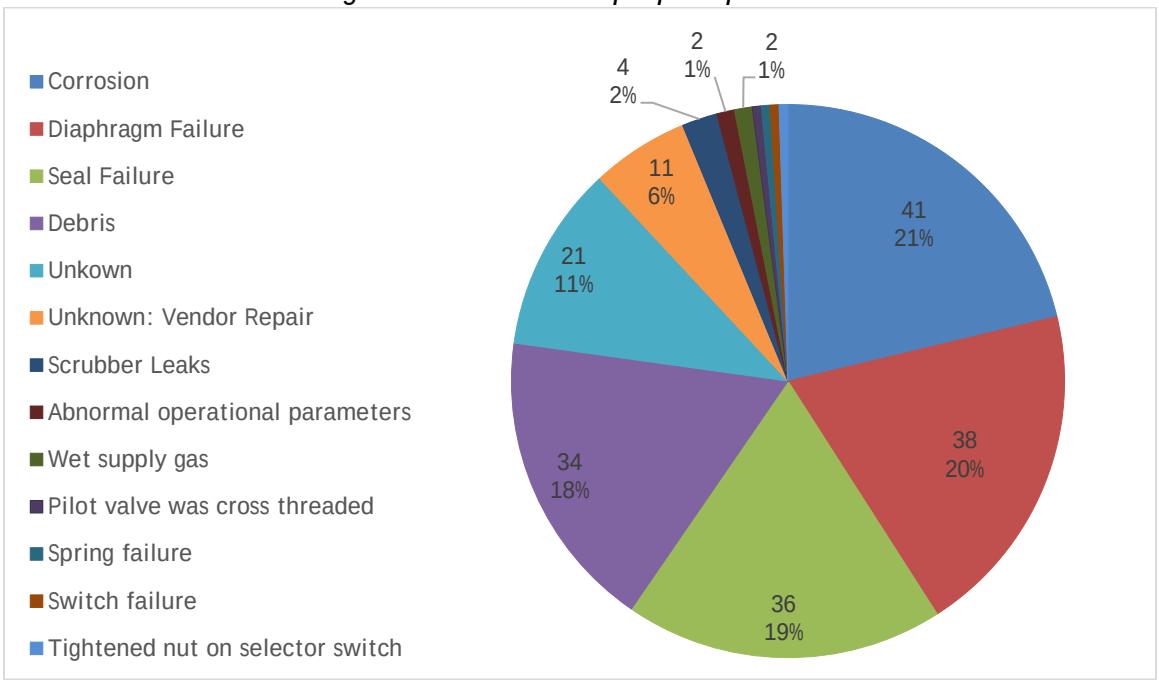
Operators tracked the facility equipment associated with each PC in the study. The majority of PCs are in-service on separation vessels. About 5% of PCs on separators were found to be improperly operating. The second most common PC equipment location was on the compressor engines. PCs on compressor engines had a relatively high improper rate of 12.3%. PCs found on all other equipment had a 2% improper operation rate.

Figure 4. Proper Operation rate by equipment location



The study revealed that there were a myriad of reasons that a PC might operate in an improper manner. The four largest causes were attributed to corrosion, diaphragm failure, seal failure, and debris blocking the internal mechanism from reseating.

Figure 5. Causes of improper operation

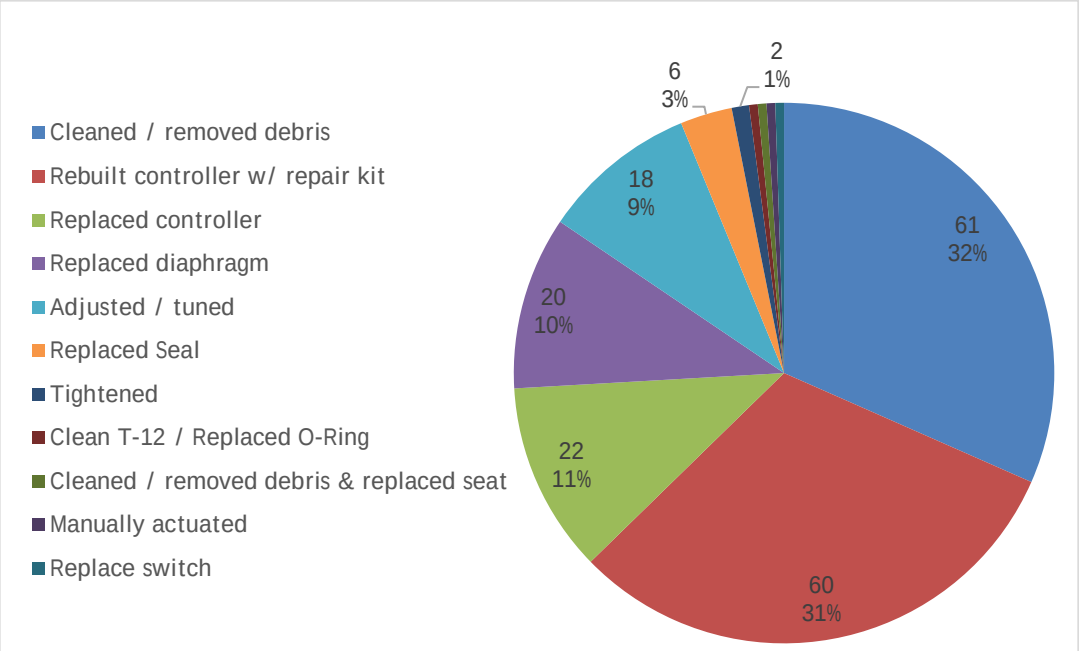


Operators made attempts to return all PCs to proper operation at the time of inspection if possible. Fifty (26%) of the 193 improperly operating PCs were repaired immediately. Ninety-

two PCs that needed repair were done on the same day of the inspection. 101 of the repairs were made at least a day later, with an average lag time of 4 days later.

Some repairs required a shut down or replacement of the PC. Those types of repairs take longer to complete and may have to be scheduled for repair soon thereafter or during the next planned shutdown of the facility. The majority of repairs were simply cleaning the PC and/or removing debris. Another common repair was to rebuild the PC with spare parts provided in a manufacturer repair kit.

Figure 6. PC repair actions



4.4.2 Midstream Data

As discussed previously, only two natural gas compressor stations of the 50 operated by participating companies use natural gas-driven PCs and were surveyed by the participating operator. All other natural gas compressor stations in the NAA owned by these participating operators utilized air-driven controllers and so therefore were not part of this study. The inspections of the two subject natural gas compressor stations occurred over two days in late August and early September. A total of 23 PCs were inspected. Four (4) models of PCs were documented. None of the surveyed PCs were found to be operating improperly. The PCs were used to monitor and control liquid levels and pressure.

4.5 PCTF Study Findings and Conclusions

The key findings and conclusions from the PCTF study are summarized below in narrative form. Additional findings are provided in the industry surveys of PC inspection costs and effectiveness, and use of no-bleed PCs, provided in Section 5.

4.5.1 Key Findings

PC Survey

- The most common manufacturers of PCs surveyed for this study were Kimray (43%), Wellmark (36%), and Fisher (15%).

- The most common models of PCs surveyed for this study were Wellmark 7400 Snaptrol (32%), Kimray T-12 (21%), Fisher 4660 (14%), Kimray 230 SGT (7%), Murphy LS200N (3%), and Norriseal 1001A (2%).
- Intermittent PCs comprise 84% and low bleed, continuous PCs comprise 16% of the 3838 PCs surveyed for this study.
- For equipment location, the PCs surveyed were found as follows:
    - 89% on separators
    - 8% on compressor engines
    - 1.4% on liquid knockouts
    - <1% on various equipment

PC Improper Operation

- The rate of PC improper operation varied:
    - by facility production:
        - Ranging from 5.1% for greater than 250 bbl/day, to 6.5% for 10-250 bbl/day, and 3.2% for 0-10 bbl/day.
    - by controller type:
        - 4.3% for pilot PCs and 8.0% for integrated PCs.
    - by controller vent type:
        - 5.3% for intermittent PCs and 3.4% for continuous PCs.
    - by controller enclosure:
        - 3.1% for enclosed PCs and 7.9% for non-enclosed PCs
    - by equipment location:
        - 4.9% for separators, 11% for compressor engines, 0% for liquid knockouts, and varying percentages for those few PCs that serviced various types of equipment.
- Overall, the observed rate of improper operation for all surveyed PCs was 5%.
- Actuations of PCs were observed only for 33% of the PCs surveyed.
- PC emissions were observed at the following locations and frequencies:
    - Vent port – 79%
    - Body – 20%
    - Vent port and body – 1%
- The following frequencies of common indicators of PC improper operations were reported.
    - 86% - Continuous bleed from vent port of intermittent PC
    - 11% - More venting than normal from continuous PC based on inspector's judgement
    - 1% - Continuous bleed from vent port of intermittent PC and PC was making unusual sound

Causes of PC Improper Operation

- The following frequencies of common causes of PC improper operations were reported:
    - Corrosion – 21%
    - Diaphragm failure - 20%
    - Seal failure – 19%
    - Debris – 18%
    - Other: Unknown - - 11%
    - Other: Vendor repair – 6%

- Other: Scrubber leaks – 2%
- Abnormal operations parameters – 1%
- Other: Wet supply gas – 1%
- Various - <1%

PC Repairs

- The following frequencies of common types of repairs of PCs that were not operating properly were reported:
  - Cleaned/removed debris – 32%
  - Rebuilt PC – 31%
  - Replaced PC – 11%
  - Replaced diaphragm – 10%
  - Adjusted/tuned PC – 9%
  - Replaced seal – 3%
  - Tightened – 1%
  - Various - <1%
- Double block and bleed was performed for 36% of the PC repairs.
- Equipment shutdown was performed for 37% of the PC repairs. Shutdown of a well was performed for 24% of the repairs.
- The time to make a PC repair varied by the type of repair, yet the average time for all types of repairs was less than 30 minutes.

4.5.2 Conclusions

This PCTF study represents the largest sample set of PC inspections in the nation to date, with 3838 PCs surveyed during the facility inspections conducted during the spring and summer of 2018. The 5% rate of improper PC operation found in the 3838 PCs inspected for this study based on emissions observed using an OGI camera demonstrates that typically (~95% of the time) PCs sampled in this study were found to be operating properly.

This study also demonstrated that an OGI camera can identify improperly operating natural gas-driven PCs. Detection of improper operation of an intermittent PC is largely determined by the observation of continuous emissions between actuations. Given that 84% of the PCs surveyed consist of intermittent PCs, the use of an IR camera is particularly effective in identifying excess emissions from intermittent PCs. Discerning improper operation of a low bleed continuous PC is less straightforward and is subject to the experience and judgement of the inspector in discerning excess emissions from improper operation.

Additionally, where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven PCs to the inspections adds minimal incremental inspection costs. Repairs of improperly operating PCs are readily made by cleaning the PC of corrosion and debris, replacing broken parts and adjusting/tuning the PC and the supply gas pressure.

4.6 Separate EPA/CDPHE Study on PCs in Denver-Julesburg Basin

4.6.1 Overview

Over a similar time period as the PCTF inspection study, EPA and CDPHE conducted a parallel study on natural-gas actuated PC emissions in the DJ Basin. The results of this parallel study were published in early 2020 in the Journal of the Air and Waste Management Association in a

paper by Stovern et al. entitled "Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging."

Briefly, the Stovern et al. paper focused on a smaller sample size of PCs (500 controllers servicing 102 wells at 31 facilities operated by seven different companies) and included counts and observations of intermittent and continuous low bleed PCs. The PCs were inspected with OGI, and the emission rate from a small subset of the inspected PCs was quantified using high-volume sampling. Although measurements required to quantify actuation volumes were outside the scope of this study, the OGI camera survey provided limited information on the frequency of occurrence for actuations. This study was performed in the spring 2018 over a period of 10 field days.

4.6.2 Study Design

Stovern et al identify two objectives for this study: 1) gather information on the types and uses of PCs employed by randomly selecting facilities representative of the overall basin and 2) investigate the use of an expeditious and less invasive PC emissions survey approach based on optical gas imaging (OGI) camera that could help inform PC operational and maintenance states.

An important aspect of the PC survey was to confirm that the exhaust port of the PC was visible during the OGI inspection so that any continuous emission through the PC pilot could be assessed. A FLIR GF320 camera was utilized to monitor emission profiles of PC for this study, which has a normal or "auto" imaging mode and a high sensitivity mode (HSM), where onboard differential image processing can enhance an operator's ability to identify lower emission rates approaching 0.5 scf/hr natural gas or even lower under ideal conditions. Comparisons between the auto and high sensitivity mode imaging were made in monitoring PC emissions to explore their differences in detection capability as a rough indicator of emission level. An extended OGI observation time of 60 sec for each PC was used to enhance detection capability, to look for anomalous temporal emission profiles indicative of potential malfunctions, and to document short time duration PC actuation events as activity data where possible. If an actuation event or unusual temporal profile was observed, the observation time was increased to 120 seconds to bound actuation frequency and further diagnose potential malfunction issues.

The well production facilities ranged in production and complexity from small facilities with minimal equipment (such as one wellhead, one separator, and one or two tanks) to larger facilities with multiple wellheads, separators including second and third stage separation vessels, complex tank batteries with vapor capture systems, multiple control devices, gas lift compressor engines, and vapor recovery units. Of the 31 well production facilities selected, the wells were 50.0% vertical, 33.3% horizontal and 16.7% directional. This distribution is consistent with the overall well type distribution for the 24,220 actively producing wells in the basin of 42.1% vertical, 38.9% horizontal, and 19% directional.

Information gathered for each pneumatic system (PS)/PC included: process working status (in use or shut-in), PS/PC identification (make/model), motive gas type, PC configuration and operational mode, process function (control, safety, or both), process equipment application (separator, combustor, compressor, etc.), and sensed process variables (e.g. temperature, pressure, and liquid level). PC-specific information such as model configuration variables, retrofit status, installation date, actuator components, and supply line pressures were also documented to the extent possible.

4.6.3 Findings

Stovern et al. (2020) reported the following findings for the EPA/CDPHE PC study:

Survey of PCs at Facilities

- A total of 615 process control pneumatic systems (PSs) were found at the 31 facilities with 59 of these being of the electronic variety that does not use gas-emitting PC pilots.
- Of the 556 PSs with gas-emitting PC pilots, 38 of these were instrument air-driven. Natural gas was found to be the exclusive motive gas type at 30 of the 31 facilities surveyed. One facility used instrument air on 38 out of 52 PCs with the natural gas models at that facility primarily serving back pressure regulation functions. Operations of instrument air-driven PCs were not further studied by Stovern et al.
- Of the 518 natural gas-driven PCs, 18 (3.5%) of these comprised a "no-vent" design where the natural gas emitted from the pilot is fully captured. These integrated pilot-actuator PCs have the potential to emit natural gas only by diaphragm or connector leaks that would be classified as equipment leaks and therefore were not further studied by Stovern et al.
- A total of 500 natural gas emitting PCs were found at 31 facilities servicing 102 wells (average of 4.9 PCs/well).
- A total of 453 of the 500 natural gas-driven PCs were found to be in service (i.e. not shut-in or depressurized); this number represents the primary count of the PCs assessed for proper operation. Of this total, 377 (83%) of the PCs were intermittent and 76 (17%) were continuous.
- A total of 447 PCs were monitored with an OGI camera for emissions as six intermittent PCs were not surveyed due to wind speeds exceeding the 9 m/s method limit.

PCs with Maintenance Issues

- Of the 371 intermittent PCs monitored, 42 (11.3%) were observed with continuous emissions and 22 were observed with actuations (5.9%). This 11.3% represent intermittent PCs experiencing some level of maintenance issue. The severity of the maintenance issues is unknown without emission rate measurement. The authors note that due to the fact that some controllers were observed in the less sensitive "auto" mode of the OGI camera (see below), the true level of maintenance issues among the intermittent PCs they surveyed was probably higher. They estimate that the true frequency of maintenance issues in this population was 11.6 to 13.6%.
- Of the 76 continuous PCs, 28 (37%) were found to have continuous emissions. Yet, it is unknown what portion of these emitting continuous PCs reflect a potential maintenance issue, since they may have been operating as designed. As described below, at least one continuous PC had measured emissions above the State regulatory standard (6 scf/hr).
- It was critical to determine the design type of the PC (intermittent or continuous) during the on-site survey because the type assignment played a role in the assessment of potential maintenance issue conditions.

PC Emission Measurements

- Emission measurements were conducted on 18 total PCs (14 intermittent PCs and 4 continuous PCs) with continuous emissions detected during the OGI camera survey. In general, the measurements were conducted on PCs that appeared to have the most significant gas signature.
- 36.8% of continuous low-bleed PCs (28 controllers) had continuous emissions that were observable with the OGI camera. Emissions were measured from four of these continuous PCs with a high-flow sampler. Measured emission rates ranged from 0.7 to 9.9 scf/hr with an average ER of 4.2 scf/hr. Three of the continuous PCs exhibited emission rates above 1.39 scf/hr; one was considered to be malfunctioning as it was emitting in excess of the 6 scf/hr State regulatory limit. Two of the measured continuous PCs had measured emissions above 1.39 scf/hr and below 6 scf/hr.
- Snapshot measurements were conducted on 14 intermittent PCs that were observed using an OGI camera to have continuous emissions (not including actuations). Three of the measurements were near or below the estimated method detection limit of the technique at (0.1 scf/hr). Observed emissions rates ranged from 0.1 up to 31.3 scf/hr (mean = 2.8 scf/hr).
- In two cases, the intermittent PCs were cycling between actuations with the OGI camera video showing steadily increasing emissions prior to actuating, followed by a sharp drop in emissions below the OGI detection threshold. These significantly variable (heavy ramping and temporally sustained) emissions were categorized as maintenance issues for these snap-acting intermittent PCs.
- The highest measured intermittent PC emission rate (31.3 scf/hr) was caused by a process issue. This PC managed back pressure on the low-pressure side of a high-low pressure separator. A suspected process control issue was identified where a bleeding valve upstream of the low-pressure vessel caused the PC to continuously actuate because the low-pressure vessel was continually exceeding the pressure set point of the PC. In this situation, the intermittent PC itself was not malfunctioning.

Auto vs. High Sensitivity Mode

- The initial protocol for the OGI camera included evaluating only auto imaging mode (the less-sensitive mode for the OGI camera used in the study) at 85 PCs that serviced 26 wells at 9 facilities. Later, both high sensitivity mode (HSM) imaging and auto mode (HSM/auto) were used for most of the PC assessments (N= 362 PCs, 22 facilities, and 76 wells).
- The continuous PC emission detection rates for the auto-only versus the HSM/auto subgroups differed significantly. For the auto-only mode subgroup, 1 of 16 continuous PC (6.3%) and 1 of the 69 intermittent PCs (1.4%) exhibited continuous emissions. For the HSM/auto subgroup, 27 of 60 continuous PCs (45%) and 41 of 302 intermittent PCs (13.6%) exhibited continuous emissions.
- OGI camera imaging modes were observed to have a significant effect on emission detectability with HSM mode detection rates being approximately 2 times higher compared to auto mode.

Actuations

- A total of 33 actuation events (AEs) were observed from 22 different PCs in the 447 monitored for this study. Based on observed emissions, only a few percent of intermittent PCs in this basin appear to have actuation frequencies greater than 1/min, with many PCs (e.g. safety category) very infrequently actuating.
- AEs were observed at only 9 of 31 facilities with the top two highest oil producing facilities accounting for 54.5% (12 of 22) of the PCs with actuations. The highest producing facilities had five separate intermittent PCs exhibiting AEs with a total of 13 observed, whereas the second-highest producing facilities had 7 PCs and 8 total AEs. There were a total of six PCs surveyed that had multiple actuations observed during the OGI survey (extended up to 2 min). Three of those PCs were located at the highest producing facility, and one PC with multiple actuations was located at the second, fifth, and sixteenth highest producers.
- The OGI camera survey indicates an expected relationship between normalized oil production and observed actuations. At a high producing facility, the same PC and process will require more actuations than at a lower producing facility. However, PCs with a maintenance issue do not show the same correlation with facility production.
- Estimated actuation volumes ranged from 0.005 to 0.185 scf per actuation event, which indicates that potential emissions from continuous emissions due to a maintenance issue may often be the dominant factor in overall emission rates for infrequently actuating PC populations. At lower producing facilities, the continuous emission component of emissions for intermittent PCs with maintenance issues becomes a more significant factor affecting average PC emissions rates for lower producing facilities.

4.6.4 Conclusions

- Although the findings of this study are representative of the DJ Basin, they are not intended to be representative of PC operating characteristics at a national level and therefore should be used with caution at that scale.
- The observed PCs per well are reasonably consistent with the 2018 data from EPA's Greenhouse Gas Reporting program for the Denver Basin with an average of 3.1 PCs per well and are significantly higher than the national average of 1.6 PCs per well (U.S. EPA 2019c).
- 83% of the PCs surveyed for this study were intermittent PCs, which is consistent with the 91% reported by Allen et al. (2014) for PCs in the Rocky Mountain region.
- The use of an OG camera to profile PC emissions was found to be a helpful approach to inform PC maintenance issues.
- Observing continuous emissions from a PC with an OGI camera on a snap-acting intermittent PC is indicative of emissions beyond the designed shut-off rate and is indicative of a maintenance issue.
- The identification of actuation events for continuous PCs and throttling process control applications was more challenging than those for intermittent PCs in snap acting applications.
- For a low bleed CPC, continuous emissions observed with an OGI camera was not informative to detect a potential maintenance issue unless in the OGI operator's judgment the emission appeared abnormally large compared to typical operation.
- 11.3% of intermittent PCs surveyed were directly observed with OGI to have continuous emissions. Due to an issue with the use of the OGI camera at some sites, this figure probably represents an underestimate of the frequency of continuous

emissions from these controllers. Stovern et al. estimate that the true frequency of continuous emissions in this population was 11.6% to 13.6%. These observations may reflect maintenance issues since these emissions were likely above the designed seepage rate of these intermittent PCs.

- As opposed to intermittent PCs, it is unknown what portion of continuous PCs were experiencing a potential maintenance issue, without measurement. One of the four continuous PCs measured was classified as malfunctioning with a measured emission rate of 9.9 scf/hr, above the 6.0 scf/hr State regulatory limit.
- The type of imaging mode (i.e. auto vs high sensitivity) utilized during the OGI camera survey was observed to significantly affect the detection rate of continuous emissions. The detection rate of continuous emissions using high sensitivity mode was 1.6 and 2.1 times higher than when using auto-mode imaging for intermittent PCs and continuous PCs, respectively. The difference between observation capabilities in high sensitivity vs. auto modes could be used in an inspection approach to approximately separate the PC populations (e.g. minor maintenance issues and significant malfunctions), so that repairs can be prioritized to minimize unnecessary emissions.
- PC actuations from process control-based PCs correlate with facility production. Facilities with lower production will have lower actuation emissions rates among its PC population and continuous emissions from PCs with maintenance issues will therefore be the controlling factor for the average operational PC emission rate. For higher producing facilities that cause PCs to actuate much more frequently, actuations will be a significant contributor to the overall average operational PC emission rate

4.7 Comparison of PCTF Study and EPA/CDPHE Study Findings and Conclusions

The following statements offer key comparisons between the findings and conclusions for the PCTF Study and EPA/CDPHE Study.

4.7.1 Findings

- Both field inspections of PCs were conducted in the DJ Basin during the spring/summer of 2018.
- Both studies focused on identifying improper operation (aka maintenance issues) of PCs using an OGI camera by trained and experienced personnel during facility inspections.
- Facility selection for each of these studies was done randomly for the operators participating in each study.
- Both studies found that the majority of natural gas-driven PCs observed consisted of intermittent PCs (PCTF – 84% vs EPA – 83%)
- The EPA/CDPHE study estimated that 11-14% of the intermittent PCs inspected were not operating properly, while the PCTF study found 5.3% of intermittent PCs were not operating properly.
- The EPA/CDPHE study found that using a camera in high sensitivity mode was more effective in finding smaller emissions from intermittent PCs.
- The EPA/CDPHE study did not evaluate whether continuous PCs were operating properly based on emissions observed with an OGI camera. The PCTF study found 3.4% of continuous PCs were not operating properly. Emissions measurements were performed by EPA/CDPHE on four continuous PCs, finding one of these PCs to have emissions in excess of the 6 scf/hr regulatory limit.
- The EPA/CDPHE study measured 14 intermittent PCs that were observed using an OGI camera to have continuous emissions. Observed emissions rates ranged from 0.1 up to

31.3 scf/hr. The elevated reading of 31.3 scf/hr was attributed to a process issue and not PC improper operation.

A significant contrast between the PCTF study and the EPA/CDPHE study is related to how integrated pilot-actuator devices were classified. Simpson (2014)[6] defines an *integral* PC as a PC that is built into an end device (i.e. valve) and does not require an external source of gas, nor does it release actuation gas to the atmosphere. Rather, it releases actuation gas into the process downstream. Similarly, Simpson defines a *local* controller is also defined as one built into the end device, but it exhausts gas to the atmosphere to move the process valve toward closed. In contrast, remote pilot controllers are PCs that are not integrated into the end device.

Note that "integral" controllers, as defined by Simpson, would be considered "Self-contained PCs" under Regulation 7. Additionally, note that Stovern et al. refer to both integral and local PCs as "integrated" PCs, and they use the term "no-vent" for PCs that Simpson defines as "integral" – those that release gas into a process downstream. The discussion below uses Simpson's terminology.

- The EPA/CDPHE study did not include integral devices in their assessment of PCs. EPA stated in its report that integral PCs have the potential to emit natural gas only by diaphragm or connector leaks and that any such leakage should be classified as an LDAR component leak, rather than as a PC that is operating improperly.
- For the PCTF study, integral devices were classified as a type of PC. 59 (8%) of the 740 integral PCs surveyed were determined to be not operating properly, compared to 134 (4.3%) of the 3,098 pilot PCs surveyed. Presumably, these devices were leaking from the diaphragm or connector, as described above.
- Since the PCTF study included integral controllers, while the EPA/CDPHE study did not, and integral controllers were operating improperly at a relatively *high* rate in the PCTF study, this suggests that the inclusion of integral controllers in the PCTF study skewed the improper operation rate slightly higher.
- Regardless if classified as a PC or not, integral controllers are included as a component in a LDAR program for equipment leaks and will therefore be assessed for leakage and repaired as needed to ensure proper operation.

4.7.2 Conclusions

- The Stovern et al. study found that using the high sensitivity mode of the OGI camera resulted in a nearly 2 times higher emission detectability compared to the auto mode. This might explain why Stovern et al found more than twice the percentage of intermittent PCs that were not operating properly compared to the PCTF study (11-14% vs 5%).
- The Stovern et al. study used a set observation time of 60-120 seconds for every PC/PS. The PCTF study did not have this requirement and if the OGI camera operator did not detect emissions within a few seconds, they would move on with the inspection. These varying approaches were utilized because each study had a different objective. The PCTF study set out, in part, to determine the effectiveness of the find and fix program, so inspection protocols were adapted to current industry practices.

[6] Simpson (2014), *Pneumatic Controllers in Upstream Oil and Gas*. https://pubs.spe.org/en/ogf/ogf-article-detail/?art=238.

The longer observation time used by Stovern et al. may also be a contributing factor to the discrepancy between the proper operation rates.

- Both studies concluded that using an OGI camera to profile PC emissions was an effective method to inform possible improper operation of intermittent PCs. However, the use of this method for identifying improper operation of continuous PCs is more challenging, except when the emissions appear to be abnormally large compared to normal operation.

5 Industry Surveys

In order to achieve the goals established by the PCTF for reassessment of the Find and Fix program, additional information needed to be gathered on the effectiveness and costs related to inspection of PCs under the find and fix program and to better understand the use of self-contained and no bleed PCs. A series of questions were developed and incorporated into survey questionnaires that operators were requested to complete. A total of three surveys were developed:

1. The effectiveness and costs of PC inspection techniques
2. The effectiveness and costs of PC repairs
3. The use of self-contained and no bleed PCs.

The surveys were completed in confidence, and then blinded and compiled by API and COGA to address industry anti-trust concerns before being shared with the PCTF in presentations that summarized the survey responses. The first two surveys were to be completed by the nine operators participating in the PCTF study within the ozone NAA. The third survey was distributed to COGA and API members with oil and gas production operations in the state. As described below, the second survey was developed but not completed.

5.1 Effectiveness and Costs of Inspection Techniques (NAA only)

Highlights from the results of survey questions provided to the nine operators participating in the PCTF study on the effectiveness and costs of PC inspection techniques are provided in the following bullets.

- The majority of operators use a combination of employees and contractors to conduct PC inspections. Some operators use employees only.
- The majority of operators use the same party for both LDAR and PC inspections.
- Operators typically conduct LDAR and PC inspections during the same facility visit.
- Operators generally replied that it can be helpful to know in advance whether the PC is an intermittent or low bleed in order to understand if emissions are expected between actuations (low bleed) or not (intermittent).
- Operators also indicated that understanding the process the PC is controlling is beneficial in making a determination whether a PC is operating properly or not.
- For intermittent PCs, operators typically look for continuous emissions between actuations. For continuous bleed PCs, operators typically look for emissions that appear abnormal for that type and application of controller.
- Operators found using OGI camera inspections along with AVO indicators was effective, although OGI cameras are more effective at finding smaller leaks. Soapy water may be used to further pinpoint a leak location.

NMED Exhibit 93

- AVO indicators such as the presence of liquids at or around/below the vent and whether dependent processes are operating properly can be useful to determine whether a PC is operating properly or not.
- Safety limitations in the use of OGI cameras are largely driven by whether the OGI camera is intrinsically safe or not. An intrinsically safe camera does not pose a potential ignition source and can be used in Class 1 Division 2 areas as defined by OSHA in CFR 1926.449. OGI cameras that are not intrinsically safe may require a hot work permit to be allowed on site at a facility or the camera operator may have to maintain a minimum safe distance from the equipment being observed.
- Responses on the average time to inspect a PC varied depending on the experience of the inspector and included various caveats including weather conditions. The inspection time varies and is dependent on the type of PC and if emissions are observed. If no emissions are observed, then only a few to several seconds is generally sufficient to determine that the controller is operating properly. If emissions are observed, then the time to make this determination is dependent on whether the controller is actuating or not, the type of controller, and the characteristics of emissions observed. It could take up to several minutes to make this determination.
- The costs to conduct PC inspections are variable and likely highly dependent on the size and makeup of facilities of operators and internal programs and processes. Some operators indicated that the incremental equipment costs are not significant since this equipment is required for LDAR inspections. Other operators estimated that incremental annual equipment costs for PC inspections represent a small percent of LDAR related equipment costs. Ultimately, incremental annual equipment costs for PC inspections are dependent on the number of PC inspections performed.

5.2 Effectiveness and Costs of Repairs (NAA only)

Due to the need to focus on regulatory proposals to be considered for the December 2019 AQCC rulemaking, and the willingness of operators to expand the PC "find and fix program" statewide, it was not necessary to complete the planned repair cost survey.

Separately, the PCTF study results indicated that those PCs found to be improperly operating were successfully repaired and the majority of repairs were completed either immediately, the same day of the inspection, or within a few days of the inspection.

Operators seek to repair PCs in order to return them to proper operation since it is in their interest to maintain and optimize production operations. The cost of repairs is considered a normal operation and maintenance cost. The ability to more readily identify PCs that are not operating properly using an OGI camera allows earlier detection of those PCs needing repair that would otherwise eventually fail to control their intended process function and need subsequent repair.

The repair costs range in regard to the extent of the repair. These repairs can range from cleaning the PC of debris or residue that collects over time, replacing worn parts, or replacing the entire controller. Operators stock spare parts, repair kits or extra PCs that are then used to repair or replace the defective PC as a means to promptly make a repair.

The costs of repairs was not considered an impediment to supporting expansion of the PC "find and fix" program from the NAA to statewide during the AQCC December 2019 rulemaking.

5.3 Use of Self-contained and No-Bleed PCs (State-wide survey)

COGA developed and distributed a survey to better understand the use of self-contained and no-bleed PCs. The survey utilized the following definitions in order to establish a common understanding in completing the questions.

- Instrument air-driven PC: Any PC that is uses compressed air as the valve's actuating gas. Known as "no-bleed" under CO Regulation 7.
- Natural gas-driven PC with exhaust routed to process/sales: Any PC that directs gas to a process or sales line instead of to the atmosphere. Known as "self-contained" under CO Regulation 7.
- Natural gas-driven PC with exhaust routed to combustion control: Any PC that directs gas to a combustion control device instead of to the atmosphere.
- Non-pneumatic mechanical controllers: Any controller that uses mechanical force (not a pressurized gas) to trigger actuation.
- Non-pneumatic electric controllers: Any controller that uses an electrical signal (not a pressurized gas) and motor to trigger actuation.

The survey results are summarized below:

- 12 Operator Responses for production facilities
  - 3 Operators in Piceance, 9 in DJ.
    - >5,400 Total Production Facilities: ~4,200 DJ NAA, ~100 DJ AA & ~1,200 Piceance
    - >22,400 total wells: ~15,700 DJ NAA, ~500 DJ AA & ~6,200 Piceance
    - Percentage of facilities where on-site electrical grid power is used:
      - 19% DJ NAA
      - 63% DJ AA
      - 4% Piceance
- Operator Responses for compressor stations
  - 4 Operators in Piceance, 1 in DJ responded.
    - 16 Compressors stations in DJ NAA, 38 in Piceance
    - Percentage of compressor stations where on-site electrical grid power is used:
      - 100% in DJ NAA
      - 76% in Piceance
  - DJ NAA - 1 operator
    - 16 compressor stations
    - All use instrument air-driven PCs (11 new, 5 retrofitted)
  - DJ AA - No compressor station operator responded
  - Piceance Basin - 4 operators responded
    - 38 compressor stations
    - 9 new stations use instrument air-driven PCs
- Summary of Usage
  - The majority of PCs in use in Colorado are conventional natural gas-driven PCs
  - Most of the non-conventional controllers in use in the state are located
    - In the DJ NAA
    - At new facilities receiving production from horizontal wells
  - The most commonly used non-conventional controllers are air-driven PCs
  - Other non-conventional controller technologies usually only replace a fraction of the PCs at a site

- Consideration for Use
  - Safety
    - Instrument air-driven PCs
      - Some operators expressed concern with facilities using both instrument air-driven and natural gas-driven PCs: potential risk of flammable mixtures or explosion
      - One operator noted that fail-safe close valves need to be used so the site/well can shut-in in case of power loss or air compressor malfunction
    - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
      - The required additional piping/plumbing could significantly complicate work areas
      - There are backpressure issues with remote PCs preventing exhaust vapors from reaching process/sales or combustion control
      - Backpressure can also slow actuation and affect operation
    - Non-pneumatic mechanical controllers
      - Some operators indicated mechanical dumps are more prone to failure due to erosion.
      - One operator noted that mechanical dumps may not have emergency shut down ability.
    - Non-pneumatic electric controllers
      - It was noted electrical controllers may not have a fail-safe capability and do not return to a safe position when power is lost, unlike conventional natural gas-driven PCs. Electric fail safe close valves require programming.
      - Electrical classification determines safe location on site.
    - Overall
      - Non-conventional have a positive impact on safety by reducing the quantity of hydrocarbon vapors in the atmosphere at facilities.
  - Costs
    - Instrument air-driven PCs
      - New facilities: incremental capital cost of $70K - $140K (depending on production/number of wells)
        - Additional piping, air compressor, supporting infrastructure, grid power/generator.
        - Use of grid power is critical for most, generators also used by some.
        - Additional maintenance costs required for air compressor and a desiccant air dryer.
        - One operator reported reduced maintenance on instrument air-driven PCs themselves.
        - One operator mentioned a backup instrument gas may be required, increasing costs.
      - Existing facilities: incremental capital cost of $90K - $180K (depending on production/number of wells)

        - Several operators reported that, due to declining production, retrofits are not cost effective and have primarily been done under compliance order.
        - Loss of production for retrofit, in addition to reasons listed above.
        - Additional incremental cost is on top of the initial cost to run instrument gas line.
        - One operator reported the need to hydro vacuum instrument air lines before retrofitting
    - Natural gas-driven PC with exhaust routed to process/sales
        - Significant cost associated with design of a complex vapor capture system.
        - Cost associated with compression to safely and reliably get emissions into process lines.
        - Additional maintenance on vapor control system (VCS) lines.
    - Natural gas-driven PC with exhaust routed to combustion control
        - Cost associated with re-piping equipment. May be do-able for PCs in close proximity to control device, very high cost otherwise.
        - VCS: Additional maintenance on lines and may require updates to the VCS analysis.
        - Some compressor stations are not equipped with ECD: high cost for low reductions.
    - Non-pneumatic mechanical controllers
        - Some mechanical dumps usually have lower upfront cost but higher maintenance cost.
        - For retrofits, cost of new controllers when natural gas-driven controllers are already in use.
    - Non-pneumatic electrical controllers
        - One operator reported an incremental cost of $7K - $10K per well.
        - Controllers have a higher upfront cost and higher maintenance cost.
        - Several operators reported that retrofits are not cost effective.
- Technical
    - Instrument air-driven PC
        - Sufficient grid power availability (true for new and potential retrofits).
        - Very frequent maintenance on air compressors required to ensure reliability.
            - One operator noted liquid collection and freezing may require backup compressors.
        - Considerations for power loss:
            - Some operators do not have back up options and site shuts in.
            - One operator reported using natural gas powered back up air compressors.
            - One operator reported using pressurized air bottles.
    - Natural gas-driven PC with exhaust routed to process/sales

        - Low pressure and low volume gas needing compression to process/sales.
        - Concerns with vapor collection lines such as air intrusion through components, debris and/or condensate build up, freezing, and backpressure concerns.
        - Not all exhaust from natural gas-driven PCs can be captured.
    - Natural gas-driven PCs with exhaust routed to combustion control
        - Low pressure and low volume may make it difficult for gas to reach combustor.
        - One operator mentioned experience indicating back pressure which affects valve actuation and maintaining stable stream to the combustor.
    - Non-pneumatic mechanical controllers
        - Generally can only replace a specific type of PC: dump valves/liquid level.
        - Experience shows that mechanical controllers are not as precise or as reliable as natural gas-driven PCs for process control.
    - Non-pneumatic electric controllers
        - Need for reliable electrical power (e.g. solar with battery and generator/grid as backup).
        - There are no electric replacement options for some natural gas-driven PCs.
        - There are limitations on where those controllers can be located (e.g. not compressors).
        - Electric fail safe close valves requires programming knowledge.
- Land/Leasehold
    - Instrument air-driven PCs
        - Ability to bring grid power may be limited: landowner restrictions, BLM land & FS land with approval requirements, remote/mountainous locations.
        - Pad size needs to be sufficient to accommodate air compressor and additional infrastructure in an area that is safe for electrical equipment.
            - Especially challenging for existing facilities where land has already been reclaimed.
    - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
        - None identified
    - Non-pneumatic mechanical controllers
        - None identified
    - Non-pneumatic electric controllers
        - None identified
- Other
    - Instrument air-driven PCs
        - Pros:
            - Instrument air-driven PCs are a proven technology and usually use same/similar PCs.
            - Instrument air-driven PCs are not subject to the find and fix program.

        - Reg. 7 requires the use of no-bleed (instrument air-driven PCs) at facilities that use grid power.
    - Cons:
        - Grid power availability is utility dependent and can be very complex (permitting and approvals for new lines, proximity to power line does not mean availability).
        - Electric generators, if used, require permitting through APCD and have extra emissions.
        - Retrofits are not cost effective and primarily been done under compliance order.
- Natural gas-driven PC with exhaust routed to process/sales
    - Reliability (operation and maintenance very complex). Other options are more desirable.
    - Required by Reg. 7 once grid power is used on site and if technically and economically feasible.
    - Process/sales gas line occasional downtime may require redundancy.
    - Emissions associated with required additional compression.
- Natural gas-driven PC with exhaust routed to combustion control
    - Not considered as no-bleed or self-contained under Reg. 7 definitions.
    - Reliability is a major concern: other options are more desirable.
- Non-pneumatic mechanical controllers
    - None identified
- Non-pneumatic electric controllers
    - One operator reported less maintenance needed for such controllers.
    - Not a proven technology, cannot cover all functions usually covered by natural gas-driven PCs.
    - Use and maintenance requires staff with knowledge related to electrical systems.

- Survey Takeaways
    - Fail-safe options a concern for non-natural gas-driven technologies
    - Instrument air-driven PCs
        - Electrical grid power use is crucial, upfront cost is high
        - Proven technology, familiar make/model of PCs, less training
        - Safety and cost effectiveness concerns for retrofits
    - Natura gas-driven PCs with exhaust routed to process/sales/control
        - Operationally burdensome, reliability issues
        - Only feasible for a small subset of PCs
    - Mechanical controllers
        - Can only replace very specific functions (dump valves)
        - Cheaper upfront
        - Reliability and precision concerns
    - Electrical controllers
        - Require reliable power
        - Require trained staff
        - Only feasible for a small subset of controllers

According to the industry survey on zero-emitting PCs, the practice of capturing gas and routing emissions from a self-contained PC to emission control devices (ECD) is relatively uncommon and is highly dependent upon the distance between the vent port of the PC and the ECD. The PCTF study identified 50 PCs where PC vented emissions were routed to a nearby ECD. All of these PCs that were routed to an ECD were operating properly. The majority of these 50 PCs serviced a level control for a liquid condensate burner knockout pot which was located within a few feet of the ECD. In most cases, these knockout pots are drained by gravity or manually and are not controlled by a PC.

Routing to a process is relatively uncommon due to pressure differences between the vent port and the process. In general, the gas pressure from the vent port is too low to route to a facility process.

The category of no-bleed PCs can be considered a misnomer as all "pneumatic" controllers bleed or vent as part of their normal operation. The term "no-bleed" usually refers to those PCs that use instrument air as a motive force, rather than natural gas. In order to utilize instrument air, an air compressor, desiccants and filters, and pressure regulators are typically installed. The power to operate the air compressor is either provided using an electrical generator that is fueled by natural gas or diesel, or by a connection to an accessible utility line that provides adequate electrical power to the facility. The use of a natural gas or diesel fuel powered generator may result in a net emissions disbenefit in providing instrument air in lieu of natural gas for operating PCs. However, the net emissions benefit or disbenefit would vary on a case-by-case basis.

(Note that low power air compressors designed driving pneumatics using solar-battery systems for electricity,[7] and hybrid solar-gas powered electric compression systems,[8] are both available on the market in Canada.)

For new development of multi-well pads, operators pursue commitments from electric utilities to provide a connection and adequate power to a planned facility for electrification of equipment including air compressors for instrument air. A number of factors, many of which are beyond the operator's control, dictate whether the utility can provide an accessible connection and adequate power when the facility is being constructed. If the utility is not capable of meeting the requested commitment, then the operator will typically either rely on a natural gas or diesel-fired generator to power an air compressor, or utilize natural gas pressure as a conventional power source for PC operation.

5.4 Electrical Infrastructure for Oil and Gas Development

As part of the joint effort with the SHER work group, information was collected from API and COGA operators regarding the availability and planning for the use of electrical power from the grid or the use of natural gas or diesel oil powered generators to provide electrical power at oil and gas production facilities. A presentation was given during the July 12, 2019, SHER meeting which included the following talking points:

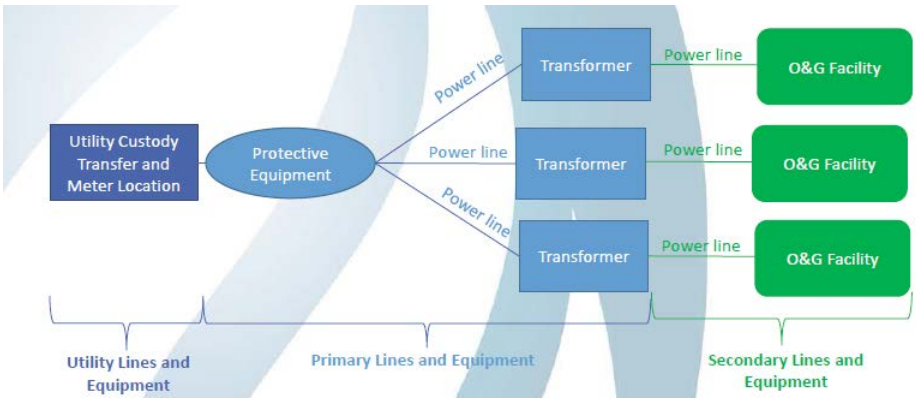
- Urban growth and development is an issue and impacts infrastructure availability

[7] See https://lcotechnologies.com/crossfire-compressor.html.
[8] See https://westgentech.com/.

NMED Exhibit 93

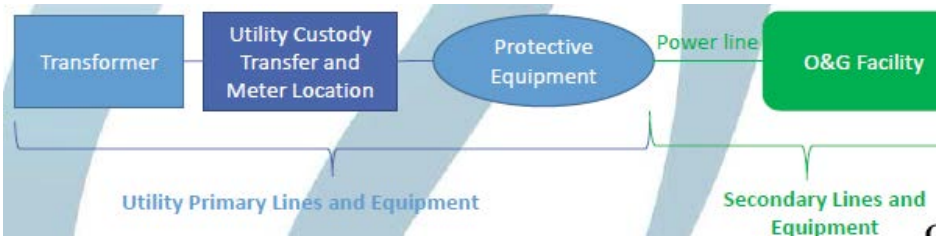
- Federal Lands and The National Environmental Policy Act (NEPA)/ The Federal Land Policy and Management Act (FLPMA) processes in remote areas are also obstacles to the use of electrical grid power
- Colorado has public utilities and cooperatives that provide power:
    - Each utility has different power drop timelines (1-3 years)
    - Each utility has different requirements on ownership and installation requirements between primary and secondary power lines and equipment
    - Primary lines are typically higher voltage lines while secondary lines are supplying power to a location (480-120 volts)
- Primary Meter – primary and secondary lines and equipment after custody transfer are installed, owned, operated and maintained by the company. In this case the O&G Facilities owner.

Figure 7. Primary Meter Ownership



- Secondary Meter –Only secondary lines and equipment after custody transfer are owned, operated and maintained by the O&G Facility owner. Everything upstream of custody transfer is installed, owned and operated by the utility.

Figure 8. Secondary Meter Ownership



- Primary Metering
    - The company has the staffing and technical ability to install, own, operate and maintain all the electrical equipment
    - Shorter lead times for power drop because less line and equipment needs to be installed by the utility
    - Higher costs for companies that only have a few O&G facilities in an area that requires power
    - Lower cost for companies with many O&G facilities in an area that requires power
    - Might not be an option because of right-of-way and surface user agreements

- Secondary Metering
    - Longer lead times for power drop to wait for utility to install primary lines and equipment
    - Costs may be higher depending on the location and amount of power needed
    - Some utilities require companies to perform primary metering so this might not be an option
- Challenges include:
    - Slowdowns from utility companies due to increased residential development
    - Changes in schedule from drilling permit issuance delays, operator agreement challenges with local governments, or right-of-way changes
    - Can be limited by proximity and capacity of grid power depending on utility
    - Power plant expansions dependent on air and other permitting
    - Cost may be prohibitive for operators in limited development areas
    - Small operators may not be able to effectively negotiate cost and availability
    - Contractual third party agreements may limit operator access
    - Timing often uncertain and power generation needed as backup

6 Good Engineering and Maintenance Practices

In 2017, the AQCC adopted Regulation 7 Part D, Section III.F.1. (formerly Section XVIII.F.1), requiring operators to operate and maintain PCs consistent with manufacturer's specifications, if available, or utilize good engineering and maintenance practices. The SBAP recognizes the need to more fully develop and document those practices, which include but are not necessarily limited to, ensuring proper operation. Data collected by the PCTF can be used to develop and document good engineering and maintenance practices.

Due to the unavailability of documentation from PC manufacturers, there are no widely agreed upon routine or preventive maintenance schedules. Individual operators have developed their own maintenance and operating plans in accordance with industry best practices and Regulation Number 7 requirements. While individual operators may have company-specific protocols for their PC program, all operators are in agreement on some key practices. The use of OGI cameras as the proper inspection tool to identify improperly operating PCs is universally accepted, at this time, by all industry members of the PCTF. However, identification of improper operation from a continuous low-bleed PC may require additional training/experience for the OGI camera operator. The findings above from the survey results on PC inspections also reflect key practices.

There are some barriers to developing prescriptive PC protocols because of the wide variability in how these devices function and the wide variety of designs and specific applications that are employed. More work needs to be done if developing prescriptive maintenance protocols is a goal of the AQCC.

6.1.1 The Environmental Partnership

API established The Environmental Partnership (TEP) in 2017 to "continuously improve the industry's environmental performance by taking action, learning about best practices and technologies, and fostering collaboration in order to responsibly develop our nation's essential natural gas and oil resources." TEP's initial focus is to further reduce the industry's air emissions in continuing to reduce methane, a greenhouse gas, and VOCs, which is one precursor to the formation of ground-level ozone. TEP hosted their first annual conference in

2018 as described in their 2019 Annual Report[9]. The conference focused on PCs and brought together producers, manufacturers, researchers, and regulators to discuss PC technology and how it might be improved.

In addition to periodically checking for proper operation of the controller through AVO and AIMM inspections, operators participating in this study concur with the "Pneumatic Controller Maintenance Work Practices" published by TEP as a wallet card for its members to provide to field personnel responsible for inspecting and maintaining PCs for proper operation of oil and gas production facilities. This wallet card is shown below:



7 Recommendations

The PCTF offers the following recommendations for consideration by the AQCC. Where there was not consensus on specific elements assigned to the PCTF, individual stakeholder positions are presented as such.

7.1 Effectiveness of current program (NAA only)

Pursuant to AQCC Reg 7 CTG rulemaking in November 2017, the PC find and fix program that applied only to the ozone NAA took effect on June 30, 2018, which was during the same summer of the PC field surveys performed for the PCTF study. The PC find and fix program has proven effective as demonstrated in the Division's 2018 LDAR Annual Report[10], which included the results of the PC find and fix program for the NAA, as described below. The AQCC extended the PC find and fix program state-wide effective May 1, 2020, as part of the AQCC SB-181 Reg 7 rulemaking in December 2019.

[9] See https://www.api.org/~/media/Files/Policy/Environment/TEP/The-Environmental-Partnership-Annual-Report-2019.pdf

[10] See https://www.colorado.gov/pacific/cdphe/2018-ldar-annual-reports-regulation-7-section-xii-xvii-and-xviii

The Division's 2018 LDAR Annual Report (pp. 4-6) summarizes the results of PC inspections performed for the PC find and fix program. Although the report does not break out the number of PC inspections using AIMM at well production facilities that were performed in the NAA in 2018, a total of 4,053 PCs were found to need repair and of these 4,015 (99%) were returned to proper operation. For natural gas compressor stations subject to PC inspections using AIMM in the NAA in 2018, a total of 7 PCs were needed to be repaired and 6 (86%) were returned to proper operation. Upon discovery of an improperly operating PC, repairs must begin no later than five working days and the PC must be returned to proper operation no later than 30 working days. A delay in a repair may be attributed to unavailability of parts, the equipment requires a scheduled shutdown to complete the repair, or other good cause. The Division developed a list of standardized enhanced response actions to repair PCs with input from the oil and gas industry to be used for recordkeeping and annual reporting purposes. These include the following options to return a natural gas-driven PC to proper operation:

1. adjusted/tuned;
2. cleaned/removed debris;
3. tightened;
4. heated/insulated;
5. replaced part(s) of controller;
6. rebuilt controller with repair kit;
7. replaced controller; and
8. other.

Below is Figure 2 from the Division's 2018 LDAR Annual Report that shows the distribution of each type of response action, with a total of 4,060 actions reported. The two most common types of response action were to clean/remove debris, and to rebuild the pneumatic controller with a repair kit.

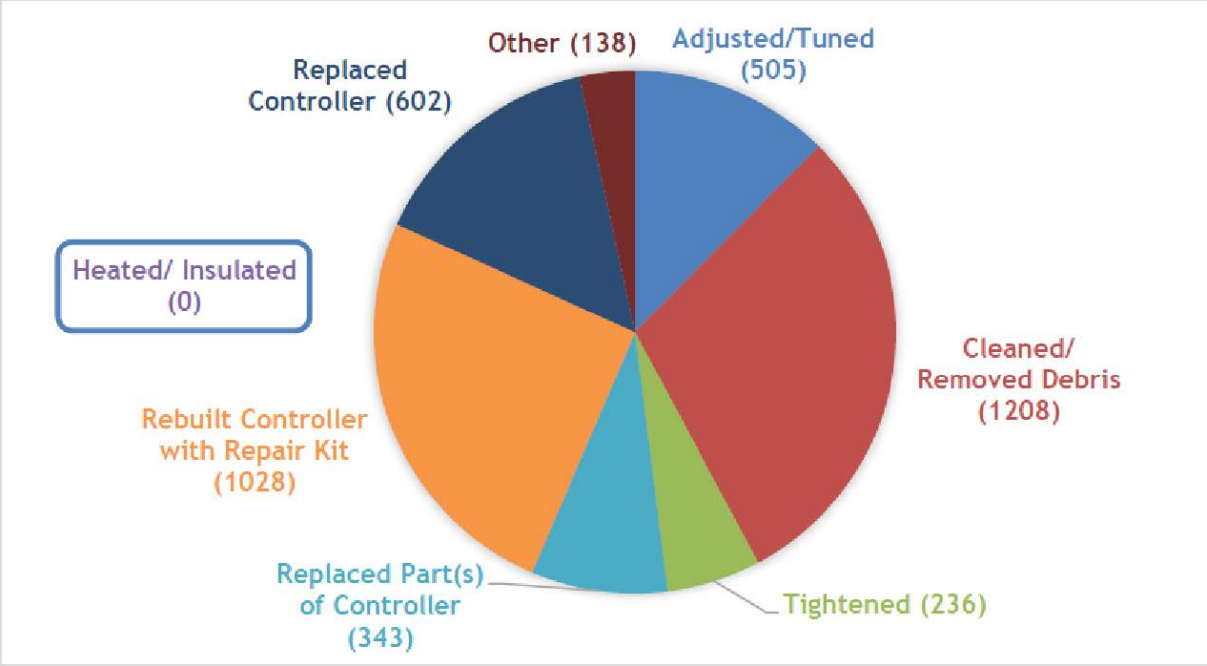


Figure 2: Enhanced response actions taken to return pneumatic controllers to proper operation, by enhanced response action category

Although not specific to natural gas-fired PCs, the Division's 2018 LDAR Annual Report on p.4 indicated that the use of an OGI camera was more effective than AVO observations during facility inspections for emission leaks from components. On page 4, the report states:

"Based on the data reported by owners/operators, more than 90% of leaks were identified through AIMM inspections despite AIMM inspections constituting only 3% of the total number of inspections at WPFs. While AVO inspections are valuable for operations and maintenance purposes, as well as being required by other sections of Regulation No. 7, the data from this year's LDAR annual reporting indicate that AIMM is a more effective monitoring method than AVO for detecting leaks."

Given the results from the 2018 PCTF field inspections, and the 2018 LDAR program and PC find and fix results, the PCTF believes the use of AIMM inspections using an OGI camera is an effective means for identifying both those emissions from PCs that indicate improper operation and from leaky LDAR components.

7.2 Definition Appropriateness

As discussed previously, due to the need to focus on regulatory proposals for consideration during the AQCC December 2019 rulemaking hearing, the PCTF did not complete its evaluation of the appropriateness of the current Reg 7 definitions related to PCs. However, revisions to these definitions will be included in the regulatory proposal specific to the use of no-bleed PCs (aka zero-bleed PCs). Currently, industry is developing a proposal that may be further modified through a future stakeholder and rulemaking process.

Stakeholder meetings will be scheduled and facilitated by the Division staff to review and solicit comments on the no-bleed PC regulatory proposal, which will include the need to make

appropriate revisions to PC-related definitions. As such, for the purposes of completing this report, the PCTF does not recommend making any changes at this time to the definitions for "enhanced response", "intermittent pneumatic controller", "no-bleed pneumatic controller", "self-contained pneumatic controller", or "pneumatic controller". Changes to these definitions will be considered separate from this report in vetting the regulatory proposal with stakeholders.

7.3 No-bleed and Self-contained PCs

As defined by Regulation 7 Part D Section III., a no-bleed PC is "any pneumatic controller that is not using hydrocarbon gas as the valve's actuating gas." Alternative actuating gases include compressor air or nitrogen, but in practice such PCs in Colorado are mainly compressed air, also known as instrument air. Instrument air systems utilize a skid-mounted compressor and often come with a dryer system to remove moisture from the air prior to compression. Once compressed, the air is routed through the same supply gas system that would otherwise contain pressurized natural gas to actuate the PCs.

As defined in Regulation 7 Part D Section III., a self-contained PC is "a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere." Such PCs utilize natural gas as the actuating gas, but have minimal emissions to atmosphere because the vent port of the controller is routed back to a process line. Likewise, although not addressed in the current Regulation 7 rule language, emissions from the vent port of the PC can be routed to a control device in some limited applications. As previously mentioned and further discussed below, the use of self-contained PCs is very limited due to technical infeasibility, safety concerns, and cost.

Additionally, mechanical or electric controllers (non-pneumatic) can be used in some very limited applications as described below. These controllers are neither no-bleed or self-contained as defined by Regulation 7 and because they have no emissions, are not subject to the regulatory requirements. However, the PCTF included these controllers in the operator survey so they are also addressed below.

BCPH, DDPHE, and CC4CA Position:

SB181 directed the AQCC to consider a requirement to reduce emissions from pneumatic devices and in 2019 the AQCC directed the PCTF to develop recommendations on the use of zero-bleed pneumatic devices for rulemaking in 2020. Because the PCTF was unable to reach consensus on a recommendation, we believe the AQCC should direct the Division to continue its research and develop a proposal for the planned December 2020 rulemaking. Specifically, the Division should continue to research and put forth recommendations based on the information provided below by Earthjustice and CATF. No-bleed and self-contained PCs are a proven technology that should be implemented in Colorado. Furthermore, the successful implementation of solar-powered PCs in Canada points to the need for serious consideration of this technology in Colorado.

7.3.1 Current applications

As discussed above in Section 5.3, most of the no-bleed PCs in use in Colorado are in the DJ basin NAA and at newer multi-horizontal well pad facilities producing significant volumes of oil and gas. The PC field study also demonstrates that the majority of compressor stations in the NAA are currently operating or under construction to operate on instrument air.

Industry Position:

No-bleed controllers can generally be utilized on any piece of equipment that utilizes a natural gas actuated PC, but as detailed below, technical feasibility, safety concerns, other regulatory requirements, contractual obligations, and cost can all limit the ability of an owner or operator to utilize no-bleed PCs on some or all pieces of equipment at a facility.

Solar-powered PCs have recently been utilized in Alberta, Canada under specific operating conditions for where they are included in the design for a separator equipment package. However, industry believes that the array of solar batteries and battery storage has not yet been fully demonstrated to be sufficient and reliable for the power demands of well pads with multiple horizontal wells that produce significant volumes of oil and gas. As technology advances and costs decrease, the use of solar panels and battery storage to provide electrical power at large oil and gas production facilities may become feasible.

Industry is currently working on a regulatory proposal regarding the use of no-bleed PCs to be considered for a future AQCC rulemaking. This regulatory proposal will build on the work developed for a no-bleed PC emission mitigation strategy proposed under the SHER stakeholder process.

CATF/EJ Position:

Regulations currently in force in Alberta and British Columbia (BC) will significantly limit the use of venting gas-driven PCs moving forward. In BC, new facilities cannot use venting gas-driven PCs after January 1, 2021. Large compressor stations will require retrofit of all venting gas-driven PCs by January 1, 2022.[11] In Alberta, no new gas-driven venting PCs can be installed after January 1, 2022 (this regulation was very recently tightened – previously operators were to be allowed to use gas-driven venting controllers for up to 10% of new controllers after January 1, 2022).[12] Both provinces also will subject existing PCs, including intermittent PCs, to various emission limits.

Solar-powered PCs have been utilized for a number of years in Alberta where they are included in the design for separator equipment packages from certain manufacturers. Other operators have utilized similar solar-powered systems in custom configurations (for example to provide more electrical power and storage than is available in standard packages). Solar systems are used on both low-production wellsites and modern, high-production tight/shale wells.

This technology has proven reliable in Alberta north of 55°N latitude, where sunlight on a clear winter day is far weaker than in Colorado, snowfall is higher, winter cloud cover is much more common, and winter temperatures are much lower (affecting battery capacity). In short, CATF and EJ believe that there is no reason that this technology cannot succeed in Colorado.

[11] See BC Regulation 282/2010, §52.05.
http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018
[12] See Alberta Energy Regulator (2020), "Directive 060 - Upstream Petroleum Industry Flaring, Incinerating, and Venting," §8.6.1. https://www.aer.ca/documents/directives/Directive060_2020.pdf

As noted above, there are also air compression systems designed for solar-powered sites on the market.

7.3.2 Effectiveness of devices

Industry Position:

Industry believes that the effectiveness of a no-bleed or self-contained PC is highly dependent on the application of the controller. The scope of the PCTF study did not evaluate the effectiveness of no-bleed PCs so no conclusions can be offered in this report. The consideration of the use of no-bleed PCs is being addressed under a SHER work group regulatory proposal as directed by SB 19-181.

CATF/EJ Position:

CAFT and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers;[13] this approach will be one of the key technologies allowing operators in Alberta and BC to comply with the provincial rules mentioned above.

7.3.3 Costs for new and retrofit facilities

Industry Position:

Based on operator survey results, the cost of instrument air systems (no-bleed pneumatic controllers) is highly variable and significantly higher for retrofits versus new installations.
The cost of self-contained PCs was not able to be ascertained through this study. However, industry has estimated that the cost to design the large and intricate vapor recovery system to capture these small emissions is significant and not cost-effective in most cases.

Likewise, industry estimates that the cost of routing controllers to a combustion device is prohibitively expensive unless the controller is located in close proximity to the control device (e.g. on the inlet to the control device itself).

Mechanical controllers, which can only be used for liquid level control in specific applications, were reported to have low capital costs, but higher maintenance costs than PCs based on operator survey results. Electric controllers were reported to cost significantly more, and also have higher maintenance costs, than PCs.

CATF/EJ Position:

The Conservation Groups' pneumatics proposal from the 2017 oil and gas rulemaking (which was also included as a SHER team proposal) was supported by an Economic Impact Assessment (EIA) documenting the cost-effectiveness of using zero-emitting approaches instead of gas-driven venting controllers. All cost calculations included in the Conservation Group's 2017 EIA include full costs for solar-powered electric systems, including: solar panels, batteries, and control panels and electronics; over-

[13] See Carbon Limits (2016), *Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness.* https://www.catf.us/wp-content/uploads/2019/09/CL2016-ZeroEmitting-Pneumatics-Alts-1Aug2016.pdf

capacity for solar panels and batteries to ensure power will be available during (for example) extended cloudy periods in winter; electric actuators; installation; and maintenance. Operators report lower maintenance costs with electric systems than gas-driven systems when only wet gas is available to operate PCs, due to deleterious effects of wet gas on some PC components.[14]

In the 2017 rulemaking and as part of the SHER team, the Conservation Groups made available spreadsheets listing parameters for calculating cost-effectiveness, such as cost estimates for various components and labor, and engineering design assumptions such as the appropriate oversizing of solar panels and maximum allowable discharge from batteries.

7.3.4 Limitations and Barriers to expanded use

Industry Position:

In addition to cost, industry believes that there are technical, safety, regulatory, and land/leasehold concerns that limit the use of no-bleed and self-contained pneumatic controllers.

In terms of instrument air systems, operators must have sufficient grid or other power to run the instrument air skid and associated equipment. Further, some facilities will not have sufficient area at the facility to install the instrument air skid and associated infrastructure or may have landowner or regulatory restrictions on the grid power right of way or installation of additional equipment at the facility. Additionally, even where some controllers can be converted to instrument air there may be some processes that need to be controlled with natural gas-driven PCs for safety or technical reasons.

The biggest limitations to utilizing self-contained PCs or routing the vent port of the controller to a control device, aside from cost, are related to pressures. If there is not a process that is operating at a relatively low pressure then the pressure released from the vent port will not be sufficient to push the gas into the process line, potentially creating a safety hazard if a safety valve is not able to actuate against the process pressure. Additionally, beyond the cost of the amount of tubing that is required the route emissions from controllers that are located throughout a facility to a process line or control device, the longer that tubing is the more pressure differential (higher than the process or control device backpressure) is required to overcome the backpressure created by the tubing itself.

As mentioned previously, industry claims that mechanical and electric controllers can only be used to control liquid level and can only be used in certain applications (such as liquid level control). Additionally, mechanical controllers have been shown to be less accurate than PCs and electric controllers cannot typically be located on compressors due to vibration and require more technical knowledge to ensure safe application.

CATF/EJ Position:

[14] See Carbon Limits (2016) at p. 15.

As noted above, air compressors designed for solar-powered sites are on the market, as are packages systems that provide compressed air using hybrid electrical systems utilizing solar and batteries for the majority of the power they consume, with a gas-fired generator available as backup for the solar generation and battery. CATF and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers.[15]

7.3.5 Opportunities for expanded use

Industry Position:

Given the current state of technology, the use of electric and mechanical controllers is limited due to the limitation outlined in the section above. Industry believes that electric and mechanical controllers have very limited applications and cannot be used in the place of all traditional PCs at a facility. While there are extensive barriers that exist for retro-fitting existing facilities with instrument air, opportunity exists to expand the use of instrument air at new larger horizontal facilities that have sufficient grid power. Many of the land use and spacing limitations can be avoided if these systems are included during the planning phase. Additionally, there is a lower cost associated with installing a new system compared to retrofitting a location.

The ability to be able to plan for and allow utilities to commit to providing access to electrical grid power with sufficient power in advance of constructing new oil and gas production facilities represents a significant opportunity to expand the use of no-bleed PCs.

CATF/EJ Position:

CATF and EJ believe that zero-emitting technology can cost-effectively reduce emissions in Colorado at both new and existing sites. The CATF and EJ recommend that the AQCC consider requiring operators to utilize zero emitting pneumatic controllers statewide at all natural gas compressor stations and all well production facilities with four or more wells producing hydrocarbons so long as it is technically feasible to do so. CATF and EJ have previously offered this proposal in the 2017 oil and gas rulemaking and through the SHER team process. CATF and EJ believe that it is supported by the EIA and supporting spreadsheets, as well as the documented use of zero-emitting technology in Canada and the fact that venting PCs are being phased out for new facilities in British Columbia and Alberta.

8 Acknowledgments

The Division would like to thank all of the members of the PCTF for all of their time and hard work over the last two and a half years. The input from all stakeholders was vital to develop and implement what was the largest study of PCs to date. The information contained in this report is the culmination of thousands of hours of effort. The Division would also like to recognize the high level of engagement, collaboration, and resource expenditure from the industry members on the PCTF.

[15] Carbon Limits (2016).

ATTACHMENT A

Pneumatic Controller (PC) Task Force Data Collection Form

General Information

Inspector

Pad/Battery/Facility/Location

Blinded ID

Date

Time

Ambient Temperature

Wind Speed (MPH)

Inventory Information

Manufacturer*

Other:

Family (If Applicable)

Model*

Other:

Sensed Variable*

Other:

Type*

Other:

Supply Pressure (If Available) & Source

(psig) Enter 'None' if no gauge

Source:

Other:

Function*

Vent Type*

Vent Control Type*

Equipment Location*

Other:

Service Type*

Name/Description

Is PC Enclosed?*

Enclosure Type, If Not Exposed to Elements*

Additional Notes:

Inspection Information

Operating Properly*

Actuation Observed*

Detection Method*

Emissions Location*

Other:

If not operating properly provide the following:

Indicator 1

Indicator 2

Other:

Additional Notes:

Repair Information

Primary Cause of Improper Operation*

Other:

Repair Date

PC Repair Method*

Other:

Did the Repair Require:*

Double block and bleed

Shutdown and purge equip. to atmosphere

Shutdown of the well

Repair Time (Mins)

Repair travel time (if required)

Additional Notes:

Re-inspection Date

PC Repair Re-inspection Method*

An asterik (*) indicates that a field has a dropdown list

ATTACHMENT B

INSTRUCTIONS FOR COMPLETING THE DATA COLLECTION FORM FOR APCD PNEUMATIC CONTROLLER STUDY

MAY 9, 2018

These instructions serve to assist operators participating in the APCD's Pneumatic Controller (PC) Study specific to selected oil and gas facilities in the Front Range/Denver Metro Area Ozone Nonattainment Area (NAA) in the collection of data related to whether PCs in service at these facilities are operating properly.

It is important the persons conducting these inspections understand the focus of this study is limited to assessing the proper operation of PCs that are actuated using pressurized natural gas as a motive force and have the ability to vent to the atmosphere during normal operation. Leaks found to be originating from a component are not considered to represent improper operation of a PC. Instead, these observations should be considered leaks of components subject to a Leak Detection and Repair Program (LDAR).

Operators conducting these inspections of PCs at facilities selected for the purposes of this study will utilize concurrently an Audio, Visual and Olfactory (AVO) method along with an Approved Instrument Monitoring Method (AIMM) for each PC being inspected. Although other potential methods may be used to detect whether a PC is operating properly or not, these methods are not utilized by participating operators with facilities in the NAA and therefore will not be considered in the scope for Phase 1 of this study. Persons conducting these inspections of PCs for this study should strive to identify and document insights that were gained in applying methods in the field to determine whether a PC is properly operating or not. Although this form serves a purpose to document a specific inspection of a PC, the real value will be in being able to accurately describe what was done, observed or evaluated to determine if a PC was operating properly, along with any repairs necessary to a PC that was not operating properly.

General Instructions

- This form is to be used by an operator in conducting an inspection at a facility selected for the PC Study to document whether a PC is properly operating or not. As an option, the inspection data can also be captured using a flat table.
- If an inspector uses the form for data entry, one form is to be completed by the operator for each PC inspected at a facility. If the inspector uses the flat table rather than the form for data entry, one row in the table is to be completed for each PC inspected at a facility.
- PCs are not considered to be in service if the supply gas is depressurized; therefore, these out of service PCs are not to be inventoried or inspected for this study.
- For a PC that is found to be operating properly, the form or table row must be completed through the Inspection Information section.
- For PC that is found to be operating improperly, the entire form or table row must be completed including the Repair Information section. Neither the repair nor the Repair Information section must be completed at the time of the inspection. If the repair is not successfully completed at the time of the inspection, the details of the successful repair must be added to the form or flat table once completed.

NMED Exhibit 93

- The confirmation of successful repair does not need to be completed at the time of the repair. The details of the repair confirmation must be added to the form or flat table once completed.
- The data collection form is provided in an Excel format tied to a flat table that can be used to compile the data for each PC inspected at a facility. Although the use of the electronic version of this form is encouraged, a hard copy of the form can be used in the field if the dropdown options are used appropriately and consistently with those in the electronic form. However, this will require that the data in the hard copy of the form be re-entered into the Excel form or flat table so that the data can be compiled for subsequent reporting.

Specific Instructions

- The specific instructions herein address the completion of individual subject fields in the data collection form or flat table.
- An asterisk symbol (*) next to the data field indicates that a dropdown menu of options exists for this specific field. To open the dropdown menu, click on the data field until the down arrow symbol is highlighted to the right of the data field and then click on this symbol. Select by clicking the option that correctly describes the characteristic specific to the PC inspected. Only one option can be selected for each data field with a dropdown menu.
- The "Other" option for a specific data field is to be used when none of the options in the dropdown menu applies to the PC. When none of the specific dropdown options apply, select the "other" option from the dropdown menu and enter as text the information in the separate "Other" data field.
- Use the additional notes data field provided in each section of the form to add free form text describing noteworthy information relevant to the inventory, inspection, or repair sections.

General Information Section

Inspector – Enter the first and last name of the person performing the inspection of the PC.

Pad/Battery/Facility/Location – Enter the operator's designated name of the facility.

Facility ID – Enter the blinded ID designated by Spirit Env. for the facility being inspected. Each operator will be provided a list of facilities randomly selected for inspection by Spirit Env. and each facility selected will have a Blinded ID.

Date – Enter the date when the inspection of the PC was conducted using the numerical month/day/year format (xx/xx/xxxx).

Time – Enter the approximate time that the inspection of the PC started in a numerical format (xx:xx) with an AM or PM designation.

Ambient Temperature - Enter the approximate temperature at the time that the inspection started in Fahrenheit degrees.

Wind Speed - Enter the approximate wind speed at the time that the inspection started in miles per hour.

Inventory Information Section

Manufacturer* – Select the manufacturer of the PC if known. The dropdown options represent PC manufacturers that are believed to be common in the DJ Basin, yet may not cover all makes. If not listed, select "Other" as a dropdown option and enter the full manufacturer name using text in the separate "Other" data field. If the manufacturer is unknown or not certain, take a photograph of the PC and later attempt to confirm the manufacturer of the PC using available information.

Family – This data field is to be completed, as applicable, if the manufacturer of the PC uses a family classification to describe its line of PCs. If no family classification exists, leave this data field blank.

Model* – Select the model of the PC if known. The dropdown options represent PC models that are believed to be common in the DJ Basin, yet may not cover all models. If not listed, select "Other" as a dropdown option and enter the model as text in the separate "Other" data field. If the model is unknown or not certain, take a photograph of the PC and later attempt to confirm the model of the PC using available information. Please be careful in selecting the correct model as some model designations may vary slightly in their labeling.

Sensed Variable* – This data field describes the process variable that the PC is controlling. Dropdown options include pressure, temperature, position, differential pressure, and level. If the process variable is not listed, select "Other" as a dropdown option and describe the variable using text in the separate "Other" data field.

Type* – This data field distinguishes the type of PC being inspected in terms of its configuration. Only three options exist: integrated, pilot or other. An integrated PC refers to a PC that has both the sensing and actuating components contained in one housing. A pilot PC describes a PC that senses a signal and remotely actuates a device that is not contained in the same housing. If the type is not listed, select "Other" as a dropdown option and describe the type by entering text in the separate "Other" data field.

Supply Pressure & Source

- This data field records the pressure of the natural gas being applied as a motive force to the PC being inspected. If a pressure gauge exists on the supply line to the PC being inspected, record the pressure reading of the gauge. If no pressure gauge is present, then enter "None" in this data field. Do not enter "zero" or "0" instead of "None" as this suggests that there is zero pressure, or the gauge is broken.
- The data field for "Source" refers to where the source of the natural gas as a motive force originates from and the dropdown options include wellhead, separator, pipeline quality or "Other". To confirm the source of the gas, the supply tubing to the PC being inspected may have to be followed to its point of origin. If the source of the natural gas is not listed, select "Other" as a dropdown option and describe the source using text in the separate "Other" data field.

Primary Function* – This data field describes the primary function that the PC being inspected. Only two options apply to this data field: process control or safety. An "Other" option is not

available. The safety option should be selected where the PC is used to isolate a pressure source or cease operation of a process.

Vent Type* – This data field describes how the PC being inspected vents during an actuation cycle. Three dropdown options are available: a continuous high bleed (> 6scf/hr); a continuous low bleed (< 6 scf/hr); and an intermittent bleed. An "Other" option is not available. To determine the correct vent type, the operators should research the vent type classified by the manufacturer for the model of the PC being inspected. Measurement of the actual vent rate is not required for this study.

Vent Control Type* – This data field describes whether the vent from the PC being inspected is captured and routed. Three dropdown options are available: vented to atmosphere; captured and routed to sales or process; or captured and routed to a flare/combustor header. An "Other" option is not available. To determine the correct option, the operator may need to follow the vent tubing to the point where it connects to piping and determine whether the piping connects to a process or sales line, or a flare/combustion device.

Equipment Location* – This data field describes the equipment associated with the PC being inspected in terms of its purpose to control the equipment's operation. Available dropdown options include: wellhead, separator, heater, combustor, compressor engine, generator, dehydrator (dehydration unit), and other. If the type of equipment is not listed, select "Other" as a dropdown option and enter the type of equipment using text in the separate "Other" data field.

Service Type* – This data field describes the service of the PC being inspected in terms of how the process variable is controlled. The dropdown options are: on/off, throttling, or unknown. An "Other" option is not available. If the inspector is unsure of whether a PC is on/off or throttling, the inspector should select unknown.

Name/Description – This data field provides a more specific description of the piece of equipment so that the PC being inspected can be identified and located, especially at facilities where there is more than one of the same equipment type (i.e. heater treater 4, water dump). No dropdown menu is available.

Is PC Enclosed? – This data field provides a yes or no answer to whether the PC is located within some type of enclosure that shields the PC from the elements such as a hinged case, a cabinet, or building. Answer "No" if no enclosure exists around the PC being inspected.

Enclosure Type (If Not Exposed to Elements) – This data field is to be completed only if the PC is enclosed as indicated by a "Yes" response to the previous data field. Three dropdown options exist for a "Yes" response: inside separator cabinet, inside compressor enclosure, or inside other enclosure? An "Other" option is not available.

Additional Notes – This data field is a text box that allows additional information to be provided that are worth noting to describe conditions specific to the facility, equipment or PC being inspected.

Inspection Information Section

Operating Properly – This data field identifies whether the PC being inspected is operating properly. Two dropdown options exist: Yes or No. An "Other" option is not available. If the "Yes" option is selected because the PC is found to be operating properly, ~~then~~ then do not complete the Detection Method data field below ~~must be completed~~. If the "No" option is selected because the PC is found to not be operating properly, then ~~do not~~ complete the Detection Method data field below.

Actuation Observed – This data field identifies whether the PC being inspected was observed to actuate during the inspection. Three dropdown options exist: Yes, No or Unknown. An "Other" option is not available.

Detection Method – This data field identifies the method used to detect whether a PC is not operating properly ~~or not~~. This data field must be completed only if the "No~~Yes~~" option is selected for the "Operating Properly" data field above. Three dropdown options exist: Audio-Visual-Olfactory (AVO) Only, Approved Instrument Monitoring Method (AIMM) Only, and AVO/AIMM. An "Other" option is not available.

- AVO refers to hearing, seeing or smelling something that indicates a PC is not operating properly. Indicators associated with hearing may include hissing or clicking. Detection of a hydrocarbon odor near a PC may not be telltale yet could still indicate a process is not being controlled properly due to an improper operation of a PC. AVO to be selected as a dropdown option when this method was able to independently determine that a PC was not operating properly.
- AIMM refers to methods approved for use by APCD under Reg 7 such as an optical gas imaging (OGI) camera. For the purposes of this PC study for the NAA, an OGI camera will be the only AIMM used. AIMM is to be selected as a dropdown option when this method was able to identify that a PC was not operating properly and AVO was not able to independently make this determination.
- AVO/AIMM is to be selected as a dropdown option when both methods in concert were required to detect that a PC was not operating properly.

Emissions Location – This data field identifies where emissions are detected from a PC being inspected that is not operating properly. Three dropdown options exist: Vent Port, Body or "Other". If the emission location is other than the Vent Port of Body, then select "Other" as a dropdown option and enter a description using text in the separate "Other" data field. Emissions from supply tubing connections or other components do not represent improper operation of a PC.

Indication of Proper Operation – This data field describes what indicator(s) were found that led to a determination that the PC being inspected was not operating properly. Two data fields with dropdown menus with options are provided including an "Other" option. If the indicator is not listed in the dropdown menu, then select "Other" as a dropdown option and enter a description using text in the separate "Other" data field. If there are more than two indicators, use the Other field to enter text describe any additional indicators.

Additional Notes – This data field is a text box that allows additional information worth noting specific to the PC being inspected. These notes can be used to provide further insight into what was done, observed or evaluated during the inspection to determine whether the PC was operating properly or not.

Repair Information Section

Primary Cause of Improper Operation – This data field identifies the primary cause of improper operation of the PC being inspected. Ten dropdown options are provided including an "Other" option. Select the option that is believed to be the primary cause. If the primary cause is not listed in the dropdown menu, then select "Other" as an option and enter a description using text in the separate "Other" data field.

Repair Date - Enter the date when the repair of the PC that was found to be operating improperly was successfully completed using the numerical month/day/year format (xx/xx/xxxx).

PC Repair Method – This data field identifies the method(s) applied to repair the PC that was inspected and found to be operating improperly. Eleven dropdown options are provided including an "Other" option. Select the option that best represents the repair method necessary to return the PC to proper operation. If the repair method applied is not listed in the dropdown menu, then select "Other" as an option and enter a description using text in the separate "Other" data field.

Did the Repair Require a double block and bleed? Shutdown and purge equipment to atmosphere? Shutdown of the well? - These data fields describe whether any of the listed actions were necessary to make the repair of the PC that was found to be operating improperly. A Yes or No response is needed for each of the three actions listed. An "Other" option is not available.

PC Repair Confirmation Method – This data field identifies the method used to confirm that the PC repair was successful to restore the PC to proper operation. Five dropdown options exist: AIMM, AVO, Soapy Water, Method 21, and Physical Inspection. Select the method used to confirm a successful repair. An "Other" option is not available.

Repair Time Onsite – This data field documents the amount of time needed once onsite to complete the successful repair of a PC found to be operating improperly. Enter the amount of time in hours using 15-minute increments (i.e. 0.25, 0.5, 0.75, 1.0, 1.25, 1.50, etc.). Repair Travel Time (if required) – This data field documents the travel time needed to visit the facility to make a necessary repair of a PC found to be improperly operating. This travel time information is only required if a separate trip is needed to make the repair separate from the trip made to conduct the inspection for this study. Enter the amount of time in hours using 15-minute increments (i.e. 0.25, 0.5, 0.75, 1.0, 1.25, 1.50, etc.)

Re-Inspection Date – Enter the date when re-inspection of a PC that was subject to repair was completed to confirm its proper operation using the numerical month/day/year format (xx/xx/xxxx).

PC Repair Re-Inspection Method – This data field identifies the method used to re-inspect a PC that was subject to repair. Three dropdown options are provided – AIMM, AVO or soapy water. Select the method used to confirm the successful repair. An "Other" option is not available.

Additional Notes - This data field is a text box that allows additional information worth noting specific to the PC being repaired and re-inspected. These notes can be used to provide further insight into what was done, observed or evaluated to successfully complete the repair and confirm the repair during the re-inspection to demonstrate that the PC was returned to proper operation.

PLEASE CHECK THAT THE FORM IS COMPLETE AFTER EACH INSPECTION AND IF A REPAIR IS REQUIRED.

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Part V

Environmental Protection Agency

40 CFR Part 98
Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2014–0831; FRL–9935–50–OAR]

RIN 2060–AS37

Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is finalizing revisions and confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule. These revisions include the addition of calculation methods and reporting requirements for greenhouse gas (GHG) emissions from gathering and boosting facilities, completions and workovers of oil wells with hydraulic fracturing, and blowdowns of natural gas transmission pipelines between compressor stations. The revisions also include the addition of well identification reporting requirements to improve the EPA's ability to verify reported data and enhance transparency. This action also finalizes confidentiality determinations for new data elements contained in these amendments.

DATES: This final rule is effective on January 1, 2016.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2014–0831. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9263; fax number: (202) 343–2342; email address: *GHGReportingRule@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/.* To submit a question, select Help Center, followed by ''Contact Us.''

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on the EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. This final rule adds calculation methods, monitoring, and data reporting requirements and finalizes confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Rule (40 CFR part 98). The Administrator determined that 40 CFR part 98 is subject to the provisions of Clean Air Act (CAA) section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine''). Entities affected by this final rule are owners and operators of petroleum and natural gas systems that directly emit GHGs, which include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS [a]	Examples of affected facilities
Petroleum and Natural Gas Systems	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.
	221210	Natural gas distribution.
	486210	Pipeline transportation of natural gas.

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Types of facilities other than those listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A and 40 CFR part 98, subpart W. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

What is the effective date? The final rule is effective on January 1, 2016.

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit (the Court) by December 21, 2015. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Section 307(d)(7)(B) of the CAA also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

AGR acid gas removal

API American Petroleum Institute
BAMM best available monitoring methods
CAA Clean Air Act
CBI confidential business information
CFR Code of Federal Regulations
CH_4 methane
CO_2 carbon dioxide
CO_2e carbon dioxide equivalent
e-GGRT Electronic Greenhouse Gas Reporting Tool
EPA U.S. Environmental Protection Agency
FERC Federal Energy Regulatory Commission
FR Federal Register
ft^3 cubic feet
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GOR gas to oil ratio
GRI Gas Research Institute
ICR information collection request
ID identification
LDC local distribution company
N_2O nitrous oxide
NAICS North American Industry Classification System
NGO non-government organization
NGPA Natural Gas Policy Act
NTTAA National Technology Transfer and Advancement Act
O&M operation and maintenance
OMB Office of Management and Budget
PHMSA Pipeline and Hazardous Materials Safety Administration
psi/ft pounds per square inch per foot
REC reduced emissions completion
RFA Regulatory Flexibility Act
scf standard cubic feet
scf/STB standard cubic feet per stock tank barrel
U.S. United States
UMRA Unfunded Mandates Reform Act of 1995
WWW worldwide web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background
A. Organization of This Preamble
B. Background on This Action
C. Legal Authority
D. How do these amendments apply to 2015 and 2016 reports?
II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment
A. Summary of Final Amendments for Oil Wells With Hydraulic Fracturing
B. Summary of Final Amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment
C. Summary of Final Amendments for the Onshore Natural Gas Transmission Pipeline Segment
D. Summary of Final Amendments for Well Identification Numbers
E. Summary of Final Amendments to Best Available Monitoring Methods
III. Final Confidentiality Determinations
A. Summary of Final Confidentiality Determinations for New Subpart W Data Elements
B. Summary of Public Comments and Responses on the Proposed Confidentiality Determinations
IV. Impacts of the Final Amendments to Subpart W
A. Impacts of the Final Amendments
B. Summary of Comments and Responses on the Impacts of the Proposed Rule
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. Background

A. Organization of This Preamble

Section I of this preamble provides background information regarding the origin of the final amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 of the Greenhouse Gas Reporting Rule (hereafter referred to as ''part 98'') as well as the legal authority for making confidentiality determinations for the data to be reported. Section II of this preamble contains information on the final amendments to part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as ''subpart W''), including a summary of the major comments that the EPA considered in the development of this final rule. Section III of this preamble discusses the final confidentiality determinations for new data reporting elements. Section IV of this preamble discusses the impacts of the final amendments to subpart W. Finally, Section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on This Action

The EPA's Greenhouse Gas Reporting Program (GHGRP) requires annual reporting of GHG data and other relevant information from large sources and suppliers in the United States. On October 30, 2009, the EPA published part 98 for collecting information regarding GHG emissions from a broad range of industry sectors (74 FR 56260). Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of part 98 (75 FR 16448; April 10, 2009), the final October 2009 rule did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (79 FR 18608; April 12, 2010), and a subsequent final rule was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458) (hereafter referred to as ''the final subpart W rule''). Following promulgation, the EPA finalized actions revising subpart W (76 FR 22825, April 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 80554, December 23, 2011; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014).

On December 9, 2014, the EPA proposed ''2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (79 FR 76267) to require the reporting of GHG emissions from several sources that had not previously been included in subpart W. These sources include completions and workovers of oil wells with hydraulic fracturing, petroleum and natural gas gathering and boosting systems, and transmission pipeline blowdowns between compressor stations. The reporting requirements for completions and workovers of oil wells with hydraulic fracturing were proposed to be included as part of the existing Onshore Petroleum and Natural Gas Production industry segment. For the other sources, the EPA proposed two new industry segments: The Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting facilities, and the Onshore Natural Gas Transmission Pipeline segment for transmission pipeline blowdowns between compressor stations. The EPA also proposed to require the reporting of a well identification number for oil and gas wells covered in the Onshore Petroleum and Natural Gas Production segment. In addition, the EPA proposed confidentiality determinations for new data elements contained in the proposed amendments. The public comment period for these proposed rule amendments ended on February 24, 2015, following a 2-week extension of the original comment period end date (80 FR 6495; February 5, 2015).

In this action, the EPA is finalizing additions and revisions to the subpart W calculation, monitoring, and reporting requirements for new sources, with some changes made in response to public comments. Responses to comments submitted on the proposed amendments can be found in sections II, III, and IV of this preamble as well as in ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. As noted in the preamble to the proposed amendments (79 FR 73148; December 9, 2014), these additions and revisions further the EPA's goals of improving the completeness, quality, accuracy, and transparency of data from this sector, and improving the ability of agencies and the public to use these GHG data to analyze emissions and understand emission trends.

The *Strategy to Reduce Methane Emissions* in the President's *Climate Action Plan* summarizes the sources of methane (CH_4) emissions, commits to new steps to cut emissions of this potent GHG, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut CH_4 emissions from several sectors, including the oil and natural gas sector. In the strategy, the EPA was tasked to review regulatory requirements to address potential gaps in coverage, improve methods, and help ensure high quality data reporting.[1] The final revisions to subpart W covered in this action are responsive to this task by addressing data gaps in subpart W, specifying methods for measuring CH_4 emissions, and providing data that can be used to further analyze CH_4 emissions in this industry.

This action also addresses a petition the EPA received from a group of non-government organizations (NGOs) requesting that the EPA collect data from emissions sources not currently included in subpart W, including well completion emissions from oil wells that co-produce natural gas, facilities and pipelines in the gathering and boosting segment, and transmission pipeline blowdown events (''Petition for Rulemaking'').[2] Table 2 of this preamble summarizes how the EPA has responded to the Petition for Rulemaking. These revisions, and previously finalized revisions where noted in Table 2, reflect the EPA's complete response to the Petition for Rulemaking. It is our position that we have fully responded to the NGO petition, however, any requests included in the petition that have not been responded to in Table 2 are considered denied.

TABLE 2—EPA RESPONSE TO PETITION FOR RULEMAKING

Request in petition	EPA's response	Final rule citations (40 CFR)
Clarify that oil wells that co-produce natural gas (''co-producing wells''), specifically wells in tight-oil formations like the Bakken and Eagle Ford, are subject to the completion reporting requirements as currently written. Expand the well completion reporting requirements to all wells, ensuring co-producing wells in any formation type are required to report completion emissions.	The EPA is not changing the definition of ''gas well'' or ''oil well.'' Instead, the EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers with hydraulic fracturing for wells in the Onshore Petroleum and Natural Gas Production segment, regardless of whether their primary product is oil or natural gas.	98.232(c)(6) 98.232(c)(8) 98.236(g)
Require reporting from facilities and pipelines in the gathering and boosting segment of the natural gas industry.	The EPA is finalizing the proposal to amend subpart W to add a new industry segment, Onshore Petroleum and Natural Gas Gathering and Boosting, which covers emissions from equipment used by gathering pipeline systems that move petroleum and natural gas from the well to either larger gathering pipeline systems, natural gas processing plants, natural gas transmission pipelines, or natural gas distribution pipelines.	98.230(a)(9) 98.232(j) 98.233 (various) 98.236(a)(9)
Require reporting from transmission pipeline blowdown events.	The EPA is finalizing the proposal to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment.	98.230(a)(10) 98.232(m) 98.236(aa)(11)
Require reporters to include API well identification numbers along with their submissions to help the public and policymakers understand which sources are reporting and how the threshold may be adjusted to most effectively provide emissions information.	The EPA is requiring the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment for information related specifically to wells.	98.236(f), (g), (h), (l), and (m) 98.238
Phase out the use of best available monitoring methods (BAMM), which will further help to ensure Subpart W data are rigorous, and comprehensive.	Prior to these amendments, BAMM was discontinued for all sources except specific sources that were affected by the amendments finalized on November 25, 2014 (79 FR 70352); those BAMM provisions will be unavailable after December 31, 2015. Reporters will be allowed to use BAMM for the 2016 reporting year for only the new industry segments and emission sources included in this action. The EPA is not allowing the use of BAMM beyond 2016.	98.234(f) and (g)

[1] *Climate Action Plan—Strategy to Reduce Methane Emissions.* The White House, Washington, DC, March 2014. Available at *http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.*

[2] *Petition for Rulemaking and Interpretive Guidance Ensuring Comprehensive Coverage of Methane Sources Under Subpart W of the Greenhouse Gas Reporting Rule—Petroleum And Natural Gas Systems;* Submitted by Clean Air Task Force, Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club; March 19, 2013. Docket Item No. EPA–HQ–OAR–2014–0831–0005.

TABLE 2—EPA RESPONSE TO PETITION FOR RULEMAKING—Continued

Request in petition	EPA's response	Final rule citations (40 CFR)
Consider including advanced innovative monitoring methods as a way to accelerate development and deployment of real-time continuous CH_4 emission monitoring in the oil and natural gas sector.	The agency is assessing the potential opportunities for application of remote sensing technologies and other innovations in measurement or monitoring technology to identifying and calculating emissions from affected sources under subpart W and requested comment in the proposal. The EPA received multiple comments in response to the request for comments on the feasibility, possible regulatory approaches, and provisions necessary to incorporate or allow the use of advanced measurement or monitoring methods in subpart W. All of the comments received are included in "Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" in Docket ID No. EPA–HQ–OAR–2014–0831. The EPA is not including provisions related to advanced measurement or monitoring methods in this rule and is not responding to these comments in this rulemaking. Instead, following review of the data and information received in comments, the EPA may propose amendments related to the use of innovative technologies in reporting to the GHGRP in a future rulemaking.	

Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 final GHG reporting rule (74 FR 56260; October 30, 2009), CAA section 114(a)(1) provides the EPA broad authority to require the information to be gathered by this rule because such data would inform and are relevant to the EPA's carrying out a wide variety of CAA provisions. See the preambles to the proposed (74 FR 16448; April 10, 2009) and final GHG reporting rule (74 FR 56260; October 30, 2009) for further information.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing final confidentiality determinations for the new data elements required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information that qualifies for confidential treatment. The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA.

D. How do these amendments apply to 2015 and 2016 reports?

These amendments are effective on January 1, 2016. Thus, beginning on January 1, 2016, facilities must follow the revised methods in subpart W, as amended, to calculate emissions occurring during the 2016 calendar year (*i.e.,* reporting year 2016). The first annual reports of emissions calculated using the amended requirements will be those submitted by March 31, 2017, covering reporting year 2016. For reporting year 2015, reporters will continue to calculate emissions and other relevant data for the reports that are submitted according to the requirements in part 98 that are applicable to reporting year 2015 (*i.e.,* the requirements in place until the effective date of this final rule).

For reporting year 2016 only, we are allowing the use of best available monitoring methods (BAMM) on a short-term transitional basis for facilities new to reporting under subpart W as well as reporters of facilities subject to new monitoring requirements associated with these revisions. Reporters have the option of using BAMM for only the new industry segments and emission sources included in this action from January 1, 2016, to December 31, 2016, without seeking prior EPA approval. The EPA will not accept requests for an extension for the use of BAMM beyond the time periods listed above. The EPA is not allowing the use of BAMM for the new well identification number provisions in the Onshore Petroleum and Natural Gas Production segment because the well identification number is not a parameter that requires monitoring equipment to be measured and, therefore, does not meet the requirements for BAMM. In addition, reporters should already have well identification numbers readily available for all wells and associated equipment to which this reporting requirement applies. See section II.E of this preamble for more information.

II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment

In this action, the EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers of oil wells with hydraulic fracturing as part of the existing Onshore Petroleum and Natural Gas Production industry segment. The EPA is also adding requirements for two new industry segments: the Onshore Petroleum and Natural Gas Gathering and Boosting segment for petroleum and natural gas gathering and boosting systems, and the Onshore Natural Gas Transmission Pipeline segment for transmission pipeline blowdowns between compressor stations. Finally, the EPA is requiring the reporting of well identification numbers for oil and gas well-specific information (*e.g.,* completions and workovers, associated gas venting and flaring) reported in the Onshore Petroleum and Natural Gas Production segment. The comments received on this rule generally did not dispute the merit of adding these new segments and sources to subpart W, but they did provide a number of suggestions regarding the technical details of monitoring, reporting, and applicability.

Sections II.A through II.E of this preamble describe the requirements and other amendments that we are finalizing in this rulemaking. Section II.A describes the final amendments for the

reporting of GHG emissions from completions and workovers of oil wells with hydraulic fracturing. Section II.B describes the final amendments for the reporting of GHG emissions from sources in the new Onshore Petroleum and Natural Gas Gathering and Boosting segment. Section II.C describes the final amendments for the reporting of GHG emissions from sources in the new Onshore Natural Gas Transmission Pipeline segment. Section II.D describes the requirements for reporting well identification numbers for the Onshore Petroleum and Natural Gas Production segment. Finally, section II.E provides a summary of the final amendments to the best available monitoring method requirements. The amendments described in each section are followed by a summary of the major comments on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and the EPA's responses.

Finally, in the preamble to the proposed rule, the EPA stated that the agency is ''assessing the potential opportunities for applying remote sensing technologies and other innovations in measurement or monitoring technology to identifying and calculating emissions from affected sources under subpart W'' (79 FR 73148; December 9, 2014). The EPA did not propose, and therefore is not finalizing, any amendments to subpart W to this effect, but the EPA did request comment on the feasibility, possible regulatory approaches, provisions necessary to incorporate or allow the use of advanced measurement or monitoring methods in subpart W, and methods to ensure compliance with those provisions in an efficient manner. The EPA also requested comment on the memorandum ''Discussion Paper on Potential Implementation of Alternative Monitoring under the GHGRP'' in Docket ID No. EPA–HQ–OAR–2014–0831. All of the comments received are included in ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. The EPA will consider these comments in the context of any future action related to alternative monitoring.

The amendments in this action will advance EPA's goal of maximizing rule effectiveness. For example, these amendments provide clear monitoring, calculation and reporting requirements for new segments and sources in subpart W, thus enabling government, regulated entities, and the public to easily identify and understand rule requirements. In addition, specific changes such as increasing the flexibility and time period for transitional BAMM will make compliance easier than non-compliance.

These amendments will also improve the EPA's ability to assess compliance by adding reporting elements that allow the EPA to more thoroughly verify greenhouse gas data and understand trends in emissions. For example, the requirement for the Onshore Petroleum and Natural Gas Production segment to report well identification numbers will allow the EPA to link GHGRP data with other data sources and assess the completeness and representativeness of the data collected relative to all activity in the U.S. oil and gas production sector. Lastly, these amendments further advance the ability of the GHGRP to provide access to quality data on greenhouse gas emissions by adding key petroleum and natural gas emission sources to this program. One example is the addition of the Onshore Petroleum and Natural Gas Gathering and Boosting segment, a significant greenhouse gas emissions segment that had not been previously covered under the GHGRP.

A. Summary of Final Amendments for Oil Wells With Hydraulic Fracturing

1. Summary of Final Amendments

The EPA is amending subpart W to require the reporting of GHG emissions from completions and workovers with hydraulic fracturing for wells in the Onshore Petroleum and Natural Gas Production segment, regardless of whether their primary product is oil or natural gas. In general, commenters supported inclusion of emissions from completions and workovers of oil wells with hydraulic fracturing in subpart W, and a few commenters provided targeted technical edits and suggestions for this source. Consistent with the requirements for completions and workovers of gas wells with hydraulic fracturing, and consistent with the proposed requirements, the new provisions include the reporting of activity data on the number of completions and workovers of oil wells with hydraulic fracturing and on the use of flaring and reduced emission completions (RECs). In response to public comments, the final monitoring and reporting amendments do not apply to completions and workovers of oil wells with hydraulic fracturing that have a gas to oil ratio (GOR) of less than 300 standard cubic feet per stock tank barrel (scf/STB).

The EPA is also amending the equations and definitions in 40 CFR 98.233(g) to reflect applicability to completions and workovers of all gas and oil wells with hydraulic fracturing. As in the proposal, the final amendments require the use of either Equation W–10A or W–10B for calculating GHG emissions from completions and workovers of oil wells with hydraulic fracturing. Equation W–10A is used to calculate emissions from wells using inputs obtained from a representative sample of wells within a sub-basin and the ratio of the gas flowback rate to the production flow rate, and Equation W–10B is used to calculate emissions using inputs obtained from all wells within a sub-basin and the flow rate and flow volume of the gas vented or flared. As proposed, the EPA is finalizing that emissions be calculated and reported separately for gas wells and oil wells by sub-basin and well type combination.[3] Furthermore, as proposed, the final amendments require the use of Calculation Method 1 for calculating inputs to Equations W–12A and W–12B for oil wells. Calculation Method 1 relies on direct measurement of gas flow rate during flowback to develop calculation inputs; the requirements for the location of the flow meter used to measure the gas flow rate for oil wells are the same as the location requirements for gas wells. Other provisions that apply to completions and workovers of gas wells with hydraulic fracturing also apply to completions and workovers of oil wells with hydraulic fracturing, including the determination of wells that constitute a representative sample for use in Equation W–10A.

For oil wells that do not meter gas production, such as some wells with a relatively low GOR, the EPA is adding a new Equation W–12C as proposed to calculate, rather than measure, the value of $PR_{s,p}$ (the average gas production flow rate during the first 30 days of production after the completion or workover), which is used as an input to Equation W–10A. In this Equation W–12C, the value of $PR_{s,p}$ is calculated by multiplying the GOR of the well by the measured oil production rate over the

[3] Within subpart W, an individual well is labeled an ''oil well'' or ''gas well'' depending on the formation type reported for that well. If wells produce from more than one formation type, then the well is classified into only one type based on the formation type with the most contribution to production as determined by the reporter's engineering knowledge. See the definition of ''Sub-basin category, for onshore natural gas production'' in 40 CFR 98.238.

first 30 days of production after the completion or workover.

2. Summary of Comments and Responses

Comment: Several commenters responded to the EPA's request for comment on whether to establish a minimum GOR threshold such that oil wells with a very low GOR would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. Most of these commenters supported establishment of a cutoff for wells with very low emissions. One commenter urged the EPA to require monitoring and reporting for all completions and workovers with hydraulic fracturing but stated that if a threshold is set, it should be set at a level that ensures that all significant emissions sources are included and that sources are able to clearly determine whether they are required to report. Three commenters supported setting a minimum GOR threshold. One commenter suggested a minimum GOR threshold of 300 and stated that, based on industry experience, oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. The second commenter agreed that operators should only have to monitor and report emissions if the GOR is great enough to operate a separator and direct measurement is possible. The third commenter supporting a minimum GOR threshold did not provide a suggestion for a specific numeric threshold but stated that the emissions from wells with a low GOR are insignificant, and the time and resources involved in measuring the flowback and reporting emissions for wells expected to have minimal emissions would outweigh any contribution of these emissions to the overall source category totals. This commenter supported the inclusion of a threshold so that only significant sources of emissions would be included.

Response: The EPA agrees that including a minimum GOR threshold will help minimize reporting burden while still capturing most of the emissions from this source. Energy Information Administration data show that the number of ''oil only'' wells drilled from 2007–2012 was less than 20 percent of all new wells.[4] These wells would have a GOR approaching zero and, therefore, would be expected to have low emissions. We believe that having no threshold may create an unnecessary burden for operators to report emissions for these wells with just a trace of gas. Given that the EPA is finalizing the proposed requirement that the oil well flow meter be located downstream of the separator, the separator must be operating for the owner or operator to be able to measure the flow rate and estimate emissions from completions and workovers of oil wells with hydraulic fracturing. One commenter, an industry trade association, suggested a threshold of 300 scf/STB based on the industry trade association's experience that separators typically do not operate at a GOR less than 300 scf/STB.

The primary concern when determining the level for a threshold is volatility; the threshold must be low enough that the oil produced is considered non-volatile. Non-volatile ''black oils'' (*i.e.,* oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900 scf/STB.[5] Oil wells with a GOR less than the 300 scf/STB suggested by the commenter are at the lower end of this range, and completions and workovers with hydraulic fracturing of these wells will not likely have enough gas associated that can be separated. Therefore, the final monitoring and reporting requirements do not apply to completions and workovers of oil wells with hydraulic fracturing that have a GOR of less than 300 scf/STB.

Comment: Several commenters responded to the EPA's request for comment on whether to establish a minimum well pressure threshold such that oil wells with a very low well pressure would not be subject to the monitoring and reporting requirements for GHG emissions from completions and workovers with hydraulic fracturing. Most of these commenters supported establishment of a cutoff for wells with very low well pressure. One commenter urged the EPA to require monitoring and reporting for all completions and workovers with hydraulic fracturing but stated that if a threshold is set, it should be set at a level that ensures that all significant emissions sources are included and that sources are able to clearly determine whether they are required to report. Three commenters supported setting a minimum well pressure threshold. One commenter suggested a minimum well pressure threshold of 0.4645 pounds per square inch per foot (psi/ft) because this is the vertical pressure gradient needed for a well to flow back, based on experience with the Natural Gas STAR program. The second commenter suggested that operators should only have to monitor and report emissions if the pressure of the reservoir during oil well completions and workovers is greater than the pressure gradient of 0.433 psi/ft and noted that the pressure needed varies based on the density of the materials in the column and the depth of the well. The third commenter supporting a minimum well pressure threshold did not provide a suggestion for a threshold but supported the inclusion of a threshold so that only significant sources of emissions would be included.

Response: The EPA evaluated the commenters' suggestions and has decided not to include a minimum well pressure threshold. Both commenters who suggested a specific value noted in their comments that these pressure gradients are the minimum needed for the well to produce. In other words, according to the commenters' rationale, wells with pressures below the suggested pressure thresholds would not have any production, regardless of whether a threshold is included in the final rule. As a result, specifying that reporting of emissions from completions and workovers of oil wells with hydraulic fracturing is not required below those pressures is redundant. Therefore, the final rule does not include a minimum well or reservoir pressure threshold for completions and workovers of oil wells with hydraulic fracturing.

B. Summary of Final Amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment

The EPA is amending subpart W to add a new industry segment, Onshore Petroleum and Natural Gas Gathering and Boosting, that covers emissions from equipment used by gathering pipeline systems that move petroleum and natural gas from the well to either larger gathering pipeline systems, natural gas processing plants, natural gas transmission pipelines, or natural gas distribution pipelines. A gathering and boosting system is a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more well-defined connection points to gas and oil production and a well-defined downstream endpoint, typically a gas

[4] In this analysis, all hydrocarbon production in the liquid state at the wellhead was considered oil. J. Lieskovsky and S. Gorgen. ''Drilling often results in both oil and natural gas production.'' *Today in Energy,* U.S. Energy Information Administration, October 29, 2013. *http://www.eia.gov/todayinenergy/detail.cfm?id=13571.* Accessed June 9, 2015.

[5] M.P. Walsh. ''Oil Reservoir Primary Drive Mechanisms.'' In *Petroleum Engineering Handbook, Volume V: Reservoir Engineering and Petrophysics,* E.D. Holstein (Ed.), L.W. Lake (Ed. in Chief), pp. V–895–980. Society of Petroleum Engineers, 2007.

processing plant or transmission pipeline. Gathering pipelines are pipelines used to transport gas from the furthermost downstream point in an onshore production facility to certain endpoints, generally either a gas processing facility or point of connection to a transmission pipeline. Compressors located along the gathering and boosting system are used to control or ''boost'' the pressure of the gas in the pipeline and keep the gas moving downstream. Commenters generally supported inclusion of gathering and boosting system emissions in subpart W, and many commenters suggested targeted revisions concerning definitions, what emission sources should be included in the segment and methods for individual emission sources.

The remainder of this section describes the final reporting requirements for this new industry segment, including the segment description, definitions, calculation methods, and information to be reported. The amendments described in each section are followed by a summary of the major comments, if any, on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and the EPA's responses.

1. Segment Description for the Onshore Petroleum and Natural Gas Gathering and Boosting Segment

a. Summary of Final Amendments

The EPA is finalizing the definition of the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230 as gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline, or a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to, gathering pipelines, separators, compressors, acid gas removal (AGR) units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. The Onshore Petroleum and Natural Gas Gathering and Boosting segment does not include equipment and pipelines that are reported under any other industry segment defined in subpart W. The segment definition is being finalized as proposed, except that the final amendments provide two clarifications regarding gathering pipelines. First, gathering pipelines operating on a vacuum are not included because they would not be expected to have emissions. Second, to address comments regarding the inclusion of liquid and multiphase streams in the segment, the definition clarifies that gathering pipelines with a GOR less than 300 scf/STB are not a part of the segment.

b. Summary of Comments and Responses

Comment: Commenters requested that the EPA remove ''Petroleum and'' from the proposed segment name, ''Onshore Petroleum and Natural Gas Gathering and Boosting.'' The commenters asserted that the removal would provide a clear demarcation between onshore petroleum and natural gas production and onshore natural gas gathering and boosting. They also stated that such a change would be more consistent with the segment definition, which includes pipelines and equipment ''used to compress, dehydrate, sweeten, or transport the gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline.'' The commenter stated that the type of equipment included in the gathering and boosting segment is ''synonymous'' with gas gathering and boosting systems, not liquid or petroleum, and they noted that the emission factor for equipment leaks from gathering pipelines is not applicable to gathering pipelines that carry mostly liquid.

Commenters also specifically requested that the EPA exclude petroleum gathering pipelines from the gathering and boosting segment because the fugitive gas emissions from these gathering pipelines would be negligible. Both commenters stated that the proposed emission factor for gathering pipeline leaks is only applicable to gas gathering pipelines. Two commenters also requested that multi-phase flow lines from wells to a centralized production facility where initial separation occurs be retained in the Onshore Petroleum and Natural Gas Production segment rather than included in the new gathering and boosting segment.

Response: The EPA is finalizing the segment name as proposed and not removing ''Petroleum and'' from the segment name or moving multiphase gathering pipelines to the Onshore Petroleum and Natural Gas Production segment. We proposed including ''Petroleum and'' in the segment name to reflect the complex nature of upstream operations where wells can produce oil, natural gas, or a mixture of both and to signify the inclusion of GHG emissions from gathering and boosting systems moving high volatility liquids in this new segment. Even in wells that produce primarily liquids at surface temperature and pressure conditions, there is often a volatile gaseous component. This associated gas is usually considered wet due to the high content of natural gas liquids (volatile components) to go along with gaseous CH_4. Similarly, the inclusion of all petroleum gathering pipelines in the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including multiphase pipelines, is appropriate, because gathering lines are a key component to gathering and boosting systems. Therefore, all gathering pipelines that collect petroleum and/or natural gas from onshore production gas or oil wells and transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline are considered part of the final Onshore Petroleum and Natural Gas Gathering and Boosting segment.

However, the EPA does agree that gathering pipelines carrying mostly oil have a low potential for GHG emissions. We note that the ratio of CH_4 to volatile components increases as the GOR increases. Therefore, to clarify our intent to exclude gathering pipelines containing oil, the final rule clarifies that the Onshore Petroleum and Natural Gas Gathering and Boosting segment does not include gathering pipelines with a GOR of less than 300 scf/STB. Operators of gathering pipelines below that threshold are not required to include those pipelines in their gathering and boosting facility. See section II.B.5 of this preamble for additional discussion.

Finally, as part of evaluating this comment, the EPA reviewed the proposed definitions related to the Onshore Petroleum and Natural Gas Gathering and Boosting segment and recognizes that two of them referred to ''the gas'' rather than ''the petroleum and/or natural gas.'' One was the proposed description of the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230, as identified by the commenters, and the other was the definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238. For consistency throughout the final rule with the intent stated in this response, the final description of the Onshore

Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230 refers to ''petroleum and/or natural gas'' and the final definition of ''gathering and boosting system owner or operator'' in 40 CFR 98.238 refers to ''the petroleum or natural gas transported.''

Comment: One commenter stated that there may be confusion regarding which equipment should be reported in the different industry segments, which could lead to emissions being mistakenly excluded or double-counted. For example, gathering and boosting equipment located on a single well pad or associated with a single well pad could be double-counted, especially if it is operated by one entity but owned by another. The commenter also noted that confusion over the proper segment for this type of equipment could make the difference between reporting emissions or not reporting emissions if a facility is close to the reporting threshold of 25,000 metric tons carbon dioxide equivalent (CO_2e). Therefore, the commenter requested that the EPA incorporate by reference the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) federally defined boundaries of production, gathering and boosting, and transmission segments to ensure state/federal transparency and consistency.

Response: The EPA is not changing the segment description for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3). As stated at proposal, the EPA decided not to make any changes to the existing segment descriptions to provide consistency for reporters in that segment. This decision allows the EPA to ensure that the data gap in subpart W related to gathering and boosting systems is addressed while minimizing confusion over changes to other segments. Instead, the EPA is reiterating the intention for the Onshore Petroleum and Natural Gas Gathering and Boosting segment to cover equipment and emission sources not included in reporting for the existing Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments.

The EPA does not agree that emissions from the same equipment will be reported under more than one industry segment in a given reporting year; however, we acknowledge that similar equipment may exist in adjacent industry segments as defined in subpart W. The owner or operator of the equipment in question should first determine if that equipment is subject to reporting in another segment of subpart W, such as the Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments. If the equipment is not subject to reporting in another segment of subpart W, then the owner or operator should evaluate whether or not the equipment is included in the Onshore Petroleum and Natural Gas Gathering and Boosting source category. For example, if a gathering and boosting owner or operator also owns or operates equipment on or associated with a single well pad (40 CFR 98.230(a)(2)), that equipment is part of the Onshore Petroleum and Natural Gas Production segment, not the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Therefore, emissions from that equipment should not be included when determining if the gathering and boosting facility exceeds the reporting threshold.

Comment: One commenter requested that the EPA clarify the proper segment for AGR units and revise the rule accordingly. The commenter suggested that the Natural Gas Processing segment should explicitly exclude sulfur dioxide and carbon dioxide (CO_2) removal units, so that it is clear that those units do not report under both the Natural Gas Processing segment and the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The commenter stated that this revision would be more consistent with the definition of gas processing plant in other EPA rules. If the EPA does not make this change, the commenter stated that AGR units should not be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment because they are already included in the Natural Gas Processing segment. The commenter noted that AGR units are specifically defined in 40 CFR 98.238 as a process unit that separates hydrogen sulfide and/or CO_2 from sour natural gas using liquid or solid absorbents or membrane separators.

Response: The EPA agrees that emissions from a particular acid gas removal unit should not be reported under both the Natural Gas Processing segment and the Onshore Petroleum and Natural Gas Gathering and Boosting segment. However, as noted previously in this preamble, the EPA is not changing the segment description for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3). Instead, the EPA is reiterating the intention for the Onshore Petroleum and Natural Gas Gathering and Boosting segment to cover equipment and emission sources not included in reporting for the Onshore Petroleum and Natural Gas Production or Onshore Natural Gas Processing segments. The final segment description for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in 40 CFR 98.230(a)(10) specifies that gathering and boosting equipment does not include equipment reported under any other industry segment defined in 40 CFR 98.230(a), which should address the commenter's concern about reporting under multiple segments.

Regarding the commenter's suggestion to exclude AGR units from the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA believes AGR units should be reported under subpart W and that the current requirements, coupled with the revisions in this rulemaking, allow for a clear demarcation of where they should be included and reported. While most AGR units will be included in the Onshore Natural Gas Processing segment, the EPA does not agree that the Onshore Natural Gas Processing segment includes all AGR vents, particularly those in processes that do not fractionate gas liquids with an annual average throughput of less than 25 million scf per day. Therefore, the final Onshore Petroleum and Natural Gas Gathering and Boosting segment includes AGR vents that do not meet the segment descriptions for the Onshore Petroleum and Natural Gas Production segment in 40 CFR 98.230(a)(2) or the Onshore Natural Gas Processing segment in 40 CFR 98.230(a)(3) but do meet the Onshore Petroleum and Natural Gas Gathering and Boosting segment description in 40 CFR 98.230(a)(10).

2. Definitions

a. Summary of Final Amendments

The EPA is finalizing the definition of ''gathering and boosting system'' as proposed and is finalizing the definition of ''gathering and boosting system owner or operator'' as proposed with a clarification that the fluid being transported may be petroleum or natural gas. Specifically, a gathering and boosting system is a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, local distribution company (LDC) pipeline, or other gathering and boosting system. A gathering and

boosting system owner or operator is any person that: (1) Holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline; or (2) is responsible for custody of the petroleum or natural gas transported. In complex ownership scenarios, the owner/operator assigns a designated representative responsible for reporting consistent with 40 CFR 98.4.

The EPA is also finalizing the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting'' in 40 CFR 98.238 as proposed. A facility with respect to onshore petroleum and natural gas gathering and boosting is all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in 40 CFR 98.238. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting systems and equipment that the person owns or operates in the basin are considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system. Emissions from an onshore petroleum and natural gas gathering and boosting facility only need to be reported if the collection of emission sources emits 25,000 metric tons CO_2e or more per year.

b. Summary of Comments and Responses

Comment: Multiple commenters provided comments on the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting.'' Some commenters supported the basin-level approach that the EPA proposed, although a few asked the EPA to clarify how to report their emissions if their gathering and boosting system is in more than one basin. Other commenters disagreed with the basin-level approach and suggested that the EPA should use the definition of facility in 40 CFR 98.6. These commenters asserted that the basin-level approach would result in an expansive definition of facility that includes huge numbers of emissions sources and that this approach is not consistent with how a facility is defined elsewhere in the GHGRP or with traditional notions of aggregation under the CAA. One commenter asserted that defining a facility in a way that is not consistent with other CAA programs will make it difficult for the EPA to use the GHGRP data to inform future policy decisions. The commenter also stated that the EPA has not provided any explanation of why basin-wide aggregation is a reasonable data request under section 114 of the CAA.

Commenters opposing the basin-level facility definition noted that the Onshore Petroleum and Natural Gas Gathering and Boosting segment has very different characteristics from the Onshore Petroleum and Natural Gas Production segment, which also uses the basin-level approach to defining a facility. One commenter specifically noted that production sources are located at well-defined, discrete locations, owners and operators of production sites know where the wells are physically located and how many operate in a single production basin. In contrast, the commenter stated, the gathering and boosting operations of one owner or operator in a single hydrocarbon basin may include hundreds or thousands of miles of pipelines with multiple sites, including interconnects, meter stations, scrubber stations, pigging stations, compressor stations, and gas treating plants. Another commenter stated that gathering and boosting sites have the ability to boost and move gas from multiple basins within the same site, whereas production typically maintains operations and moves gas within one basin.

Another commenter also disagreed with the basin-level approach, noting that the term ''basin'' is not common terminology that is used in the gathering and boosting industry segment. The commenter suggested that the EPA use a county- or parish-level approach with an equipment threshold (to determine which equipment should be counted when determining if the 25,000 metric tons CO_2e reporting threshold has been exceeded).

Response: The EPA is finalizing the definition of ''facility with respect to onshore petroleum and natural gas gathering and boosting'' as proposed. As noted in the preamble to the proposed amendments, the basin-level approach to defining a facility for the Onshore Petroleum and Natural Gas Gathering and Boosting segment is expected to achieve a balance of providing geographically specific information while also reducing burden on reporters. This approach also recognizes the fact that gathering and boosting facilities are more dispersed than processing facilities and are geographically similar to the Onshore Petroleum and Natural Gas Production segment in size and number of sources because, by their nature, they are needed to process and transport the petroleum and natural gas produced in a given basin. While some gathering and boosting operations may span multiple basins or may only be present in a portion of a basin, as will some onshore production operations, the EPA has concluded that a basin-level facility definition is the best reflection of how this industry is organized operationally.

In ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Proposed Rule'' (Docket Item No. EPA–HQ–OAR–2014–0831–0018), we evaluated the option of using the definition of ''facility'' found in 40 CFR 98.6 for gathering and boosting facilities, and we found that this definition would provide limited data on the proposed Onshore Petroleum and Natural Gas Gathering and Boosting segment compared to the basin-level approach, due to the fact that fewer facilities would exceed the 25,000 metric tons CO_2e reporting threshold. It would also likely be more burdensome overall to reporters, because a larger number of facilities would have to be evaluated to determine whether they exceed the 25,000 metric tons CO_2e reporting threshold, and a larger number of ''facility'' reports would be required for each owner or operator. The commenters did not provide any new information that would enable us to re-evaluate this conclusion. A county- or parish-level approach would similarly result in a larger number of smaller facilities to be evaluated to determine whether they exceed the reporting threshold than the basin-level approach. This approach would result in fewer facilities reporting than a basin-level definition, especially if an equipment threshold were defined as requested by the commenter, as well as a higher burden for owners or operators with multiple facilities in a basin that exceed the 25,000 metric tons CO_2e reporting threshold. Therefore, the EPA concluded that these options would not achieve the goals that were articulated in the preamble to the proposed rule of ''having a thorough data set and transparent, complete information for this sector while minimizing burden to reporters'' (79 FR 73156; December 9,

2014). For more detail on this analysis, see ''Greenhouse Gas Reporting Rule: Technical Support for Final 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831. We disagree with the comment that aggregation of data would not provide a data set that the EPA can use to inform future policy decisions. The purpose of this rule is to collect emissions and activity data for this industry and understand the relative emission sources, which we anticipate the aggregated data will help to promote. Therefore, the aggregated data can still inform future GHG policy. As we have pointed out previously, the EPA's definition of ''facility'' for purposes of part 98 in no way impacts the ''facility'' definition for similar sources under existing CAA programs.[6] Information collected under part 98 can inform a number of different CAA programs and the Agency's authority under CAA section 114 as the basis for part 98 is independent from the EPA's authority for other CAA programs.

To address the commenters' question about reporting a system in two basins, we are confirming in this response that reporters should submit one report per basin (*i.e.,* per facility as it is defined in subpart W) and that the 25,000 metric tons CO_2e per year reporting threshold applies to each basin/facility separately. In other words, the reporter should determine the emissions from the portion of gathering and boosting system associated with each basin. If the total emissions in each basin exceed the 25,000 metric tons CO_2e per year reporting threshold, then the reporter submits two reports. If the total emissions in one basin exceed the 25,000 metric tons CO_2e threshold, but the emissions in the other basin are below the threshold, then the reporter submits one report (for the facility that exceeds the threshold).

Regarding the commenter's question regarding the reasonableness of collecting data at the basin-level under the CAA, the EPA established its basis for collecting basin-level data in the final subpart W rule, when the EPA finalized the requirements for the Onshore Petroleum and Natural Gas Production segment. Additionally, as noted earlier in this section, more granular collection of data for this segment would result in higher burden for owners or operators with multiple operations in a basin that exceed the 25,000 metric tons CO_2e reporting threshold. See also, ''Greenhouse Gas Emissions Reporting from the Petroleum and Natural Gas Industry, Background Technical Support Document (Docket Item No. EPA–HQ–OAR–2009–0923–3610) and ''Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments'' (Docket Item No. EPA–HQ–OAR–2009–0923–3608).

3. Blowdown Vent Stacks

a. Summary of Final Amendments

The EPA is finalizing the requirements for blowdowns of equipment in the Onshore Petroleum and Natural Gas Gathering and Boosting segment with some clarifications from proposal. Emissions should be calculated using the same methods that are used for the Onshore Natural Gas Processing segment. The same exemptions, including those for volumes less than 50 cubic feet (ft^3) and for desiccant dehydrator reloading, apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment. In response to comments that the segment is geographically dispersed and blowdowns may occur without personnel on-site or nearby, making it difficult to determine emissions from a blowdown event, the final amendments specify that for emergency blowdowns, reporters may use engineering estimates based on best available information to determine the temperature and pressure used in Equation W–14A.

b. Summary of Comments and Responses

Comment: Commenters stated that the EPA should not include reporting of blowdown vent stack emissions due to the large burden on the reporter. Instead, the commenters stated, blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should be treated similarly to blowdowns in the Onshore Petroleum and Natural Gas Production segment, where they are excluded because they are not located at consolidated facility sites and are not manned. Commenters also stated that blowdowns from gathering and boosting systems contribute minimally to overall GHG emissions. One commenter noted that while there is an exemption for any blowdown of a volume less than 50 ft^3, there is also a burden to determine if the physical volume meets this reporting threshold. To reduce the burden, some commenters suggested only including emissions from blowdown vent stacks located at a facility site (*e.g.,* compressor station, central tank battery). Other commenters stated if blowdowns remain in the segment, the EPA should allow reporters to use an emission factor approach to calculate emissions. Another commenter stated that the EPA's supporting documentation focuses on gathering pipeline blowdowns, but the regulatory text appears to include all the blowdowns occurring within a basin, including individual equipment blowdowns. The commenter requested that the EPA clarify its intent if blowdowns remain in the segment.

Response: The EPA has evaluated these comments and has decided to finalize the reporting requirements for blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment with some revisions to address the commenters' concerns. While the EPA does recognize that many gathering and boosting systems are geographically dispersed, as noted by the commenters, the nature of the Onshore Petroleum and Natural Gas Gathering and Boosting segment is such that the amount of fluid passing through a gathering and boosting system will be much greater than the amount of fluid at individual well pads. Therefore, the EPA has determined that the potential for emissions from blowdowns in the Onshore Petroleum and Natural Gas Gathering and Boosting segment is higher than blowdowns in the Onshore Petroleum and Natural Gas Production segment, and they should not be excluded. However, the EPA acknowledges that the geographic dispersion of the segment, and the fact that some blowdowns occur without facility personnel on site, may make it difficult to measure emissions from blowdowns, particularly emergency blowdowns. Therefore, the final amendments include a provision specifying that for emergency blowdowns, reporters may use engineering estimates based on best available information to determine the temperature at actual conditions in the unique physical volume and absolute pressure at actual conditions in the unique physical volume for use in Equation W–14A.

To respond to the commenter's request regarding whether only gathering pipeline blowdowns or all equipment blowdowns should be included, the EPA is clarifying that the intent is to include emissions from the ''blowdown vent stacks'' source type as defined in subpart A of part 98. The focus on blowdown vent stacks located on gathering pipelines in the supporting documentation was not intended to imply that only gathering pipeline blowdowns should be reported. On the

[6] Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart W: Petroleum and Natural Gas Systems, Docket Id. No. EPA–HQ–OAR–2009–0923.

contrary, the proposal supporting documentation reflects the fact that the EPA expected that blowdown vent stacks located at boosting stations would be similar to blowdown vent stacks in other industry segments and conducted a separate evaluation to determine whether the same calculation methods would be appropriate for gathering pipeline blowdown vent stacks. The final rule supporting documentation more clearly reflects this intent. The EPA also notes that while measuring equipment to determine whether it exceeds the 50 ft^3 physical volume threshold for reporting may create an initial burden on reporters, the threshold will lead to a burden reduction as reporters become familiar with the identification process.

4. Storage Tank Vented Emissions

a. Summary of Final Amendments

The EPA is finalizing the same methods for calculating emissions for atmospheric storage tanks located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as in the Onshore Petroleum and Natural Gas Production segment, as proposed but with a few clarifications. Specifically, the EPA is clarifying some of the language within 40 CFR 98.233(j) and 40 CFR 98.236(j) that was originally written to apply to Onshore Petroleum and Natural Gas Production facilities and not proposed to be amended to also apply to storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. In particular, references to a ''wellhead separator'' have been clarified to refer simply to a ''separator,'' which is a defined term in 40 CFR 98.238. To accommodate Onshore Petroleum and Natural Gas Gathering and Boosting storage tanks that do not receive hydrocarbon liquids from a separator or well, Calculation Methods 1 and 2 have been amended to specify how to estimate emissions if liquids are received from non-separator equipment. In addition, certain instances of ''sub-basin'' have been amended to refer to ''county'' to clarify the requirements for Onshore Petroleum and Natural Gas Gathering and Boosting reporters. All other provisions in 40 CFR 98.233(j) apply to the Onshore Petroleum and Natural Gas Gathering and Boosting segment, including the 10 barrels per day threshold for determining which calculation method may be used for estimating emissions.

b. Summary of Comments and Responses

Comment: One commenter stated that combining the requirements for storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment and the Onshore Petroleum and Natural Gas Production segment results in confusing terminology and unclear requirements. In particular, the commenter noted that the terms ''separator(s),'' ''gas-liquid separator(s),'' ''wellhead separator(s),'' and ''wellhead gas-liquid separator(s),'' appear throughout the storage tank requirements. The commenter asked whether the EPA intended all of these terms to refer to the same equipment. The commenter also noted that not all gathering and boosting system storage tanks receive liquids directly from separators, and no gathering and boosting storage tanks receive liquids directly from wellhead separators. Therefore, the commenter stated, the requirements for storage tanks in the Onshore Petroleum and Natural Gas Gathering and Boosting segment are unclear.

The commenter also noted inconsistency between use of the terms ''oil,'' ''sales oil,'' and ''stabilized oil'' in 40 CFR 98.233(j) and 40 CFR 98.236(j). The commenter stated that Onshore Petroleum and Natural Gas Gathering and Boosting facilities may process condensate but not oil, and the commenter asked the EPA to clarify how those terms should be applied to the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

Finally, the commenter noted that Calculation Method 1 for storage tanks requires use of the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category. The commenter stated that the term ''sub-basin'' has no relevance to the Onshore Petroleum and Natural Gas Gathering and Boosting segment because the composition of condensate processed at a compressor station may have little relationship to the oil or gas formation below the compressor station.

Response: The EPA agrees that the language in 40 CFR 98.233(j) and 40 CFR 98.236(j) should be clear for all Onshore Petroleum and Natural Gas Production facilities and all Onshore Petroleum and Natural Gas Gathering and Boosting facilities to which it applies. The existing definition of ''separator'' in 40 CFR 98.238 is a vessel in which streams of multiple phases are gravity separated into individual streams of single phase. This general definition and the general term ''gas-liquid separator'' apply to both Onshore Petroleum and Natural Gas Production facilities and all Onshore Petroleum and Natural Gas Gathering and Boosting facilities. Therefore, the EPA has reviewed the language and is amending references to a ''well,'' ''well pad,'' or ''wellhead,'' which are terms that are not expected to apply to most Onshore Petroleum and Natural Gas Gathering and Boosting facilities. The final provisions in 40 CFR 98.233(j) and 40 CFR 98.236(j) refer more generally to separators or gas-liquid separators. To address the comment that not all gathering and boosting system storage tanks receive liquids directly from separators, the EPA has amended 40 CFR 98.233(j)(1) and (2) to specify how those calculation methodologies may be used for Onshore Petroleum and Natural Gas Gathering and Boosting storage tanks receiving hydrocarbon liquids from non-separator equipment (*i.e.,* without a well or separator directly upstream of the storage tank).

Regarding the particular material being stored in storage tanks, the EPA agrees that there is inconsistency in some of the terms that could cause some confusion. The EPA is clarifying in this response that for the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the intent is for ''oil'' to refer more generally to hydrocarbon liquids, which is consistent with the statement in 40 CFR 98.233(j) that reporters are required to calculate emissions ''from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids.'' The proposed separate reporting requirements for quantity of produced oil throughput and produced condensate throughput in 40 CFR 98.236(aa)(10) have been revised, and the final rule requires reporting of the hydrocarbon liquids received by the facility and the hydrocarbon liquids leaving the facility. Finally, the EPA notes that the term ''sales oil'' is already defined in Subpart A to include ''produced crude oil or condensate,'' so there is no further clarification needed.

Regarding the term ''sub-basin,'' the EPA agrees with the commenter that the definition of ''sub-basin category, for onshore natural gas production'' in 40 CFR 98.238 is not relevant for Onshore Petroleum and Natural Gas Gathering and Boosting facilities. The EPA also agrees that the operations within a section of a gathering and boosting system may not be related to the formation type below the surface of the ground at that location, especially as the material travels further from the wells supplying gas and hydrocarbon liquids to the system. As a result of this comment, the EPA reviewed the use of the term ''sub-basin'' as it was proposed to apply to Onshore Petroleum and Natural Gas Gathering and Boosting facilities. In 40 CFR 98.233(j), the calculation methods provide options to

estimate unknown parameters using information from a previous analysis of the composition in the sub-basin category. In these cases, the intent is to estimate unknown parameters from a representative unit (*e.g.,* well, separator). To reflect a similar intent for Onshore Petroleum and Natural Gas Gathering and Boosting facilities, 40 CFR 98.233(j)(1)(vii)(B) and 40 CFR 98.233(j)(1)(vii)(C) in Calculation Method 1 clarify that representative separators or non-separator equipment are located within the same county for Onshore Petroleum and Natural Gas Gathering and Boosting reporters. For Calculation Method 2, the term ''sub-basin category'' is used to describe calculation of emissions for flow to storage tanks directly from wells. The final rule includes a new paragraph 40 CFR 98.233(j)(2)(iii) to address calculation of emissions from flow to a tank from equipment other than a well or separator (such as a stabilizer or slug catcher), and this paragraph also clarifies that representative analyses should come from other non-separator equipment located within the same county. Finally, there are reporting requirements for a ''sub-basin ID'' in 40 CFR 98.236. The final rule specifies that for Onshore Petroleum and Natural Gas Gathering and Boosting, the information to be reported is the county in which the equipment is located.

5. Gathering Pipelines

a. Summary of Final Amendments

The EPA is finalizing the requirements for calculating emissions from gathering pipelines defined to be included in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as proposed. The methodology is similar to the approach used for equipment leaks in the Onshore Petroleum and Natural Gas Production segment. For gathering lines, reporters use the population count and emission factor approach in 40 CFR 98.233(r). The emission factors in Table W–1A for gathering pipelines are whole gas emission factors based on the U.S. GHG Inventory. The population count is the miles of gathering pipeline, similar to the approach used for calculating emissions from natural gas distribution pipelines in the Natural Gas Distribution segment. As noted in section II.B.1.a of this preamble, gathering pipelines with a GOR less than 300 scf/STB are not included in this segment.

b. Summary of Comments and Responses

Comment: One commenter asserted that the EPA should revise the proposed emission factor of 2.81 standard cubic feet (scf)/hour/mile for leaks from gathering pipelines to be based on characteristics of currently operating gathering pipelines rather than distribution pipelines or older data on gathering pipelines. The commenter also noted that this emission factor is not applicable to gathering pipelines that carry primarily liquids, as there is no gas stream until after separation. The commenter identified gathering pipeline-specific data from PHMSA and used the data to calculate a suggested emission factor of 2.23 scf/hour/mile.

Response: We reviewed the underlying data used to develop the proposed emission factor, and we agree with the commenter that the proposed emission factor could better account for differences between pipeline types and for currently operating gathering pipelines. In the 1996 Gas Research Institute (GRI)/EPA report that is the basis of the emission factor, material-specific emissions factors for gathering lines were developed using data from direct measurement of distribution pipelines conducted in the 1990s, not gathering pipelines. These material-specific emission factors are the same emission factors used by the commenter as the starting point for their revised emission factor.

We agree with the commenter that the emission factors should better represent currently operating gathering pipelines; however, there is significant variability in gathering pipelines and gathering system configurations. Owners and operators currently report the mileage of pipeline by gathering pipeline type to PHMSA.[7] Therefore, rather than calculate a single emission factor for gathering pipelines based on a distribution of gathering pipeline materials, as was done at proposal, the EPA determined that the most appropriate approach is to develop gathering pipeline emission factors for four pipeline material types: Protected steel, unprotected steel, plastic, and cast iron. (For more information about the development of these emission factors, see ''Greenhouse Gas Reporting Rule: Technical Support for Final 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831.) The final amendments require reporters to estimate emissions using material-specific emission factors provided in the rule and to report gathering pipeline mileage by material type.

The EPA also notes that reporters will not need to calculate emissions from gathering pipelines that carry hydrocarbon liquids if they are below the minimum GOR threshold for the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

6. Other Emission Sources

a. Summary of Final Amendments

The EPA is finalizing the requirements for natural gas pneumatic devices and pneumatic pumps located in the Onshore Petroleum and Natural Gas Gathering and Boosting segment as proposed. Gathering and boosting reporters will use the same methods for calculating emissions as in the Onshore Petroleum and Natural Gas Production segment. The EPA is also finalizing the requirements for acid gas removal units, dehydrators, and flare stacks as proposed. The methods are the same as the methods for these sources in both the Onshore Petroleum and Natural Gas Production segment and the Onshore Natural Gas Processing segment. The EPA is also finalizing the requirements for compressors and equipment leaks as proposed, with one clarification regarding how to count ''meters/piping'' for equipment leaks. Gathering and boosting reporters use the same method as in the Onshore Petroleum and Natural Gas Production segment. Specifically, a reporter will need to establish an inventory of the components or equipment subject to the population counts, apply the emission factors, and then update the inventory each year to account for new or retired components or equipment.

b. Summary of Comments and Responses

Comment: Two commenters stated that the major equipment categories for calculating equipment leaks by population count are not clear for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. Both commenters requested that the EPA clarify how to count ''meters/piping'' for the Onshore Petroleum and Natural Gas Gathering and Boosting segment. One commenter also requested clarification regarding separators, compressors, and in-line heaters (specifically, whether small heating systems used to ensure a temperate environment for a meter are considered in-line heaters). The

[7] U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. Natural and Other Gas Transmission and Gathering Pipeline Systems: Annual Report for Calendar Year. Form PHMSA F 7100.2–1 (rev 10–2014). OMB No. 2137–0522, Expires: 10/31/2016.

commenter also noted that there was limited time to evaluate the appropriateness of the emission factors in Table W–1A and the component counts in Table W–1B for gathering and boosting systems.

Response: The categories in Table W–1B represent the types of equipment that are generally expected to be found in the field for Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting facilities.[8] For the Onshore Petroleum and Natural Gas Gathering and Boosting segment, the EPA realizes that reporters will only use those categories that apply (*e.g.,* reporters will not include wellheads, as that equipment type is specific to Onshore Petroleum and Natural Gas Production facilities).

Most of the major equipment categories are described by function in the rule. For the example of a separator, 40 CFR 98.238 defines a separator as ''a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.'' Any device meeting this functional definition will fall into this major equipment category. Other major categories are described in the rule by their functional role, including dehydrators and compressors. For the in-line heater example for which the commenter requested clarification, the equipment described is not located in line with the fluid flow and therefore would not be considered in this equipment category.

The EPA agrees with both commenters that the measurement of meters/piping in the Onshore Petroleum and Natural Gas Gathering and Boosting segment was not clear as proposed. The final rule specifies that reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should count the number of meters in the facility and use that as the count for ''meters/piping.''

Comment: Two commenters supported the use of calculation methods that include emission factors for the Onshore Petroleum and Natural Gas Gathering and Boosting segment because they are less burdensome to the industry. However, the commenters also requested that the EPA allow reporters the option to use any available data/information that provides the best representation of emissions from their specific sources, including manufacturer data, test data, measurement and/or monitoring data. The commenters compared this option to the approach in state-level emissions inventories that require an emissions reporting hierarchy. The commenters noted that this approach will provide the EPA with more accurate emissions data that could be used to update the emission factors for the Onshore Petroleum and Natural Gas Gathering and Boosting segment.

Response: The calculation methods provided in subpart W were selected to minimize burden on industry while maintaining the necessary quality and consistency of data to inform policy. Therefore, outside of the BAMM provisions being finalized in this rulemaking, the EPA does not agree to allow reporters to use customized, individual information for their emission sources at this time. The EPA is currently investigating additional calculation methods for subpart W sources and may propose additional calculation methods in the future.

C. Summary of Final Amendments for the Onshore Natural Gas Transmission Pipeline Segment

1. Summary of Final Amendments

The EPA is finalizing the proposal to add reporting requirements for emissions from natural gas transmission pipeline blowdowns between compressor stations in a new Onshore Natural Gas Transmission Pipeline segment. Commenters generally had no objections to the merit of including this segment in subpart W but did suggest technical edits and clarifications for targeted provisions. As noted in the preamble to the proposed amendments, a blowdown is the release of gas from transmission pipelines that causes a reduction in system pressure or a complete depressurization. The EPA is clarifying that for the purposes of the Onshore Natural Gas Transmission Pipeline segment, the blowdowns that must be reported are blowdowns of a pipeline or section of pipeline.

The EPA is finalizing clarifications to the proposed definition of onshore natural gas transmission pipeline owner or operator. For interstate pipelines, the onshore natural gas transmission pipeline owner or operator is the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, as proposed. For intrastate pipelines, the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act (NGPA). If the intrastate pipeline is not subject to section 311 of the NGPA, the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers. Finally, the owner or operator of a pipeline that falls under the ''Hinshaw Exemption'' is the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224.

The EPA is finalizing the definition of facility for the new Onshore Natural Gas Transmission Pipeline segment as proposed; the facility is the total U.S. mileage of natural gas transmission pipelines owned or operated by an onshore natural gas transmission pipeline owner or operator. If an owner or operator has multiple pipelines in the United States, the facility is considered the aggregate of those pipelines, even if they are not interconnected.

The EPA is finalizing the requirement that reporters use the methods in 40 CFR 98.233(i) to calculate or measure emissions from pipeline blowdown events as proposed. One method allows a reporter to calculate emissions based on the volume of the pipeline segment between isolation valves that is blown down and the pressure and temperature of the gas within the pipeline. The second method allows the reporter to measure the emissions from the blowdown using a flow meter on the blowdown vent stack. In both methods, the reporter calculates both CH_4 and CO_2 emissions from the volume of natural gas vented using either default gas composition or engineering estimates of composition as specified in 40 CFR 98.233(u)(2)(iii).

The EPA is not finalizing the proposed requirement to report the emissions and location (latitude and longitude) of each blowdown event. Instead, the EPA is requiring that Onshore Natural Gas Transmission Pipeline reporters report the total CH_4 and CO_2 emissions in each state, the number of blowdowns in each state, and the miles of pipeline in each state. In addition, instead of requiring Onshore Natural Gas Transmission Pipeline reporters to use the same equipment and event type categories as other industry segments reporting blowdown emissions, the EPA is including reporting categories specific to the Onshore Natural Gas Transmission Pipeline segment.

[8] See the memorandum ''Equipment-Level Population Emission Factors for Onshore Production,'' Docket Item No. EPA–HQ–OAR–2009–0923–3582, for more information regarding the derivation of this table.

NMED Exhibit 97 - 0014

2. Summary of Comments and Responses

Comment: Several commenters noted that not all intrastate pipelines are subject to section 311 of the NGPA and asked the EPA to clarify which intrastate pipelines are subject to reporting. One commenter requested that the EPA clarify that intrastate pipelines not subject to the NGPA are not required to report under subpart W. Another commenter suggested revising the definition of owner or operator to state that if section 311 of the NGPA does not apply, the intrastate transmission pipeline owner or operator is the owner or operator identified on required reports with the appropriate state agency.

Response: It was our intent to include transmission pipelines (including intrastate pipelines) that meet the already existing subpart W definition of ''transmission pipeline'' in the Onshore Natural Gas Transmission Pipeline segment. A transmission pipeline in subpart W is defined in 40 CFR 98.238 as a Federal Energy Regulatory Commission (FERC) rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994). After reviewing the comments on the proposed rule, we re-reviewed section 311 of the NGPA and found that only operators of some intrastate pipelines, including those that transport natural gas on behalf of an interstate pipeline or sell natural gas to an interstate pipeline, are required to prepare a Statement of Operating Conditions for compliance under section 311 of the NGPA. Therefore, to clarify how to determine the owner and operator of intrastate transmission pipelines, the finalized definition of ''onshore natural gas transmission pipeline owner or operator'' specifies that for intrastate transmission pipelines not subject to section 311 of the NGPA, the owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers. The EPA also found that the proposed definition of ''onshore natural gas transmission pipeline owner or operator'' did not specify how to determine the owner or operator of pipelines that fall under the ''Hinshaw Exemption.'' The EPA notes that similar to intrastate pipelines, pipelines that fall under the ''Hinshaw Exemption'' must apply for a ''blanket certificate'' under 18 CFR 284.224 in order to transport petroleum or natural gas on behalf of interstate pipelines. Therefore, the finalized definition of ''onshore natural gas transmission pipeline owner or operator'' also specifies that for a pipeline that falls under the ''Hinshaw Exemption,'' the owner or operator is the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224.

Comment: Commenters appreciated that the EPA provided a threshold of 50 ft^3 of physical volume for blowdown emissions reporting but requested several changes. Commenters requested that the EPA include a list of ancillary equipment, such as metering and/or regulating stations, pipeline interconnects, and pig launchers and receivers, that would be excluded from reporting of blowdown emissions. One commenter suggested that, alternatively, the physical volume threshold could be increased to 3,000 thousand cubic feet to clearly exclude blowdowns of ancillary facilities along the pipeline. Another commenter stated that it is not feasible to establish a specific *de minimis* volume threshold to exclude all ancillary equipment.

Response: The EPA is finalizing the reporting threshold of 50 ft^3 of physical volume for blowdowns in the Onshore Natural Gas Transmission Pipeline segment as proposed. This threshold excludes smaller blowdown sources that have little contribution to emissions, consistent with other industry segments within subpart W that must report blowdown stack vent emissions. The EPA is not increasing the physical volume reporting threshold to account for blowdowns from ancillary equipment, as this would be inconsistent with the EPA's previous analysis in ''Equipment Threshold for Blowdowns'' (see Docket Item No. EPA–HQ–OAR–2009–0923–3581), and commenters were divided on whether increasing the threshold would even address their primary concern.

The EPA agrees that the emphasis for the Onshore Natural Gas Transmission Pipeline segment is on calculating and reporting blowdown emissions from pipeline segments, not ancillary equipment. However, any list of ancillary equipment that would be excluded from blowdown reporting could be incomplete, resulting in reporting of emissions from other equipment that is ancillary but not on the list in the rule. In addition, some of the equipment identified as ''ancillary'' in this segment is not considered ancillary in other industry segments, which could lead to confusion among reporters. Instead, the final rule clarifies that facilities in the Onshore Natural Gas Transmission Pipeline segment report pipeline blowdown emissions from blowdown vent stacks. If the blowdown does not include a pipeline segment or has a physical volume of less than 50 ft^3, then that blowdown is not required to be reported.

Comment: Several commenters stated that the blowdown equipment and event type categories in 40 CFR 98.233(i)(2) were developed for compressor station blowdowns and would not provide meaningful information regarding pipeline blowdowns in the Onshore Natural Gas Transmission Pipeline segment. The commenters provided suggestions for categories that would be more applicable to Onshore Natural Gas Transmission Pipeline blowdowns and would provide more valuable information than relying on the categories in the existing rule.

Response: The EPA agrees with the commenters that the rule should include blowdown categories specific to blowdowns in the Onshore Natural Gas Transmission Pipeline segment. The final rule specifies that blowdowns must be grouped into one of the following categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined by PHMSA, and all other pipeline segments with a physical volume greater than or equal to 50 ft^3.

Comment: Commenters requested that the EPA not finalize the requirement to report latitude and longitude for each blowdown event. The commenters indicated this requirement would be burdensome, such data are not currently collected, the requirement is inconsistent with the Paperwork Reduction Act, and the data would not be useful in determining the inventory. Some commenters also suggested aggregating emissions at the state level or only at the national/facility level.

Response: The requirement to report latitude and longitude of each blowdown was included in the proposed rule to help characterize the emissions from the new Onshore Natural Gas Transmission Pipeline segment on a more granular level than the nationwide facility. The EPA evaluated this comment and has noted the commenters' assertion that the latitude and longitude of each

blowdown is not information currently reported elsewhere and may result in additional burden. Therefore, the EPA is not finalizing the requirement to report the emissions or latitude and longitude for each individual blowdown. Instead, the EPA is finalizing requirements for reporters to aggregate blowdown emissions by state and report the number of blowdowns and mileage of pipeline per state.

Comment: Two commenters questioned the requirement to report the data elements in proposed 40 CFR 98.236(aa)(11). Two commenters noted that the quantities of natural gas in this section are duplicative of information reported to FERC annually in FERC Form 2, although the units of measure are dekatherms rather than thousand standard cubic feet. One commenter noted that for the GHGRP reporting, they would assume 1 dekatherm is equivalent to 1,000 scf of natural gas, based on the approximate heat value of natural gas. The other commenter opposed these reporting requirements because they are duplicative and inconsistent with the requirements of the PRA, which is intended to reduce the information burden imposed by the federal government by requiring that agencies ensure that reported information is not duplicative of other available data and has a practical utility. This commenter stated that the EPA has not followed the PRA. The commenter also stated that the requested information is irrelevant to assisting EPA in verifying pipeline blowdown emissions; in particular, the information cannot be used to calculate pipeline blowdown volumes.

Response: As the EPA has noted elsewhere, the data collected in the GHGRP will be used to inform future policy decisions. As such, information regarding emissions and the inputs needed to verify those emissions is only part of the information that is needed. It is important to understand that, to inform future policy, activity data is often as useful as emissions estimates. The EPA has determined that data elements in 40 CFR 98.236(aa)(11) are activity data that will be used to determine how to use the emissions data to inform future policy decisions. It is essential that reporters provide and certify the data they gather under this rule so that EPA has a complete inventory from all sources under this rule and can directly relate the activity data to the emissions data reported, which will provide for appropriate verification of the emissions data reported.

The EPA agrees with the first commenter that for purposes of reporting the data elements in 40 CFR 98.236(aa)(11), reporters may consider 1 dekatherm equal to 1,000 scf.

Comment: Several commenters asserted that the EPA has not been consistent in its decisions on whether to include pipeline leaks across the subpart W industry segments. Some commenters supported the EPA's proposal not to include leaks from transmission pipelines and noted the decision was consistent with the Onshore Petroleum and Natural Gas Production segment. Conversely, one commenter stated that transmission pipeline leaks should be reported, consistent with the new Onshore Petroleum and Natural Gas Gathering and Boosting segment. This commenter noted that accidental leaks at these facilities can be a significant source of CH_4 emissions, as evidenced by the magnitude of emissions from pipeline incidents reported to PHMSA, and leaks at remote locations may not be noticed or repaired immediately.

Response: The EPA previously considered fugitive emissions that result from leaks in transmission pipelines in the re-proposal of subpart W in April 2010 (75 FR 18616; April 12, 2010) but did not include provisions for these emissions in either the proposed or final rules. The April 2010 preamble explained that the EPA did not propose reporting requirements for fugitive emissions from leaks in natural gas pipeline segments between compressor stations due to the dispersed nature of the fugitive emissions and the fact that, once fugitives are found, the leaks causing the emissions are usually addressed quickly for safety reasons (75 FR 18616; April 12, 2010). The EPA also noted in the proposal preamble for these amendments (79 FR 76267; December 9, 2014) that larger fugitive leaks are currently reported to PHMSA as part of 49 CFR 191.3. Under this provision, any pipeline incident that results in unintentional gas loss of 3 million ft^3 or more must be reported. The commenter that noted that emissions can be significant cited the emissions reported to PHMSA under this provision, and the EPA does not find it necessary to require owners and operators to report this same information under the GHGRP. The focus of the PHMSA reporting requirements is to identify major safety-related incidents that are not a part of typical operations. Therefore, the EPA is not finalizing a requirement to report fugitive emissions from transmission pipeline leaks but will continue to review this source as part of the EPA's ongoing effort to ensure comprehensive, high quality data in subpart W.

D. Summary of Final Amendments for Well Identification Numbers

1. Summary of Final Amendments

The EPA is finalizing some of the proposed amendments to 40 CFR 98.236 to add reporting requirements for well identification numbers to improve data quality by enabling identification of wells. These well identification numbers will be reported for the first time in the report covering 2016 emissions; reporters will not be required to report well identification numbers for previous years. For the majority of wells, the well identification number reported will be the US Well Number (formerly referred to as the API Well Number, or API Number).[9] For any well that does not already have a US Well Number, the reporter will be required to provide the unique well number assigned by the permitting authority for drilling of oil and gas wells. Commenters varied in their level of support for the proposed provisions regarding well identification numbers. The EPA is adjusting the final provisions in response to concerns about these reporting provisions raised in comments.

The EPA is requiring the reporting of well identification numbers for the Onshore Petroleum and Natural Gas Production segment only for information related specifically to wells. For reporters in the Onshore Petroleum and Natural Gas Production segment that report emissions using input data that are calculated from measurements at individual wells or equipment associated with individual wells (*e.g.,* if Equation W–10A was used to calculate emissions from oil well completions and workovers with hydraulic fracturing, well testing emissions), the report must include the well identification number for which those measurements were made and the well identification number(s) of other wells to which the measurements will be applied. This includes a list of the well identification numbers by sub-basin for the producing wells at the end of the calendar year as well as lists of the well identification numbers for the wells acquired, divested, completed, and permanently taken out of production during the calendar year. The EPA is not finalizing the proposed requirement that reporters in the Onshore Petroleum and Natural Gas Production segment report a list of well identification numbers associated with different emission

[9] The Professional Petroleum Data Management Association. *The US Well Number Standard: An Identifier for Petroleum Industry Wells in the USA.* Version 2013 rev 1, published June 19, 2014. Available at *http://dl.ppdm.org/dl/1147.*

sources for all wells in a sub-basin included in the reported emissions data.

The EPA is finalizing the proposed change to update references to the ''API well number'' in subpart W to ''well identification number.'' The EPA is not otherwise changing the well identification reporting requirements finalized in 2014 (79 FR 70352; November 25, 2014). Reporters will still need to report well identification numbers for liquids unloading and for any exploratory wells for which reporting has been delayed for 2 years.

2. Summary of Comments and Responses

Comment: While one commenter supported the addition of well identification number reporting, most commenters opposed the proposal to require reporting of well identification numbers. These commenters asserted that requiring reporting of well identification numbers is an overreach of the EPA's authority for the reporting program under CAA section 114 and that the EPA has not provided a reasoned basis for the departure from the previous EPA approach that well-specific data was not necessary under Subpart W. Commenters also noted that well identification numbers are not needed to validate reported emissions. One commenter noted that the EPA has not questioned the data collected from wells thus far; nor has the EPA stated that the data already collected are insufficient to inform policy without addition of well identification numbers, so with this proposal, the EPA is no longer balancing data collection with reporting burdens. Commenters stated that mapping and maintaining a database of well identification numbers is more burdensome than the EPA estimated, and one commenter stated that it would be arbitrary and capricious to require companies to expend the resources necessary to report these data. Commenters also noted that it is not clear how to interpret the term ''associated with'' in all cases. One commenter stated that matching specific wells with emissions in the GHGRP could cause security concerns.

Response: The EPA disagrees that requiring reporting of well identification numbers is an overreach of our authority. The EPA has determined that these data elements are useful and necessary for the verification of existing data and for characterizing the emissions from the industry segment. This final revision will allow the EPA to link the GHGRP data to other databases (*i.e.* state permitting databases) to more easily match the data reported under the GHGRP with other data sources and will improve the accuracy and transparency of subpart W. Additionally, being able to match the GHGRP data to other data sources will provide the EPA with more options for analysis of the GHGRP data to better inform future policy decisions related to GHG emissions from the oil and natural gas production sector. The reporting of the well identification numbers will also allow the EPA to assess the completeness and representativeness of the data collected under the GHGRP as a portion of all activity in the oil and natural gas production sector. The EPA reiterates that CAA section 114 provides the EPA with the authority to collect emissions data, which includes information about the location of the source of emissions. Section 114 generally authorizes the EPA to gather information from any person who owns or operates an emissions source, who is subject to a requirement of the CAA, who manufactures control or process equipment, or who the Administrator believes has information necessary for the purposes of section 114(a). The EPA may gather information for purposes of establishing implementation plans or emissions standards, determining compliance, or ''carrying out any provision'' of the CAA. For these reasons, the Administrator may request that a person, on a one-time, periodic or continuous basis, establish and maintain records, make reports, install and operate monitoring equipment and, among other things, provide such information the Administrator may reasonably require. This language has been interpreted to grant the EPA broad authority. See, *e.g.,* Dow Chemical Co. v. U.S., 467 U.S. 227, 233 (1986) (''Regulatory and enforcement authority generally carries with it all modes of inquiring and investigation traditionally employed or useful to execute the authority granted.''). See, generally *Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Volume No.: 9, Legal Issues* (Docket Item No. EPA–HQ–OAR–2008–0508–2264). The requirement to report well identification numbers for well-specific data clearly fits within EPA's statutory authority. We also believe, for the reasons stated above, that we are exercising this authority reasonably in furtherance of the purposes of the Clean Air Act. Further, the EPA disagrees that this is a deviation from our previous approach to collecting data. As discussed in section II.B of this preamble, the EPA is finalizing the requirement to report Onshore Petroleum and Natural Gas Gathering and Boosting facilities at the basin-level, which is consistent with our previous approach to the Onshore Petroleum and Natural Gas Production segment.

Therefore, the EPA is finalizing the requirements to report the well identification number for well-specific data as proposed. Specifically, for reporters in the Onshore Petroleum and Natural Gas Production segment that report emissions using input data that are calculated from measurements at individual wells or equipment or operations associated with individual wells (*e.g.,* if Equation W–10A is used to calculate emissions from oil well completions and workovers with hydraulic fracturing, well testing emissions, liquids unloading), the report must include the well identification number for which those measurements were made, or for which the equipment or operations are associated. In addition, the EPA is finalizing the requirements in 40 CFR 98.236(aa)(1)(ii)(D) through (H) to include a list of the well identification numbers by sub-basin for the producing wells at the end of the calendar year and lists of the well identification numbers for the wells acquired, divested, completed, and permanently taken out of production during the calendar year. The EPA continues to expect that this is a low burden to reporters because reporters already track and maintain well identification numbers associated with measurements used for the GHGRP input data.

To respond to the comment that well identification numbers may not be available for or assigned to equipment other than wells, the EPA reviewed the permits and requirements in seven different states. Although most of the states assign unique identifiers to each emission source, the EPA found that only two of the seven states have a tracking system that links individual emission sources to specific wells and well identification numbers, and these two states are not consistent in their approach. (See ''Greenhouse Gas Reporting Rule: Technical Support for 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule'' in Docket ID No. EPA–HQ–OAR–2014–0831 for more information on this analysis.) While it may be straightforward to assign some emission sources directly to one well, particularly if there is only one well on the single well pad and the reporter does not operate any other wells nearby, the EPA's review of state requirements shows that there may be multiple scenarios in which a reporter does not know which well or wells are associated with a particular emission source. For

example, there may be multiple wells on a single well pad and multiple storage tanks associated with that well pad, and the tanks may have the ability to receive hydrocarbon liquids from several of those wells. Therefore, in light of the potential burden of requiring facilities to develop new tracking systems that would assign and track emissions to well identification numbers for the purposes of part 98, the EPA is not requiring facilities in this rulemaking to report well identification numbers for every emission source in a facility in the Onshore Petroleum and Natural Gas Production segment.

E. Summary of Final Amendments to Best Available Monitoring Methods

1. Summary of Final Amendments

As proposed, reporters will be allowed to use BAMM for the 2016 reporting year for the new industry segments and emission sources included in this action. These include calculating and reporting emissions from oil well completions and workovers with hydraulic fracturing, from onshore petroleum and natural gas gathering and boosting systems, and for transmission pipeline blowdown emissions. Reporters are allowed to use BAMM to estimate inputs to emission equations for the newly finalized emission sources for cases where the monitoring of these inputs would not be possible beginning on January 1, 2016. The use of BAMM is not allowed for the reporting of well identification numbers because reporters should already have well identification numbers readily available for all wells and associated equipment to which this reporting requirement applies and because the well identification number is not a parameter that requires monitoring equipment to be measured and, therefore, does not meet the requirements for BAMM.

For these sources, the EPA is finalizing a longer timeline for BAMM than was proposed. Reporters have the option of using BAMM for the new industry segments and emission sources included in this action from January 1, 2016, to December 31, 2016, without seeking prior EPA approval. The provision providing a set amount of automatic transitional BAMM will allow reporters to prepare for data collection while automatically being able to use BAMM, which is consistent with the approach of prior part 98 rulemakings. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment during other planned (or unplanned) process unit downtime, thus avoiding process interruptions, and is responsive to comments received on the proposed rule provisions.

The EPA is not finalizing the proposed provision to allow reporters the opportunity to request an extension for the use of BAMM. The EPA will not accept requests for an extension for the use of BAMM beyond the time periods listed above. As proposed, the EPA also is not providing transitional BAMM for these new requirements beyond December 31, 2016.

The EPA is not allowing the use of BAMM beyond 2016 and does not anticipate that BAMM will be needed beyond 2016 for the new segments and emissions sources being finalized in this rule.

2. Summary of Comments and Responses

Comment: Several commenters stated that only 3 months of automatic BAMM and 1 year of transitional BAMM is not enough time to implement the monitoring and measurement requirements for facilities newly subject to subpart W and newly added emission sources. The commenter stated that adding a new segment is a significant amendment and the EPA has set the precedent of providing at least 1 year of automatic BAMM when adding a new segment to subpart W. The commenters noted that not all gathering and boosting reporters are already reporting as Onshore Petroleum and Natural Gas Production facilities, so they will not necessarily all be familiar with the monitoring and calculation methodologies. The commenters also noted that nearly all reporters will be spending the first month working on BAMM requests for the rest of 2016.

The commenters had a variety of suggestions for how long the EPA should provide BAMM for these new emission sources. Several commenters suggested 1 year (through the end of 2016) for automatic BAMM. Another commenter suggested March 31, 2017 (*i.e.,* 1 year in addition to the EPA's proposed 3 months), and another stated that 3 years would be consistent with the length of time provided when the Onshore Petroleum and Natural Gas Production segment was added to subpart W. Some commenters addressed the length of transitional BAMM with the EPA's approval. One commenter noted that a new reporter/facility could become subject to one of the new segments beyond the end of 2016, so there should be no deadline for submitting a request for BAMM to the EPA. Another requested transitional BAMM through the end of 2018.

Response: The EPA recognizes that most of the amendments being finalized in this rulemaking are new requirements rather than clarifications of existing reporting requirements for facilities already subject to subpart W and may require the development and implementation of new systems of data collection and monitoring. Therefore, the EPA is finalizing 1 year of automatic transitional BAMM in place of the proposed 3 months of automatic transitional BAMM. This additional time for reporters to comply with the revised monitoring methods in subpart W will allow facilities to install the necessary monitoring equipment and implement any new systems of data collection that may be required. Because the amount of time for which automatic BAMM is available should be sufficient time to comply with the requirements of subpart W for the new segments and emission sources, the EPA will not provide additional BAMM beyond the automatic BAMM provisions in 40 CFR 98.234(g).

We note that 40 CFR 98.235(e) and(f) provides 6 months of reporting flexibility for facilities that become subject to subpart W or acquire new sources after reporting year 2016. Reporters may also refer to the provisions of 40 CFR 98.235 after reporting year 2016 for guidance on reporting emissions if certain required data are not collected.

III. Confidentiality Determinations

A. Summary of Final Confidentiality Determinations for New Subpart W Data Elements

In the proposed rule, we assigned new data elements to the appropriate direct emitter data categories created in the 2011 Final CBI Rule based on the type and characteristics of each data element.[10] For data elements the EPA assigned to a direct emitter category with a categorical determination, the EPA proposed that the categorical determination for the category be applied to the proposed new data element. For data elements assigned to the ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' we proposed confidentiality determinations on a case-by-case basis taking into

[10] ''Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas Reporting Rule and Amendments to Special Rules Governing Certain Information Obtained Under the Clean Air Act'' (76 FR 30782, May 26, 2011).

NMED Exhibit 97 - 0018

consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories. We also proposed individual confidentiality determinations for six new data elements without making a data category assignment. Refer to the preamble to the proposed rule (79 FR 76267; December 9, 2014) for additional information regarding the proposed confidentiality determinations.

With consideration of the data provided by commenters, the EPA is finalizing the confidentiality determinations as proposed. Specifically, the EPA is finalizing the proposed decision to require each of the new data elements to be designated as ''not CBI.''

The EPA proposed to provide reporters with the option to delay reporting of five data elements for 2 reporting years in situations where exploratory wells are the only wells in a sub-basin. We received comment requesting that the EPA provide the same 2-year delay for additional data elements associated with exploratory wells. The comment and the EPA's response are included in section III.B of this preamble. Based on consideration of the comment and consistent with the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014), the EPA is finalizing provisions to provide reporters with the option to delay reporting of five data elements as proposed and, based on comments received, an additional two data elements for 2 reporting years in situations where exploratory wells are the only wells in a sub-basin. For a given sub-basin, in situations where wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the required measurement, the following seven data elements associated with the delineation or wildcat well may be delayed for 2 reporting years: (1) The cumulative gas flowback time, in hours, for each sub-basin, from when gas is first detected until sufficient quantities are present to enable separation (40 CFR 98.236(g)(5)(i)); (2) the cumulative flowback time, in hours, for each sub-basin, after sufficient quantities of gas are present to enable separation (40 CFR 98.236(g)(5)(i)); (3) the measured flowback rate, in standard cubic feet per hour, for each sub-basin (40 CFR 98.236(g)(5)(ii)); (4) the gas to oil ratio for the well (40 CFR 98.236(g)(5)(iii)(A)); (5) the volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing (40 CFR 98.236(g)(5)(iii)(B)); (6) the total annual gas-liquid separator oil volume that is sent to applicable onshore storage tanks, in barrels (40 CFR 98.236(j)(1)(iii)); and (7) the total annual oil throughput that is sent to all atmospheric tanks, in barrels (40 CFR 98.236(j)(2)(i)(A).

Four of the seven data elements for which reporting may be delayed by 2 years are inputs to emission equations and the EPA provided the same option in the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014). Two of the seven data elements are inputs only when the applicable data are related to a single well (the two data elements in 40 CFR 98.236(g)(5)(i)), and one data element is never an input (40 CFR 98.236(j)(2)(i)(A)). Where the EPA agrees that there are early disclosure concerns related to exploratory wells, the EPA decided to treat those early disclosure concerns consistently throughout subpart W by providing the option to delay reporting by 2 years to all seven data elements listed above.

At proposal, in cases where the two data elements in 40 CFR 98.236(g)(5)(i)) are not inputs to equations, they were assigned to the ''Unit/Process Operating Characteristics that are Not Inputs to Emission Equations'' category and were proposed to be ''not CBI.'' The EPA is finalizing this determination as proposed. Specifically, the ''not CBI'' determination applies to all situations except for when the data elements are inputs to equations.

For the situations when the data elements are used as inputs to equations, the EPA is assigning them to the ''Inputs to Emission Equations'' data category and is not making confidentiality determinations for these data. The EPA evaluated and summarized any potential disclosure concerns with the reporting of the data elements assigned to the ''Inputs to Emission Equations'' data category in the memo titled ''Review for Potential Disclosure Concerns for Inputs to Emission Equations Affected by the 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' available in Docket ID No. EPA–HQ–OAR–2014–0831. Other than the exception of the early disclosure concerns for certain data elements related to exploratory wells discussed earlier in this section, the EPA has concluded that there are no disclosure concerns with the reporting of these data elements.

The data element collected under 40 CFR 98.236(j)(2)(i)(A) was proposed as ''not CBI'' and was not assigned to a data category. The EPA is finalizing this determination as proposed as well. For the data elements reported under 40 CFR 98.236(g)(5)(i)) (in cases where they are not inputs to equations) and 40 CFR 98.236(j)(2)(i)(A), the ''not CBI'' determinations will apply once the data are reported to the EPA following the 2-year delay.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed categorical assignments and confidentiality determinations. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and responses. See the memorandum ''Final Data Category Assignments and Confidentiality Determinations for Data Elements (excluding inputs to emission equations) in the 'Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of final data category assignments and confidentiality determinations, and a discussion of changes since proposal.

Comment: One commenter requested that the EPA reconsider the determination that the quantity of produced gas throughput in the calendar year and the quantity of produced gas consumed by the facility in the calendar year are ''not CBI.'' The commenter noted that the quantity of natural gas received and the quantity of processed gas leaving processing plants was maintained as CBI in the 2014 amendments (79 FR 70352; November 25, 2014). The commenter also stated that information on fuel consumed at gathering and boosting facilities is not typically publically available, and when this information is combined with the quantity of produced gas throughput, it directly indicates the fuel efficiency of a station. The commenter noted that while the EPA is correct that the agreements are long-term for a given well, revealing information about one facility's fuel efficiency could cause competitive harm by affecting contracts for other facilities owned by that company, especially if there are smaller gathering and boosting facilities in the area that do not have to report this information to the GHGRP.

The commenter also requested that the EPA clarify a number of the reporting elements in 40 CFR

98.236(aa)(10). Specifically, the commenter requested clarification of the terms ''produced gas,'' ''produced condensate,'' ''produced oil,'' ''throughput,'' and ''consumed'' as they are used in proposed 40 CFR 98.236(aa)(10). The commenter also asserted that the data element in 40 CFR 98.236(aa)(10)(ii) (''quantity of produced gas consumed'') would be redundant with subpart C and should not be finalized. Finally, the commenter stated that the requirement to report the ''quantity of gas flared, vented and/or unaccounted for in the calendar year'' in 40 CFR 98.236(10)(aa)(v) would undermine over 5 years of rule development, public comment, reconsiderations, and petitioner negotiations because it would require reporting of emissions that are otherwise exempted (*e.g.,* blowdowns below 50 ft^3).

Response: The EPA reviewed these comments and has clarified the reporting elements in 40 CFR 98.236(aa)(10) for the final rule. The final reporting requirements include: (1) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet; (2) the quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet; (3) the quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels; and (4) the quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels. The EPA has determined that these quantities will be easily accessible for all reporters and are more consistent with the reporting requirements for the Onshore Natural Gas Processing segment. The EPA is finalizing the CBI determinations for these quantities as ''not CBI,'' as proposed.

The final reporting requirements do not include the terms ''produced gas,'' ''produced condensate,'' ''produced oil,'' ''throughput,'' or ''consumed,'' so no clarification regarding the use of those terms is needed. In particular, the final rule does not include a requirement to report the quantity of produced gas consumed by the facility. The difference between the quantities received by a gathering and boosting facility and the quantities exiting the gathering and boosting facility is expected to include the quantity of gas consumed by the facility as well as the quantity of gas flared or vented in one lump sum. Therefore, the reporting requirements do not directly indicate the fuel efficiency of the stations in a gathering and boosting facility.

Comment: One commenter reiterated previously stated concerns over the disclosure of information for exploratory wells, especially when they are located in stepout areas where no prior reporting exists for a given sub-basin. The commenter supported the EPA's proposal to defer reporting of data elements related to oil well completions and workovers with hydraulic fracturing for exploratory wells, but expressed concern that EPA has not provided such a delay in reporting for all emissions data and data elements that are associated with exploratory wells. Specifically, the commenter stated that the EPA failed to provide a necessary 2-year deferral in reporting for the following data elements, which are as business sensitive and confidential as the other information for which the EPA proposed to defer reporting for 2 years:

- 40 CFR 98.236(g)(5)(iii)(A)—If you used Equation W–12C to calculate the average gas production rate for an oil well, the gas to oil ratio for the well in standard cubic feet of gas per barrel of oil.
- 40 CFR 98.236(g)(5)(iii)(B)—If you used Equation W–12C to calculate the average gas production rate for an oil well, the volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels.
- 40 CFR 98.236(g)(6)(i)—If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, the vented natural gas volume, in standard cubic feet, for each well in the sub-basin.
- 40 CFR 98.236(g)(6)(ii)—If you used Equation W–10B to calculate annual volumetric total gas emissions for completions that vent gas to the atmosphere, the flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin.
- 40 CFR 98.236(g)(7)—For each oil well completion or workover and well type combination, annual gas emissions.
- 40 CFR 98.236(g)(8)—For each oil well completion or workover and well type combination, annual CO_2 emissions.
- 40 CFR 98.236(g)(9)—For each oil well completion or workover and well type combination, annual CH_4 emissions.
- 40 CFR 98.236(g)(10)—For each oil well completion or workover and well type combination, the total N_2O emissions, if the well emissions were vented to a flare.

Response: The EPA reviewed the data elements identified by the commenter as having disclosure concerns for exploratory wells (delineation wells and wildcat wells). Consistent with the EPA's previous decisions related to exploratory wells under part 98 (79 FR 63750, October 24, 2014; 79 FR 70352, November 25, 2014), the EPA has determined that, for gas well completions or workovers with hydraulic fracturing of wildcat wells and/or delineation wells, early public disclosure of some of the additional data elements identified by the commenter could reveal the well productivity of wildcat wells and/or delineation wells, thereby resulting in the loss of investment value.

The additional data elements that could reveal well productivity for wildcat and/or delineation wells are as follows:

- The gas to oil ratio for the well (40 CFR 98.236(g)(5)(iii)(A))
- The volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing (40 CFR 98.236(g)(5)(iii)(B))

As the EPA has previously noted (79 FR 70352, November 25, 2014), in the interim period before these data are reported to the EPA, the EPA will be able to verify the majority of the emissions using data elements that will be reported to the EPA. For the seven total data elements that may be delayed for 2 years, the EPA will verify emissions using other data reported to the EPA, and will conclude verification upon receipt of the data. The EPA agrees with the commenter that a 2-year delay of reporting is sufficient to prevent early public disclosure of these data and will provide sufficient time for the reporter to thoroughly conduct an assessment of the well. Given the results of this evaluation, the EPA determined that, for these data elements, in those cases where delineation wells or wildcat wells are the only wells in a sub-basin, reporters should be provided an option to delay reporting of the given data element for 2 reporting years starting in 2015. In such cases, if the 2-year delay in reporting is used, the reporter must indicate for each delayed reporting element that wildcat wells and/or delineation wells are the only wells in a sub-basin that can be used for the measurement in the current reporting year. In addition, when reporters report the delayed data elements after the 2-year delay, they must also report the well identification numbers for the applicable wildcat and/or delineation wells in the sub-basin for which the reporting element was delayed. For example, if a delineation or wildcat well is completed in 2015 in a sub-basin that

has only delineation or wildcat wells or these are the only wells for which measurements can be made, then the reporter may: (1) Elect to report these seven data elements in their 2016 annual report submitted by March 31, 2017, or (2) elect to delay reporting of these data elements for up to 2 years. If the reporter elects to delay reporting, then the well identification numbers for the wildcat and delineation wells in the sub-basin for which reporting has been delayed and the data elements delayed from reporting must be reported no later than March 31, 2019.

The following inputs meet the definition of emission data in 40 CFR 2.301(a)(2)(i) because they indicate the amount or frequency of gas emitted by the facility: Volume of natural gas vented (reported under 40 CFR 98.236(g)(6)(i)) and flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation (reported under 40 CFR 98.236(g)(6)(ii)). Without corresponding activity data, such as a count of the exploratory wells in a sub-basin or production or flow rate data for a sub-basin containing only exploratory wells, there is no potential to disclose business sensitive information based on these data elements. Therefore, the EPA is not providing an option to delay reporting of these data elements for 2 reporting years.

Similarly, the data element annual gas emissions (reported under 40 CFR 98.236(g)(7)) meets the definition of emission data in 40 CFR 2.301(a)(2)(i) and is assigned to the ''Emissions'' data category because it indicates the amount of gas emitted by the facility. In addition, the following data elements meet the definition of emission data in 40 CFR 2.301(a)(2)(i) and are assigned to the ''Emissions'' data category because they are emissions of pollutants emitted by the source: annual CO_2 emissions (reported under 40 CFR 98.236(g)(8)), annual CH_4 emissions (reported under 40 CFR 98.236(g)(9)), and annual nitrous oxide (N_2O) emissions if the well emissions were vented to a flare (reported under 40 CFR 98.236(g)(10)). For these data elements that are assigned to the ''Emissions'' data category, the commenter did not claim or provide any justification for why these data elements do not meet the definition of emission data. Without corresponding activity data, such as a count of the exploratory wells in a sub-basin or production or flow rate data for a sub-basin containing only exploratory wells, there is no potential to disclose business sensitive information based on these data elements. Therefore, the EPA is not providing an option to delay reporting of these data elements for 2 reporting years.

IV. Impacts of the Final Amendments to Subpart W

A. Impacts of the Final Amendments

The final amendments to subpart W add monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. The EPA is adding 213 new data elements to the reporting requirements. The new data elements impose additional burden and costs because, for each of the new data elements that are required to be reported, reporters are required to calculate the data element using readily available data and report the value to the EPA via e-GGRT as part of the annual report currently required under part 98.

The EPA calculated the increase in reporting and recordkeeping burden associated with the new data elements by adjusting labor hours upwards per reporter for all affected industry segments. For all three segments, an estimate of 10 hours per year per reporter was allotted for reporting via e-GGRT and 10 hours per year per reporter was allotted for recordkeeping.

Costs to reporters associated with this rulemaking are expressed as labor costs (*i.e.,* the cost of labor by facility staff to comply with the amendments), capital costs for equipment and travel, and operation and maintenance (O&M) costs.

Reporters in the Onshore Petroleum and Natural Gas Production segment have to monitor and report emissions and data elements associated with oil well completions and workovers with hydraulic fracturing. Reporters in this segment also have to report the well identification numbers associated with individual oil and gas wells. The addition of the requirement to report emissions associated with oil well completions and workovers with hydraulic fracturing is expected to cause an increase in the amount of emissions that count towards determining applicability under subpart W. The addition of reporting requirements for oil wells with hydraulic fracturing is expected to affect 246 existing reporters and to cause approximately 50 new reporters to exceed the reporting threshold for the onshore petroleum and natural gas production facility. These numbers have not changed from proposal.

The 50 new reporters will be required to estimate and report emissions data and related data elements associated with several different emission sources within this new industry segment, including acid gas removal units, associated natural gas venting and flaring, storage tanks, dehydrators, equipment leaks, liquids unloading, and pneumatic devices.

Reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment must estimate and report emissions data and related data elements associated with several different emission sources within this new industry segment, including acid gas removal units, storage tanks, blowdown vents, dehydrators, equipment leaks, flare stacks, and pneumatic devices. Approximately 200 new reporters are expected to be subject to subpart W due to the amendments for the Onshore Petroleum and Natural Gas Gathering and Boosting segment in this rulemaking. This number has not changed from proposal.

Reporters in the Onshore Natural Gas Transmission Pipeline segment will need to estimate and report emissions data and related data elements associated with transmission pipeline blowdown activities. Approximately 183 new reporters in this segment are expected to be subject to subpart W. This number increased from 150 to 183 since proposal due to public comment.

The EPA received multiple comments regarding the impacts of the proposed amendments. After evaluating these comments and reviewing other changes from proposal, the EPA revised the impacts assessment slightly from proposal. The final amendments to subpart W are not expected to significantly change the burden calculated at proposal.

The EPA has determined that the cost associated with this final action will be $7,190,235 each year and has worked to minimize burden to reporters where practicable. See the memorandum, ''Assessment of Impacts of the 2015 Final Revisions to Subpart W'' in Docket ID No. EPA–HQ–OAR–2014–0831 for additional information.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the impacts of the proposed amendments to subpart W of part 98. We note that numerous commenters asserted that the burden was underestimated, and some provided suggestions for improvement, but most of those comments did not include the detailed information the EPA needed to assess the comment

fully, such as a suggestion for a revised burden estimate, support for the suggestion, and an explanation of why the suggested value is representative of all sources subject to the same requirements. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2014–0831 for a complete listing of all comments and responses.

Comment: One commenter asked for an explanation for the estimate of 200 respondents in the Onshore Petroleum and Natural Gas Gathering and Boosting segment. The commenter noted that the EPA estimated the number of reporters in the Onshore Natural Gas Processing industry segment as 291 reporters. The commenter stated by the nature of the industry, any company with a processing plant will most likely also have an associated gathering system subject to reporting and suggested that the number of reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment should total 291, at minimum, but potentially more.

Response: Due to differences in the definitions of the two industry segments, the EPA disagrees that the number of reporters in the Onshore Petroleum and Natural Gas Gathering and Boosting segment should match the number of reporters in the Onshore Natural Gas Processing segment. The EPA estimate of 200 respondents was based on the regulatory analysis for Office of Pipeline Safety (OPS) safety regulations. In the analysis, it was estimated that 50 percent of the 400 natural gas gathering pipeline operators under regulation are small entities operating small diameter, low pressure (Type B) gathering lines and fifty percent are large diameter, high pressure lines (Type A) potentially subject to the safety regulation (depending upon proximity to population centers).[11]

Comment: One commenter noted that the EPA estimated that there are 150 reporters for Onshore Natural Gas Transmission Pipeline facilities at proposal. However, the commenter stated that the EPA should expect 183 reporters in the segment based on the number of operators that are required to complete a PHMSA annual report (PHMSA F–7100–2) or are regulated by FERC under section 311 of the NGPA.

Response: The EPA agrees with the suggested change. The preamble to the final amendments, the final Supporting Statement, and the memorandum ''Assessment of Impacts of the 2015 Final Revisions to Subpart W'' (see Docket ID No. EPA–HQ–OAR–2014–0831) have been updated to reflect the change from 150 reporters to 183 reporters in the Onshore Natural Gas Transmission Pipeline segment.

Comment: Two commenters objected to the collection of well identification numbers. One commenter noted that collection would require significant resources and would be unduly burdensome on operators. The other commenter stated that the burdens associated with collecting and reporting this data far outweigh any minimal benefits in data quality.

Response: The EPA is finalizing the well identification number reporting requirements for well-specific data as proposed, but the EPA is not requiring well identification numbers to be reported in this rulemaking for equipment other than wells. See section II.D of this preamble for additional discussion responding to this comment.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

In addition, the EPA prepared an analysis of the potential costs associated with the final amendments to subpart W. This analysis is contained in the memorandum ''Assessment of Impacts of the 2015 Final Revisions to Subpart W.'' A copy of the analysis is available in the docket for this action (see Docket ID No. EPA–HQ–OAR–2014–0831) and the analysis is briefly summarized in section IV of this preamble.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2300.16. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action adds monitoring and reporting requirements for reporters in three industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, and Onshore Natural Gas Transmission Pipeline. Data collection complements the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and provides a critical tool for communities to identify nearby sources of GHGs and provide information to state and local governments. The data can be used to complement atmospheric GHG studies and inform updates to emission inventories. Various activity data are collected that can be used to improve understanding of the occurrence of emissions from a variety of sources.

Data collected must be made available to the public unless the data qualify for CBI treatment under the CAA and EPA regulations. All data determined by the EPA to be CBI are safeguarded in accordance with regulations in 40 CFR chapter 1, part 2, subpart B.

Respondents/Affected Entities: The respondents in this information collection include owners and operators of petroleum and natural gas systems facilities that must report their GHG emissions to the EPA to comply with subpart W of part 98.

Respondent's Obligation To Respond: The respondent's obligation to respond is mandatory under the authority provided in CAA section 114.

Estimated Number of Respondents: Approximately 3,300 respondents per year.

Frequency of Response: Annual.

Total Estimated Burden: 317,100 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total Estimated Cost: $29.2 million (per year), includes $1.1 million annualized capital and 2.8 million operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities

[11] U.S. Department of Transportation. Pipeline and Hazardous Materials Safety Administration. *Draft Regulatory Evaluation, Regulated Natural Gas Gathering Lines, Regulatory Analysis,* Docket RSPA–1998–4868. Available at *www.viadata.com/pipeliner/library_docs/Gatheringanalysis.pdf.*

subject to the requirements of this action are: (1) A small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The Agency has determined that a few small businesses may experience an insignificant impact. Details of this analysis are presented in section IV.B of the preamble to the proposed amendments (79 FR 76267; December 9, 2014).

Although this final rule will not have a significant economic impact on a substantial number of small entities, the EPA nonetheless has tried to reduce the impact of this rule on small entities. As part of the process of finalizing the subpart W 2010 final rule, the EPA took several steps to evaluate the effect of the rule on small entities. For example, the EPA determined appropriate thresholds that reduced the number of small businesses reporting. In addition, the EPA supports a ''help desk'' for the rule, which is available to answer questions on the provisions in the rule. Finally, the EPA continues to conduct significant outreach on the GHG reporting rule and maintains an ''open door'' policy for stakeholders to help inform the EPA's understanding of key issues for the industries.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that emit GHGs. Although few facilities that will be subject to the rule are likely to be owned by tribal governments, the EPA has sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final subpart W that was promulgated on November 30, 2010 (75 FR 74458).

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in section IV.F of the preamble to the re-proposal of subpart W published on April 12, 2010 (75 FR 18608), and section IV.F of the preamble to the subpart W 2010 final rule published on November 30, 2010 (75 FR 74458).

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks, that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will **not** have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations because it does not affect the level of protection provided to human health or the environment. Instead, this rule addresses information collection and reporting procedures.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Reporting and recordkeeping requirements.

Dated: October 1, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 1. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart W—Petroleum and Natural Gas Systems

■ 2. Section 98.230 is amended by adding paragraphs (a)(9) and (10) to read as follows:

§ 98.230 Definition of the source category.

(a) * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* Onshore petroleum and natural gas gathering and boosting means gathering pipelines and other equipment used to collect petroleum and/or natural gas from onshore production gas or oil wells and used to compress, dehydrate, sweeten, or transport the petroleum and/or natural gas to a natural gas processing facility, a natural gas transmission pipeline or to a natural gas distribution pipeline. Gathering and boosting equipment includes, but is not limited to gathering pipelines, separators, compressors, acid gas removal units, dehydrators, pneumatic devices/pumps, storage vessels, engines, boilers, heaters, and flares. Gathering and boosting equipment does not include equipment reported under any other industry segment defined in this section. Gathering pipelines operating on a vacuum and gathering pipelines with a GOR) less than 300 standard cubic feet per stock tank barrel (scf/STB) are not included in this industry segment (oil

here refers to hydrocarbon liquids of all API gravities).

(10) *Onshore natural gas transmission pipeline.* Onshore natural gas transmission pipeline means all natural gas transmission pipelines as defined in § 98.238.

* * * * *

■ 3. Section 98.231 is amended by revising paragraph (a) to read as follows:

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of § 98.2(a)(2), except for the industry segments in paragraphs (a)(1) through (4) of this section.

(1) Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year.

(2) Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(3) Facilities must report emissions from the onshore petroleum and natural gas gathering and boosting industry segment only if emission sources specified in § 98.232(j) emit 25,000 metric tons of CO_2 equivalent or more per year.

(4) Facilities must report emissions from the onshore natural gas transmission pipeline industry segment only if emission sources specified in § 98.232(m) emit 25,000 metric tons of CO_2 equivalent or more per year.

* * * * *

■ 4. Section 98.232 is amended by:
■ a. Revising paragraphs (a) and (c)(6) and (8);
■ b. Adding paragraph (j);
■ c. Revising paragraph (k); and
■ d. Adding paragraph (m).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (j) and (m) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (j) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

* * * * *

(c) * * *

(6) Well venting during well completions with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

* * * * *

(8) Well venting during well workovers with hydraulic fracturing that have a GOR of 300 scf/STB or greater (oil here refers to hydrocarbon liquids produced of all API gravities).

* * * * *

(j) For an onshore petroleum and natural gas gathering and boosting facility, report CO_2, CH_4, and N_2O emissions from the following source types:

(1) Natural gas pneumatic device venting.

(2) Natural gas driven pneumatic pump venting.

(3) Acid gas removal vents.

(4) Dehydrator vents.

(5) Blowdown vent stacks.

(6) Storage tank vented emissions.

(7) Flare stack emissions.

(8) Centrifugal compressor venting.

(9) Reciprocating compressor venting.

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(11) Gathering pipeline equipment leaks.

(12) You must use the methods in § 98.233(z) and report under this subpart the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas gathering and boosting facility as defined in § 98.238. Stationary or portable equipment includes the following equipment, which are integral to the movement of natural gas: Natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section. Onshore petroleum and natural gas gathering and boosting facilities must report stationary and portable combustion emissions as specified in paragraph (j) of this section.

* * * * *

(m) For onshore natural gas transmission pipeline, report pipeline blowdown CO_2 and CH_4 emissions from blowdown vent stacks.

■ 5. Section 98.233 is amended by:
■ a. Revising the parameters ''EF_t'' and ''GHG_i'' of Equation W–1 in paragraph (a);
■ b. Revising paragraph (a)(2);
■ c. Revising the parameter ''EF'' of Equation W–2 in paragraph (c);
■ d. Revising paragraph (d)(8)(iii);
■ e. Revising paragraphs (g) introductory text, (g)(1) introductory text, (g)(1)(i), and paragraph (g)(1)(ii) heading;
■ f. Revising the parameters ''FRM_s,'' ''$FR_{s,p}$'' and ''$PR_{s,p}$'' of Equation W–12A in paragraph (g)(1)(iii);
■ g. Revising the parameters ''$FRM_{i,}$'' and ''$PR_{s,p}$'' of Equation W–12B in paragraph (g)(1)(iv);
■ h. Revising paragraphs (g)(1)(v) and (vi);
■ i. Adding paragraph (g)(1)(vii);
■ j. Revising paragraph (g)(2) introductory text;
■ k. Adding paragraph (g)(2)(iv);
■ l. Revising paragraph (g)(4) introductory text;
■ m. Revising paragraph (i)(2) introductory text;
■ n. Revising the parameters ''T_a'' and ''P_a'' of Equation W–14A in paragraph (i)(2)(i);
■ o. Revising paragraphs (j) introductory text, (j)(1) through (3), and (j)(6);
■ p. Revising paragraph (n)(2)(i);
■ q. Revising paragraphs (o) introductory text and (o)(10);
■ r. Revising paragraphs (p) introductory text and (p)(10);
■ s. Revising paragraphs (r) introductory text, (r)(2) introductory text, and (r)(2)(i);
■ t. Revising paragraphs (u)(2)(i) and (iii); and
■ x. Revising paragraphs (z) introductory text and (z)(1)(ii).

The revisions and additions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) * * *

* * * * *

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production,

onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W–1A of this subpart.

GHG_i = For onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, onshore natural gas transmission compression facilities, and underground natural gas storage facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas or processed natural gas for each facility as specified in paragraphs (u)(2)(i), (iii), and (iv) of this section.

* * * * *

(2) For the onshore petroleum and natural gas production industry segment, you have the option in the first two consecutive calendar years to determine ''$Count_t$'' for Equation W–1 of this section for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data. For the onshore petroleum and natural gas gathering and boosting industry segment, you have the option in the first two consecutive calendar years to determine ''$Count_t$'' for Equation W–1 for each type of natural gas pneumatic device (continuous high bleed, continuous low bleed, and intermittent bleed) using engineering estimates based on best available data.

* * * * *

(c) * * *

* * * * *

EF = Population emissions factors for natural gas driven pneumatic pumps (in standard cubic feet per hour per pump) listed in Table W–1A of this subpart for onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting facilities.

* * * * *

(d) * * *

(8) * * *

(iii) If a continuous gas analyzer is not available or installed, you may use the outlet pipeline quality specification for CO_2 in natural gas.

* * * * *

(g) *Well venting during completions and workovers with hydraulic fracturing.* Calculate annual volumetric natural gas emissions from gas well and oil well venting during completions and workovers involving hydraulic fracturing using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the gas flowback rate is measured from a specified number of example completions or workovers and Equation W–10B applies when the gas flowback vent or flare volume is measured for each completion or workover. Completion and workover activities are separated into two periods, an initial period when flowback is routed to open pits or tanks and a subsequent period when gas content is sufficient to route the flowback to a separator or when the gas content is sufficient to allow measurement by the devices specified in paragraph (g)(1) of this section, regardless of whether a separator is actually utilized. If you elect to use Equation W–10A, you must follow the procedures specified in paragraph (g)(1). If you elect to use Equation W–10B, you must use a recording flow meter installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback. For either equation, emissions must be calculated separately for completions and workovers, for each sub-basin, and for each well type combination identified in paragraph (g)(2) of this section. You must calculate CH_4 and CO_2 volumetric and mass emissions as specified in paragraph (g)(3) of this section. If emissions from well venting during completions and workovers with hydraulic fracturing are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (g)(4) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_{p,s} \times FRM_s \times PR_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FRM_i \div 2 \times PR_{s,p} \right] \right] \quad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} + \left[T_{p,i} \times FR_{p,i} \div 2 \right] \right] \quad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric natural gas emissions in standard cubic feet from gas venting during well completions or workovers following hydraulic fracturing for each sub-basin and well type combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type combination.

$T_{p,s}$ = Cumulative amount of time of flowback, after sufficient quantities of gas are present to enable separation, where gas vented or flared for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of venting or flaring.

$T_{p,i}$ = Cumulative amount of time of flowback to open tanks/pits, from when gas is first detected until sufficient quantities of gas are present to enable separation, for the completion or workover, in hours, for each well, p, in a sub-basin and well type combination during the reporting year. This may include non-contiguous periods of routing to open tanks/pits but does not include periods when the oil well ceases to produce fluids to the surface.

FRM_s = Ratio of average gas flowback, during the period when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iii) of this section.

FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, calculated using procedures specified in paragraph (g)(1)(iv) of this section, for the period of flow to open tanks/pits.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of each well p, that was measured in the sub-basin and well type combination. If applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

$EnF_{s,p}$ = Volume of N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job or during flowback for each well, p, as determined by using an appropriate meter according to methods described in § 98.234(b), or by using receipts of gas purchases that are used for the energized fracture job or injection during flowback. Convert to standard conditions using paragraph (t) of this section. If the fracture process did

NMED Exhibit 97 - 0025

not inject gas into the reservoir or if the injected gas is CO_2 then $EnF_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of vented or flared gas for each well, p, in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure gas flowback during the separation period of the completion or workover according to methods set forth in § 98.234(b).

$FR_{p,i}$ = Flow rate vented or flared of each well, p, in standard cubic feet per hour measured using a recording flow meter (digital or analog) on the vent line to measure the flowback, at the beginning of the period of time when sufficient quantities of gas are present to enable separation, of the completion or workover according to methods set forth in § 98.234(b).

(1) If you elect to use Equation W–10A of this section on gas wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) of this section, or Calculation Method 2 as specified in paragraph (g)(1)(ii) of this section, to determine the value of FRM_s and FRM_i. If you elect to use Equation W–10A of this section on oil wells, you must use Calculation Method 1 as specified in paragraph (g)(1)(i) to determine the value of FRM_s and FRM_i. These values must be based on the flow rate for flowback gases, once sufficient gas is present to enable separation. The number of measurements or calculations required to estimate FRM_s and FRM_i must be determined individually for completions and workovers per sub-basin and well type combination as follows: Complete measurements or calculations for at least one completion or workover for less than or equal to 25 completions or workovers for each well type combination within a sub-basin; complete measurements or calculations for at least two completions or workovers for 26 to 50 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least three completions or workovers for 51 to 100 completions or workovers for each sub-basin and well type combination; complete measurements or calculations for at least four completions or workovers for 101 to 250 completions or workovers for each sub-basin and well type combination; and complete measurements or calculations for at least five completions or workovers for greater than 250 completions or workovers for each sub-basin and well type combination.

(i) *Calculation Method 1.* You must use Equation W–12A of this section as specified in paragraph (g)(1)(iii) of this section to determine the value of FRM_s. You must use Equation W–12B of this section as specified in paragraph (g)(1)(iv) of this section to determine the value of FRM_i. The procedures specified in paragraphs (g)(1)(v) and (vi) of this section also apply. When making gas flowback measurements for use in Equations W–12A and W–12B of this section, you must use a recording flow meter (digital or analog) installed on the vent line, downstream of a separator and ahead of a flare or vent, to measure the gas flowback rates in units of standard cubic feet per hour according to methods set forth in § 98.234(b).

(ii) *Calculation Method 2 (for gas wells).* * * *

(iii) * * *

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FRM_s = Ratio of average gas flowback rate, during the period of time when sufficient quantities of gas are present to enable separation, of well completions and workovers from hydraulic fracturing to 30-day gas production rate for each sub-basin and well type combination.

$FR_{s,p}$ = Measured average gas flowback rate from Calculation Method 1 described in paragraph (g)(1)(i) of this section or calculated average flowback rate from Calculation Method 2 described in paragraph (g)(1)(ii) of this section, during the separation period in standard cubic feet per hour for well(s) p for each sub-basin and well type combination. Convert measured and calculated FR_a values from actual conditions upstream of the restriction orifice (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W–33 in paragraph (t) of this section. You may not use flow volume as used in Equation W–10B of this section converted to a flow rate for this parameter.

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour for each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

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(iv) * * *

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FRM_i = Ratio of initial gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate for the sub-basin and well type combination, for the period of flow to open tanks/pits.

* * * * *

$PR_{s,p}$ = Average gas production flow rate during the first 30-days of production after completions of newly drilled wells or well workovers using hydraulic fracturing, in standard cubic feet per hour of each well, p, that was measured in the sub-basin and well type combination. For oil wells for which production is not measured continuously during the first 30 days of production, the average flow rate may be based on individual well production tests conducted within the first 30 days of production. Alternatively, if applicable, $PR_{s,p}$ may be calculated for oil wells using procedures specified in paragraph (g)(1)(vii) of this section.

* * * * *

(v) For Equation W–10A of this section, the ratio of gas flowback rate during well completions and workovers from hydraulic fracturing to 30-day gas production rate are applied to all well completions and well workovers, respectively, in the sub-basin and well type combination for the total number of hours of flowback and for the first 30 day average gas production rate for each of these wells.

(vi) For Equations W–12A and W–12B of this section, calculate new flowback rates for well completions and well workovers in each sub-basin and well type combination once every two years starting in the first calendar year of data collection.

(vii) For oil wells where the gas production rate is not metered and you elect to use Equation W–10A of this section, calculate the average gas production rate ($PR_{s,p}$) using Equation W–12C of this section. If GOR cannot be determined from your available data, then you must use one of the procedures specified in paragraph (g)(1)(vii)(A) or (B) of this section to determine GOR. If GOR from each well is not available, use the GOR from a cluster of wells in the same sub-basin category.

$$PR_{s,p} = GOR_p * \frac{V_p}{720} \qquad \text{(Eq. W-12C)}$$

Where:

$PR_{s,p}$ = Average gas production flow rate during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in standard cubic feet per hour of well p, in the sub-basin and well type combination.

GOR_p = Average gas to oil ratio during the first 30 days of production after completions of newly drilled wells or workovers using hydraulic fracturing in standard cubic feet of gas per barrel of oil for each well p, that was measured in the sub-basin and well type combination; oil here refers to hydrocarbon liquids produced of all API gravities.

V_p = Volume of oil produced during the first 30 days of production after completions of newly drilled wells or well workovers using hydraulic fracturing in barrels of each well p, that was measured in the sub-basin and well type combination.

720 = Conversion from 30 days of production to hourly production rate.

(A) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(B) You may use an industry standard practice as described in § 98.234(b).

(2) For paragraphs (g) introductory text and (g)(1) of this section, measurements and calculations are completed separately for workovers and completions per sub-basin and well type combination. A well type combination is a unique combination of the parameters listed in paragraphs (g)(2)(i) through (iv) of this section.

* * * * *

(iv) Oil well or gas well.

* * * * *

(4) Calculate annual emissions from well venting during well completions and workovers from hydraulic fracturing where all or a portion of the gas is flared as specified in paragraphs (g)(4)(i) and (ii) of this section.

* * * * *

(i) * * *

(2) *Method for determining emissions from blowdown vent stacks according to equipment or event type.* If you elect to determine emissions according to each equipment or event type, using unique physical volumes as calculated in paragraph (i)(1) of this section, you must calculate emissions as specified in paragraph (i)(2)(i) of this section and either paragraph (i)(2)(ii) or, if applicable, paragraph (i)(2)(iii) of this section for each equipment or event type. For industry segments other than onshore natural gas transmission pipeline, equipment or event types must be grouped into the following seven categories: Facility piping (*i.e.,* piping within the facility boundary other than physical volumes associated with distribution pipelines), pipeline venting (*i.e.,* physical volumes associated with distribution pipelines vented within the facility boundary), compressors, scrubbers/strainers, pig launchers and receivers, emergency shutdowns (this category includes emergency shutdown blowdown emissions regardless of equipment type), and all other equipment with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple equipment types and the emissions cannot be apportioned to the different equipment types, then categorize the blowdown event as the equipment type that represented the largest portion of the emissions for the blowdown event. For the onshore natural gas transmission pipeline segment, pipeline segments or event types must be grouped into the following eight categories: Pipeline integrity work (*e.g.,* the preparation work of modifying facilities, ongoing assessments, maintenance or mitigation), traditional operations or pipeline maintenance, equipment replacement or repair (*e.g.,* valves), pipe abandonment, new construction or modification of pipelines including commissioning and change of service, operational precaution during activities (*e.g.* excavation near pipelines), emergency shutdowns including pipeline incidents as defined in 49 CFR 191.3, and all other pipeline segments with a physical volume greater than or equal to 50 cubic feet. If a blowdown event resulted in emissions from multiple categories and the emissions cannot be apportioned to the different categories, then categorize the blowdown event in the category that represented the largest portion of the emissions for the blowdown event.

(i) * * *

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T_a = Temperature at actual conditions in the unique physical volume (°F). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the temperature.

* * * * *

P_a = Absolute pressure at actual conditions in the unique physical volume (psia). For emergency blowdowns at onshore petroleum and natural gas gathering and boosting facilities, engineering estimates based on best available information may be used to determine the pressure.

* * * * *

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* Calculate CH_4, CO_2, and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities (including stationary liquid storage not owned or operated by the reporter), as specified in this paragraph (j). For gas-liquid separators or onshore petroleum and natural gas gathering and boosting non-separator equipment (*e.g.,* stabilizers, slug catchers) with annual average daily throughput of oil greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 using Calculation Method 1 or 2 as specified in paragraphs (j)(1) and (2) of this section. For wells flowing directly to atmospheric storage tanks without passing through a separator with throughput greater than or equal to 10 barrels per day, calculate annual CH_4 and CO_2 emissions using Calculation Method 2 as specified in paragraph (j)(2) of this section. For hydrocarbon liquids flowing to gas-liquid separators or non-separator equipment or directly to atmospheric storage tanks with throughput less than 10 barrels per day, use Calculation Method 3 as specified in paragraph (j)(3) of this section. If you use Calculation Method 1 or Calculation Method 2 for separators, you must also calculate emissions that may have occurred due to dump valves not closing properly using the method specified in paragraph (j)(6) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a vapor recovery system, you must adjust the emissions downward according to paragraph (j)(4) of this section. If emissions from atmospheric pressure fixed roof storage tanks are routed to a flare, you must calculate CH_4, CO_2, and N_2O annual emissions as specified in paragraph (j)(5) of this section.

(1) *Calculation Method 1.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks and onshore petroleum and natural gas gathering and boosting storage tanks using operating conditions in the last gas-liquid separator or non-separator equipment before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator or non-separator equipment enters an atmospheric pressure storage tank. The following parameters must be determined for typical operating

conditions over the year by engineering estimate and process knowledge based on best available data, and must be used at a minimum to characterize emissions from liquid transferred to tanks:

(i) Separator or non-separator equipment temperature.

(ii) Separator or non-separator equipment pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator or non-separator equipment oil composition and Reid vapor pressure. If this data is not available, determine these parameters by using one of the methods described in paragraphs (j)(1)(vii)(A) through (C) of this section.

(A) If separator or non-separator equipment oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator or non-separator equipment pressure first, and API gravity secondarily.

(B) If separator or non-separator equipment oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category for onshore petroleum and natural gas production or from the county for onshore petroleum and natural gas gathering and boosting.

(C) Analyze a representative sample of separator or non-separator equipment oil in each sub-basin category for onshore petroleum and natural gas production or each county for onshore petroleum and natural gas gathering and boosting for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Method 2.* Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(i) of this section for gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(ii) of this section for wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting (if applicable). Calculate annual CH_4 and CO_2 emissions using the methods in paragraph (j)(2)(iii) of this section for non-separator equipment with annual average daily hydrocarbon liquids throughput greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks in onshore petroleum and natural gas gathering and boosting.

(i) *Flow to storage tank after passing through a separator.* Assume that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(ii) *Flow to storage tank direct from wells.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(ii)(A) or (B) of this section.

(A) If well production oil and gas compositions are available through a previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(B) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(iii) *Flow to storage tank direct from non-separator equipment.* Calculate CH_4 and CO_2 emissions using either of the methods in paragraph (j)(2)(iii)(A) or (B) of this section.

(A) If other non-separator equipment liquid and gas compositions are available through a previous analysis, select the latest available analysis that is representative of liquid and gas from non-separator equipment in the same county and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(B) If non-separator equipment liquid and gas compositions are not available, use default liquid and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match the non-separator equipment gas/liquid ratio and API gravity and assume all of the CH_4 and CO_2 in both hydrocarbon liquids and gas are emitted from the tank.

(3) *Calculation Method 3.* Calculate CH_4 and CO_2 emissions using Equation W–15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators, wells, or non-separator equipment in thousand standard cubic feet per separator, well, or non-separator equipment per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators, wells, or non-separator equipment with annual average daily throughput less than 10 barrels per day. Count only separators, wells, or non-separator equipment that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

* * * * *

(6) If you use Calculation Method 1 or Calculation Method 2 in paragraph (j)(1) or (2) of this section, calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i,o} = \left(CF_n * \frac{E_n}{8760} * T_n \right) \qquad \text{(Eq. W-16)}$$

Where:

$E_{s,i,o}$ = Annual volumetric GHG emissions at standard conditions from each storage tank in cubic feet that resulted from the dump valve on the gas-liquid separator not closing properly.

E_n = Storage tank emissions as determined in paragraphs (j)(1), (j)(2) and, if applicable, (j)(4) of this section in standard cubic feet per year.

T_n = Total time a dump valve is not closing properly in the calendar year in hours. Estimate T_n based on maintenance, operations, or routine separator inspections that indicate the period of time when the valve was malfunctioning in open or partially open position.

CF_n = Correction factor for tank emissions for time period T_n is 2.87 for crude oil production. Correction factor for tank emissions for time period T_n is 4.37 for gas condensate production.

8,760 = Conversion to hourly emissions.

* * * * *

(n) * * *

(2) * * *

(i) For onshore natural gas production and onshore petroleum and natural gas gathering and boosting, determine the GHG mole fraction using paragraph (u)(2)(i) of this section.

* * * * *

(o) *Centrifugal compressor venting.* If you are required to report emissions from centrifugal compressor venting as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2), you must conduct volumetric emission measurements specified in paragraph (o)(1) of this section using methods specified in paragraphs (o)(2) through (5) of this section; perform calculations specified in paragraphs (o)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (o)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (o)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (o)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (o)(1) through (12) do not apply. If you are required to report emissions from centrifugal compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(19) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(8), you must calculate volumetric emissions as specified in paragraph (o)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (o)(11).

* * * * *

(10) *Method for calculating volumetric GHG emissions from wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from centrifugal compressor wet seal oil degassing vents at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–25 of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-25)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from centrifugal compressor wet seals, at standard conditions, in cubic feet.

Count = Total number of centrifugal compressors that have wet seal oil degassing vents.

$EF_{i,s}$ = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(p) *Reciprocating compressor venting.* If you are required to report emissions from reciprocating compressor venting as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1), you must conduct volumetric emission measurements specified in paragraph (p)(1) of this section using methods specified in paragraphs (p)(2) through (5) of this section; perform calculations specified in paragraphs (p)(6) through (9) of this section; and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11) of this section. If emissions from a compressor source are routed to a flare, paragraphs (p)(1) through (11) do not apply and instead you must calculate CH_4, CO_2, and N_2O emissions as specified in paragraph (p)(12) of this section. If emissions from a compressor source are captured for fuel use or are routed to a thermal oxidizer, paragraphs (p)(1) through (12) do not apply and instead you must calculate and report emissions as specified in subpart C of this part. If emissions from a compressor source are routed to vapor recovery, paragraphs (p)(1) through (12) do not apply. If you are required to report emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility as specified in § 98.232(c)(11) or an onshore petroleum and natural gas gathering and boosting facility as specified in § 98.232(j)(5), you must calculate volumetric emissions as specified in paragraph (p)(10); and calculate CH_4 and CO_2 mass emissions as specified in paragraph (p)(11).

* * * * *

(10) *Method for calculating volumetric GHG emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility.* You must calculate emissions from reciprocating compressor venting at an onshore petroleum and natural gas production facility or an onshore petroleum and natural gas gathering and boosting facility using Equation W–29D of this section.

$$E_{s,i} = Count * EF_{i,s} \qquad \text{(Eq. W-29D)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG_i (either CH_4 or CO_2) emissions from reciprocating compressors, at standard conditions, in cubic feet.

Count = Total number of reciprocating compressors.

$EF_{i,s}$ = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

* * * * *

(r) *Equipment leaks by population count.* This paragraph (r) applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), (i)(6), (j)(10), and (j)(11) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. You must calculate emissions from all emission sources listed in this paragraph using Equation W–32A of this section, except for natural gas distribution facility emission sources listed in § 98.232(i)(3). Natural gas distribution facility emission sources listed in § 98.232(i)(3) must calculate emissions using Equation W–32B of this section and according to paragraph (r)(6)(ii) of this section.

$$E_{s,e,i} = Count_e * EF_{s,e} * GHG_i * T_e \quad \text{(Eq. W-32A)}$$

$$E_{s,MR,i} = Count_{MR} * EF_{s,MR,i} * T_{w,avg} \quad \text{(Eq. W-32B)}$$

Where:

$E_{s,e,i}$ = Annual volumetric emissions of GHG_i from the emission source type in standard cubic feet. The emission source type may be a component (*e.g.* connector, open-ended line, etc.), below grade metering-regulating station, below grade transmission-distribution transfer station, distribution main, distribution service, or gathering pipeline.

$E_{s,MR,i}$ = Annual volumetric emissions of GHG_i from all meter/regulator runs at above grade metering regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the annual volumetric emissions of GHG_i from all meter/regulator runs at above grade transmission-distribution transfer stations, in standard cubic feet.

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–4 of this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W–7 of this subpart.

$Count_{MR}$ = Total number of meter/regulator runs at above grade metering-regulating stations that are not above grade transmission-distribution transfer stations or, when used to calculate emissions according to paragraph (q)(9) of this section, the total number of meter/regulator runs at above grade transmission-distribution transfer stations.

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A and W–4 through W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart.

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs, as determined in Equation W–31 of this section.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_e = Average estimated time that each emission source type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

$T_{w,avg}$ = Average estimated time that each meter/regulator run was operational in the calendar year, in hours per meter/regulator run, using engineering estimate based on best available data.

* * * * *

(2) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas population emission factors listed in Table W–1A of this subpart. Major equipment and components associated with gas wells and onshore petroleum and natural gas gathering and boosting systems are considered gas service components in reference to Table W–1A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W–1A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the calculation methods described in this paragraph (r)(2), except for miles of gathering pipelines by material type, which must be determined using Component Count Method 2 in paragraph (r)(2)(ii) of this section. The same calculation method must be used for the entire calendar year.

(i) *Component Count Method 1.* For all onshore petroleum and natural gas production operations and onshore petroleum and natural gas gathering and boosting operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart. For meters/piping, use one meters/piping per well-pad for onshore petroleum and natural gas production operations and the number of meters in the facility for onshore petroleum and natural gas gathering and boosting operations.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B of this subpart for onshore natural gas production and onshore petroleum and natural gas gathering and boosting; and Table W–1C of this subpart for onshore oil production. Use the appropriate factor

in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

* * * * *

(u) * * *

(2) * * *

(i) *GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities.* If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

* * * * *

(iii) *GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment and the onshore natural gas transmission pipeline industry segment.* You may use either a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas or site specific engineering estimates based on best available data.

* * * * *

(z) *Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraphs (z)(3) and (4) of this section, as follows:

(1) * * *

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore petroleum and natural gas production facilities, at onshore petroleum and natural gas gathering and boosting facilities, and at natural gas distribution facilities will be reported according to the requirements specified in § 98.236(z) and not according to the reporting requirements specified in subpart C of this part.

* * * * *

■ 6. Section 98.234 is amended by adding paragraph (g) to read as follows:

§ 98.234 Monitoring and QA/QC requirements.

* * * * *

(g) *Special reporting provisions for best available monitoring methods in reporting year 2016*—(1) *Best available monitoring methods.* From January 1, 2016, to December 31, 2016, you must use the calculation methodologies and equations in § 98.233 but you may use the best available monitoring method as described in paragraph (g)(2) of this section for any parameter specified in paragraphs (g)(3) through (6) of this section for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2016. Starting no later than January 1, 2017, you must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part. For onshore petroleum and natural gas production, this paragraph (g)(1) only applies if emissions from well completions and workovers of oil wells with hydraulic fracturing cause your facility to exceed the reporting threshold in § 98.231(a)(1).

(2) Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(3) *Best available monitoring methods for well-related measurement data for oil wells with hydraulic fracturing.* You may use best available monitoring methods for any well-related measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for venting during well completions and workovers of oil wells with hydraulic fracturing.

(4) *Best available monitoring methods for measurement data for onshore petroleum and natural gas gathering and boosting facilities.* You may use best available monitoring methods for any leak detection and/or measurement data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart for acid gas removal vents as specified in § 98.233(d).

(5) *Best available monitoring methods for measurement data for natural gas transmission pipelines.* You may use best available monitoring methods for any measurement data for natural gas transmission pipelines that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for blowdown vent stacks.

(6) *Best available monitoring methods for specified activity data.* You may use best available monitoring methods for activity data as listed in paragraphs (g)(6)(i) through (iii) of this section that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart for well completions and workovers of oil wells with hydraulic fracturing, onshore petroleum and natural gas gathering and boosting facilities, or natural gas transmission pipelines.

(i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (g), (o), (p), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in § 98.233(g) and (i).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (n), and (z).

* * * * *

■ 7. Section 98.236 is amended by:

■ a. Revising paragraph (a) introductory text;

■ b. Adding paragraphs (a)(9) and (10);

■ c. Revising paragraphs (d)(1)(i) and (vi);

■ d. Revising paragraphs (e)(1)(i) and (xviii);

■ e. Revising paragraphs (f)(1)(ii), (f)(1)(xi)(A), (f)(1)(xii)(A), and (f)(2)(i);

■ f. Revising paragraphs (g) introductory text, (g)(1), (g)(2), (g)(5), and (g)(6);

■ g. Revising paragraphs (h)(1)(i) and (iv), (h)(2)(i) and (iv), (h)(3)(i), and (h)(4)(i);

■ h. Revising paragraphs (i) introductory text and (i)(1) introductory text;

■ i. Adding paragraph (i)(3);

■ j. Revising paragraphs (j) introductory text and (j)(1) introductory text;

■ k. Revising paragraphs (j)(1)(i), (iii), (iv) (v), (vii), and (viii);

■ l. Revising paragraphs (j)(2)(i) introductory text, (j)(2)(i)(A) through (C), (j)(2)(ii), (j)(2)(iii) introductory text, (j)(2)(iii)(A) and (B), and (j)(3) introductory text;

■ m. Revising paragraph (l)(1) introductory text;

■ n. Redesignating paragraphs (l)(1)(ii) through (vi) as paragraphs (l)(1)(iii) through (vii), respectively;

■ o. Adding paragraph (l)(1)(ii);

■ p. Revising newly designated paragraph (l)(1)(v);

■ q. Revising paragraph (l)(2) introductory text;

■ r. Redesignating paragraphs (l)(2)(ii) through (vii) as paragraphs (l)(2)(iii) through (viii), respectively;

■ s. Adding paragraph (l)(2)(ii);

■ t. Revising newly designated paragraph (l)(2)(v);

■ u. Revising paragraph (l)(3) introductory text;

■ v. Redesignating paragraphs (l)(3)(ii) through (v) as paragraphs (l)(3)(iii) through (vi), respectively;

■ w. Adding paragraph (l)(3)(ii);

■ x. Revising newly designated paragraph (l)(3)(iv);

■ y. Revising paragraph (l)(4) introductory text;
■ a. Redesignating paragraphs (l)(4)(ii) through (vi) as paragraphs (l)(4)(iii) through (vii), respectively;
■ aa. Adding paragraph (l)(4)(ii);
■ bb. Revising newly designated paragraph (l)(4)(iv);
■ cc. Revising paragraphs (m)(1), (m)(5), (m)(6), (m)(7)(i), (m)(8)(i);
■ dd. Revising paragraph (n)(1);
■ ee. Revising paragraphs (o) introductory text and (o)(5) introductory text;
■ ff. Revising paragraphs (p) introductory text and (p)(5) introductory text;
■ gg. Revising paragraphs (r)(1) introductory text, (r)(1)(i), (r)(3) introductory text, and (r)(3)(ii) introductory text;
■ hh. Revising paragraph (z) introductory text;
■ ii. Revising paragraphs (aa) introductory text and (aa)(1)(ii)(D) through (H);
■ jj. Adding paragraphs (aa)(10) and (11); and
■ kk. Revising paragraph (cc).

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

* * * * *

(a) The annual report must include the information specified in paragraphs (a)(1) through (10) of this section for each applicable industry segment. The annual report must also include annual emissions totals, in metric tons of each GHG, for each applicable industry segment listed in paragraphs (a)(1) through (10), and each applicable emission source listed in paragraphs (b) through (z) of this section.

* * * * *

(9) *Onshore petroleum and natural gas gathering and boosting.* For the equipment/activities specified in paragraphs (a)(9)(i) through (xi) of this section, report the information specified in the applicable paragraphs of this section.

(i) *Natural gas pneumatic devices.* Report the information specified in paragraph (b) of this section.

(ii) *Natural gas driven pneumatic pumps.* Report the information specified in paragraph (c) of this section.

(iii) *Acid gas removal units.* Report the information specified in paragraph (d) of this section.

(iv) *Dehydrators.* Report the information specified in paragraph (e) of this section.

(v) *Blowdown vent stacks.* Report the information specified in paragraph (i) of this section.

(vi) *Storage tanks.* Report the information specified in paragraph (j) of this section.

(vii) *Flare stacks.* Report the information specified in paragraph (n) of this section.

(viii) *Centrifugal compressors.* Report the information specified in paragraph (o) of this section.

(ix) *Reciprocating compressors.* Report the information specified in paragraph (p) of this section.

(x) *Equipment leaks by population count.* Report the information specified in paragraph (r) of this section.

(xi) *Combustion equipment.* Report the information specified in paragraph (z) of this section.

(10) *Onshore natural gas transmission pipeline.* For blowdown vent stacks, report the information specified in paragraph (i) of this section.

* * * * *

(d) * * *

(1) * * *

(i) A unique name or ID number for the acid gas removal unit. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single acid gas removal unit for each location it operates at in a given year.

* * * * *

(vi) Sub-basin ID that best represents the wells supplying gas to the unit (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the unit (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(e) * * *

(1) * * *

(i) A unique name or ID number for the dehydrator. For the onshore petroleum and natural gas production and the onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single dehydrator for each location it operates at in a given year.

* * * * *

(xviii) Sub-basin ID that best represents the wells supplying gas to the dehydrator (for the onshore petroleum and natural gas production industry segment only) or name of the county that best represents the equipment supplying gas to the dehydrator (for the onshore petroleum and natural gas gathering and boosting industry segment only).

* * * * *

(f) * * *

(1) * * *

(ii) Well tubing diameter and pressure group ID and a list of the well ID numbers associated with each sub-basin and well tubing diameter and pressure group ID.

* * * * *

(xi) * * *

(A) Well ID number of tested well.

* * * * *

(xii) * * *

(A) Well ID number.

* * * * *

(2) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin.

* * * * *

(g) *Completions and workovers with hydraulic fracturing.* You must indicate whether your facility had any well completions or workovers with hydraulic fracturing during the calendar year. If your facility had well completions or workovers with hydraulic fracturing during the calendar year, then you must report information specified in paragraphs (g)(1) through (10) of this section, for each sub-basin and well type combination. Report information separately for completions and workovers.

(1) Sub-basin ID and a list of the well ID numbers associated with each sub-basin that had completions or workovers with hydraulic fracturing during the calendar year.

(2) Well type combination (horizontal or vertical, gas well or oil well).

* * * * *

(5) If you used Equation W–10A of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(5)(i) through (iii) of this section.

(i) Cumulative gas flowback time, in hours, from when gas is first detected until sufficient quantities are present to enable separation, and the cumulative flowback time, in hours, after sufficient quantities of gas are present to enable separation (sum of ''$T_{p,i}$'' and sum of ''$T_{p,s}$'' values used in Equation W–10A of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells included in this number. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total number of hours of flowback from all wells during completions or workovers and the well ID number(s) for the well(s) included in the number.

(ii) For the measured well(s), the flowback rate, in standard cubic feet per

hour (average of ''$FR_{s,p}$'' values used in Equation W–12A of § 98.233), and the well ID numbers of the wells for which it is measured. You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured flowback rate during well completion or workover and the well ID number(s) for the well(s) included in the measurement.

(iii) If you used Equation W–12C of § 98.233 to calculate the average gas production rate for an oil well, then you must report the information specified in paragraphs (g)(5)(iii)(A) and (B) of this section.

(A) Gas to oil ratio for the well in standard cubic feet of gas per barrel of oil (''GOR_p'' in Equation W–12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the gas to oil ratio for the well and the well ID number for the well.

(B) Volume of oil produced during the first 30 days of production after completions of each newly drilled well or well workover using hydraulic fracturing, in barrels (''V_p'' in Equation W–12C of § 98.233). You may delay the reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced during the first 30 days of production after well completion or workover and the well ID number for the well.

(6) If you used Equation W–10B of § 98.233 to calculate annual volumetric total gas emissions, then you must report the information specified in paragraphs (g)(6)(i) through (iii) of this section.

(i) Vented natural gas volume, in standard cubic feet, for each well in the sub-basin (''$FV_{s,p}$'' in Equation W–10B of § 98.233).

(ii) Flow rate at the beginning of the period of time when sufficient quantities of gas are present to enable separation, in standard cubic feet per hour, for each well in the sub-basin (''$FR_{p,i}$'' in Equation W–10B of § 98.233).

(iii) The well ID number for which vented natural gas volume was measured.

* * * * *

(h) * * *

(1) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and without flaring.

* * * * *

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin without flaring, in standard cubic feet per hour (average of all ''V_p'' used in Equation W–13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(2) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well completions without hydraulic fracturing and with flaring.

* * * * *

(iv) Average daily gas production rate for all completions without hydraulic fracturing in the sub-basin with flaring, in standard cubic feet per hour (the average of all ''V_p'' from Equation W–13B of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that can be used for the measurement. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average daily gas production rate for all wells during completions and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(3) * * *

(i) Sub-basin ID and a list of the well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and without flaring.

* * * * *

(4) * * *

(i) Sub-basin ID and a list of well ID numbers associated with each sub-basin for gas well workovers without hydraulic fracturing and with flaring.

* * * * *

(i) *Blowdown vent stacks.* You must indicate whether your facility has blowdown vent stacks. If your facility has blowdown vent stacks, then you must report whether emissions were calculated by equipment or event type or by using flow meters or a combination of both. If you calculated emissions by equipment or event type for any blowdown vent stacks, then you must report the information specified in paragraph (i)(1) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated by equipment or event type. If you calculated emissions using flow meters for any blowdown vent stacks, then you must report the information specified in paragraph (i)(2) of this section considering, in aggregate, all blowdown vent stacks for which emissions were calculated using flow meters. For the onshore natural gas transmission pipeline segment, you must also report the information in paragraph (i)(3) of this section.

(1) *Report by equipment or event type.* If you calculated emissions from blowdown vent stacks by the seven categories listed in § 98.233(i)(2) for industry segments other than the onshore natural gas transmission pipeline segment, then you must report the equipment or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each equipment or event type. If a blowdown event resulted in emissions from multiple equipment types, and the emissions cannot be apportioned to the different equipment types, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the equipment type that represented the largest portion of the emissions for the blowdown event. If you calculated emissions from blowdown vent stacks by the eight categories listed in § 98.233(i)(2) for the onshore natural gas transmission pipeline segment, then you must report the pipeline segments or event types and the information specified in paragraphs (i)(1)(i) through (iii) of this section for each ''equipment or event type'' (*i.e.,* category). If a blowdown event resulted in emissions from multiple categories, and the emissions cannot be apportioned to the different categories, then you may report the information in paragraphs (i)(1)(i) through (iii) of this section for the ''equipment or event type'' (*i.e.,* category) that represented the largest portion of the emissions for the blowdown event.

* * * * *

(3) *Onshore natural gas transmission pipeline segment.* Report the information in paragraphs (i)(3)(i) through (iii) of this section for each state.

(i) Annual CO_2 emissions in metric tons CO_2.

(ii) Annual CH_4 emissions in metric tons CH_4.

(iii) Annual number of blowdown events.

(j) *Onshore production and onshore petroleum and natural gas gathering and boosting storage tanks.* You must indicate whether your facility sends produced oil to atmospheric tanks. If your facility sends produced oil to atmospheric tanks, then you must indicate which Calculation Method(s) you used to calculate GHG emissions, and you must report the information specified in paragraphs (j)(1) and (2) of this section as applicable. If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any atmospheric tanks were observed to have malfunctioning dump valves during the calendar year, then you must indicate that dump valves were malfunctioning and you must report the information specified in paragraph (j)(3) of this section.

(1) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j) to calculate GHG emissions, then you must report the information specified in paragraphs (j)(1)(i) through (xvi) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) and by calculation method. Onshore petroleum and natural gas gathering and boosting facilities do not report the information specified in paragraphs (j)(1)(ix) and (xi) of this section.

(i) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

* * * * *

(iii) The total annual oil volume from gas-liquid separators and direct from wells or non-separator equipment that is sent to applicable onshore production and onshore petroleum and natural gas gathering and boosting storage tanks, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil production greater than or equal to 10 barrels per day and flowing to gas-liquid separators or direct to storage tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total volume of oil from all wells and the well ID number(s) for the well(s) included in this volume.

(iv) The average gas-liquid separator or non-separator equipment temperature, in degrees Fahrenheit.

(v) The average gas-liquid separator or non-separator equipment pressure, in pounds per square inch gauge.

* * * * *

(vii) The minimum and maximum concentration (mole fraction) of CO_2 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

(viii) The minimum and maximum concentration (mole fraction) of CH_4 in flash gas from onshore production and onshore natural gas gathering and boosting storage tanks.

* * * * *

(2) * * *

(i) Report the information specified in paragraphs (j)(2)(i)(A) through (F) of this section, at the basin level, for atmospheric tanks where emissions were calculated using Calculation Method 3 of § 98.233(j). Onshore gathering and boosting facilities do not report the information specified in paragraphs (j)(2)(i)(E) and (F) of this section.

(A) The total annual oil/condensate throughput that is sent to all atmospheric tanks in the basin, in barrels. You may delay reporting of this data element for onshore production if you indicate in the annual report that wildcat wells and delineation wells are the only wells in the sub-basin with oil/condensate production less than 10 barrels per day and that send oil/condensate to atmospheric tanks. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the total annual oil/condensate throughput from all wells and the well ID number(s) for the well(s) included in this volume.

(B) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with flares.

(C) An estimate of the fraction of oil/condensate throughput reported in paragraph (j)(2)(i)(A) of this section sent to atmospheric tanks in the basin that controlled emissions with vapor recovery systems.

* * * * *

(ii) Report the information specified in paragraphs (j)(2)(ii)(A) through (D) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that did not control emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares.

(C) Annual CO_2 emissions, in metric tons CO_2, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(D) Annual CH_4 emissions, in metric tons CH_4, from atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that did not control emissions with flares, calculated using Equation W–15 of § 98.233(j) and adjusted for vapor recovery, if applicable.

(iii) Report the information specified in paragraphs (j)(2)(iii)(A) through (E) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) with atmospheric tanks whose emissions were calculated using Calculation Method 3 of § 98.233(j) and that controlled emissions with flares.

(A) Sub-basin ID (for onshore production) or county name (for onshore petroleum and natural gas gathering and boosting).

(B) The number of atmospheric tanks in the sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting) that controlled emissions with flares.

* * * * *

(3) If you used Calculation Method 1 or Calculation Method 2 of § 98.233(j), and any gas-liquid separator liquid dump values did not close properly during the calendar year, then you must report the information specified in paragraphs (j)(3)(i) through (iv) of this section for each sub-basin (for onshore production) or county (for onshore petroleum and natural gas gathering and boosting).

* * * * *

(l) * * *

(1) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual

conditions from oil wells and the emissions are not vented to a flare, then you must report the information specified in paragraphs (l)(1)(i) through (vii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(2) If you used Equation W–17A of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from oil wells and the emissions are vented to a flare, then you must report the information specified in paragraphs (l)(2)(i) through (viii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(v) Average flow rate for well(s) tested, in barrels of oil per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average flow rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(3) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were not vented to a flare, then you must report the information specified in paragraphs (l)(3)(i) through (vi) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(4) If you used Equation W–17B of § 98.233 to calculate annual volumetric natural gas emissions at actual conditions from gas wells and the emissions were vented to a flare, then you must report the information specified in paragraphs (l)(4)(i) through (vii) of this section.

* * * * *

(ii) Well ID numbers for the wells tested in the calendar year.

* * * * *

(iv) Average annual production rate for well(s) tested, in actual cubic feet per day. You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells that are tested. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured average annual production rate for well(s) tested and the well ID number(s) for the well(s) included in the measurement.

* * * * *

(m) * * *

(1) Sub-basin ID and a list of well ID numbers for wells for which associated gas was vented or flared.

* * * * *

(5) Volume of oil produced, in barrels, in the calendar year during the time periods in which associated gas was vented or flared (the sum of "$V_{p,q}$" used in Equation W–18 of § 98.233). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells are the only wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the volume of oil produced for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(6) Total volume of associated gas sent to sales, in standard cubic feet, in the calendar year during time periods in which associated gas was vented or flared (the sum of "SG" values used in Equation W–18 of § 98.233(m)). You may delay reporting of this data element if you indicate in the annual report that wildcat wells and/or delineation wells from which associated gas was vented or flared. If you elect to delay reporting of this data element, you must report by the date specified in § 98.236(cc) the measured total volume of associated gas sent to sales for well(s) with associated gas venting and flaring and the well ID number(s) for the well(s) included in the measurement.

(7) * * *

(i) Total number of wells for which associated gas was vented directly to the atmosphere without flaring and a list of their well ID numbers.

* * * * *

(8) * * *

(i) Total number of wells for which associated gas was flared and a list of their well ID numbers.

* * * * *

(n) * * *

(1) Unique name or ID for the flare stack. For the onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting industry segments, a different name or ID may be used for a single flare stack for each location where it operates at in a given calendar year.

* * * * *

(o) *Centrifugal compressors.* You must indicate whether your facility has centrifugal compressors. You must report the information specified in paragraphs (o)(1) and (2) of this section for all centrifugal compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(o)(2) or (4), you must report the information specified in paragraph (o)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(o)(3) or (5), you must report the information specified in paragraph (o)(4) of this section. Centrifugal compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (o)(1) through (4) of this section and instead must report the information specified in paragraph (o)(5) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Centrifugal compressors with wet seal degassing vents in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (o)(5)(i) through (iii) of this section.

* * * * *

(p) *Reciprocating compressors.* You must indicate whether your facility has reciprocating compressors. You must report the information specified in

paragraphs (p)(1) and (2) of this section for all reciprocating compressors at your facility. For each compressor source or manifolded group of compressor sources that you conduct as found leak measurements as specified in § 98.233(p)(2) or (4), you must report the information specified in paragraph (p)(3) of this section. For each compressor source or manifolded group of compressor sources that you conduct continuous monitoring as specified in § 98.233(p)(3) or (5), you must report the information specified in paragraph (p)(4) of this section. Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting are not required to report information in paragraphs (p)(1) through (4) of this section and instead must report the information specified in paragraph (p)(5) of this section.

* * * * *

(5) *Onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting.* Reciprocating compressors in onshore petroleum and natural gas production and onshore petroleum and natural gas gathering and boosting must report the information specified in paragraphs (p)(5)(i) through (iii) of this section.

* * * * *

(r) * * *

(1) You must indicate whether your facility contains any of the emission source types required to use Equation W–32A of § 98.233. You must report the information specified in paragraphs (r)(1)(i) through (v) of this section separately for each emission source type required to use Equation W–32A that is located at your facility. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(1)(i) through (v) separately by component type, service type, and geographic location (*i.e.,* Eastern U.S. or Western U.S.).

(i) Emission source type. Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the component type, service type and geographic location.

* * * * *

(3) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must also report the information specified in paragraphs (r)(3)(i) and (ii) of this section.

* * * * *

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W–1B and W–1C of this subpart.

* * * * *

(z) *Combustion equipment at onshore petroleum and natural gas production facilities, onshore petroleum and natural gas gathering and boosting facilities, and natural gas distribution facilities.* If your facility is required by § 98.232(c)(22), (i)(7), or (j)(12) to report emissions from combustion equipment, then you must indicate whether your facility has any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section. If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xvii), (a)(8)(i), or (a)(9)(xi) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

* * * * *

(aa) Each facility must report the information specified in paragraphs (aa)(1) through (11) of this section, for each applicable industry segment, by using best available data. If a quantity required to be reported is zero, you must report zero as the value.

(1) * * *

(ii) * * *

(D) The number of producing wells at the end of the calendar year and a list of the well ID numbers (exclude only those wells permanently taken out of production, *i.e.,* plugged and abandoned).

(E) The number of producing wells acquired during the calendar year and a list of the well ID numbers.

(F) The number of producing wells divested during the calendar year and a list of the well ID numbers.

(G) The number of wells completed during the calendar year and a list of the well ID numbers.

(H) The number of wells permanently taken out of production (*i.e.,* plugged and abandoned) during the calendar year and a list of the well ID numbers.

* * * * *

(10) For onshore petroleum and natural gas gathering and boosting facilities, report the quantities specified in paragraphs (aa)(10)(i) through (iv) of this section.

(i) The quantity of gas received by the gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(ii) The quantity of gas transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in thousand standard cubic feet.

(iii) The quantity of all hydrocarbon liquids received by the gathering and boosting facility in the calendar year, in barrels.

(iv) The quantity of all hydrocarbon liquids transported to a natural gas processing facility, a natural gas transmission pipeline, a natural gas distribution pipeline, or another gathering and boosting facility in the calendar year, in barrels.

(11) For onshore natural gas transmission pipeline facilities, report the quantities specified in paragraphs (aa)(11)(i) through (vi) of this section.

(i) The quantity of natural gas received at all custody transfer stations in the calendar year, in thousand standard cubic feet. This value may include meter corrections, but only for the calendar year covered by the annual report.

(ii) The quantity of natural gas withdrawn from in-system storage in the calendar year, in thousand standard cubic feet.

(iii) The quantity of natural gas added to in-system storage in the calendar year, in thousand standard cubic feet.

(iv) The quantity of natural gas transferred to third parties such as LDCs or other transmission pipelines, in thousand standard cubic feet.

(v) The quantity of natural gas consumed by the transmission pipeline facility for operational purposes, in thousand standard cubic feet.

(vi) The miles of transmission pipeline for each state in the facility.

* * * * *

(cc) If you elect to delay reporting the information in paragraph (g)(5)(i), (g)(5)(ii), (g)(5)(iii)(A), (g)(5)(iii)(B), (h)(1)(iv), (h)(2)(iv), (j)(1)(iii), (j)(2)(i)(A), (l)(1)(iv), (l)(2)(iv), (l)(3)(iii), (l)(4)(iii), (m)(5), or (m)(6) of this section, you must report the information required in that paragraph no later than the date 2 years following the date specified in § 98.3(b) introductory text.

■ 8. Section 98.238 is amended by adding definitions for ''Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements,'' ''Facility with respect to the onshore natural gas transmission pipeline segment,'' ''Gathering and

boosting system,'' ''Gathering and boosting system owner or operator,'' ''Onshore natural gas transmission pipeline owner or operator,'' and ''Well identification (ID) number'' in alphabetical order to read as follows:

§ 98.238 Definitions.

* * * * *

Facility with respect to onshore petroleum and natural gas gathering and boosting for purposes of reporting under this subpart and for the corresponding subpart A requirements means all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin as defined in this section. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline. The facility does not include equipment and pipelines that are part of any other industry segment defined in this subpart.

* * * * *

Facility with respect to the onshore natural gas transmission pipeline segment means the total U.S. mileage of natural gas transmission pipelines, as defined in this section, owned and operated by an onshore natural gas transmission pipeline owner or operator as defined in this section. The facility does not include pipelines that are part of any other industry segment defined in this subpart.

* * * * *

Gathering and boosting system means a single network of pipelines, compressors and process equipment, including equipment to perform natural gas compression, dehydration, and acid gas removal, that has one or more connection points to gas and oil production and a downstream endpoint, typically a gas processing plant, transmission pipeline, LDC pipeline, or other gathering and boosting system.

Gathering and boosting system owner or operator means any person that holds a contract in which they agree to transport petroleum or natural gas from one or more onshore petroleum and natural gas production wells to a natural gas processing facility, another gathering and boosting system, a natural gas transmission pipeline, or a distribution pipeline, or any person responsible for custody of the petroleum or natural gas transported.

* * * * *

Onshore natural gas transmission pipeline owner or operator means, for interstate pipelines, the person identified as the transmission pipeline owner or operator on the Certificate of Public Convenience and Necessity issued under 15 U.S.C. 717f, or, for intrastate pipelines, the person identified as the owner or operator on the transmission pipeline's Statement of Operating Conditions under section 311 of the Natural Gas Policy Act, or for pipelines that fall under the ''Hinshaw Exemption'' as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994), the person identified as the owner or operator on blanket certificates issued under 18 CFR 284.224. If an intrastate pipeline is not subject to section 311 of the Natural Gas Policy Act (NGPA), the onshore natural gas transmission pipeline owner or operator is the person identified as the owner or operator on reports to the state regulatory body regulating rates and charges for the sale of natural gas to consumers.

* * * * *

Well identification (ID) number means the unique and permanent identification number assigned to a petroleum or natural gas well. If the well has been assigned a US Well Number, the well ID number required in this subpart is the US Well Number. If a US Well Number has not been assigned to the well, the well ID number is the identifier established by the well's permitting authority.

* * * * *

■ 9. Revise Table W–1A of subpart W of part 98 to read as follows:

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003

TABLE W–1A TO SUBPART W OF PART 98—DEFAULT WHOLE GAS EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION FACILITIES AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING FACILITIES—Continued

Onshore petroleum and natural gas production and Onshore petroleum and natural gas gathering and boosting	Emission factor (scf/hour/component)
Open-ended Line	0.006
Other [5]	0.003
Population Emission Factors—Gathering Pipelines, by Material Type [7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60
Western U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other [5]	0.003
Population Emission Factors—Gathering Pipelines by Material Type [7]	
Protected Steel	0.47
Unprotected Steel	16.59
Plastic/Composite	2.50
Cast Iron	27.60

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emission Factor is in units of ''scf/hour/device.''
[3] Emission Factor is in units of ''scf/hour/pump.''
[4] Hydrocarbon liquids greater than or equal to 20°API are considered ''light crude.''
[5] ''Others'' category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered ''heavy crude.''
[7] Emission factors are in units of ''scf/hour/mile of pipeline.''

■ 10. Amend Table W–1B of subpart W of part 98 by revising the table heading to read as follows:

TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING EQUIPMENT

* * * * *

[FR Doc. 2015–25840 Filed 10–21–15; 08:45 am]
BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA–HQ–OAR–2015–0764; FRL–9955–12–OAR]

RIN 2060–AS73

Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency is finalizing revisions and confidentiality determinations for the petroleum and natural gas systems source category of the Greenhouse Gas Reporting Program. In particular, this action adds new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the fugitive emissions monitoring methods in the recently finalized new source performance standards for the oil and gas industry. This action also adds emission factors for leaking equipment to be used in conjunction with these monitoring methods to calculate and report greenhouse gas emissions resulting from equipment leaks. Finally, this action finalizes reporting requirements and confidentiality determinations for nine new or substantially revised data elements contained in these amendments.

DATES: This final rule is effective on January 1, 2017.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2015–0764. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available electronically through *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC–6207A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 343–9334; fax number: (202) 343–2342; email address: *GHGReporting@epa.gov.* For technical information, please go to the Greenhouse Gas Reporting Rule Web site, *http://www.epa.gov/ghgreporting/.* To submit a question, select Help Center, followed by ''Contact Us.''

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of this final rule will also be available through the WWW. Following the Administrator's signature, a copy of this action will be posted on the EPA's Greenhouse Gas Reporting Rule Web site at *http://www.epa.gov/ghgreporting/index.html.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. These revisions affect entities that must submit annual greenhouse gas (GHG) reports under the Greenhouse Gas Reporting Program (GHGRP), codified in the Code of Federal Regulations (CFR) at 40 CFR part 98. This rule applies to all petroleum and natural gas systems facilities that are subject to 40 CFR part 98, regardless of the facility's location, and ensures that all these facilities across the United States (U.S.) report GHG data consistently, and therefore is ''nationally applicable'' within the meaning of section 307(b)(1) of the Clean Air Act (CAA). Further, the Administrator has determined that rules codified in 40 CFR part 98 are subject to the provisions of CAA section 307(d). (See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').) These are amendments to existing regulations. These amended regulations affect owners or operators of petroleum and natural gas systems that directly emit GHGs. Regulated categories and entities include, but are not limited to, those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS [a]	Examples of affected facilities
Petroleum and Natural Gas Systems	486210	Pipeline transportation of natural gas.
	221210	Natural gas distribution.
	211111	Crude petroleum and natural gas extraction.
	211112	Natural gas liquid extraction.

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Other types of facilities than those listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you should carefully examine the applicability criteria found in 40 CFR part 98, subpart A and 40 CFR part 98, subpart W. If you have questions regarding the applicability of this action to a particular facility, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

What is the effective date? The final rule is effective on January 1, 2017. Section 553(d) of the Administrative Procedure Act (APA), 5 U.S.C. Chapter 5, generally provides that rules may not take effect earlier than 30 days after they are published in the **Federal Register**. The EPA is issuing this final rule under section 307(d)(1) of the Clean Air Act, which states: ''The provisions of section 553 through 557 * * * of Title 5 shall not, except as expressly provided in this section, apply to actions to which this subsection applies.'' Thus, section 553(d) of the APA does not apply to this rule. The EPA is nevertheless acting consistently with the purposes underlying APA section 553(d) in making the first set of amendments to this rule effective on January 1, 2017. Section 553(d) allows an effective date less than 30 days after publication for a rule that ''grants or recognizes an exemption or relieves a restriction'' or ''as otherwise provided by the agency for good cause found and published with the rule.'' As explained below, the EPA finds that there is good cause for the first set of amendments to this rule to become effective on January 1, 2017, even though this may result in an effective date fewer than 30 days from date of publication in the **Federal Register**.

While this action is being signed prior to December 1, 2016, there is likely to

be a significant delay in the publication of this rule as it contains complex equations and tables and is relatively long. As an example, the EPA Administrator signed the Greenhouse Gas Reporting Rule: 2015 Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems final rule on October 1, 2015, but the rule was not published in the **Federal Register** until October 22, 2015 (80 FR 64262). The purpose of the 30-day waiting period prescribed in 5 U.S.C. 553(d) is to give affected parties a reasonable time to adjust their behavior and prepare before the final rule takes effect. To employ the APA section 553(d)(3) ''good cause'' exemption, an agency must balance the necessity for immediate implementation against principles of fundamental fairness which require that all affected persons be afforded a reasonable amount of time to prepare for the effective date of its ruling.[1] Where, as here, the final rule will be signed and made available on the EPA Web site more than 30 days before the effective date, but where the publication is likely to be delayed due to the complexity and length of the rule, the regulated entities are afforded this reasonable amount of time. We balance these circumstances with the need for the amendments to be effective by January 1, 2017; a delayed effective date would result in regulatory uncertainty, program disruption, and an inability to have the amendments effective for the 2017 reporting year. Accordingly, we find good cause exists to make this rule effective on January 1, 2017, consistent with the purposes of APA section 553(d)(3).

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit (the Court) by January 30, 2017 Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. Section 307(d)(7)(B) of the CAA also provides a mechanism for the EPA to convene a proceeding for reconsideration, ''[i]f the person raising an objection can demonstrate to the EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule.'' Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, William Jefferson Clinton Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20004. Note that under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by the EPA to enforce these requirements.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

APA Administrative Procedure Act
CAA Clean Air Act
CBI Confidential Business Information
CFR Code of Federal Regulations
CH4 methane
CO_2 carbon dioxide
CRA Congressional Review Act
DOT Department of Transportation
EPA U.S. Environmental Protection Agency
FR Federal Register
GHG greenhouse gas
GHGRP Greenhouse Gas Reporting Program
GRI Gas Research Institute
ICR Information Collection Request
LNG liquefied natural gas
NAICS North American Industry Classification System
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act
OGI optical gas imaging
OMB Office of Management and Budget
ppmv parts per million by volume
PRA Paperwork Reduction Act
RFA Regulatory Flexibility Act
U.S. United States
UMRA Unfunded Mandates Reform Act
VOC volatile organic compounds
WWW Worldwide Web

Organization of This Document. The following outline is provided to aid in locating information in this preamble.

I. Background
A. Organization of This Preamble
B. Background on This Action
C. Legal Authority
D. How do these amendments apply to 2016 and 2017 reports?
II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment
A. Summary of Final Amendments—General
B. Summary of Final Amendments to the Requirement To Use the Calculation Methodology Based on Equipment Leak Surveys
C. Summary of Final Amendments to Monitoring Methods
D. Summary of Final Amendments to Components To Be Surveyed
E. Summary of Final Amendments to Leaker Emission Factors and the Calculation Methodology Based on Equipment Leak Surveys
F. Summary of Final Amendments to Reporting Requirements
III. Final Confidentiality Determinations
A. Summary of Final Confidentiality Determinations for New or Substantially Revised Subpart W Data Elements
B. Summary of Public Comments and Responses on the Proposed Confidentiality Determinations
IV. Impacts of the Final Amendments to Subpart W
A. Impacts of the Final Amendments
B. Summary of Comments and Responses on the Impacts of the Proposed Rule
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act

I. Background

A. Organization of This Preamble

Section I of this preamble provides background information regarding the origin of the final amendments. This section also discusses the EPA's legal authority under the CAA to promulgate and amend 40 CFR part 98 of the Greenhouse Gas Reporting Rule (hereafter referred to as ''part 98'') as well as the legal authority for making confidentiality determinations for the data to be reported. Section II of this preamble contains information on the final amendments to part 98, subpart W (Petroleum and Natural Gas Systems) (hereafter referred to as ''subpart W''), including a summary of the major comments that the EPA considered in the development of this final rule. Section III of this preamble discusses the final confidentiality determinations for new or substantially revised data

[1] *Omnipoint Corp.* v. *FCC*, 78 F3d 620, 630 (D.C. Cir. 1996), quoting *U.S.* v. *Gavrilovic*, 551 F.2d 1099, 1105 (8th Cir. 1977).

reporting elements. Section IV of this preamble discusses the impacts of the final amendments to subpart W. Finally, section V of this preamble describes the statutory and executive order requirements applicable to this action.

B. Background on This Action

The EPA's GHGRP requires annual reporting of GHG data and other relevant information from large sources and suppliers in the United States. On October 30, 2009, the EPA published part 98 in the **Federal Register** (FR) for collecting information regarding GHG emissions from a broad range of industry sectors (74 FR 56260). Although reporting requirements for petroleum and natural gas systems were originally proposed to be part of part 98 (74 FR 16448, April 10, 2009), the final October 2009 rulemaking did not include the petroleum and natural gas systems source category as one of the 29 source categories for which reporting requirements were finalized. The EPA re-proposed subpart W in 2010 (75 FR 18608; April 12, 2010), and a subsequent final rulemaking was published on November 30, 2010, with the requirements for the petroleum and natural gas systems source category at 40 CFR part 98, subpart W (75 FR 74458). Following promulgation, the EPA finalized several actions revising subpart W (76 FR 22825, April 25, 2011; 76 FR 53057, August 25, 2011; 76 FR 59533, September 27, 2011; 76 FR 80554, December 23, 2011; 77 FR 51477, August 24, 2012; 78 FR 25392, May 1, 2013; 78 FR 71904, November 29, 2013; 79 FR 70352, November 25, 2014; 80 FR 64262, October 22, 2015).[2]

The Strategy to Reduce Methane Emissions in the President's Climate Action Plan summarizes the sources of CH_4 emissions, commits to new steps to cut emissions of this potent GHG, and outlines the Administration's efforts to improve the measurement of these emissions. The strategy builds on progress to date and takes steps to further cut CH_4 emissions from several sectors, including the oil and natural gas sector. In the strategy, the EPA was specifically tasked with continuing to review GHGRP regulatory requirements to address potential gaps in coverage, improve methods, and ensure high quality data reporting.[3] On January 14, 2015, the Obama administration provided additional direction to the EPA to ''explore potential regulatory opportunities for applying remote sensing technologies and other innovations in measurement and monitoring technology to further improve the identification and quantification of emissions'' in the oil and natural gas sector, such as the emissions submitted as part of GHGRP annual reporting.[4]

Under subpart W, GHGs that must be reported by each industry segment and applicable source types are specified in 40 CFR 98.232, including equipment leaks from listed component types. In order to fulfill these equipment leak emissions reporting requirements, reporters must utilize one of two calculation methodologies [5] to calculate GHG emissions from equipment leaks as specified in 40 CFR 98.233: (1) Calculation methodology based on equipment leak surveys (40 CFR 98.233(q)), or (2) calculation methodology based on population counts (40 CFR 98.233(r).[6] For example, facilities in the Onshore Natural Gas Processing and Onshore Natural Gas Transmission Compression industry segments use the calculation methodology based on equipment leak surveys for most components at their facilities. If 40 CFR 98.233(q) specifies that an equipment leak survey is required for the subsection of listed component types in 40 CFR 98.232, reporters must use one of the monitoring methods specified in 40 CFR 98.234 when conducting those equipment leak surveys to detect leaking components at the facility. The calculation methodology based on equipment leak surveys requires that the reporter then determine the total amount of time each component was assumed to be leaking and multiply that by the concentration of the methane (CH_4) and carbon dioxide (CO_2) in the gas and the applicable emission factor (referred to as a ''leaker emission factor''), listed in Table W–1E and Table W–2 through Table W–7, to calculate emissions. Finally, 40 CFR 98.236 specifies the data elements that must be reported to the EPA.

On January 29, 2016, the EPA proposed ''Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (81 FR 4987) to add new monitoring methods for detecting leaks from oil and gas equipment, to revise which industry segments and sources use the calculation methodology based on equipment leak surveys or the calculation methodology based on population counts, to clarify how the definition of fugitive emission components in the new source performance standards (NSPS) for the oil and natural gas sector (40 CFR part 60, subpart OOOOa, at 81 FR 35824) (hereafter referred to as the ''NSPS subpart OOOOa'') aligns with the equipment components subject to subpart W, to add leaker emission factors for multiple industry segments, and to add reporting requirements and confidentiality determinations for new or substantially revised data elements. Under those proposed amendments, facilities with fugitive emissions components at a well site or compressor station subject to the NSPS subpart OOOOa would use data derived from the NSPS subpart OOOOa fugitive emissions requirements (*i.e.*, which components were determined to have fugitive emissions) along with the subpart W leaker emission factors to calculate and report GHG emissions to the GHGRP. The proposed revisions provided the opportunity for owners and operators of sources not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards (*e.g.,* sources participating in a voluntarily implemented program) and not already required to conduct leak surveys under subpart W to optionally use the calculation methodology at 40 CFR 98.233(q) to calculate and report their GHG emissions to the GHGRP. The EPA also proposed that facilities that are already required to conduct leak surveys under subpart W would be able to use the newly proposed monitoring method(s) in 40 CFR 98.234. In addition, the EPA proposed new reporting requirements for all reporters using the calculation methodology

[2] See Greenhouse Gas Reporting Program, Historical Rulemakings. Available at *https://www.epa.gov/ghgreporting/rulemaking-notices-ghg-reporting.*

[3] Climate Action Plan—Strategy to Reduce Methane Emissions. The White House, Washington, DC, March 2014. Available at *http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.*

[4] FACT SHEET: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions. The White House, Office of the Press Secretary, January 14, 2015. Available at *https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.*

[5] Throughout this preamble, the term ''calculation methodology'' refers to the procedures used to calculate emissions (*e.g.,* ''calculation methodology based on equipment leak surveys'' refers to the methodology described in 40 CFR 98.233(q)) and ''monitoring method'' refers to the technology, test method, or other method of determining whether an individual component is leaking (see 40 CFR 98.234(a)). The term ''leak detection method'' that is used in the 40 CFR part 98 subpart W regulatory text has the same meaning as ''monitoring method'' used in this preamble.

[6] Reporters using the calculation methodology based on population counts determine the total number of all components in the facility and multiply that count by the average estimated time of operation, the concentration of the CH_4 and CO_2 in the gas, and the applicable emission factor (referred to as a ''population emission factor'') to calculate emissions.

based on equipment leak surveys and proposed to require reporters using the calculation methodology for the first time to begin reporting the information associated with that methodology. Finally, the EPA proposed confidentiality determinations for nine new or substantially revised data elements. The public comment period for these proposed rule amendments ended on March 15, 2016, following a 15-day extension of the original comment period end date (81 FR 9797; February 26, 2016). On June 3, 2016, the EPA published the final NSPS subpart OOOOa requirements (81 FR 35824).

In this action, the EPA is finalizing revisions to subpart W largely as proposed, with some changes made after consideration of public comments. Summaries of significant comments submitted on the proposed amendments and the EPA's responses to those comments can be found in sections II, III, and IV of this preamble. All comments submitted on the proposed amendments and the EPA's additional responses to the comments can be found in ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764.

As further detailed in the preamble to the proposed amendments, these revisions advance the EPA's goal of maximizing rule effectiveness by providing a mechanism for facilities to use the NSPS subpart OOOOa monitoring results for purposes of GHGRP subpart W reporting. This alignment reduces burden for entities subject to the fugitive emissions/equipment leak detection method requirements in both programs, and, when combined with the other amendments being finalized in this revision, provides clear monitoring methods, equipment leak survey and calculation methodologies and emission factors, and reporting requirements in subpart W, thus enabling government, regulated entities, and the public to easily identify and understand regulatory requirements. These amendments also further advance the ability of the GHGRP to provide access to high quality data on GHG emissions by adding the ability for reporters to use data collected during equipment leak surveys and to perform site-specific equipment leak calculations.

C. Legal Authority

The EPA is finalizing these rule amendments under its existing CAA authority provided in CAA section 114. As stated in the preamble to the 2009 final GHG reporting rule (74 FR 56260; October 30, 2009), CAA section 114(a)(1) provides the EPA broad authority to require the information to be gathered by this rule because such data will inform and are relevant to the EPA's carrying out a wide variety of CAA provisions. See the preambles to the proposed (74 FR 16448; April 10, 2009) and final GHG reporting rule (74 FR 56260; October 30, 2009) for further information.

In addition, pursuant to sections 114, 301, and 307 of the CAA, the EPA is publishing final confidentiality determinations for the new or substantially revised data elements required by these amendments. Section 114(c) requires that the EPA make information obtained under section 114 available to the public, except for information (excluding emission data) that qualifies for confidential treatment. The Administrator has determined that this action is subject to the provisions of section 307(d) of the CAA. Section 307(d) contains a set of procedures relating to the issuance and review of certain CAA rules.

D. How do these amendments apply to 2016 and 2017 reports?

These amendments are effective on January 1, 2017. Starting with the 2017 reporting year, facilities must follow the revised methods to detect equipment leaks (if applicable) and to calculate and report their annual equipment leak emissions. The first annual reports of emissions calculated using the amended requirements will be those submitted by April 2, 2018, covering reporting year 2017. For reporting year 2016, reporters will calculate emissions according to the requirements in part 98 that are applicable to reporting year 2016 (*i.e.,* the requirements in place until the effective date of this final rule).

II. Summary of Final Revisions and Other Amendments to Subpart W and Responses to Public Comment

Sections II.A through II.F of this preamble describe the revisions that we are finalizing in this rulemaking. Section II.A provides a general summary of the final amendments to subpart W. Section II.B describes the final amendments to the requirement to use the calculation methodology based on equipment leak surveys. Section II.C describes the final amendments to the subpart W monitoring methods. Section II.D describes the final amendments for component types to be surveyed. Section II.E describes the final amendments to the subpart W leaker emission factors. Finally, section II.F provides a summary of the final amendments to the subpart W reporting requirements. The amendments described in each section are followed by a summary of the major comments on those amendments and the EPA's responses. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for a complete listing of all comments and the EPA's responses.

A. Summary of Final Amendments—General

1. Summary of Final Amendments

In this action, the EPA is amending subpart W to add new monitoring methods for detecting leaks from oil and gas equipment in the petroleum and natural gas systems source category consistent with the NSPS subpart OOOOa. The EPA is also specifying that facilities with a collection of fugitive emissions components at a well site or compressor station subject to the NSPS subpart OOOOa (40 CFR 60.5397a) would be required to survey those components, except as otherwise specified in this subpart W final rule, for the subpart W calculation methodology based on equipment leak surveys using one of the new monitoring methods being added to subpart W. In practice, this means that facilities can use the results of the NSPS subpart OOOOa-required fugitive emissions monitoring survey to fulfill these subpart W requirements. The EPA is adding leaker emission factors to be used in conjunction with the calculation methodology based on equipment leak surveys to calculate and report GHG emissions. The revisions provide the opportunity for owners and operators of sources not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards (*e.g.,* sources participating in a voluntarily implemented program) and not already required to conduct leak surveys under subpart W to optionally use the calculation methodology at 40 CFR 98.233(q) to calculate and report their GHG emissions, and to use the new monitoring methods in 40 CFR 98.234 to do so.

Facilities in certain subpart W industry segments [7] that are already required to conduct leak surveys will be able to use the new monitoring methods

[7] These segments are Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment.

in 40 CFR 98.234. If they use either of the two new monitoring methods in 40 CFR 98.234(a)(6) or (7) that are consistent with the NSPS subpart OOOOa, then in addition to surveying the components currently subject to the survey requirements in subpart W, they must also survey all other components that are fugitive emissions components in the NSPS subpart OOOOa, with limited exceptions, as specified in 40 CFR 98.232 (see sections II.C and II.D of this preamble). If they use any of the monitoring methods currently in 40 CFR 98.234(a)(1) through (5), then in addition to surveying the components currently subject to the survey requirements in subpart W, they may elect to survey the other components specified in 40 CFR 98.232.

The comments received on this rule generally do not dispute the merit of allowing the use of new monitoring methods in subpart W, but they do include issues related to the adequacy of the notice and comment process, the calculation methodology based on equipment leak surveys, reporting, and applicability.

2. Summary of Comments and Responses

Comment: Numerous commenters stated that the EPA's reference to the proposed NSPS subpart OOOOa included in the subpart W proposal was premature, and substantively and procedurally flawed. According to these commenters, by relying on a proposed action, the EPA did not provide the opportunity for notice or comment on how the rule would ultimately affect stakeholders. These commenters stated that at the very least the EPA made it difficult and increased burden for stakeholders to evaluate scope and impacts and to provide comment. Commenters stated that they could only comment on the effect of the incorporation of the NSPS subpart OOOOa proposed requirements, as they could not review and comment on the effect of the finalized NSPS subpart OOOOa requirements on subpart W prior to closure of the comment period for the subpart W proposal. Specifically, the commenters expressed concern that because the EPA received so many comments on the proposed NSPS subpart OOOOa, the final NSPS subpart OOOOa provisions would likely be significantly different in certain aspects and that those details were unknowable at the time of comment. Noting that the EPA expressed intent in the preamble to the subpart W proposed amendments to incorporate the final NSPS subpart OOOOa provisions in the final subpart W rule, the commenters stated they inherently would have no formal opportunity to meaningfully comment on the effect those final NSPS subpart OOOOa provisions would have on subpart W reporters. Several commenters stated that this created substantive and procedural flaws in the proposed rule, as the EPA provided neither the ''terms or substance'' nor a ''description of the subjects and issues involved'' of the proposed rule as required for notice and comment rulemaking under the Administrative Procedure Act, 5 U.S.C. 553(b), nor did the EPA meet the more stringent notice and comment requirements of CAA section 307. Several commenters stated that EPA similarly did not consider changes that might be made to the final NSPS subpart OOOOa through the judicial review process.

Several commenters requested that the EPA either finalize, or re-propose or re-open the public comment period for, the proposed alignment of subpart W with the NSPS subpart OOOOa only after the NSPS subpart OOOOa is finalized. Other commenters requested that the EPA withdraw the proposal to amend subpart W and reconsider whether any revisions are necessary once the NSPS subpart OOOOa is in effect.

Response: The EPA disagrees that the proposed rule for this subpart W revision was premature, or substantively and procedurally flawed. This action is focused on aligning the subpart W requirements, to the extent possible, with the finalized NSPS subpart OOOOa fugitive emission requirements so that facilities may use the results of the NSPS subpart OOOOa-required fugitive emissions monitoring surveys to fulfill subpart W requirements, and does so through revisions that incorporate final NSPS subpart OOOOa monitoring methods into subpart W and make their use mandatory in subpart W surveys for most components subject to NSPS subpart OOOOa. The proposed rule for subpart W clearly specified that only a monitoring method finalized in the NSPS subpart OOOOa rule would be finalized for subpart W, which ensured that no requirement would reference any monitoring method that was merely at proposal stage. The proposed rule provided adequate notice and opportunity to comment on how the rule will affect stakeholders, and thus this final rule is in compliance with the relevant requirements of CAA section 307(d). Multiple commenters cited the Administrative Procedure Act (APA), including 5 U.S.C. 553(b)(3), which requires that a notice of proposed rulemaking shall include ''either the terms or substance of the proposed rule or a description of the subjects and issues involved.'' The EPA notes that our process is also consistent with the notice and comment requirements of the APA, 5 U.S.C. 551–559. In the preamble to the proposed and final rule, as well as in ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764, the EPA describes at length the statement and purpose of the revisions, provides explanations for any changes in the rule, and responds to all comments submitted.

Specifically, in regards to the proposed rule referencing the then proposed NSPS subpart OOOOa monitoring method(s) and fugitive emissions component definition,[8] the EPA disagrees that the proposed rule did not give adequate notice and therefore the EPA did not re-propose or re-open the comment period for this action. The proposed rule clearly laid out the EPA's proposal and requested comment regarding alternatives, as well as the detailed reasoning behind and goals of the proposal. The EPA provided this detailed explanation to ensure that commenters had ample notice of the revisions under consideration, and provided 45 days for the public comment period. This process accords with proper notice and comment procedure. Commenters posit that referencing the then proposed NSPS subpart OOOOa standard in the proposed rule renders this notice premature and inadequate, and the EPA respectfully disagrees. First, in proposing to add the NSPS subpart OOOOa equipment leak detection methods as approved monitoring methods for subpart W surveys, the EPA was not proposing to require any new collection of data under subpart W, as the data on fugitive emissions components would already be collected to meet the requirements of NSPS subpart OOOOa. Instead, the EPA proposed to add these new monitoring methods under subpart W so that reporters would be able to use, for the purpose of compliance with the proposed mandatory subpart W equipment leak survey, calculation, and reporting requirements, whatever data would already be collected as a result of complying with the monitoring method(s) that would be finalized in the NSPS subpart OOOOa. Similarly, while the EPA proposed to include all fugitive emissions components subject to the

[8] The NSPS subpart OOOOa rule has since been finalized. 81 FR 35824 (June 3, 2016).

final NSPS subpart OOOOa monitoring methods within subpart W emissions reporting requirements, with some exceptions, which would mean that additional components would fall within the scope of subpart W applicability, these data would already be collected under the NSPS subpart OOOOa, meaning that no new data would need to be collected for subpart W that was not already required by another CAA program. As such, the substance of the monitoring method(s) and fugitive emission component definition was not at issue for purposes of subpart W within these revisions, as that process took place within the NSPS subpart OOOOa rulemaking. Rather, the EPA ensured that reporters were provided notice of the proposal to add the monitoring methods and scope of components that would be finalized under the NSPS OOOOa as additional monitoring methods and applicable components for subpart W, provided notice of the proposed additional subpart W equipment leak survey, calculation, and reporting requirements for equipment components subject to the NSPS subpart OOOOa, and made clear that the intent of these revisions was to align the programs so that reporters would use the data gathered in complying with the finalized NSPS subpart OOOOa to comply with their subpart W requirements. The proposed rule further explained the purpose behind this proposed revision, as detailed in the proposed rule (81 FR 4987; January 29, 2016), including reducing burden on reporters by minimizing the potential equipment leak surveys required at a given facility across CAA programs. As noted earlier, the proposed rule for subpart W clearly specified that only a monitoring method finalized in the NSPS subpart OOOOa rule would be finalized for subpart W, which ensured that no requirement would reference any monitoring method that was merely at proposal stage. In fact, the proposed rule for subpart W clearly detailed the NSPS subpart OOOOa proposed monitoring method, and identified that the NSPS subpart OOOOa proposal included a potential alternative monitoring method, and furthermore explained that any method(s) added in this final subpart W action would be the method(s) that were finalized in the NSPS subpart OOOOa.

Furthermore, Subpart W currently includes an optical gas imaging (OGI) method (see 40 CFR 98.234(a)(1)) and Method 21 (40 CFR 98.234(a)(2)) in the subpart W list of monitoring methods. While there are differences in the application of the methods between the current subpart W and the final NSPS subpart OOOOa,[9] necessitating this revision, current use of OGI and Method 21 for purposes of subpart W provides support that the methods at issue provide reliable data for use in subpart W emissions reporting.

This final rule incorporates the monitoring methods finalized in the NSPS subpart OOOOa with some changes from proposal. To the extent the specifics of how this final subpart W rule is adding method(s) in accordance with the NSPS subpart OOOOa differ from the specifics in the subpart W proposal, as explained further in section II.C of this preamble, these changes are consistent with the purpose detailed in the proposed rule and were made to ensure only those portions of the final NSPS subpart OOOOa that are essential to the integrity of the methods are referenced within the requirements of subpart W. This final rule revises applicable components subject to subpart W to include all components subject to the final NSPS subpart OOOOa, except for the finalized as proposed exclusion of certain components, as further detailed in section II.D of this preamble. The EPA notes that while we finalized the reference to the NSPS subpart OOOOa with certain exceptions regarding applicable components as proposed, the final NSPS subpart OOOOa definition of fugitive emission components was narrower in scope than that rule's proposal. This final rule also includes revisions, with some changes from proposal as detailed in Sections II.B, II.D, II.E, and II.F of this preamble, to how reporters must use the data obtained in accordance with the methods finalized in the NSPS subpart OOOOa for subpart W reporting.

Although the EPA's own reasoned consideration and its assessment of public comment have resulted in some modifications to the final rule, as explained further in sections II.B through II.F of this preamble, such changes reflect the goals and alternatives in the EPA's original proposal, and the proposed rule ensured that interested parties were ''fairly apprised'' of the elements ultimately included in this final rulemaking. See, *e.g.,* United Steelworkers of America v. Schuylkill Metals, 828 F.2d 314 (5th Cir. 1987).

While some changes occurred to the NSPS subpart OOOOa requirements from proposal to final in that rulemaking, including changes to the substance of the monitoring methods and the fugitive emission component definition, those substantive changes are out of scope of this subpart W rulemaking that is intended to align with the final NSPS subpart OOOOa requirements; however, commenters were provided full notice and opportunity to comment within that NSPS subpart OOOOa rulemaking, as fully explained within those proposed and final preambles, the EPA's response to comments, and the docket of that action.[10]

The commenter is correct that the EPA did not consider changes that may be made to the final NSPS subpart OOOOa through the judicial review process. Any such potential, future changes are premature to consider at this time.

B. Summary of Final Amendments to the Requirement To Use the Calculation Methodology Based on Equipment Leak Surveys

1. Summary of Final Amendments

As noted in section I.B of this preamble, subpart W presently requires reporters with sources in certain industry segments to use the calculation methodology based on population counts according to 40 CFR 98.233(r). For example, reporters in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are required either to count the number of equipment components of each type (*e.g.,* valve, connector, open-ended line, or pressure relief valve) or to count the number of major equipment at the facility and then calculate the number of equipment components of each type using default average component counts for each piece of major equipment in Tables W–1B and W–1C to subpart W (40 CFR 98.233(r)(2)). The resulting equipment component counts are then multiplied by default ''population emission factors'' in Table W–1A to subpart W to calculate emissions from equipment leaks.

Other reporters are required to use the calculation methodology based on equipment leak surveys according to 40 CFR 98.233(q) using one of the monitoring methods in 40 CFR 98.234(a). For example, reporters in the Onshore Natural Gas Transmission Compression industry segment must conduct at least one equipment leak survey in a calendar year for the compressor and non-compressor components in gas service listed in Table W–3A to subpart W. These reporters then use the number of leaking

[9] See section II.C of this preamble.

[10] Docket ID No. EPA–HQ–OAR–2010–0505.

components in the calendar year, the average amount of time each component was leaking, and the default ''leaker emission factors'' in Table W–3A to subpart W to calculate emissions according to Equation W–30.

The EPA is finalizing the proposal to apply the calculation methodology based on equipment leak surveys in 40 CFR 98.233(q) to additional reporters in subpart W. Specifically, reporters in any subpart W industry segment with a well site(s) and/or compressor station(s) required to conduct fugitive emissions monitoring to comply with the NSPS subpart OOOOa will be required to use the calculation methodology based on equipment leak surveys for those components [11] under subpart W using the new monitoring methods consistent with the NSPS subpart OOOOa (see section II.C of this preamble). While these are new calculation methodology and equipment leak survey requirements for the subpart W reporting of these components, reporters may meet the survey requirements by counting the actual number of components with fugitive emissions identified through implementation of the NSPS subpart OOOOa as leaks for purposes of subpart W and use those counts with the calculation methodologies specified in 40 CFR 98.233(q) to determine equipment leak emissions for those components.

We received extensive comment regarding the proposed revisions to require facilities in the Onshore Natural Gas Processing industry segment to use the results of the leak surveys conducted to comply with the NSPS subpart OOOOa equipment leak requirements for reporting under subpart W. We are still reviewing those comments and are not taking final action on those revisions at this time.

For other sources of equipment leaks (*i.e.,* those not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards),[12] the amended subpart W requirements depend on whether the component types are currently required to be reported using the calculation methodology based on equipment leak surveys (40 CFR 98.233(q)) or the calculation methodology based on population counts (40 CFR 98.233(r)). For components at facilities in industry segments that are currently required to use the calculation methodology based on equipment leak surveys to comply with subpart W, the EPA is finalizing as proposed that reporters must continue to conduct equipment leak surveys as required by subpart W but may use any monitoring method in 40 CFR 98.234(a). If they use either of the two new monitoring methods in 40 CFR 98.234(a)(6) or (7) that are consistent with the NSPS subpart OOOOa, then in addition to surveying the components currently subject to the survey requirements in subpart W, they must also survey all other components that are fugitive emissions components in the NSPS subpart OOOOa, with limited exceptions, as specified in 40 CFR 98.232 (see sections II.C and II.D of this preamble). If they use any of the monitoring methods currently in 40 CFR 98.234(a)(1) through (5), then in addition to surveying the components currently subject to the survey requirements in subpart W, they may elect to survey the other components specified in 40 CFR 98.232.

For components at facilities in industry segments that are currently required to use the calculation methodology based on population counts, the reporter may continue to use that methodology. Alternatively, the EPA is finalizing as proposed the option that the reporter may elect to use the calculation methodology based on equipment leak surveys (40 CFR 98.233(q)(1)(iv)) in lieu of the calculation methodology based on population counts (40 CFR 98.233(r)). If this option is selected, then the reporter must use any of the monitoring methods in 40 CFR 98.234(a). If they use a monitoring method in 40 CFR 98.234(a)(6) or (7), then they must survey all components that would otherwise be subject to the calculation methodology based on population counts, and they must also survey all other components that are fugitive emissions components in the NSPS subpart OOOOa, with limited exceptions, as specified in 40 CFR 98.232. If they use any of the monitoring methods currently in 40 CFR 98.234(a)(1) through (5), then in addition to surveying the components that would otherwise be subject to the calculation methodology based on population counts, they may elect to survey the other specified in 40 CFR 98.232. The intent of the new provision in 40 CFR 98.233(q)(1)(iv) is to allow flexibility for reporters currently required to use the calculation methodology based on population counts for components that are not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards.

The burden of using the calculation methodology based on equipment leak surveys will be similar to using the existing subpart W calculation methodology based on population counts, and the results will be more representative of the number of leaks at the facility than the calculation methodology based on population counts. Table 2 of this preamble provides a summary of the equipment leak calculation methodologies and monitoring methods that will be available to each industry segment covered by subpart W under these amendments.

TABLE 2—FINAL EQUIPMENT LEAK REQUIREMENTS FOR SUBPART W

Subpart W industry segments [a]	Components subject to 40 CFR 60.5397a of the NSPS subpart OOOOa		Components not subject to 40 CFR 60.5397a of the NSPS subpart OOOOa	
	Subpart W calculation methodology [b]	Subpart W monitoring method for leak detection [c]	Subpart W calculation methodology	Subpart W monitoring method for leak detection [d]
Onshore Petroleum and Natural Gas Production.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)); OR Population count (40 CFR 98.233(r)).	Any method in 40 CFR 98.234(a). N/A.
Onshore Natural Gas Transmission Compression; Underground Natural Gas Storage: Storage stations, gas service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)) [e].	Any method in 40 CFR 98.234(a).

[11] See section II.D of this preamble.

[12] Except for onshore natural gas processing and natural gas distribution.

TABLE 2—FINAL EQUIPMENT LEAK REQUIREMENTS FOR SUBPART W—Continued

Subpart W industry segments [a]	Components subject to 40 CFR 60.5397a of the NSPS subpart OOOOa		Components not subject to 40 CFR 60.5397a of the NSPS subpart OOOOa	
	Subpart W calculation methodology [b]	Subpart W monitoring method for leak detection [c]	Subpart W calculation methodology	Subpart W monitoring method for leak detection [d]
Underground Natural Gas Storage: Storage wellheads, gas service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)); OR Population count (40 CFR 98.233(r)).	Any method in 40 CFR 98.234(a). N/A.
LNG [f] Storage: LNG Service; LNG Import and Export Equipment: LNG Service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)).	Any method in 40 CFR 98.234(a).
LNG Storage: Gas Service; LNG Import and Export Equipment: Gas Service.	Leak survey (40 CFR 98.233(q)).	OGI or Method 21 as specified in the NSPS subpart OOOOa.	Leak survey (40 CFR 98.233(q)); OR Population count (40 CFR 98.233(r)) [g].	Any method in 40 CFR 98.234(a). N/A.

[a] Onshore Natural Gas Processing and Natural Gas Distribution are not included in this table because we are not revising the calculation methodology and monitoring method for leak detection for these industry segments in this action. The current requirements are still applicable to components in these industry segments.

[b] The term "calculation methodology" refers to the procedures used to calculate emissions (*e.g.,* "calculation methodology based on equipment leak surveys" refers to the methodology described in 40 CFR 98.233(q)) and "monitoring method" refers to the technology, test method, or other method of determining whether an individual component is leaking (see 40 CFR 98.234(a)).

[c] OGI as specified in the NSPS subpart OOOOa is codified in subpart W at 40 CFR 98.234(a)(6) and Method 21 as specified in the NSPS subpart OOOOa is codified in subpart W at 40 CFR 98.234(a)(7).

[d] "Any method in 40 CFR 98.234(a)" means any of the following methods: OGI as specified in 40 CFR 60.18 (40 CFR 98.234(a)(1)), Method 21 with a leak definition of 10,000 parts per million by volume (ppmv)(40 CFR 98.234(a)(2)), Infrared laser beam illuminated instrument (40 CFR 98.234(a)(3)), Acoustic leak detection device (40 CFR 98.234(a)(5)), OGI as specified in the NSPS subpart OOOOa (40 CFR 98.234(a)(6)) or Method 21 with a leak definition of 500 ppmv (40 CFR 98.234(a)(7)).

[e] Reporting is required for emissions from valves, connectors, open-ended lines, pressure relief valves, and meters but is optional for instruments and other components unless the reporter elects to use either OGI or Method 21 as specified in the NSPS subpart OOOOa (40 CFR 98.234(a)(6) or (7)), in which case reporting is also required for instruments and other fugitive emissions components.[13]

[f] LNG = liquefied natural gas.

[g] Reporting is only required for emissions from vapor recovery compressors if this option is chosen.

2. Summary of Comments and Responses

Comment: Several commenters stated that facilities in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments should not be required to use the NSPS subpart OOOOa results to calculate GHG emissions to comply with subpart W. They stated that the proposed NSPS subpart OOOOa leak detection program was limited to one monitoring method, which is inconsistent with the current flexibility for reporters conducting equipment leak surveys for subpart W to choose any monitoring method within 40 CFR 98.234(a). The commenters asserted that this requirement will result in some subpart W reporters having to manage multiple equipment leak survey programs within one facility, especially if the facility is located within a state with a different leak detection program, and this result is overly burdensome. In addition, the commenters stated that the equipment leak survey results will be internally inconsistent if they use different methods, and a facility's emissions could appear to increase one year simply because the number of sites subject to the NSPS subpart OOOOa increases, requiring the reporter to use the OGI method in the NSPS subpart OOOOa for an increased number of components. Instead, the reporters suggested, use of the calculation methodology based on equipment leak surveys, including the selection of monitoring method within 40 CFR 98.234(a), should be voluntary for all facilities not currently required to conduct leak surveys under subpart W.

In contrast, another commenter requested that the EPA require all subpart W reporters to detect leaks using direct equipment leak detection technologies such as OGI. The commenter stated that leak detection using OGI can produce more accurate data than current subpart W methods and that the EPA's approach is consistent with the EPA's stated goals to enhance the rigor and transparency of subpart W data. In addition, the commenter stated that applying OGI detection uniformly across subpart W sources will produce data that is readily comparable across facilities and will allow the EPA to assess the performance of facilities over time.

Response: For facilities that have affected sources required to conduct fugitive emissions monitoring to comply with the NSPS subpart OOOOa well site or compressor station fugitive emissions standards, the EPA is finalizing as proposed that these components must meet the subpart W calculation methodology based on equipment leak survey requirements. In practice, this means reporters can meet these requirements by counting the actual number of components with fugitive emissions identified through implementation of the NSPS subpart OOOOa as leaks for purposes of subpart W. This requirement will achieve the EPA's stated goal of alignment with the NSPS subpart OOOOa and will assist in providing the EPA with a greater understanding of emission reductions.

At this time, we are not requiring all subpart W facilities to perform a leak detection survey using direct equipment leak detection technologies such as OGI. Rather this action is focused on aligning the subpart W requirements, to the extent possible, with the NSPS subpart OOOOa fugitive emission requirements so that facilities may use the results of the NSPS subpart OOOOa-required

[13] See section II.D.1 of this preamble for the EPA's decision on the final subpart W requirements for components not subject to 40 CFR 60.5397a of the NSPS Subpart OOOOa from affected facilities in the Onshore Natural Gas Transmission Compression industry segment, and storage stations in gas service within the Underground Natural Gas Storage industry segment.

fugitive emissions monitoring surveys to fulfill subpart W requirements.

The EPA does not agree that a subpart W requirement to use the results of a previously completed leak survey within the subpart W calculation methodology based on equipment leak surveys will result in an undue burden to these reporters. For components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions standards, there is little to no burden associated with using the number of components found to have fugitive emissions as the number of leaking components in the subpart W calculation methodology based on equipment leak surveys. The only additional piece of information these reporters need to calculate emissions is the amount of time each component was leaking, and this is a straightforward determination based on the dates of the equipment leak surveys. See section IV.B of this preamble for information and responses to comments related to the EPA's burden estimates for these amendments.

C. Summary of Final Amendments to Monitoring Methods

1. Summary of Final Amendments

The EPA is finalizing the proposal to add OGI, as specified in the NSPS subpart OOOOa, to the list of monitoring methods in 40 CFR 98.234(a). The addition of this specific OGI method to subpart W at 40 CFR 98.234(a)(6) aligns the methods in the two rulemakings and allows subpart W facilities to directly use information derived from the implementation of the fugitive emissions monitoring conducted under the NSPS subpart OOOOa to calculate and report equipment leak emissions to the GHGRP.

The EPA has made changes to the proposed subpart W amendments after consideration of public comment and/or to be consistent with the final revisions made to the corresponding proposed NSPS subpart OOOOa specifications. The proposed subpart W amendments cross-referenced the proposed 40 CFR 60.5397a(b) through (e) and (g) through (i), which included the requirements to: (1) Develop a corporate-wide fugitive emissions monitoring plan; (2) develop a site-specific monitoring plan; (3) observe each fugitive emissions component for fugitive emissions; (4) conduct monitoring surveys semiannually; and (5) adjust the frequency of monitoring surveys based on the percent of the fugitive emissions components detected to have fugitive emissions. For the reasons described below, the final amendments to subpart W for the OGI method cross-reference a portion of the NSPS subpart OOOOa requirements to develop the fugitive emissions monitoring plan and the NSPS subpart OOOOa requirements to observe each fugitive emissions component for fugitive emissions.

The final NSPS subpart OOOOa requires an emissions monitoring plan that covers the affected sources within each company-defined area. This monitoring plan includes information about the survey frequency, monitoring method and instrument selected, repair procedures and timeframes, recordkeeping, and procedures for calibrating the monitoring instrument and verifying that it can detect fugitive emissions at the required levels.

For the final subpart W amendments, the EPA evaluated the NSPS subpart OOOOa requirements for the monitoring plan along with the level of detail in the existing monitoring methods in 40 CFR 98.234(a). The EPA determined that information about the monitoring instrument selected and procedures for calibrating the monitoring instrument and verifying that it can detect fugitive emissions at the required levels is necessary to ensure the OGI monitoring is performed correctly. Therefore, the new OGI detection method in subpart W does include the NSPS subpart OOOOa requirement to develop a monitoring plan that describes the OGI instrument (40 CFR 60.5397a(c)(3)) and how the OGI survey will be conducted to ensure that fugitive emissions can be imaged effectively (40 CFR 60.5397a(c)(7)). The EPA determined that the NSPS subpart OOOOa survey frequency should not be cross-referenced in subpart W because cross-referencing these frequencies would override the current annual survey requirement in subpart W regardless of whether the use of the new monitoring methods is voluntary or mandatory. The EPA determined that the repair procedures and timeframes should not be cross-referenced because subpart W is part of a reporting program and does not require repair of detected leaks. The EPA also determined that the NSPS subpart OOOOa recordkeeping requirements should not be cross-referenced because they include provisions that are not applicable to greenhouse gas reporting, such as records related to repairs. Applicable recordkeeping requirements for all leak detection methods in subpart W are specified at 40 CFR 98.237.

The final site-specific monitoring plan in the NSPS subpart OOOOa includes three items specific to the OGI method: (1) A sitemap; (2) a defined observation path for the operator that ensures that all fugitive emissions components are within sight of the path; and (3) a monitoring plan for difficult-to-monitor and unsafe-to-monitor fugitive emissions components. The EPA has reviewed these elements as well and determined not to cross-reference these three elements in subpart W. The observation path and the sitemap ensure that the OGI operator visualizes all of the components that must be surveyed, analogous to requirements in some rules to identify all of the equipment that must be monitored using Method 21 (*e.g.,* 40 CFR 60.486a(e)(1) and 40 CFR 63.162(c)). Subpart W does not include these identification requirements as part of the Method 21 requirements in 40 CFR 98.234(a)(2), so it would be inconsistent to require the observation path as part of the new OGI method. However, while we are not finalizing the explicit requirement to define the observation path the operator will follow during their survey, we do note that 40 CFR part 98, subpart A requires a written GHG monitoring plan for all facilities subject to the GHGRP (see 40 CFR 98.4(g)(5)). Defining an observation path is one item that could be included in the GHG monitoring plan to meet the requirement to describe ''procedures and methods that are used for quality assurance . . . of all . . . other instrumentation'' used to collect data to comply with the GHGRP (40 CFR 98.3(g)(5)(i)(C)).

The EPA is finalizing the proposed requirement to observe each fugitive emissions component for fugitive emissions (40 CFR 60.5397a(e)).[14] The EPA considers surveying all fugitive emissions components (instead of just the current list of equipment in subpart W for a particular industry segment) to be an inherent part of the NSPS subpart OOOOa OGI method.

The EPA is not cross-referencing the semi-annual (well sites) and quarterly (compressor stations) monitoring frequencies of the final NSPS subpart OOOOa. As noted above, cross-referencing these monitoring frequencies would override the current annual survey requirement in subpart W regardless of whether the use of the new monitoring methods is voluntary or mandatory. The EPA is instead clarifying that for reporters with components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and for which surveys are required or elected, the results from each equipment leak

[14] See section II.D.1 of this preamble for details regarding the specific NSPS subpart OOOOa-defined fugitive emissions components that are not considered sources of ''equipment leaks'' in subpart W.

survey must be used to calculate GHG emissions for subpart W. The EPA is further clarifying that it is not our intent to require reporters that are not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements to conduct more than one equipment leak survey in a calendar year for purposes of GHGRP reporting, solely because they choose to use the OGI method. The EPA also notes that the proposed NSPS subpart OOOOa provisions for adjusting the frequency of equipment leak surveys based on the percent of the fugitive emissions components detected to have fugitive emissions were not included in the final NSPS subpart OOOOa and therefore are not cross-referenced in the final subpart W revisions.

Finally, consistent with the final NSPS subpart OOOOa, the EPA is finalizing the use of Method 21 as an alternative monitoring method to OGI (as specified in the NSPS subpart OOOOa) at 40 CFR 98.234(a)(7). As the EPA noted in the preamble for this proposed revision to subpart W (81 FR 4989; Jan. 29, 2016), the NSPS subpart OOOOa proposal identified EPA Method 21 as a monitoring method that may also be used to conduct resurveys of repaired components when fugitive emissions are detected (80 FR 56612 (well sites) and 80 FR 56612 (compressor stations)), and the EPA requested comment on including in the final rule the use of Method 21 for fugitive emissions monitoring as well (80 FR 56638 (well sites) and 80 FR 56643 (compressor stations)). The EPA also made clear in the preamble to these proposed revisions to subpart W that, consistent with the goal of aligning the methods in the two rulemakings (subpart W and the NSPS subpart OOOOa), the EPA expected that the final amendments to subpart W for monitoring methods would reference the final version of the method(s) in the NSPS subpart OOOOa, including any changes made to the NSPS subpart OOOOa in response to comments on the proposed monitoring method(s) (81 FR 4991). Accordingly, the EPA is finalizing the use of Method 21 as an alternative monitoring method to OGI (as specified in the NSPS subpart OOOOa) at 40 CFR 98.234(a)(7).

For reporters that elect to use Method 21 as specified in 40 CFR 98.234(a)(7), either for components that are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements or voluntarily, a leak is detected if an instrument reading of 500 ppmv or greater is measured. As explained in this section regarding the NSPS subpart OOOOa OGI monitoring method, we determined that the requirements in 40 CFR 60.5397a(b) are consistent with the requirements of subpart W regarding the development of an emissions monitoring plan; this monitoring plan is required to include verification that the procedures of Method 21 are followed consistent with the requirements in 40 CFR 60.5397a(c)(8). Also, as with the NSPS subpart OOOOa OGI method, the EPA is requiring in subpart W observation of each fugitive emissions component for fugitive emissions consistent with the requirements in 40 CFR 60.5397a(e); the EPA considers surveying all fugitive emissions components to be an inherent part of the NSPS subpart OOOOa Method 21 alternative to the OGI method and is consistent with requirements in subpart W to conduct a complete equipment leak survey.

At this time, the EPA is not adding any other monitoring methods to subpart W. We will continue to evaluate equipment leak detection methods and technologies [15] and may amend subpart W to allow the use of additional methods in the future.

2. Summary of Comments and Responses

Comment: Many commenters disagreed with the EPA's proposal to add only the OGI method as specified in the NSPS subpart OOOOa to 40 CFR 98.234(a) of subpart W. They asserted that while OGI is an effective method for finding the majority of emissions more quickly than EPA Method 21, it is also a costly technology that cannot quantify emissions. The commenters stated that OGI has other limitations, especially in non-ideal weather conditions; one commenter also stated that use of the OGI camera requires a hot work permit in many instances.

Response: Due to similar comments on the proposed NSPS subpart OOOOa, the final NSPS subpart OOOOa provides owners and operators of new, modified, or reconstructed well sites or compressor stations with the option of using EPA Method 21 with a repair threshold of 500 ppmv if they elect not to use the OGI method (40 CFR 60.5397a). As discussed in section II.C.1 of this preamble, the final amendments to subpart W provide for the use of EPA Method 21 where a leak is detected for purposes of subpart W if an instrument reading of 500 ppmv or greater is measured. This amendment to subpart W maintains the alignment with the NSPS subpart OOOOa well site and compressor station fugitive emissions monitoring requirements, so that reporters can directly use the NSPS subpart OOOOa monitoring results to count the number of leaks under subpart W.

Comment: Many commenters stated that leak detection technology is a rapidly growing field and there are many alternative technologies and new technologies in development that may be more accurate and less costly than OGI. Some commenters noted that recent emphasis on CH_4 emissions has caused vendors to focus on CH_4 leak detection. Therefore, according to the commenters, some of those technologies may be better options for the purpose of reporting emissions under subpart W than other leak detection programs. The commenters stated that the EPA's proposal to limit leak surveys to a prescriptive list of methods could limit development of these new technologies.

Commenters provided a variety of suggestions for incorporation of new and emerging technologies into subpart W. Three commenters recommended that the EPA establish a clear process for industry, vendors, and/or the EPA to evaluate the efficacy and accuracy of alternative CH_4 monitoring technologies and approve the use of those technologies. One of these commenters noted that any technology evaluation process should be straightforward and more streamlined than the years-long process needed to approve emissions control devices or continuous emissions monitoring systems. Another of these commenters suggested that the EPA model a technology evaluation process after the vendor testing program for flares and combustors, in which the EPA sets testing protocols and vendors demonstrate that they can meet specific criteria. A fourth commenter suggested that the EPA develop a pilot program to incentivize the accelerated development and deployment of advanced monitoring and detection technologies and to compare the effectiveness of these approaches to periodic, OGI-based surveys.

Response: The EPA agrees with the commenters that emissions monitoring in the oil and gas sector is a field of emerging technology, and major advances are expected in the near future. We are seeing a rapidly growing push to develop and produce low-cost monitoring technologies to find fugitive CH_4 emissions sooner and at lower levels than current technology allows, thus enhancing the ability of operators to detect fugitive emissions. The EPA agrees that continued development of these cost-effective technologies is

[15] For example, the EPA has issued a voluntary request for information inviting all parties to provide information on innovative technologies to detect, measure, and mitigate emissions from the oil and gas industry. See 81 FR 46670 (July 18, 2016).

important. However, the EPA does not have enough information at this time to evaluate specific technologies to determine if they are equivalent to or better than the monitoring methods provided in and being added to 40 CFR 98.234(a). The EPA may evaluate new options as they become available and determine if they are equivalent to existing methods. For example, the final NSPS subpart OOOOa provides a process for the EPA to determine that a technology can be used as an ''alternative means of emission limitation.'' [16] As technologies are approved through this process, the EPA anticipates that it would contemporaneously incorporate these monitoring methods in subpart W to ensure continued alignment between the NSPS subpart OOOOa and subpart W through future notice and comment rulemaking.

Comment: Multiple commenters addressed the proposed requirement to consider any fugitive emissions observed using OGI during the NSPS subpart OOOOa fugitive emissions monitoring as a leak for purposes of subpart W. Most of these commenters objected to the proposal and stated that the definition of a leak for subpart W should be 10,000 ppmv, regardless of the monitoring method used. These commenters asserted that setting the leak definition consistent with the current methods in subpart W would ensure that the new methods result in new information being collected and reported consistently within a facility and consistent with the equipment leak data already in the GHGRP. One commenter noted that defining a leak as emissions at a set concentration is much less subjective than defining a leak as any emissions observed with OGI, and setting the leak definition at 10,000 ppmv rather than a lower concentration would allow operators to focus on finding (and fixing) large leaks instead of spending resources to identify many small leaks that do not contribute much to overall emissions. Another commenter noted that a leak definition of 10,000 ppmv is consistent with the leaker emission factors currently provided in subpart W as well as the proposed new leaker emission factors.

One commenter agreed with a subpart W leak being defined as any fugitive emissions observed using OGI during the NSPS subpart OOOOa fugitive emissions monitoring or emissions above 500 ppmv detected via EPA Method 21, but the commenter asserted that the leak definition for any new or emerging technologies used in a voluntary leak survey should be 5,000 ppmv. The commenter noted that these new technologies are likely to be more sensitive and detect emissions at lower concentrations than OGI, and companies that are employing more accurate instruments should not be ''penalized'' by having to report more leaks than if they used OGI.

Response: Subpart W already includes OGI and EPA Method 21 with a leak definition of 10,000 ppmv for use by reporters currently required to conduct leak surveys for subpart W. The final amendments also provide for use of these methods by reporters electing to conduct an equipment leak survey voluntarily (*i.e.,* for sources currently required to use the calculation methodology based on population counts that are not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements). The EPA is adding the methods used for fugitive emissions monitoring in the NSPS subpart OOOOa to 40 CFR 98.234(a), as approved monitoring methods for subpart W leak surveys. This addition facilitates alignment with the NSPS subpart OOOOa and will allow reporters to directly use the NSPS subpart OOOOa monitoring results to count the number of leaks under subpart W. Finally, as noted in section II.C.1 of this preamble, the EPA is not adding any other monitoring methods to subpart W at this time, so it is not necessary to consider a different leak definition for new or emerging technologies.

The EPA disagrees that using a leak definition other than 10,000 ppmv would undermine the quality of the data reported to the GHGRP. First, subpart W currently includes an OGI monitoring method in 40 CFR 98.234(a)(1). While this monitoring method allows facilities to screen the observed leaks using Method 21, it does not require it, and we do not expect that many reporters actively use dual monitoring methods in their leak surveys to screen all OGI-detected leaks using Method 21.

Second, we are also finalizing, consistent with the final NSPS subpart OOOOa rule, the ability to use Method 21 with a leak definition of 500 ppmv as an alternative to the OGI method. We agree with commenters that the average emissions rate of leaks identified using Method 21 with a leak definition of 500 ppmv would be less than the average emissions rate of leaks identified using Method 21 with a leak definition of 10,000 ppmv. To address this issue, we are also finalizing separate leaker factors that are appropriate for reporters using this alternative method (Method 21 with a leak definition of 500 ppmv). As described in further detail in section II.E.1 of this preamble and in the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' in Docket ID No. EPA–HQ–OAR–2015–0764, these additional emission factors were developed from the same data set that was used to develop the original population emission factors and the proposed leaker factors.[17] Therefore, this additional Method 21 monitoring method, which includes a different leak definition than the other Method 21-based method already available in subpart W at 40 CFR 98.234(a)(2), has been specifically considered and new emission factors are provided in the final rule to ensure that this new monitoring method's leak definition will not undermine the quality of the emissions reported under subpart W.

If the EPA did not provide the ability for reporters to use the monitoring methods required by the NSPS subpart OOOOa within subpart W, reporters would not be able to use the NSPS subpart OOOOa monitoring results directly; instead, they would have to measure each occurrence of fugitive emissions individually to determine if it is a leak for purposes of subpart W, which would increase the burden for those reporters.

D. Summary of Final Amendments for Components To Be Surveyed

1. Summary of Final Amendments

The EPA proposed to align the subpart W equipment components with the NSPS subpart OOOOa definition of ''fugitive emissions component,'' with certain exceptions.[18] After careful consideration of comments, the EPA is finalizing that provision consistent with the final NSPS subpart OOOOa definition of ''fugitive emissions component'' with certain exceptions consistent with the proposal, as described in further detail in this section below. A ''fugitive emissions component'' is defined in 40 CFR 60.5430a of the final NSPS subpart

[16] See 40 CFR 60.5398a titled ''What are the alternative means of emission limitations for GHG and volatile organic compounds from well completions, reciprocating compressors, the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?''

[17] This data set was developed from monitoring conducted using Method 21 with a leak definition of 10,000 ppmv.

[18] See 81 FR 4994 for a discussion of the differences between the proposed definition of ''fugitive emissions component'' and the proposed components subject to equipment leak reporting in subpart W.

OOOOa to include any component that has the potential to emit fugitive emissions of CH4 or volatile organic compounds at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to 40 CFR 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to 40 CFR 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from a location other than the vent are considered fugitive emissions.

As noted in the preamble to the proposed subpart W amendments, some of the components listed in the NSPS subpart OOOOa definition of fugitive emissions component are already included as part of the subpart W equipment leaks calculation methodologies (either based on equipment leak surveys or on population counts), while other fugitive emissions components are specifically addressed in other calculation methodologies in subpart W. As part of developing the proposed amendments for subpart W, we compared the list of components in the NSPS subpart OOOOa proposed definition of fugitive emissions component with the current methodologies in subpart W to identify which fugitive emissions components were already covered by an existing requirement in subpart W and which fugitive emissions components would be specifically covered in subpart W when using the OGI method as specified in the proposed NSPS subpart OOOOa.

Table 3 of this preamble provides a summary of the applicable subpart W calculation methodologies for components subject to the fugitive emissions standards in the final NSPS subpart OOOOa. The basis for excluding certain components that are subject to the fugitive emissions standards in the final NSPS subpart OOOOa from the final equipment leak survey requirements in 40 CFR 98.233(q) is discussed below.

TABLE 3—FINAL SUBPART W CALCULATION METHODOLOGY REQUIREMENTS FOR COMPONENTS SUBJECT TO THE FUGITIVE EMISSIONS STANDARDS IN NSPS SUBPART OOOOa

Type of component in definition of fugitive emissions component and subject to the fugitive emissions standards in NSPS subpart OOOOa	Applicable GHG emissions calculation methodology in subpart W by industry segment for components that are also subject to the fugitive emissions standards for well sites or compressor stations in the NSPS subpart OOOOa[a]		
	Onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting	Underground natural gas storage, LNG storage, LNG import and export equipment	Onshore natural gas transmission compression
Thief hatches or other openings on controlled storage vessels not subject to 40 CFR 60.5395a.	• 40 CFR 98.233(j)	• 40 CFR 98.233(q) (use factor for "other" components in Tables W–4A, W–5A, and W–6A to subpart W)[b].	• 40 CFR 98.233(k).
Compressors, excluding emissions from vents that are part of normal operations (*i.e.,* wet seal oil degassing vents).	• 40 CFR 98.233(q) for blowdown valve leakage and isolation valve leakage (use factor for "open-ended line" in Table W–1E to subpart W)[b]. • 40 CFR 98.233(q) for all other leaks from the housing (use factor for "other" components in Table W–1E to subpart W)[b]. • 40 CFR 98.233(p)(10) for rod packing venting from reciprocating compressors.	• 40 CFR 98.233(o) for blowdown valve leakage and isolation valve leakage from centrifugal compressors. • 40 CFR 98.233(p) for blowdown valve leakage, isolation valve leakage, and rod packing venting from reciprocating compressors. • 40 CFR 98.233(q) for all other leaks from the housing (use factor for "other" components in Table W–4A, W–5A, and W–6A to subpart W)[b].	• 40 CFR 98.233(o) for blowdown valve leakage and isolation valve leakage from centrifugal compressors • 40 CFR 98.233(p) for blowdown valve leakage, isolation valve leakage, and rod packing venting from reciprocating compressors • 40 CFR 98.233(q) for all other leaks from the housing (use factor for "other" components in Tables W–3A, to subpart W)[b]
All other components	• 40 CFR 98.233(q) (use factors for applicable component types in Table W–1E to subpart W)[b].	• 40 CFR 98.233(q) (use factors for applicable component types in Tables W–4A, W–5A, and W–6A to subpart W)[c].	• 40 CFR 98.233(q) (use factors for applicable component types in Table W–3A to subpart W)[c].

[a] Onshore Natural Gas Processing and Natural Gas Distribution are not included in this table because we are not revising the calculation methodology and monitoring method for leak detection for these industry segments in this action. The current requirements are still applicable to components in these industry segments.

[b] The leaker emission factors for "other" components are being finalized in this revision.

[c] The leaker emission factors include both factors in the current rule and factors that are being finalized in this action, depending on the specific component and the monitoring method used to conduct the survey, as discussed in section II.E.1 of this preamble.

At proposal, we determined that the subpart W calculation methodology for storage tanks in 40 CFR 98.233(j) already includes emissions from thief hatches or other openings on storage vessels in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. However, we requested comment on whether the agency should consider separate approaches for controlled storage tanks and uncontrolled storage tanks. The final definition of "fugitive emissions component" in the NSPS subpart OOOOa (40 CFR 60.5430a) includes only thief hatches or other openings on a controlled storage vessel; it does not specifically list openings on uncontrolled storage vessels. We reviewed the subpart W calculation methodology specifically for storage tanks with a vapor recovery system (40 CFR 98.233(j)(4)) and storage tanks with a flare (40 CFR 98.233(j)(5)). The procedure for determining emissions from a tank with a vapor recovery system instructs reporters to adjust the storage tank emissions downward by the magnitude of emissions recovered using

a vapor recovery system as determined by engineering estimate based on best available data (40 CFR 98.233(j)(4)(i)). The procedure for determining emissions from a tank with a flare references 40 CFR 98.233(n), which instructs reporters to use engineering calculations based on process knowledge, company records, and best available data to determine the flow to the flare if the flare does not have a continuous flow measurement device. If a reporter sees fugitive emissions from a thief hatch or other opening on a controlled storage vessel during an equipment leak survey conducted using OGI, the reporter should consider that information as part of the ''best available data'' used to calculate emissions from that storage tank. Therefore, we have concluded that emissions from thief hatches or other openings on storage vessels in the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments are already included in the subpart W storage tank emission calculations in 40 CFR 98.233(j) and are finalizing, consistent with the proposal, that they are not to be considered when determining emissions from equipment leaks for purposes of subpart W.

We are also finalizing as proposed the exclusion of thief hatches and other openings on transmission storage tanks from the equipment leak reporting requirements.[19] We note that, for purposes of subpart W reporting, a leaking thief hatch or other opening is functionally a secondary vent, and thus subject to annual screening on an uncontrolled tank according to 40 CFR 98.233(k)(1). If screening shows vapors from the thief hatch or opening are continuous for 5 minutes, then a method in 40 CFR 98.233(k)(2) must be used to quantify the leak rate, and this amount must be combined with any other vent leak rates for reporting.

We are also finalizing the proposed distinction between equipment leak emissions and compressor emissions. Specifically, for centrifugal compressors, emission sources include wet seal oil degassing vents (for centrifugal compressors with wet seals), blowdown valve leakage, and isolation valve leakage. For reciprocating compressors, emission sources include reciprocating compressor rod packing vents, blowdown valve leakage, and isolation valve leakage.

For compressors in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments under subpart W, the compressor methodologies only cover emissions from centrifugal compressor wet seal oil degassing vents and from reciprocating compressor rod packing vents. Thus, the EPA is finalizing as proposed, for these industry segments, that blowdown valve leakage and isolation valve leakage are considered equipment leaks (*i.e.,* open-ended lines), and finalizing as proposed that emissions from centrifugal compressor wet seal oil degassing vents and from reciprocating compressor rod packing vents are not considered equipment leaks when using the calculation methodology based on equipment leak surveys in 40 CFR 98.233(q).[20]

For the Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment segments, subpart W requires reporters to make ''as found'' or continuous measurements for compressor emission sources, so the reporters will have either direct measurement data or site-specific emission factors by which to calculate emissions from all of the compressor sources listed above (*i.e.,* wet seal oil degassing vents for centrifugal compressors with wet seals, rod packing vents for reciprocating compressors, and blowdown valve leakage and isolation valve leakage for both centrifugal and reciprocating compressors). Therefore, we are finalizing as proposed to exclude these compressor emission sources from the requirements in the calculation methodology based on equipment leak surveys so that reporters do not double-count emissions from these sources in their GHGRP reports.

Finally, as noted in section II.C.1 of this preamble, we are finalizing the proposed determination that for purposes of subpart W, all other fugitive emissions components as defined in the NSPS subpart OOOOa not specifically identified above (*e.g.,* thief hatches or other openings on a controlled storage vessel, compressor sources with explicit calculation methodologies in subpart W) will be considered equipment components when conducting an equipment leak survey using the OGI method as specified in the NSPS subpart OOOOa or EPA Method 21 with a leak definition of 500 ppmv. In other words, we consider the provision requiring monitoring of fugitive emissions components as defined in the NSPS subpart OOOOa in 40 CFR 60.5397a(e) to be an inherent part of the NSPS subpart OOOOa OGI method and EPA Method 21 with a leak definition of 500 ppmv. Therefore, if a reporter with components not subject to the NSPS subpart OOOOa well site or compressor station fugitive emission requirements elects to use the NSPS subpart OOOOa OGI method or EPA Method 21 with a leak definition of 500 ppmv for purposes of subpart W, they are also electing to survey these additional components.

2. Summary of Comments and Responses

Comment: Several commenters stated that the NSPS subpart OOOOa proposed definition of ''fugitive emissions component'' is too expansive. Because it includes many more emission sources than a more traditional definition of equipment, the commenters asserted that it is inconsistent with current subpart W requirements. The commenters stated that aligning subpart W with the NSPS subpart OOOOa in this respect will complicate the question of which components must be monitored at subpart W facilities and will result in facilities having higher numbers of leaks than they would have if they used any other equipment leak detection method in subpart W. Some commenters stated that even for well sites and compressor station sites subject to the NSPS subpart OOOOa, component types considered to be equipment under subpart W should be consistent with a more traditional definition of equipment. Other commenters requested that equipment under subpart W only include component types for which the EPA can provide specific population factors and leaker emission factors.

Response: As noted in section II.D.1 of this preamble, the final definition of ''fugitive emissions component'' in the NSPS subpart OOOOa (40 CFR 60.5430a) does not list as many explicit individual component types, as originally proposed. The EPA is finalizing, with the exceptions discussed in section II.D.1 of this preamble and consistent with the extent proposed, this alignment with the NSPS subpart OOOOa, so that reporters may directly use the NSPS subpart OOOOa monitoring results to count the number of leaks under subpart W. Reporters using the calculation methodology based on equipment leak surveys for

[19] The exceptions to equipment leak reporting requirements were included in Tables W–1E and W–3 through W–6 of the proposal. The final rule moves these exceptions to 40 CFR 98.232, to increase clarity and reduce confusion while achieving the same purpose and effect.

[20] 40 CFR 98.233(q) specifies which subsections in 40 CFR 98.232 (*i.e.,* which components) must follow the calculation methodology based on equipment leak surveys in 40 CFR 98.233(q), and 40 CFR 98.232 subsections identify exceptions from the list of components for which equipment leak reporting is required.

components not subject to the NSPS subpart OOOOa may choose which monitoring method to use. If a reporter chooses to use one of the monitoring methods listed in 40 CFR 98.234(a)(1) through (5), that reporter would use the current list of equipment components for the appropriate industry segment in 40 CFR 98.232 (*e.g.,* the list of equipment at 40 CFR 98.232(e)(7) for the Onshore Natural Gas Transmission Compression industry segment). If a reporter chooses to use the OGI method as specified in the NSPS subpart OOOOa or EPA Method 21 with a leak definition of 500 ppmv, the reporter would use both the current list and the newly added list of equipment components for the appropriate industry segment in 40 CFR 98.232, which in conjunction include the NSPS subpart OOOOa definition of ''fugitive emissions component'' in 40 CFR 60.5430a with the exceptions discussed in section II.D.1 of this preamble (*e.g.,* the list of equipment at 40 CFR 98.232(e)(7) and (8) for the Onshore Natural Gas Transmission Compression industry segment).

E. Summary of Final Amendments to Leaker Emission Factors and the Calculation Methodology Based on Equipment Leak Surveys

1. Summary of Final Amendments

To quantify emissions from leaking equipment components, subpart W includes leaker emission factors for each component type in each industry segment currently required to use the calculation methodology based on equipment leak surveys. In contrast to the population emission factors, which are multiplied by the total facility component counts, leaker emission factors are multiplied by the actual number of leaks for each component type, as identified by the equipment leak survey. These amendments increase the component types that are required or may elect to use the calculation methodology based on equipment leak surveys, including most of the component types currently using the subpart W calculation methodology based on population counts.[21] Therefore, new leaker emission factors are being added so that reporters can calculate their GHG emissions for these new component types.

Specifically, the EPA proposed to add new sets of leaker emission factors to subpart W for: (1) The Onshore Petroleum and Natural Gas Production industry segment; (2) the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment; (3) storage wellheads in gas service in the Underground Natural Gas Storage industry segment; (4) LNG storage components in gas service in the LNG Storage industry segment; and (5) LNG terminals components in gas service for the LNG Import and Export Equipment industry segment. For industry segments that already include a set of leaker emission factors, the EPA also proposed to expand that set of leaker emission factors to include certain additional components to better align with the definition of fugitive emissions components in the NSPS subpart OOOOa. See the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket Item No. EPA–HQ–OAR–2015–0764–0028, for more information on the development of the proposed leaker emission factors.

We are finalizing the leaker emission factors for the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments as proposed, with clarifications for flanges and connectors noted below. We are also finalizing the following leaker emission factors as proposed: (1) The leaker emission factors for ''other'' components in Tables W–3A, W–4A, W–5A, and W–6A to subpart W; (2) the leaker emission factors for storage wellhead equipment in gas service within Table W–4A to subpart W; and (3) the leaker emission factors for equipment in gas service for LNG storage components within Table W–5A to subpart W and for LNG terminal components within Table W–6A to subpart W. We are also finalizing the proposal to expand the existing leaker emission factor for meters to also include instruments in Tables W–3A and W–4A to subpart W for the Onshore Natural Gas Transmission Compression and Underground Natural Gas Storage industry segments, respectively. All but one of the proposed leaker factors for flanges in Tables W–3 through W–6 to subpart W (Tables W–3A, W–4A, W–5A, and W–6A to subpart W in these final amendments) were the same as the leaker factors for connectors; the exception was for flanges in gas service associated with storage wellheads at Underground Natural Gas Storage facilities, which had a proposed leaker factor that differed from the proposed leaker factor for connectors in the same service. Flanges are a type of connector, which means the proposed flange factors that were identical to the existing connector factors were redundant. Therefore, we have not finalized the proposed separate factors for flanges where the factor was the same as the factor for connectors and are finalizing that flanges must use the final connector factor, meaning the effect of the final amendments is the same as the proposal. The separate factors for connectors and flanges for storage wellheads in gas service at Underground Natural Gas Storage facilities are finalized as proposed, but to clarify that the factor for connectors applies only to all types of connectors other than flanges, the component name has been changed from ''connector'' in the proposal to ''connector (other)'' in Table W–4A of the final amendments. This change also makes the terminology in Table W–4A consistent with the terminology in Tables W–1A and W–1E, which also specify factors for flanges that differ from the factors for other types of connectors.

We are not finalizing the proposed addition of pumps to the leaker factors in Table W–2 for the Onshore Natural Gas Processing industry segment. As described in section II.B.1 of this preamble, we are not taking final action on the Onshore Natural Gas Processing revisions at this time.

In addition to finalizing nearly all of the proposed leaker factors, we are also finalizing an additional set of emission factors corresponding to the average emissions rates of components identified using Method 21 with a leak definition of 500 ppmv. The proposed leaker factors were developed based on Method 21 monitoring using a leak definition of 10,000 ppmv and were to be applied by all reporters regardless of the leak survey monitoring method used. As noted in section II.C of this preamble, the final NSPS subpart OOOOa includes an additional alternative that allows reporters to use Method 21 with a leak definition of 500 ppmv. On average, the emissions from a leak identified with a Method 21 reading above 500 ppmv are less than the emissions from a leak identified with a Method 21 reading of 10,000 ppmv or higher. Consequently, the leaker factor (which is the average emissions rate) for leaks identified when using a leak definition of 500 ppmv is smaller than the leaker factor for leaks identified when using a leak definition of 10,000 ppmv. Therefore, in order to use the NSPS subpart OOOOa survey results directly to calculate equipment leak emissions for subpart W when Method 21 with a leak definition of 500

[21] The NSPS subpart OOOOa fugitive emission requirements do not apply to fugitive emissions components in the Natural Gas Distribution industry segment.

NMED Exhibit 98 - 0014

ppmv is used, leaker factors were developed consistent with the average emissions rate of a ''leak'' defined as a measurement reading of 500 ppmv or more using Method 21. We developed these new leaker factors using data from EPA's Protocol for Equipment Leak Emissions Estimates [22] consistent with the data used to develop the proposed leaker factors for Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments. See the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' in Docket ID No. EPA–HQ–OAR–2015–0764, which provides more information on the development of the final leaker emission factors. The inclusion of leaker factors specific to Method 21 with a leak definition of 500 ppmv is consistent with our proposal to align subpart W calculation methodologies with the monitoring requirements in the NSPS subpart OOOOa.

We are also finalizing the proposed amendments to the time variable $T_{p,z}$ in Equation W–30 to clarify the total time a surveyed component found leaking is assumed to be leaking and operational. The previous language for the definition of the time variable specifically considers a first leak survey and a last leak survey in the year but does not provide specific language with respect to the duration of any ''intermediate'' survey conducted between the first and last survey. Therefore, the EPA proposed to amend the definition of the time variable to clarify how to determine the duration of a leak if more than two leak surveys are conducted in a year and to instruct reporters to sum the individual durations to determine the total time the component was leaking during the year.

The EPA is finalizing this amendment as proposed. The amendments to the time variable $T_{p,z}$ define each equipment leak survey as covering a unique, non-overlapping time period and we are clarifying our intent that a leak detected in the first or any intermediate survey is not considered to continue leaking past the date of that specific equipment leak survey. For the last survey conducted in the calendar year, the leak is assumed to continue until the end of the year. For example, if a reporter conducts three equipment leak surveys in a calendar year and a particular component is found to be leaking in the first and second surveys but not the third, the total leak duration is the sum of the time from January 1 to the date of the second survey. If a reporter conducts three equipment leak surveys in a calendar year and a particular component is found to be leaking in the first and last surveys but not the second, then the total leak duration is the sum of the time from January 1 to the date of the first survey and the time from the date of the second survey to December 31.

See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for all comments and the EPA's responses to comments on other aspects of the time variable $T_{p,z}$ in Equation W–30.

Finally, 40 CFR 98.233(q) includes a provision requiring reporters to conduct one equipment leak survey in a calendar year (which must include ''all component types'' subject to 40 CFR 98.233(q)) or multiple ''complete'' equipment leak surveys in a calendar year. In response to comments as part of the 2010 subpart W final rule, the EPA noted that subsequent equipment leak surveys should be ''conducted for an entire facility.'' [23]

The EPA has reviewed how this interpretation could interact with these final amendments for components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and finds that additional clarification is necessary. For example, a facility in the Onshore Petroleum and Natural Gas Production industry segment or the Onshore Petroleum and Natural Gas Gathering and Boosting industry segment may have some components that are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and some components that are not. In such a case, multiple equipment leak surveys would be conducted for the components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements, to fulfill the requirements of the NSPS subpart OOOOa for those components, that would be consistent with subpart W monitoring methods under these final revisions.

However, under the current interpretation of a ''complete'' survey, it would appear that these reporters would either: (1) Be unable to use the NSPS subpart OOOOa fugitive emissions monitoring results as directed, because they did not survey all components at the facility; or (2) be forced to monitor all components at the facility on the same frequency as the components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements to meet the subpart W requirement to use all additional leak surveys conducted in accordance with NSPS OOOOa. The first interpretation would render these final amendments useless, and the second interpretation would increase the burden beyond the EPA's intentions, and could also have unintended consequences for the components subject to the NSPS subpart OOOOa (*e.g.*, a subpart W facility with some components subject to the NSPS subpart OOOOa well site fugitive emissions requirements and others subject to the NSPS subpart OOOOa compressor station fugitive emissions requirements could end up being required to monitor the fugitive emissions components at a well site four times a year instead of twice). Therefore, the EPA is clarifying in 40 CFR 98.233(q)(2)(i) that any monitoring conducted pursuant to and in compliance with the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements constitutes a ''complete'' survey for purposes of subpart W and must be used for subpart W reporting. The EPA is further clarifying that, to meet the requirements of 40 CFR 98.233(q), at least one equipment leak survey must be conducted in a calendar year.

2. Summary of Comments and Responses

Comment: Several commenters addressed the EPA's proposed leaker emission factors. Some of the commenters indicated that the EPA/Gas Research Institute (GRI) data set upon which the proposed factors are based is an older data set and asserted that it may not be representative of operating practices and procedures that have changed significantly over the past 20 years. In addition, the commenters stated that the EPA/GRI data set includes a limited population of measurements, so the proposed leaker emission factors may not account for operational variability on a regional or national level. Some commenters requested that the EPA consider newer studies, including those cited in

[22] U.S. Environmental Protection Agency. *Protocol for Equipment Leak Emissions Estimates.* EPA–453/R–95–017. November 1995. Docket Item No. EPA–HQ–OAR–2009–0927–0043.

[23] U.S. Environmental Protection Agency. *Mandatory Greenhouse Gas Reporting Rule Subpart W—Petroleum and Natural Gas: EPA's Response to Public Comments.* November 2010. Docket Item No. EPA–HQ–OAR–2009–0923–3608. Response to Comment Number EPA–HQ–OAR–2009–0923–1014–9, pp. 1281–1282.

NMED Exhibit 98 - 0015

''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764–0028) either instead of or in combination with the EPA/GRI data set.

Several commenters urged the EPA to work with the regulated community to improve the default leaker emission factors in subpart W. One commenter noted that the proposed leaker emission factors may be a viable interim solution but recommended that the EPA analyze more robust data sets consisting of the combined results of all studies for each industry segment and evaluate whether the subpart W leaker emission factors should be revised.

Response: As described in the preamble to the proposed rule and the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' (Docket ID No. EPA–HQ–OAR–2015–0764), the EPA has determined that the EPA/GRI data set is appropriate to base leaker emission factors in these subpart W amendments. We note that the EPA/GRI data set provides sufficient data to develop leaker emission factors and that using this data set for the leaker emission factors provides consistency with the population emission factors used by reporters that do not conduct equipment leak surveys.

The EPA agrees that there are numerous recent studies that could be used to either replace or supplement the EPA/GRI study data, and many of these are described in the technical support document. The EPA evaluated these other studies and found that the leaker emission factors determined from these data sets agreed reasonably well with the leaker emission factors developed from the EPA/GRI data set, suggesting that the EPA/GRI leaker emission factors are still valid. Commenters that supported a different basis for the leaker emission factors than the EPA/GRI data set did not provide specific information explaining why another study would be a better basis or address any of the specific considerations listed above, although the comments received suggest that stakeholders are interested in further involvement in the assessment of the available data. Therefore, for the reasons stated in the preamble to the proposed rule and the document ''Greenhouse Gas Reporting Rule: Technical Support for Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems Final Rule'' in Docket ID No. EPA–HQ–OAR–2015–0764, the EPA is finalizing the leaker emission factors as proposed.

The EPA appreciates the commenters' interest in providing a thorough review of the available study data to develop an accurate set of leaker emission factors. The EPA is committed to working with stakeholders to ensure that GHGRP requirements and calculation methods are based upon the most robust data available. If the EPA determines that revisions to the subpart W leaker emission factors are appropriate in the future based on additional information, we anticipate that we will propose to amend the rule accordingly.

Comment: Numerous commenters stated that reporters should be allowed to use site-specific leak quantification data if available, either directly for each individual leak (*i.e.,* direct measurement data) or to develop their own leaker emission factors on a facility-specific, company-specific, or product-specific basis. Most of these commenters supported the EPA's proposal to include default leaker emission factors, but stated that reporters should not be limited to using them if the facility has more accurate, site-specific information. Some commenters further noted that the site-specific data reported to the GHGRP could be used to improve the default leaker emission factors in the future. One commenter also requested that the EPA require quantification of any leak that a reporter elects not to repair.

Response: The EPA did not propose and, after review and consideration of comments, is not finalizing provisions allowing reporters to use site-specific information to calculate equipment leak emissions for subpart W. While we agree that direct measurement has the potential to provide more accurate emissions data than using emission factors, we would need to develop criteria and guidelines for using direct measurement data consistently across subpart W reporters for calculating equipment leak emissions. Similarly, we agree that using site-specific emission factors can provide more accurate emissions data than using default emission factors, but a robust set of requirements would be needed for reporters to use when developing their own emission factors to ensure that those factors are as unbiased and representative as possible. In addition, if reporters are using direct measurement or their own emission factors, we would most likely need to amend the reporting requirements (*e.g.*, to require reporters to provide site-specific emission factors), and we would need to consider whether any other amendments would be needed to enable us to review and verify reported data. In either of these cases, we would provide the opportunity for the public to comment on those amended requirements before finalizing them within subpart W.

F. Summary of Final Amendments to Reporting Requirements

1. Summary of Final Amendments

The EPA is finalizing largely as proposed the new reporting requirements for facilities conducting equipment leak surveys under subpart W. Reporters in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments, reporters with storage wellheads in the Underground Natural Gas Storage industry segment, and reporters with components in gas service in the LNG Storage and LNG Import and Export Equipment industry segments that begin using the calculation methodology based on equipment leak surveys must report the information currently listed in 40 CFR 98.236(q)(1) and (2), which includes the number of equipment leak surveys, component types, number of leaking components, average time the components were assumed to be leaking, and annual CO_2 and CH_4 emissions. Facilities that conduct surveys using the new monitoring methods in 40 CFR 98.234(a)(6) or (7) must also report the data elements in 40 CFR 98.236(q)(2) for additional component types specified in 40 CFR 98.232. Reporters may elect to report the data elements in 40 CFR 98.236(q)(2) for the additional component types if they conduct surveys using a monitoring method in 40 CFR 98.234(a)(1) through (5).

The data elements in 40 CFR 98.236(q)(1) and (2) are already required to be reported by facilities conducting equipment leak surveys in the Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage (storage stations), and LNG Storage and LNG Import and Export Equipment (components in LNG service) industry segments. However, facilities in those segments conducting equipment leak surveys using the new OGI method or Method 21, as specified in the NSPS subpart OOOOa (finalized in subpart W as 40 CFR 98.234(a)(6) or (7)), must begin reporting the data elements in 40 CFR 98.236(q)(2) for component types with the new leaker emission factors, including component types that are not currently subject to reporting. Facilities conducting equipment leak surveys using a monitoring method in 40 CFR

98.234(a)(1) through (5) may elect to begin reporting the data elements in 40 CFR 98.236(q)(2) for other components that are not currently subject to reporting.

In addition, the EPA is finalizing as proposed three new reporting requirements for facilities conducting equipment leak surveys in all of the above segments as well as the Onshore Natural Gas Processing and Natural Gas Distribution segments. First, facilities in those segments will be required to report the monitoring method(s) in 40 CFR 98.234(a) used to conduct the survey(s). Second, facilities in the above segments except for Onshore Natural Gas Processing and Natural Gas Distribution will be required to indicate whether any of their component types are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements. Finally, facilities with components for which the calculation methodology based on equipment leak surveys is optional (*e.g.,* facilities in the Onshore Petroleum and Natural Gas Production segment) will be required to indicate whether they elected to use the calculation methodology based on equipment leak surveys for any of their component types at the facility.

Additionally, in reviewing specific reporting requirements while responding to public comments, we recognized that the reporting requirements at 40 CFR 98.236(r)(3)(ii) were unclear, and could be misinterpreted with respect to how this reporting element relates to the calculated emissions. Therefore, we are revising 40 CFR 98.236(r)(3)(ii) by adding the phrase ''. . . for which equipment leak emissions are calculated using the methodology in § 98.233(r)'' to clarify our original intent that the major equipment counts reported under this requirement are specific to equipment for which emissions are calculated using the population count methodology.

2. Summary of Comments and Responses

Comment: Two commenters addressed the proposed requirement in 40 CFR 98.236(q)(1)(iii) to indicate whether any component types at a facility are subject to the NSPS subpart OOOOa. One commenter opposed the addition, stating that it is overly burdensome to require reporters to delineate reporting of emission sources subject to the NSPS subpart OOOOa, especially if this is intended to be a numeric response regarding the number of individual components subject to the NSPS subpart OOOOa. Another commenter asserted that it is not clear if the response to proposed 40 CFR 98.236(q)(1)(iii) is a single yes or no for each facility or if the EPA will be expecting a yes or no response for each component type.

Response: In the final rule, the EPA has revised the proposed requirement in 40 CFR 98.236(q)(1)(iii) (indicate whether any component types are subject to the NSPS subpart OOOOa) to be clear that the EPA expects only one yes or no response for an entire facility. While the EPA understands that the number of leaking components and equipment leak emissions may increase as the number of components subject to the NSPS subpart OOOOa increases, this response will allow the EPA to provide transparent data related to changes in emissions for facilities with components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements over time. This data element will also support verification that the appropriate GHGRP monitoring method was used by the facility.

III. Confidentiality Determinations

A. Summary of Final Confidentiality Determinations for New Subpart W Data Elements

As noted in the proposed rule, we are applying the same approach as previously used for making confidentiality determinations for data elements reported under the GHGRP. In the ''Confidentiality Determinations for Data Required Under the Mandatory Greenhouse Gas Reporting Rule and Amendments to Special Rules Governing Certain Information Obtained Under the Clean Air Act'' (hereafter referred to as ''2011 Final CBI Rulemaking'') (76 FR 30782, May 26, 2011), the EPA grouped part 98 data elements for which EPA was determining confidentiality status through that rulemaking into 22 data categories (11 direct emitter data categories and 11 supplier data categories) with each of the 22 data categories containing data elements that are similar in type or characteristics. The EPA then made categorical confidentiality determinations for eight direct emitter data categories and eight supplier data categories and applied the categorical confidentiality determination to all data elements assigned to the category. Of these data categories with categorical determinations, the EPA determined that four direct emitter data categories are comprised of those data elements that meet the definition of ''emission data,'' as defined at 40 CFR 2.301(a), and are, therefore, not entitled to confidential treatment under section 114(c) of the CAA.[24] The EPA determined that the other four direct emitter data categories and the eight supplier data categories do not meet the definition of ''emission data.'' For these data categories that are determined not to be emission data, the EPA determined categorically that data in three direct emitter data categories and five supplier data categories are eligible for confidential treatment as CBI, and that the data in one direct emitter data category and three supplier data categories are ineligible for confidential treatment as CBI. For two direct emitter data categories, ''Unit/Process 'Static' Characteristics that Are Not Inputs to Emission Equations'' and ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' and three supplier data categories, ''GHGs Reported,'' ''Production/Throughput Quantities and Composition,'' and ''Unit/Process Operating Characteristics,'' the EPA determined in the 2011 Final CBI Rulemaking that the data elements assigned to those categories are not emission data, but the EPA did not make categorical CBI determinations for them. Rather, the EPA made CBI determinations for each individual data element included in those categories on a case-by-case basis taking into consideration the criteria in 40 CFR 2.208. The EPA did not make a final confidentiality determination for data elements assigned to the inputs to emission equation data category (a direct emitter data category) in the 2011 Final CBI Rulemaking. However, the EPA has since proposed and finalized an approach for addressing disclosure concerns associated with inputs to emissions equations.[25]

In the proposed rule, we assigned the nine proposed new or substantially revised data elements to the appropriate direct emitter data categories created in the 2011 Final CBI Rulemaking based on the type and characteristics of each data element. For the seven data elements the EPA assigned to a direct emitter category with a categorical determination, the EPA proposed that the categorical determination for the category be applied to the proposed new or substantially revised data elements,

[24] Direct emitter data categories that meet the definition of ''emission data'' in 40 CFR 2.301(a) are ''Facility and Unit Identifier Information,'' ''Emissions,'' ''Calculation Methodology and Methodological Tier,'' and ''Data Elements Reported for Periods of Missing Data that are not Inputs to Emission Equations.''

[25] Revisions to Reporting and Recordkeeping Requirements, and Confidentiality Determinations Under the Greenhouse Gas Reporting Program; Final Rule. (79 FR 63750, October 24, 2014).

as shown in Table 4 of this preamble. For the two data elements assigned to the ''Unit/Process Operating Characteristics that Are Not Inputs to Emission Equations,'' we proposed confidentiality determinations on a case-by-case basis taking into consideration the criteria in 40 CFR 2.208, consistent with the approach used for data elements previously assigned to these two data categories, as shown in Table 5 of this preamble. Refer to the preamble to the proposed rule (81 FR 4987; January 29, 2016) for additional information regarding the proposed confidentiality determinations.

With consideration of the information provided by commenters, the EPA is finalizing the confidentiality determinations as proposed. Specifically, the EPA is finalizing the proposed determination for each of the nine new or substantially revised data elements to be designated as ''emission data'' or ''not CBI.''

TABLE 4—FINAL DATA CATEGORY ASSIGNMENTS AND CONFIDENTIALITY DETERMINATIONS FOR NEW DATA ELEMENTS ASSIGNED TO CATEGORIES WITH CATEGORICAL DETERMINATIONS

Citation	Data element	Final category assignment	Categorical determination (as established in 2011)[26]
§ 98.236(q)(1)(i)	The number of complete equipment leak surveys performed during the calendar year.	Test and Calibration Methods.	Not Emission Data and Not CBI.
§ 98.236(q)(1)(iii)	Whether any component types were subject to 40 CFR part 60, subpart OOOOa.	Facility and Unit Identifier Information.	Emission Data.
§ 98.236(q)(1)(iv)	Whether you elected to comply with § 98.233(q) per § 98.233(q)(1)(iii).	Facility and Unit Identifier Information.	Emission Data.
§ 98.236(q)(1)(v)	Each type of method described in § 98.234(a) that was used to conduct leak surveys.	Test and Calibration Methods.	Not Emission Data and Not CBI.
§ 98.236(q)(2)(i)	For each component type that is located at your facility, component type.	Facility and Unit Identifier Information.	Emission Data.
§ 98.236(q)(2)(iv)	For each component type that is located at your facility, annual CO_2 emissions, in metric tons CO_2.	Emissions	Emission Data.
§ 98.236(q)(2)(v)	For each component type that is located at your facility, annual CH_4 emissions, in metric tons CH_4.	Emissions	Emission Data.

TABLE 5—FINAL CONFIDENTIALITY FOR DATA ELEMENTS ASSIGNED TO THE ''UNIT/PROCESS OPERATING CHARACTERISTICS THAT ARE NOT INPUTS TO EMISSION EQUATIONS'' DATA CATEGORY

Citation	Data element	Final confidentiality determination and rationale
§ 98.236(q)(2)(ii)	For each component type that is located at your facility, total number of the surveyed component type that were identified as leaking in the calendar year (''x_p'' in Equation W–30).	Not Emission Data (Categorical Determination as Established in 2011). Not CBI. The term ''equipment leaks'' refers to those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening. Leaking components at a facility may have a correlation to the level of maintenance at a facility. However, there is no direct correlation between the level of maintenance and process efficiency, *i.e.,* a higher number of leaks in one facility do not indicate that the processes have been running longer or more frequently than those processes at another facility that has a lower number of leaks. Furthermore, Department of Transportation (DOT) regulations require natural gas distribution companies and transmission pipeline companies to conduct periodic leak detection and fix any leaking equipment. The number of leaks detected and fixed is reported to the DOT and is publicly available. Finally, 40 CFR part 60, subpart OOOOa requires reporting for each component with visible emissions at affected well sites and compressor station sites. The EPA is finalizing that this data element is not confidential; and that it will be considered ''not CBI.''
§ 98.236(q)(2)(iii)	For each component type that is located at your facility, average time the surveyed components are assumed to be leaking and operational, in hours (average of ''T_p,z'' from Equation W–30).	Not Emission Data (Categorical Determination as Established in 2011). Not CBI. This data element will provide information on the amount of time operational components were found to be leaking. This information provides little insight into maintenance practices at a facility because it does not identify the cause of the leaks or the nature and cost of repairs. Therefore, this information would not be likely to cause substantial competitive harm to reporters. For this reason, we are finalizing the average time operational components were found leaking be designated as ''not CBI.''

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the proposed categorical assignments and confidentiality determinations. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–

[26] The categorical confidentiality determinations for the data categories listed in this table were finalized on May 26, 2011 (see 76 FR 30782).

0764 for a complete listing of all comments and responses. See the memorandum ''Final Data Category Assignments and Confidentiality Determinations for Data Elements in the 'Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Final Rule' '' in Docket ID No. EPA–HQ–OAR–2015–0764 for a complete listing of final data category assignments and confidentiality determinations.

Comment: One commenter stated that the EPA should reconsider the proposed determination of ''not CBI'' for the number of components identified as leaking in a calendar year and the average time the surveyed components are assumed to be leaking. The commenter asserted that designating this information as CBI would encourage more reporters to voluntarily conduct leak surveys. The commenter also noted that this information is publically available for some sources and suggested that the rule provide an exception from classification as CBI for components subject to State programs or NSPS that already require public disclosure. Another commenter requested that the EPA protect the community's right to know and not allow companies to keep the public from finding out about leaks from hydrocarbon facilities.

Response: While it is possible that the requirement to report the number of leaking components and the average time those components were leaking could discourage some reporters from conducting voluntary equipment leak surveys, this is not a valid reason to allow reporters to claim these data elements as confidential. As noted in section III.C of the preamble to the proposed rule, the EPA proposed that disclosure of these data elements is unlikely to cause substantial harm to a business's competitive position, and the commenter did not indicate that the EPA's determination was incorrect. Therefore, the EPA is finalizing the confidentiality determinations for these data elements as ''not CBI.''

IV. Impacts of the Final Amendments to Subpart W

A. Impacts of the Final Amendments

The final amendments to subpart W revise costs associated with the use of the monitoring methods and the calculation methodology based on equipment leak surveys for reporters in the following industry segments: Onshore Petroleum and Natural Gas Production, Onshore Petroleum and Natural Gas Gathering and Boosting, Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, LNG Storage, and LNG Import and Export Equipment. Reporters in these industry segments are required to use the results of fugitive emissions component monitoring required for well sites and compressor stations under the NSPS subpart OOOOa. Reporters in these segments with components not subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and for which they are currently required to use the calculation methodology based on population counts under subpart W may voluntarily use the calculation methodology based on equipment leak surveys for those components if the equipment leak survey is conducted following a monitoring method listed in subpart W.

The EPA received comments from one commenter regarding the specific impacts of the proposed amendments. After evaluating these comments and reviewing other changes from proposal, the EPA revised the impacts assessment from proposal. The EPA estimates that the costs of the final amendments to subpart W are slightly more burdensome than we estimated at proposal, but they do not significantly change the overall burden to subpart W reporters. The EPA estimated that the additional costs to subpart W reporters in the Onshore Petroleum and Natural Gas Production and the Onshore Petroleum and Natural Gas Gathering and Boosting industry segments to transition their existing equipment leak recordkeeping, calculating, and reporting systems to use the calculation methodology based on equipment leak surveys and to determine which components are subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and which are not, will be approximately $110,000 per year, or about $410 per reporter. The EPA estimated that the additional costs for subpart W reporters in the other industry segments (*i.e.,* Onshore Natural Gas Transmission Compression, Underground Natural Gas Storage, Liquefied Natural Gas (LNG) Storage, and LNG Import and Export Equipment) to add a few new emission factors to their existing systems (rather than transitioning their recordkeeping, calculating, and reporting systems) and to determine which components are covered by the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and which are not, will be approximately $20,000 per year or about $110 per reporter. The total costs are approximately $128,400 per year for all reporters, or about $286 per reporter. See the memorandum, ''Assessment of Impacts of the Final Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for additional information.

B. Summary of Comments and Responses

This section summarizes the major comments and responses related to the impacts of the proposed amendments to subpart W of part 98. We note that while several commenters asserted that the proposed rule would be burdensome for many operators and suggested revisions to the rule requirements that would reduce the burden, only one commenter provided comments on the EPA's impacts estimate and supporting statement, and that commenter's major comments are summarized in this section. See ''Response to Public Comments on Greenhouse Gas Reporting Rule: Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764 for a complete listing of all comments and responses.

Comment: One commenter stated that the EPA's estimate of two hours of labor and $198 per reporter significantly underestimates and misrepresents the amount of time and effort that goes into implementing a new rule. The commenter provided a cost estimate that assumes more labor hours than in the EPA's memorandum ''Assessment of Impacts of the Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' (Docket Item No. EPA–HQ–OAR–2015–0764–0025). The commenter noted that as more sites become subject to the NSPS subpart OOOOa at a facility, the costs of managing the data and processing it into a usable format for the GHGRP will increase each year for that reporter. The commenter also noted that the EPA was incorrect in assuming that there would be no costs for facilities in the Onshore Natural Gas Processing segment.

Response: The EPA has evaluated the comments and has made changes to the estimate of burden in the supporting statement. The following paragraphs address each of the points in the commenter's detailed cost estimate included with the comment letter and explain how the points are being addressed in the final burden and cost estimate.

The commenter suggested adding burden of two hours in the first year related to the initial monitoring plan development and burden of 0.5 hours in subsequent years related to yearly monitoring plan revisions. The EPA did not include costs at proposal related to the monitoring plan because the subpart W amendments do not require the development of a separate monitoring plan. Instead, the subpart W amendments cross reference the monitoring plan that is already being developed according to the NSPS subpart OOOOa. The EPA recognizes that reporters that are not subject to the NSPS subpart OOOOa would not already be required to develop a monitoring plan under the NSPS subpart OOOOa; however, reporters that elect to use one of the new leak detection methods are also electing to incur the burden of developing a monitoring plan. Therefore, there is no monitoring plan burden associated with the subpart W amendments and the final burden and cost estimate has not changed from proposal as a result of this comment.

The commenter suggested changing the number of hours to revise the reporting system to five hours and to allow one hour for maintenance in each subsequent year. At proposal, the EPA estimated that revising the reporting system to use the calculation methodology based on equipment leak surveys would require two hours. The commenter did not provide the basis for their estimate of five hours to update the data management system. The overall reporting costs for compliance already include a burden of ten hours per year and the EPA disagrees that updating the data management system would encompass half of that allotment because EPA anticipates that reporters would only need to add a few emission factors for leaking components to their existing system, rather than something more time-intensive such as creating a new data management system. We reviewed the revisions expected to be needed in the data management system. While we maintain that two hours are sufficient to implement the calculation methodology based on equipment leak surveys into a reporter's existing system, we recognize that this process will also require quality assurance reviews and testing to ensure the data are stored properly and the calculations are performed correctly. Therefore, we increased the number of hours estimated to revise the reporting system from two hours to 3.5 hours to account for these additional quality reviews of the data management system. However, the EPA has made no changes to burden associated with maintenance of the revised reporting system because the EPA asserts that any reporting system maintenance related to subpart W is already reflected in the twenty hours per year allotted to each subpart W reporter for recordkeeping and reporting activities.

The commenter suggested that the EPA adjust the proposed burden and cost estimate by adding the following activities and burden estimates: (1) Time for staff to process the survey data resulting from the calculation methodology based on equipment leak surveys and to enter it into the GHGRP system at a burden of three hours per year; (2) time for staff training at a burden of two hours for initial training and one hour per year in subsequent years; and (3) time for staff to review the data for quality assurance, follow missing data requirements, report data to the EPA, and retain all records at a burden of four total hours per year.

At proposal, the EPA did not include burden related to these activities because they are covered by the twenty hours per year already accounted for in the overall subpart W reporter burden for recordkeeping and reporting activities. Therefore, the final burden and cost estimate has not changed from proposal as a result of these comments.

However, at proposal, the EPA did not account for the time associated with determining which components in the reporting system are covered by the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and which are not. As a result, the EPA has added 0.5 hours per reporter in the first year that the reporter has an affected collection of fugitive emissions components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements and 0.1 hours per reporter in subsequent years.

Finally, for the reasons described in section II.B.2 of this preamble, the final rule language specifies that the requirement to use the NSPS subpart OOOOa results as part of the calculation methodology based on equipment leak surveys only applies to components subject to the NSPS subpart OOOOa well site or compressor station fugitive emissions requirements. The subpart W equipment leak survey requirements for facilities in the Onshore Natural Gas Processing segment do not change as a result of these amendments. Therefore, the EPA is not including any burden estimate for Onshore Natural Gas Processing reporters (i.e., the revisions to the burden estimate described in this response do not apply to the Onshore Natural Gas Processing segment).

Overall, the burden and cost estimate has been revised as discussed above from 502 hours and $50,000 per year at proposal to approximately 1,295 hours and $128,400 per year for all reporters.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-and-executive orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

The information collection activities in this rule have been submitted for approval to the OMB under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2300.19. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here. The information collection requirements are not enforceable until OMB approves them.

This action increases burden for industry segments that conduct equipment leak surveys. These revisions are expected to increase respondent burden for subpart W reporters that become subject to the NSPS subpart OOOOa well site or compressor station fugitive requirements. To accommodate the new methods and emission factors added by these final amendments, the EPA expects that each affected subpart W reporter will either revise their reporter-specific calculation mechanism (i.e., calculation spreadsheet, recordkeeping database, etc.) or add a few new emission factors to the reporter-specific calculation mechanism, when and if the reporter becomes subject to the NSPS subpart OOOOa well site or compressor station fugitive requirements. The recordkeeping and reporting requirements are being finalized as proposed. Impacts associated with the final revisions to the recordkeeping and reporting requirements are detailed in the memorandum ''Assessment of Impacts of the Final Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems''

(see Docket ID No. EPA–HQ–OAR–2015–0764).

Data collection provides a critical tool for communities to identify nearby sources of GHGs and provides information to state and local governments. The data can be used to complement atmospheric GHG studies and inform updates to emission inventories such as the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory). Various activity data are collected that can be used to improve understanding of the occurrence of emissions from a variety of sources.

Data collected must be made available to the public unless the data qualify for CBI treatment under the CAA and EPA regulations. All data determined by the EPA to be CBI are safeguarded in accordance with regulations in 40 CFR chapter 1, part 2, subpart B.

Respondents/affected entities: The respondents in this information collection include owners and operators of petroleum and natural gas systems facilities that report their GHG emissions from equipment leaks to the EPA to comply with subpart W.

Respondent's obligation to respond: The respondent's obligation to respond is mandatory under the authority provided in CAA section 114.

Estimated number of respondents: Approximately 899 respondents per year.

Frequency of response: Annual.

Total estimated burden: 1,295 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $128,400 (per year), includes $0 annualized capital or operation and maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the EPA will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities directly regulated by this final rule include small businesses in the petroleum and natural gas industry. The EPA has determined that some small businesses will be affected because their production processes emit GHGs exceeding the reporting threshold. This action includes amendments that may result in a small burden increase on some subpart W reporters, but the EPA has determined that the increased cost of less than $286 per reporter is not a significant impact. Details of this analysis are presented in ''Assessment of Impacts of the Final Leak Detection Methodology Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems'' in Docket ID No. EPA–HQ–OAR–2015–0764.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. As shown in sections IV.A and V.B of this preamble, the annual cost of this action is $128,400, which is well under $100 million per year.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This regulation will apply directly to petroleum and natural gas facilities that emit GHGs. Although few facilities that will be subject to the rule are likely to be owned by tribal governments, the EPA sought opportunities to provide information to tribal governments and representatives during the development of the proposed and final subpart W that was promulgated on November 30, 2010 (75 FR 74458).

The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in section IV.F of the preamble to the re-proposal of subpart W published on April 12, 2010 (75 FR 18608), and section IV.F of the preamble to the subpart W 2010 final rule published on November 30, 2010 (75 FR 74458).

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it does not concern an environmental health risk or safety risk.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action is not subject to Executive Order 12898 (59 FR 7629, February 16, 1994) because it does not establish an environmental health or safety standard. Instead, this rule addresses information collection and reporting and verification procedures.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Reporting and recordkeeping requirements.

Dated: November 10, 2016.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 98—MANDATORY GREENHOUSE GAS REPORTING

■ 1. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart W—Petroleum and Natural Gas Systems

■ 2. Section 98.232 is amended by:
■ a. Revising paragraph (c)(21);
■ b. Adding paragraph (e)(8);
■ c. Revising paragraph (f)(5);
■ d. Adding paragraphs (f)(6) through (8);
■ e. Revising paragraphs (g)(3) and (4);
■ f. Adding paragraphs (g)(5) through (7);
■ g. Revising paragraphs (h)(4) and (5);
■ h. Adding paragraphs (h)(6) through (8); and
■ i. Revising paragraph (j)(10).

The revisions and additions read as follows:

§ 98.232 GHGs to report.

* * * * *

(c) * * *

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components listed in paragraph (c)(11) or (19) of this section, and it does not include thief hatches or other openings on a storage vessel).

* * * * *

(e) * * *

(8) Equipment leaks from all other components that are not listed in paragraph (e)(1), (2), or (7) of this section and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). The other components subject to this paragraph (e)(8) also do not include thief hatches or other openings on a storage vessel. If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(f) * * *

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters associated with storage stations.

(6) Equipment leaks from all other components that are associated with storage stations, are not listed in paragraph (f)(1), (2), or (5) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(7) Equipment leaks from valves, connectors, open-ended lines, and pressure relief valves associated with storage wellheads.

(8) Equipment leaks from all other components that are associated with storage wellheads, are not listed in paragraph (f)(1), (2), or (7) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a, of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these other components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these other components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(g) * * *

(3) Flare stack emissions.

(4) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(5) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (g)(6) of this section.

(6) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a).

(7) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (g)(1) or (2) of this section, and are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

(h) * * *

(4) Flare stack emissions.

(5) Equipment leaks from valves, pump seals, connectors, and other equipment leak sources in LNG service.

(6) Equipment leaks from vapor recovery compressors, if you do not survey components associated with vapor recovery compressors in accordance with paragraph (h)(7) of this section.

(7) Equipment leaks from all components in gas service that are associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a).

(8) Equipment leaks from all components in gas service that are not associated with a vapor recovery compressor, are not listed in paragraph (h)(1) or (2) of this section, and that are either subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter or you elect to survey using a leak detection method described in § 98.234(a)(6) or (7). If these components are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you may also elect to report emissions from these components if you elect to survey them using a leak detection method described in § 98.234(a)(1) through (5).

* * * * *

(j) * * *

(10) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other components (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps, but does not include components in paragraph (j)(8) or (9) of this section, and it does not include thief hatches or other openings on a storage vessel).

* * * * *

■ 3. Section 98.233 is amended by:
■ a. Revising the parameter EF_t of Equation W–1 in paragraph (a) introductory text, and paragraph (q);

■ b. Removing the first two sentences of paragraph (r) introductory text and adding four sentences in their place; and

■ c. Revising the parameters $Count_e$ and $EF_{s,e}$ of Equation W–32A in paragraph (r) introductory text, and paragraphs (r)(3) through (5).

The revisions read as follows:

§ 98.233 Calculating GHG emissions.

* * * * *

(a) * * *

* * * * *

EF_t = Population emission factors for natural gas pneumatic device vents (in standard cubic feet per hour per device) of each type ''t'' listed in Tables W–1A, W–3B, and W–4B to this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively. Onshore petroleum and natural gas gathering and boosting facilities must use the population emission factors listed in Table W–1A to this subpart.

* * * * *

(q) *Equipment leak surveys.* For the components identified in paragraphs (q)(1)(i) through (iii) of this section, you must conduct equipment leak surveys using the leak detection methods specified in paragraphs (q)(1)(i) through (iii) of this section. For the components identified in paragraph (q)(1)(iv) of this section, you may elect to conduct equipment leak surveys, and if you elect to conduct surveys, you must use a leak detection method specified in paragraph (q)(1)(iv) of this section. This paragraph (q) applies to components in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Components in streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (q) and do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported.

(1) *Survey requirements.* (i) For the components listed in § 98.232(e)(7), (f)(5), (g)(4), and (h)(5), that are not subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods listed in § 98.234(a) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(ii) For the components listed in § 98.232(d)(7) and (i)(1), you must conduct surveys using any of the leak detection methods listed in § 98.234(a)(1) through (5) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iii) For the components listed in § 98.232(c)(21), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), and (j)(10) that are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter, you must conduct surveys using any of the leak detection methods in § 98.234(a)(6) or (7) and calculate equipment leak emissions using the procedures specified in paragraph (q)(2) of this section.

(iv) For the components listed in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), or (j)(10), that are not subject to fugitive emissions standards in § 60.5397a of this chapter, you may elect to conduct surveys according to this paragraph (q), and, if you elect to do so, then you must use one of the leak detection methods in § 98.234(a).

(A) If you elect to use a leak detection method in § 98.234(a)(1) through (5) for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) in lieu of the population count methodology specified in paragraph (r) of this section, then you must calculate emissions for the surveyed component types in § 98.232(c)(21), (f)(7), (g)(6), (h)(7), or (j)(10) using the procedures in paragraph (q)(2) of this section.

(B) If you elect to use a leak detection method in § 98.234(a)(1) through (5) for the surveyed component types in § 98.232(e)(8), (f)(6), (f)(8), (g)(7), and (h)(8), then you must use the procedures in paragraph (q)(2) of this section to calculate those emissions.

(C) If you elect to use a leak detection method in § 98.234(a)(6) or (7) for any elective survey under this subparagraph (q)(1)(iv), then you must survey the component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) that are not subject to fugitive emissions standards in § 60.5397a of this chapter, and you must calculate emissions from the surveyed component types in § 98.232(c)(21), (e)(8), (f)(6), (f)(7), (f)(8), (g)(6), (g)(7), (h)(7), (h)(8), and (j)(10) using the emission calculation requirements in paragraph (q)(2) of this section.

(2) *Emission calculation methodology.* For industry segments listed in § 98.230(a)(2) through (9), if equipment leaks are detected during surveys required or elected for components listed in paragraphs (q)(1)(i) through (iv) of this section, then you must calculate equipment leak emissions per component type per reporting facility using Equation W–30 of this section and the requirements specified in paragraphs (q)(2)(i) through (xi) of this section. For the industry segment listed in § 98.230(a)(8), the results from Equation W–30 are used to calculate population emission factors on a meter/regulator run basis using Equation W–31 of this section. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(2)(x)(A) of this section, then you must calculate the emissions from all above grade transmission-distribution transfer stations as specified in paragraph (q)(2)(xi) of this section.

$$E_{s,p,i} = GHG_i * EF_{s,p} * \sum_{z=1}^{x_p} T_{p,z} \qquad \text{(Eq. W-30)}$$

Where:

$E_{s,p,i}$ = Annual total volumetric emissions of GHGi from specific component type ''p'' (in accordance with paragraphs (q)(1)(i) through (iv) of this section) in standard (''s'') cubic feet, as specified in paragraphs (q)(2)(ii) through (x) of this section.

x_p = Total number of specific component type ''p'' detected as leaking in any leak survey during the year. A component found leaking in two or more surveys during the year is counted as one leaking component.

$EF_{s,p}$ = Leaker emission factor for specific component types listed in Tables W–1E, W–2, W–3A, W–4A, W–5A, W–6A, and W–7 to this subpart.

GHG_i = For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural

gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

$T_{p,z}$ = The total time the surveyed component ''z,'' component type ''p,'' was assumed to be leaking and operational, in hours. If one leak detection survey is conducted in the calendar year, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted in the calendar year, assume a component found leaking in the first survey was leaking since the beginning of the year until the date of the survey; assume a component found leaking in the last survey of the year was leaking from the preceding survey through the end of the year; assume a component found leaking in a survey between the first and last surveys of the year was leaking since the preceding survey until the date of the survey; and sum times for all leaking periods. For each leaking component, account for time the component was not operational (*i.e.,* not operating under pressure) using an engineering estimate based on best available data.

(i) You must conduct at least one leak detection survey in a calendar year. The leak detection surveys selected must be conducted during the calendar year. If you conduct multiple complete leak detection surveys in a calendar year, you must use the results from each complete leak detection survey when calculating emissions using Equation W–30. For components subject to the well site and compressor station fugitive emissions standards in § 60.5397a of this chapter, each survey conducted in accordance with § 60.5397a of this chapter will be considered a complete leak detection survey for purposes of this section.

(ii) Calculate both CO_2 and CH_4 mass emissions using calculations in paragraph (v) of this section.

(iii) Onshore petroleum and natural gas production facilities must use the appropriate default whole gas leaker emission factors for components in gas service, light crude service, and heavy crude service listed in Table W–1E to this subpart.

(iv) Onshore petroleum and natural gas gathering and boosting facilities must use the appropriate default whole gas leaker factors for components in gas service listed in Table W–1E to this subpart.

(v) Onshore natural gas processing facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–2 to this subpart.

(vi) Onshore natural gas transmission compression facilities must use the appropriate default total hydrocarbon leaker emission factors for compressor components in gas service and non-compressor components in gas service listed in Table W–3A to this subpart.

(vii) Underground natural gas storage facilities must use the appropriate default total hydrocarbon leaker emission factors for storage stations or storage wellheads in gas service listed in Table W–4A to this subpart.

(viii) LNG storage facilities must use the appropriate default methane leaker emission factors for LNG storage components in LNG service or gas service listed in Table W–5A to this subpart.

(ix) LNG import and export facilities must use the appropriate default methane leaker emission factors for LNG terminals components in LNG service or gas service listed in Table W–6A to this subpart.

(x) Natural gas distribution facilities must use Equation W–30 of this section and the default methane leaker emission factors for transmission-distribution transfer station components in gas service listed in Table W–7 to this subpart to calculate component emissions from annual equipment leak surveys conducted at above grade transmission-distribution transfer stations. Natural gas distribution facilities are required to perform equipment leak surveys only at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do not meet the definition of transmission-distribution transfer stations are not required to perform equipment leak surveys under this section.

(A) Natural gas distribution facilities may choose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years ''n,'' not exceeding a five year period to cover all above grade transmission-distribution transfer stations. If the facility chooses to use the multiple year option, then the number of transmission-distribution transfer stations that are monitored in each year should be approximately equal across all years in the cycle.

(B) Use Equation W–31 of this section to determine the meter/regulator run population emission factors for each GHG_i. As additional survey data become available, you must recalculate the meter/regulator run population emission factors for each GHG_i annually according to paragraph (q)(2)(x)(C) of this section.

$$EF_{s,MR,i} = \frac{\sum_{y=1}^{n}\sum_{p=1}^{7} E_{s,p,i,y}}{\sum_{y=1}^{n}\sum_{w=1}^{Count_{MR,y}} T_{w,y}} \qquad \text{(Eq. W-31)}$$

Where:

$EF_{s,MR,i}$ = Meter/regulator run population emission factor for GHG_i based on all surveyed above grade transmission-distribution transfer stations over ''n'' years, in standard cubic feet of GHG_i per operational hour of all meter/regulator runs.

$E_{s,p,i,y}$ = Annual total volumetric emissions at standard conditions of GHG_i from component type ''p'' during year ''y'' in standard (''s'') cubic feet, as calculated using Equation W–30 of this section.

p = Seven component types listed in Table W–7 to this subpart for transmission-distribution transfer stations.

$T_{w,y}$ = The total time the surveyed meter/regulator run ''w'' was operational, in hours during survey year ''y'' using an engineering estimate based on best available data.

$Count_{MR,y}$ = Count of meter/regulator runs surveyed at above grade transmission-distribution transfer stations in year ''y''.

y = Year of data included in emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(C) of this section.

n = Number of years of data, according to paragraph (q)(2)(x)(A) of this section, whose results are used to calculate emission factor ''$EF_{s,MR,i}$'' according to paragraph (q)(2)(x)(C) of this section.

(C) The emission factor ''$EFs_{,MR,i,}$'' based on annual equipment leak surveys at above grade transmission-distribution transfer stations, must be calculated

annually. If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(2)(x)(A) of this section and you have submitted a smaller number of annual reports than the duration of the selected cycle period of 5 years or less, then all available data from the current year and previous years must be used in the calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 of this section. After the first survey cycle of ''n'' years is completed and beginning in calendar year (n+1), the survey will continue on a rolling basis by including the survey results from the current calendar year ''y'' and survey results from all previous $(n-1)$ calendar years, such that each annual calculation of the emission factor ''$EF_{s,MR,i}$'' from Equation W–31 is based on survey results from ''n'' years. Upon completion of a cycle, you may elect to change the number of years in the next cycle period (to be 5 years or less). If the number of years in the new cycle is greater than the number of years in the previous cycle, calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and the survey results from the preceding number years that is equal to the number of years in the previous cycle period. If the number of years, ''n_{new},'' in the new cycle is smaller than the number of years in the previous cycle, ''n,'' calculate ''$EF_{s,MR,i}$'' from Equation W–31 in each year of the new cycle using the survey results from the current calendar year and survey results from all previous $(n_{new}-1)$ calendar years.

(xi) If you chose to conduct equipment leak surveys at all above grade transmission-distribution transfer stations over multiple years, ''n,'' according to paragraph (q)(2)(x)(A) of this section, you must use the meter/regulator run population emission factors calculated using Equation W–31 of this section and the total count of all meter/regulator runs at above grade transmission-distribution transfer stations to calculate emissions from all above grade transmission-distribution transfer stations using Equation W–32B in paragraph (r) of this section.

(r) * * * This paragraph (r) applies to emissions sources listed in § 98.232(c)(21), (f)(7), (g)(5), (h)(6), and (j)(10) if you are not required to comply with paragraph (q) of this section and if you do not elect to comply with paragraph (q) of this section for these components in lieu of this paragraph (r). This paragraph (r) also applies to emission sources listed in § 98.232(i)(2), (i)(3), (i)(4), (i)(5), (i)(6), and (j)(11). To be subject to the requirements of this paragraph (r), the listed emissions sources also must contact streams with gas content greater than 10 percent CH plus CO_2 by weight. Emissions sources that contact streams with gas content less than or equal to 10 percent CH_4 plus CO_2 by weight are exempt from the requirements of this paragraph (r) and do not need to be reported. * * *

* * * * *

$Count_e$ = Total number of the emission source type at the facility. For onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C to this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D to this subpart. Onshore petroleum and natural gas gathering and boosting facilities must also count the miles of gathering pipelines by material type (protected steel, unprotected steel, plastic, or cast iron). Underground natural gas storage facilities must count each component listed in Table W–4B to this subpart. LNG storage facilities must count the number of vapor recovery compressors. LNG import and export facilities must count the number of vapor recovery compressors. Natural gas distribution facilities must count: (1) The number of distribution services by material type; (2) miles of distribution mains by material type; and (3) number of below grade metering-regulating stations, by pressure type; as listed in Table W–7 to this subpart.

* * * * *

$EF_{s,e}$ = Population emission factor for the specific emission source type, as listed in Tables W–1A, W–4B, W–5B, W–6B, and W–7 to this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D to this subpart.

* * * * *

(3) Underground natural gas storage facilities must use the appropriate default total hydrocarbon population emission factors for storage wellheads in gas service listed in Table W–4B to this subpart.

(4) LNG storage facilities must use the appropriate default methane population emission factor for LNG storage compressors in gas service listed in Table W–5B to this subpart.

(5) LNG import and export facilities must use the appropriate default methane population emission factor for LNG terminal compressors in gas service listed in Table W–6B to this subpart.

* * * * *

■ 4. Section 98.234 is amended by:

■ a. Revising paragraph (a) introductory text, the paragraph (a)(1) heading, and the fourth sentence in paragraph (a)(2); and

■ b. Adding paragraphs (a)(6) and (7).

The revisions and additions read as follows:

* * * * *

§ 98.234 Monitoring and QA/QC requirements.

(a) You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of through-valve leakage from all source types listed in § 98.233(k), (o), and (p) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(i) that occur during a calendar year. You must use any of the methods described in paragraphs (a)(1) through (5) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(ii) that occur during a calendar year. You must use one of the methods described in paragraph (a)(6) or (7) of this section to conduct leak detection(s) of equipment leaks from components as specified in § 98.233(q)(1)(iii). If electing to comply with § 98.233(q) as specified in § 98.233(q)(1)(iv), you must use any of the methods described in paragraphs (a)(1) through (7) of this section to conduct leak detection(s) of equipment leaks from component types as specified in § 98.233(q)(1)(iv) that occur during a calendar year.

(1) Optical gas imaging instrument as specified in § 60.18 of this chapter. * * *

* * * * *

(2) * * * If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(1) of this section to monitor inaccessible equipment leaks or vented emissions.

* * * * *

(6) Optical gas imaging instrument as specified in § 60.5397a of this chapter. Use an optical gas imaging instrument for equipment leak detection in accordance with § 60.5397a(b), (c)(3), (c)(7), and (e) of this chapter and paragraphs (a)(6)(i) through (iii) of this section. Unless using methods in paragraph (a)(7) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring

personnel more than 2 meters above a support surface.

(i) For the purposes of this subpart, any visible emissions from a component listed in § 98.232 observed by the optical gas imaging instrument is a leak.

(ii) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(iii) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a(b) of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

(7) Method 21 as specified in § 60.5397a of this chapter. Use the equipment leak detection methods in appendix A–7 to part 60 of this chapter, Method 21, in accordance with § 60.5397a(b), (c)(8), and (e) of this chapter and paragraphs (a)(7)(i) through (iii) of this section. Inaccessible emissions sources, as defined in part 60 of this chapter, are not exempt from this subpart. If the equipment leak detection methods in this paragraph cannot be used, you must use alternative leak detection devices as described in paragraph (a)(6) of this section to monitor inaccessible equipment leaks.

(i) For the purposes of this subpart, any instrument reading from a component listed in § 98.232 of this chapter of 500 ppm or greater using Method 21 is a leak.

(ii) For the purposes of this subpart, the term ''fugitive emissions component'' in § 60.5397a of this chapter means ''component.''

(iii) For the purpose of complying with § 98.233(q)(1)(iv), the phrase ''the collection of fugitive emissions components at well sites and compressor stations'' in § 60.5397a(b) of this chapter means ''the collection of components for which you elect to comply with § 98.233(q)(1)(iv).''

* * * * *

■ 5. Section 98.236 is amended by:
■ a. Redesignating paragraphs (a)(1)(xiv) through (xvii) as paragraphs (a)(1)(xv) through (xviii), respectively;
■ b. Adding new paragraph (a)(1)(xiv);
■ c. Redesignating paragraphs (a)(9)(x) and (xi) as paragraphs (a)(9)(xi) and (xii), respectively;
■ d. Adding new paragraph (a)(9)(x);
■ e. Revising paragraph (q) introductory text, paragraph (q)(1), paragraph (q)(2) introductory text, paragraph (r)(3)(ii) introductory text, and the second sentence of paragraph (z) introductory text.

The revisions and additions read as follows:

§ 98.236 Data reporting requirements.

* * * * *

(a) * * *

(1) * * *

(xiv) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

* * * * *

(9) * * *

(x) Equipment leak surveys. Report the information specified in paragraph (q) of this section.

* * * * *

(q) Equipment leak surveys. For any components subject to or complying with the requirements of § 98.233(q), you must report the information specified in paragraphs (q)(1) and (2) of this section. Natural gas distribution facilities with emission sources listed in § 98.232(i)(1) must also report the information specified in paragraph (q)(3) of this section.

(1) You must report the information specified in paragraphs (q)(1)(i) through (v) of this section.

(i) Except as specified in paragraph (q)(1)(ii) of this section, the number of complete equipment leak surveys performed during the calendar year.

(ii) Natural gas distribution facilities performing equipment leak surveys across a multiple year leak survey cycle must report the number of years in the leak survey cycle.

(iii) Except for onshore natural gas processing facilities and natural gas distribution facilities, indicate whether any equipment components at your facility are subject to the well site or compressor station fugitive emissions standards in § 60.5397a of this chapter. Report the indication per facility, not per component type.

(iv) For facilities in onshore petroleum and natural gas production, onshore petroleum and natural gas gathering and boosting, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment, indicate whether you elected to comply with § 98.233(q) according to § 98.233(q)(1)(iv) for any equipment components at your facility.

(v) Report each type of method described in § 98.234(a) that was used to conduct leak surveys.

(2) You must indicate whether your facility contains any of the component types subject to or complying with § 98.233(q) that are listed in § 98.232(c)(21), (d)(7), (e)(7), (e)(8), (f)(5), (f)(6), (f)(7), (f)(8), (g)(4), (g)(6), (g)(7), (h)(5), (h)(7), (h)(8), (i)(1), or (j)(10) for your facility's industry segment. For each component type that is located at your facility, you must report the information specified in paragraphs (q)(2)(i) through (v) of this section. If a component type is located at your facility and no leaks were identified from that component, then you must report the information in paragraphs (q)(2)(i) through (v) of this section but report a zero (''0'') for the information required according to paragraphs (q)(2)(ii) through (v) of this section.

* * * * *

(r) * * *

(3) * * *

(ii) Onshore petroleum and natural gas production facilities and onshore petroleum and natural gas gathering and boosting facilities must report the information specified in paragraphs (r)(3)(ii)(A) and (B) of this section, for each major equipment type, production type (*i.e.,* natural gas or crude oil), and geographic location combination in Tables W–1B and W–1C to this subpart for which equipment leak emissions are calculated using the methodology in § 98.233(r).

* * * * *

(z) * * * If your facility contains any combustion units subject to reporting according to paragraph (a)(1)(xviii), (a)(8)(i), or (a)(9)(xii) of this section, then you must report the information specified in paragraphs (z)(1) and (2) of this section, as applicable.

* * * * *

■ 6. Add Table W–1E to subpart W of part 98 in numerical order to read as follows:

TABLE W–1E TO SUBPART W OF PART 98—DEFAULT WHOLE GAS LEAKER EMISSION FACTORS FOR ONSHORE PETROLEUM AND NATURAL GAS PRODUCTION AND ONSHORE PETROLEUM AND NATURAL GAS GATHERING AND BOOSTING

Equipment components	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—All Components, Gas Service [1]		
Valve	4.9	3.5
Flange	4.1	2.2
Connector (other)	1.3	0.8
Open-Ended Line [2]	2.8	1.9
Pressure Relief Valve	4.5	2.8
Pump Seal	3.7	1.4
Other [3]	4.5	2.8
Leaker Emission Factors—All Components, Light Crude Service [4]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other [3]	3.1	2.0
Leaker Emission Factors—All Components, Heavy Crude Service [5]		
Valve	3.2	2.2
Flange	2.7	1.4
Connector (other)	1.0	0.6
Open-Ended Line	1.6	1.1
Pump	3.7	2.6
Agitator Seal	3.7	2.6
Other [3]	3.1	2.0

[1] For multi-phase flow that includes gas, use the gas service emission factors.
[2] The open-ended lines component type includes blowdown valve and isolation valve leaks emitted through the blowdown vent stack for centrifugal and reciprocating compressors.
[3] "Others" category includes any equipment leak emission point not specifically listed in this table, as specified in § 98.232(c)(21) and (j)(10).
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] Hydrocarbon liquids less than 20°API are considered "heavy crude."

■ 7. Remove Table W–3 to subpart W of part 98 and add Table W–3A and Table W–3B to subpart W of part 98 in numerical order to read as follows:

TABLE W–3A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—Compressor Components, Gas Service		
Valve [1]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter or Instrument	19.33	12.39
Other [2]	4.1	2.63
Leaker Emission Factors—Non-Compressor Components, Gas Service		
Valve [1]	6.42	4.12
Connector	5.71	3.66
Open-Ended Line	11.27	7.22

TABLE W–3A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION—Continued

Onshore natural gas transmission compression	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Pressure Relief Valve	2.01	1.29
Meter or Instrument	2.93	1.88
Other [2]	4.1	2.63

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(e)(8).

TABLE W–3B TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Population emission factors—gas service onshore natural gas transmission compression	Emission factor (scf/hour/component)
Low Continuous Bleed Pneumatic Device Vents [1]	1.37
High Continuous Bleed Pneumatic Device Vents [1]	18.20
Intermittent Bleed Pneumatic Device Vents [1]	2.35

[1] Emission Factor is in units of "scf/hour/device."

■ 8. Remove Table W–4 to subpart W of part 98 and add Table W–4A and Table W–4B to subpart W of part 98 in numerical order to read as follows:

TABLE W–4A TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON LEAKER EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—Storage Station, Gas Service		
Valve [1]	14.84	9.51
Connector (other)	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other [2]	4.1	2.63
Leaker Emission Factors—Storage Wellheads, Gas Service		
Valve [1]	4.5	3.2
Connector (other than flanges)	1.2	0.7
Flange	3.8	2.0
Open-Ended Line	2.5	1.7
Pressure Relief Valve	4.1	2.5
Other [2]	4.1	2.5

[1] Valves include control valves, block valves and regulator valves.
[2] Other includes any potential equipment leak emission point in gas service that is not specifically listed in this table, as specified in § 98.232(f)(6) and (8).

TABLE W–4B TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/component)
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01

TABLE W–4B TO SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON POPULATION EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE—Continued

Underground natural gas storage	Emission factor (scf/hour/component)
Valve	0.1
Pressure Relief Valve	0.17
Open-Ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents [1]	1.37
High Continuous Bleed Pneumatic Device Vents [1]	18.20
Intermittent Bleed Pneumatic Device Vents [1]	2.35

[1] Emission Factor is in units of "scf/hour/device."

■ 9. Remove Table W–5 to subpart W of part 98 and add Table W–5A and Table W–5B to subpart W of part 98 in numerical order to read as follows:

TABLE W–5A TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in § 98.234(a)(7)
Leaker Emission Factors—LNG Storage Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other [1]	1.77	0.99
Leaker Emission Factors—LNG Storage Components, Gas Service		
Valve [2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other [3]	4.1	2.63

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(g)(6) and (7).

TABLE W–5B TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/component)
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor [1]	4.17

[1] Emission Factor is in units of "scf/hour/device."

■ 10. Remove Table W–6 to subpart W of part 98 and add Table W–6A and Table W–6B to subpart W of part 98 in numerical order to read as follows:

TABLE W–6A TO SUBPART W OF PART 98—DEFAULT METHANE LEAKER EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/component)	
	If you survey using any of the methods in § 98.234(a)(1) through (6)	If you survey using Method 21 as specified in sect; 98.234(a)(7)
Leaker Emission Factors—LNG Terminals Components, LNG Service		
Valve	1.19	0.23
Pump Seal	4.00	0.73
Connector	0.34	0.11
Other [1]	1.77	0.99
Leaker Emission Factors—LNG Terminals Components, Gas Service		
Valve [2]	14.84	9.51
Connector	5.59	3.58
Open-Ended Line	17.27	11.07
Pressure Relief Valve	39.66	25.42
Meter and Instrument	19.33	12.39
Other [3]	4.1	2.63

[1] "Other" equipment type for components in LNG service should be applied for any equipment type other than connectors, pumps, or valves.
[2] Valves include control valves, block valves and regulator valves.
[3] "Other" equipment type for components in gas service should be applied for any equipment type other than valves, connectors, flanges, open-ended lines, pressure relief valves, and meters and instruments, as specified in § 98.232(h)(7) and (8).

TABLE W–6B TO SUBPART W OF PART 98—DEFAULT METHANE POPULATION EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/component)
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor [1]	4.17

[1] Emission Factor is in units of "scf/hour/compressor."

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Convert Gas Pneumatic Controls To Instrument Air



Executive Summary

Pneumatic instrument systems powered by high-pressure natural gas are often used across the natural gas and petroleum industries for process control. Typical process control applications include pressure, temperature, liquid level, and flow rate regulation. The constant bleed of natural gas from these controllers is collectively one of the largest sources of methane emissions in the natural gas industry, estimated at approximately 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector, and <1 Bcf from processing.

Companies can achieve significant cost savings and methane emission reductions by converting natural gas-powered pneumatic control systems to compressed instrument air systems. Instrument air systems substitute compressed air for the pressurized natural gas, eliminating methane emissions and providing additional safety benefits. Cost effective applications, however, are limited to those field sites with available electrical power, either from a utility or self-generated.

Natural Gas STAR Partners have reported savings of up to 70,000 thousand cubic feet (Mcf) per year per facility by replacing natural gas-powered pneumatic systems with instrument air systems, representing annual savings of up to $490,000 per facility. Partners have found that most investments to convert pneumatic systems pay for themselves in just over one year. Individual savings will vary depending on the design, condition and specific operating conditions of the controllers.

Technology Background

The natural gas industry uses a variety of process control devices to operate valves that regulate pressure, flow, temperature, and liquid levels. Most instrumentation and control equipment falls into one of three categories: (1) pneumatic; (2) electrical; or (3) mechanical. In the vast majority of applications, the natural gas industry uses pneumatic devices, which make use of readily available high-pressure natural gas to provide the required energy and control signals. Pneumatic instrument systems powered by high-pressure natural gas are used throughout the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. Most processing plants already use instrument air, but some use gas pneumatics, and including the gathering/booster stations that feed these processing plants, there are about 13,000 gas pneumatic devices in this sector. In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at distribution company gate stations and distribution grids where they regulate flow and pressure.

Exhibit 1 depicts a pneumatic control system powered by natural gas. The pneumatic control system consists of the process control instruments and valves that are operated by natural gas regulated at approximately 20-30 pounds

Economic and Environmental Benefits

Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/year)	Value of Natural Gas Savings ($/year)			Implementation Cost ($)[a]	Payback (Months)		
		$3 per Mcf	$5 per Mcf	$7 per Mcf		$3 per Mcf	$5 per Mcf	$7 per Mcf
Replace Gas with Air in Pneumatic Systems (per facility)	20,000	$60,000	$100,000	$140,000	$60,000	12	8	6

General Assumptions:
[a] Cost of installing compressor, dryer and other accessories, and annual electricity requirements.

NMED Exhibit 99 - 0001

Exhibit 1: Natural Gas Pneumatic Control System

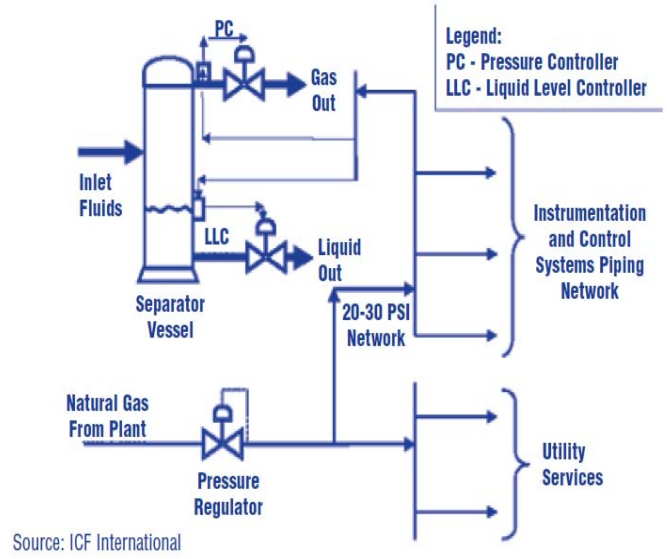
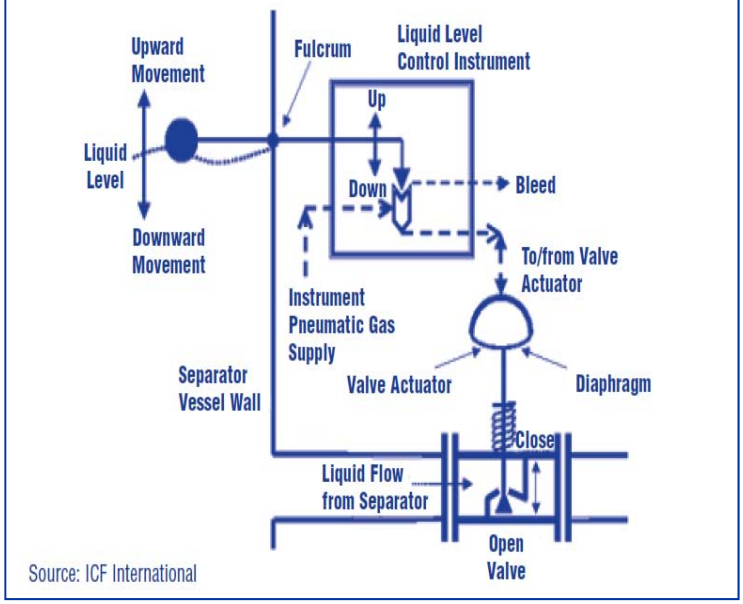


Exhibit 2: Signal and Actuation Schematics



per square inch (psi), and a network of distribution tubing to supply all of the control instruments. Natural gas is also used for a few "utility services," such as small pneumatic pumps, compressor motor starters, and isolation shutoff valves. Exhibit 2 shows a simplified diagram of a pneumatic control loop. A process condition, such as liquid level in a separator vessel, is monitored by a float that is mechanically linked to the liquid level controller outside the vessel. A rise or fall in liquid level moves the float upward or downward, which is translated to small needle valves inside the controller. Pneumatic supply gas is either directed to the valve actuator by the needle valve pinching off an orifice, or gas pressure is bled off the valve actuator. Increasing gas pressure on the valve actuator pushes down a diaphragm connected by a rod to the valve plug, causing the plug to open and increasing the flow of liquid draining out of the separator vessel. Gas pressure relieved from the valve actuator allows a spring to push the valve plug closed.

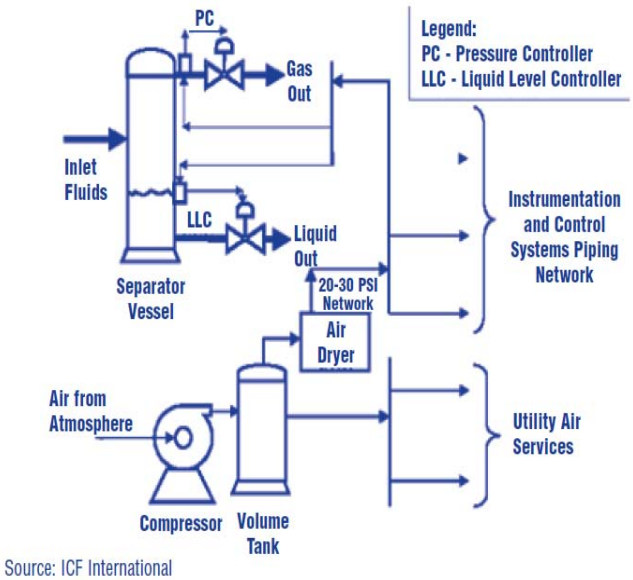
As part of normal operation, natural gas powered pneumatic devices release or bleed gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. Pneumatic control systems emit methane from tube joints, controls, and any number of points within the distribution tubing network. The actual bleed rate or emissions level largely depends on the design of the device. In general, controllers of similar design have similar steady-state bleed rates regardless of brand name. The methane emission rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment.

Many Partners have found that it is economic to substitute compressed air for natural gas in pneumatic systems. The use of instrument air eliminates methane emissions and leads to increased gas sales. In addition, by eliminating the use of a flammable substance, operational safety is significantly increased. The primary costs associated with conversion to instrument air systems are initial capital expenditures for installing compressors and related equipment and operating costs for electrical energy to power the compressor motor. Existing pneumatic gas supply piping, control instruments, and valve actuators of the gas pneumatic system can be reused in an instrument air system.

A compressed instrument air system is shown in Exhibit 3. In these systems, atmospheric air is compressed, stored in a volume tank, filtered and dried for instrument use. Air used for utility services (e.g. small pneumatic pumps, gas compressor motor starters, pneumatic tools, sand blasting) does not need to be dried. All other parts of a gas pneumatic system will work the same way with air as they do with gas.

The major components of an instrument air conversion project include the compressor, power source, dehydrator, and volume tank. The following are descriptions of each of

Exhibit 3: Compressed Instrument Air System



Source: ICF International

these components along with important installation considerations.

- **Compressor.** Compressors used for instrument air delivery are available in various types and sizes, from rotary screw (centrifugal) compressors to positive displacement (reciprocating piston) types. The size of the compressor depends on the size of the facility, the number of control devices operated by the system, and the typical bleed rates of these devices. The compressor is usually driven by an electric motor that turns on and off, depending on the pressure in the volume tank. For reliability, a full spare compressor is normally installed.

- **Power Source.** A critical component of the instrument air control system is the power source required to operate the compressor. Because high-pressure natural gas is abundant and readily available, gas pneumatic systems can run uninterrupted on a 24-hour, 7-day per week schedule. The reliability of an instrument air system, however, depends on the reliability of the compressor and electric power supply. Most large natural gas plants have either an existing electric power supply or have their own power generation system. For smaller facilities and remote locations, however, a reliable source of electric power can be difficult to assure. In some instances, solar-powered battery-operated air compressors can be cost effective for remote locations, which reduces both methane emissions and energy consumption. Small natural gas powered fuel cells are also being developed.

- **Dehydrators.** Dehydrators, or air dryers, are an integral part of the instrument air compressor system. Water vapor present in atmospheric air condenses when the air is pressurized and cooled, and can cause a number of problems to these systems, including corrosion of the instrument parts and blockage of instrument air piping and controller orifices. For smaller systems, membrane dryers have become economic. These are molecular filters that allow oxygen and nitrogen molecules to pass through the membrane, and hold back water molecules. They are very reliable, with no moving parts, and the filter element can be easily replaced. For larger applications, desiccant (alumina) dryers are more cost effective.

- **Volume Tank.** The volume tank holds enough air to allow the pneumatic control system to have an uninterrupted supply of high pressure air without having to run the air compressor continuously. The volume tank allows a large withdrawal of compressed air for a short time, such as for a motor starter, pneumatic pump, or pneumatic tools, without affecting the process control functions.

Economic and Environmental Benefits

Reducing methane emissions from pneumatic devices by converting to instrument air control and instrumentation systems can yield significant economic and environmental benefits for natural gas companies including:

- **Financial Return From Reducing Gas Emission Losses.** Assuming a natural gas price of $7.00 per Mcf, savings from reduced emissions can be estimated at $840 per year per device or $490,000 or more per year per facility. In many cases, the cost of converting to instrument air can be recovered in less than a year.

- **Increased Life of Control Devices and Improved Operational Efficiency.** Natural gas used in pneumatic control devices and instruments often contains corrosive gases (such as carbon dioxide and hydrogen sulfide) that can reduce the effective operating life of these devices. In addition, natural

gas often produces by-products of iron oxidation, which can plug small orifices in the equipment resulting in operational inefficiencies or hazards. When instrument air is used, and properly filtered and dried, system degradation is reduced and operating life is extended.

★ **Avoided Use Of Flammable Natural Gas.** Using compressed air as an alternative to natural gas eliminates the use of a flammable substance, significantly increasing the safety of natural gas processing plants and transmission and distribution systems. This can be particularly important at offshore installations, where risks associated with hazardous and flammable materials are greater.

★ **Lower Methane Emissions.** Reductions in methane emissions have been reported as high as 70,000 Mcf per facility annually, depending on the device(s) and the type of control application.

Decision Process

The conversion of natural gas pneumatics to instrument air system is applicable to all natural gas facilities and plants. To determine the most cost-effective applications, however, requires a technical and economic feasibility study. The six steps outlined below, and the practical example with cost tables, equations, and factors, can help companies to evaluate their opportunities.

Step 1: Identify Possible Locations For Instrument Air System Installations.

Most natural gas-operated pneumatic control systems can be replaced with instrument air. Instrument air systems will require new investments for the compressor, dehydrator, and other related equipment, as well as a supply of electricity. As a result, a first step in a successful instrument air conversion project is screening existing facilities to identify locations that are most suitable for cost effective projects. In general, three main factors should be considered during this process.

Decision Process for Converting Gas Pneumatic Devices to Instrument Air:

1. Identify possible locations for system installations.
2. Determine optimal system capacity.
3. Estimate the project costs.
4. Estimate gas savings.
5. Evaluate the economics.
6. Develop an implementation plan.

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

★ **Facility Layout.** The layout of a natural gas facility can significantly affect equipment and installation costs for an instrument air system. For example, conversion to instrument air might not be cost effective at decentralized facilities where tank batteries are remote or widely scattered. Instrument air is most appropriate when used at offshore platforms and onshore facilities where pneumatics are consolidated within a relatively small area.

★ **Number Of Pneumatics.** The more pneumatic controllers converted to instrument air, the greater the potential for reduced emissions and increased company savings. Conversion to instrument air is most profitable when a company is planning a facility -wide change.

★ **Available Power Supply.** Since most instrument air systems rely on electric power for operating the compressor, a cost-effective, uninterrupted electrical energy source is essential. While major facilities often have an existing power supply or their own power generation system, many smaller and remote facilities do not. For these facilities, the cost of power generation generally makes the use of instrument air unprofitable. In addition, facilities with dedicated generators need to assess whether the generators have enough available capacity to support an air compression system, as the cost of a generator upgrade can be prohibitive. Remote facilities should examine alternatives for power generation, which range from microturbines to solar power.

Step 2: Determine Optimal System Capacity.

Once project sites have been identified, it is important to determine the appropriate capacity of the new instrument air system. The capacity needed is a direct function of the amount of compressed air needed to both operate the pneumatic instrumentation and meet any utility air requirements.

★ **Instrument Air Requirements.** The compressed air needs for the pneumatic system are equivalent to the volume of gas being used to run the existing instrumentation—adjusted for air losses during the drying process. The current volume of gas usage can be determined by a direct meter reading (if a meter has been installed). In nonmetered systems, a conservative rule-of-thumb for sizing air systems is one cubic foot per minute (cfm) of instrument air for each control loop (consisting of a pneumatic controller and a control valve).

Rule-of-Thumb

1 cfm air/control loop

The initial estimate of instrument air needs should then be adjusted to account for air losses during the drying process. Typically, the membrane filters in the air dryer consume about 17 percent of the air input. As a result, the estimated volume of instrument air usage is 83 percent of the total compressed air supply: i.e., divide estimated air usage by 83 percent. Desiccant dryers do not consume air and therefore require no adjustment.

Rule-of-Thumb

17 percent of air input is consumed by the membrane dryer

★ **Utility Air Requirements.** It is common to use compressed air for utility purposes, such as engine starters, pneumatic driven pumps, pneumatic tools (e.g., impact wrenches), and sand blasting. Unlike instrument air, utility air does not have to be dried. The frequency and volumes of such utility air uses are additive. Companies will need to evaluate these other compressed air services on a site-specific basis, allowing for the possibility of expansion at the site. A general rule-of-thumb is to assume that the maximum rate of compressed air needed periodically for utility purposes will be double the steady rate used for instrument air.

Rule-of-Thumb

Pneumatic air uses: 1/3 for instrument air; 2/3 for utility air

Exhibit 4 illustrates how the instrument air compressor size can be estimated. Using the rule-of-thumb of 1 cfm/ control loop, the current gas usage would translate to approximately 35 cfm of dry instrument air. Adjusting for the dryer's air consumption (17 percent of air input), the total instrument air supply requirement will be 42 cfm. Factoring in utility air needs of about 70 cfm, the project would require a total of 112 cfm of compressed air.

Exhibit 4: Calculate Compressor Size for Converting Gas Pneumatics to Instrument Air

Given:	For an average size production site with pneumatics, glycol dehydration, compression, 35 control loops, and an average of 10 cfm utility gas usage for pneumatic pumps and compressor engine starting.
A IAu IAs UAs L	= Total Compressed Air = Instrument air use = Instrument air supply = Utility air supply = Control loops
	Rule-of-thumb: 1 cfm per control loop for estimating instrument air systems. Rule-of-thumb: 17% of air is bypassed in membrane dryers. Rule-of-thumb: 1/3 of total air used for instruments, 2/3 of total air used for utility services.
	Calculate: A = Air compressor capacity required.
A IAu IAs UAs A	= IAs + UAs = L * (1 cfm/loop) = IAu/(100% - % air bypassed in dryer) = IAu * (fraction of utility air use) / (fraction of instrument air use) = (35*1) / (100% - 17%) + (35*1) * (2/3) / (1/3) = 112 cfm

Step 3: Estimate the Project Costs.

The major costs associated with installing and operating an instrument air system are the installation costs for compressors, dryers, and volume tanks, and energy costs. The actual installation costs will be a function of the size, location, and other location specific factors. A typical conversion of a natural gas pneumatic control system to compressed instrument air costs approximately $45,000 to $75,000.

To estimate the cost for a given project, all expenses associated with the compressor, dryer, volume tank, and power supply must be calculated. Most vendors are willing to provide estimates of the equipment costs and installation requirements (including compressor size, motor horsepower, electrical power requirements, and storage capacity). Alternatively, operators can use the following information on the major system components to estimate the total installed cost of the instrument air system.

★ **Compressor Costs.** It is common to install two compressors at a facility (one operating and one stand-by spare) to ensure reliability and allow for maintenance and overhauls without service interruptions. The capacity for each of the compressors must be sufficient to handle the total expected compressed air volume for the project (i.e., both instrument and utility air). Exhibit 5 presents

cost estimates for purchasing and servicing small, medium, and large compressors. For screw-type compressors, operators should expect to overhaul the unit every 5 to 6 years. This normally involves exchanging the compressor core for a rebuilt compressor at a cost of approximately $3,929, with an additional $720 in labor expense and a $650 core exchange credit.

Exhibit 5: Air Compressor Costs

Service Size	Air Volume (cfm)	Compressor Type	Horsepower	Equipment Costs ($)	Annual Service ($/yr)	Service Life (yrs)
Small	30	Reciprocating	10	3,275[a]	434	1
Medium	125	Screw	30	16,371	868	5-6[b]
Large	350	Screw	75	28,812	868	5-6[b]

[a] Cost included package compressor with a volume tank.
[b] Rebuilt compressor costs $3,929 plus $500 labor minus $500 core exchange credit.

★ **Volume Tank.** Compressed air supply systems include a volume tank, which maintains a steady pressure with the on-off operation of the air compressor. The rule-of-thumb in determining the size of the volume tank is 1-gallon capacity for each cfm of compressed air. Exhibit 6 presents equipment costs for small, medium, and large volume tanks. Volume tanks have essentially no operating and maintenance costs.

Rule-of-Thumb

1 gallon tank capacity/1 cfm air

★ **Air Dryer Costs.** Because instrument air must be very dry to avoid plugging and corrosion, the compressed air is commonly put through a dryer. The most common dryer used in small to medium applications is a permeable membrane dryer. Larger air systems can use multiple membrane dryers, or, more cost effectively, alumina bed desiccant dryers. Membrane dryers filter out oil mist and particulate solids and have no moving parts. As a result, annual operating costs are kept low. Exhibit 7 presents equipment and service cost data for different size dryers. The appropriate sized dryer would need to accommodate the expected volume of gas needed for the instrument air system.

Exhibit 6: Volume Tank Costs

Service Size	Air Volume (gallons)	Equipment Cost ($)
Small[a]	80	655
Medium	400	1,964
Large	1,000	3,929

[a] Small reciprocating air compressors, 10 horsepower and less, are commonly supplied with a surge tank.

Exhibit 7: Air Dryer Costs

Service Size	Air Volume (cfm)	Dryer Type	Equipment Cost ($)	Annual Service ($/yr)
Small	30	membrane	1,964	724
Medium	60[a]	membrane	5,893	2,894
Large	350	alumina	13,096	4,341

[a] Largest membrane size; use multiple units, larger volumes.

Using the equipment information described above, the total installed cost for a project can be calculated. Exhibit 8 illustrates this using the earlier example of a medium-sized production facility with an instrument air requirement of 42 cfm and a maximum utility air requirement of 70 cfm (for a total of 112 cfm of compressed air). To estimate the installed cost of equipment, it is a common practice in industry to assume that installation labor is equivalent to equipment purchase cost (i.e. double equipment purchase cost to estimate the installed cost). This would be suitable for large, desiccant dried instrument air systems, but for small, skid-mounted instrument air systems a factor of 1.5 is used to estimate the total installed cost (installation labor is half the cost of equipment).

In addition to the facility costs, it is also necessary to estimate the energy costs associated with operating the system. The most significant operating cost of an air compressor is electricity, unless the site has excess self-generation capacity. To continue the example from above, assuming that electricity is purchased at 7.5 cents per kilowatt-hour (kWh) and that one compressor is in standby while the other compressor runs at full capacity half the time (a 50 percent operating factor), the electrical power

Exhibit 8: Calculate Total Installation Costs	
Given:	
Compressors (2) Volume Tanks (2-small) Membrane Dryer Installed Cost Factor	= $32,742 (Exhibit 5) = $1,310 (Exhibit 6) = $5,893 (Exhibit 7) = 1.5
Calculate Total Installed Cost:	
Equipment Cost	= Compressor Cost + Tank Cost + Dryer Cost = $32,742 + $1,310 + $5,893 = $39,945
Total Cost	= Equipment Cost * Installation Cost Factor = $39,945 * 1.5 = $59,917

cost amounts to $13,140 per year. This calculation is shown in Exhibit 9.

Step 4: Estimate Gas Savings.

To estimate the gas savings that result from the installation of an instrument air system, it is important to determine the normal bleed rates (continuous leak from piping networks, control devices, etc.), as well as the peak bleed rates (associated with movements in the control devices). One approach is to list all the control devices,

Exhibit 9: Calculate Electricity Cost	
Given:	
Engine Power Operating Factor (OF) Electricity Cost	= 30 HP = 50 percent = $0.075/kwh
Calculate Required Power:	
Electrical Power	= Engine Power * OF * Electricity Cost = [30 HP * 8,760 hrs/yr * 0.5 * $0.075/kwh] / 0.75 HP/kw = $13,140/yr

assess their normal and peak bleed rates, frequency of actuation, and estimates of leakage from the piping networks. Manufacturers of the control devices usually publish the emission rates for each type of device, and for each type of operation. Rates should be increased by 25 percent for devices that have been in service without overhaul for five to 10 years, and by about 50 percent for devices that have not been overhauled for more than 10 years to account for increased leakage associated with wear and tear. Alternatively, installing a meter can be more accurate, provided monitoring occurs over a long enough period of time to take account of all the utility uses of gas (i.e., pumps, motor starters, activation of isolation valves).

EPA's *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, provides brand name, model, and gas consumption information for a wide variety of currently used pneumatic devices. Manufacturer information and actual field measurement data, wherever available, are provided as well (see Appendix of that report). To simplify the calculation of gas savings for the purpose of this lesson learned analysis, we can use the earlier rules-of-thumb to estimate the gas savings. The gas savings for the medium-sized production facility example in Exhibit 4 include the conservatively estimated 35 cfm used in the 35 gas pneumatic controllers plus the gas used occasionally for compressor motor starters and small pneumatic chemical and transfer pumps. (Note that replacing these gas usages will result in direct savings of gas emissions.) Natural gas is not used for pneumatic tools or sand blasting, so additional compressed air provided for these services does not reduce methane emissions. Assuming an annual average of 10 cfm gas use for natural gas powered non-instrument services, the gas savings would be 45 cfm. As shown in Exhibit 10, this is equivalent to 23,652 Mcf per year and annual savings of $165,600.

Step 5: Evaluate the Economics.

The cost effectiveness of replacing the natural gas pneumatic control systems with instrument air systems

Exhibit 10: Calculate Gas Savings	
Given:	
Pneumatic instrument gas usage Other non-instrument gas usage	= 35 cfm = 10 cfm
Calculate Value of Gas Saved:	
Volume of Natural Gas Saved	= Instrument Usage + Other Usage = 35 cfm + 10 cfm = 45 cfm
Annual Volume of Gas Saved	= 45 cfm * 525,600 min/yr / 1000 = 23,652 Mcf/yr
Annual Value of Gas Saved	= volume * $7.00/Mcf = 23,652 Mcf/yr * $7.00/Mcf = $165,600/year

can be evaluated using straightforward cost-benefit economic analyses.

Exhibit 11 illustrates a cost-benefit analysis for the medium-sized production facility example. The cash flow over a five-year period is analyzed by showing the magnitude and timing of costs from Exhibits 8 and 9 (shown in parentheses) and benefits from Exhibit 10. The annual maintenance costs associated with the compressors and air dryer, from Exhibits 5 and 7, are accounted for, as well as a five-year major overhaul of a compressor per Exhibit 5. The net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. The Internal Rate of Return (IRR) reflects the discount rate at which the NPV generated by the investment equals zero.

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Step 6: Develop an Implementation Plan.

After determining the feasibility and economics of converting to an instrument air system, develop a systematic plan for implementing the required changes. This can include installing a gas measuring meter in the gas supply line, making an estimate of the number of control loops, ensuring an uninterrupted supply of electric energy for operating the compressors, and replacing old, obsolete and high-bleed controllers. It is recommended that all necessary changes be made at one time to minimize labor costs and disruption of operations. This might include a parallel strategy to install low-bleed devices in conjunction with the switch to instrument air systems. There are similar economic savings for conserving instrument air use as for conserving methane emissions with low bleed pneumatic devices. Whenever specific pneumatic devices are being replaced, such as in the case of alternative mechanical and/or electronic

Exhibit 11: Economic Analysis of Instrument Air System Conversion

	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Cost ($)	(59,917)					
O&M Cost ($)		(13,140)[a] (4,630)[b]	(13,140) (4,630)	(13,140) (4,630)	(13,140) (4,630)	(13,140) (4,630)
Overhaul Cost ($)	0	0	0	0	0	(6,286)[c]
Total Cost ($)	(59,917)	(17,770)	(17,770)	(17,770)	(17,770)	(24,057)
Gas Savings ($)	0	165,600[d]	165,600	165,600	165,600	165,600
Annual Cash Flow ($)	(59,917)	147,830	147,830	147,830	147,830	141,543
Cumulative Cash Flow ($)	(59,917)	87,912	235,742	383,571	531,401	672,944
					Payback Period (months)	5
					IRR	246%
					NPV[e]	$496,570

[a] Electrical power at 7.5 cents per kilowatt-hour.
[b] Maintenance costs include $1,736 compressor service and $2,894 air dryer membrane replacement.
[c] Compressor overhaul cost of $3,929, inflated at 10% per year.
[d] Value of gas = $7.00/Mcf.
[e] Net Present Value (NPV) based on 10% discount rate for 5 years.

systems, the existing pneumatic devices should be replaced on a similar economic basis as discussed in the companion document *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*.

When assessing options for converting gas pneumatic controls to instrument air, natural gas price may influence the decision making process. Exhibit 12 shows an economic analysis installing two 30 hp compressors, two medium sized volume tanks, and a medium sized membrane dryer at different natural gas prices.

Partner Experiences

Several EPA Natural Gas Star Partners have reported the conversion of natural gas pneumatic control systems to compressed instrument air systems as the single most significant source of methane emission reduction and a source of substantial cost savings. Exhibit 13 below highlights the accomplishments that several Natural Gas STAR Partners have reported.

Exhibit 12: Gas Price Impact on Economic Analysis

	$3/Mcf	$5/Mcf	$7/Mcf	$8/Mcf	$10/Mcf
Value of Gas Saved	$70,971	$118,286	$165,600	$189,257	$236,571
Payback Period (months)	14	8	5	5	4
Internal Rate of Return (IRR)	84%	166%	246%	286%	365%
Net Present Value (*i*=10%)	$137,853	$317,211	$496,570	$586,249	$765,607

Other Technologies

The majority of Partners' experiences in substituting natural gas-powered pneumatic devices and control instrumentation with alternative controllers have involved

Exhibit 13: Partner Reported Experience

Gas STAR Partner	Description of Project	Project Cost ($)	Annual Emissions Reductions (Mcf/yr)	Annual Savings ($/yr)[a]	Payback (months)[b]
Unocal[c] (now Chevron)	Installed an air compression system in its Fresh Water Bayou facility in southern Vermillion Parish, Louisiana	$79,000	69,350	$485,450	2
Texaco[c] (now Chevron)	Installed compressed air system to drive pneumatic devices in 10 South Louisiana facilities	$52,000	23,000	$161,000	4
Chevron[c]	Converted pneumatic controllers to compressed air, including new installations	$227,000 over 2 years	31,700	$221,900	7
ExxonMobil[d]	Installed instrument air systems at 3 production satellites and 1 central tank battery at Postle CO_2 unit	$72,000	19,163	$134,141	7
Shell	Used instrument air operated devices on over 4,300 valves at off-shore platforms	Not available	532,800	$3,729,600	Not available
Marathon	Installed 15 instrument air systems in New Mexico facilities	Not available	120 - 38,000 per facility	$840 - 226,000	Not available

[a] Value of gas = $7.00/Mcf.
[b] Calculated based on Partner-reported costs and gas savings updated to 2006 costs.
[c] Data for this report were collected prior to the Chevron-Texaco and Chevron-Unocal mergers.
[d] Data for this report were collected prior to the Exxon/Mobil merger in 1999.

the installation of compressed instrument air systems. Some additional alternatives to gas pneumatics implemented by Partners are described below:

- ★ **Liquid Nitrogen.** In a system using liquid nitrogen, the volume tank, air compressor, and dryer are replaced with a cylinder containing cryogenic liquid nitrogen. A pressure regulator allows expansion of the nitrogen gas into the instrument and control-piping network at the desired pressure. Liquid nitrogen bottles are replaced periodically. Liquid nitrogen-operated devices require handling of cryogenic liquids, which can be expensive as well as a potential safety hazard. Large volume demands on a liquid nitrogen system require a vaporizer.

- ★ **Mechanical Controls and Instrumentation System.** Mechanical instrument and control devices have a long history of use in the natural gas and petroleum industry. They are usually distinguished by the absence of pneumatic and electric components, are simple in design, and require no power source. Such equipment operates using springs, levers, baffles, flow channels, and hand wheels. They have several disadvantages, such as limited application, the need for continuous calibration, lack of sensitivity, inability to handle large variations, and potential for sticking parts.

- ★ **Electric and Electro-Pneumatic Devices.** As a result of advanced technology and increasing sophistication, the use of electronic instrument and control devices is increasing. The advantage of these devices is that they require no compression devices to supply energy to operate the equipment; a simple 120 -volt electric supply is used for power. Another advantage is that the use of electronic instrument and control devices is far less dangerous than using combustible natural gas or cryogenic liquid nitrogen cylinders. The disadvantage of these devices is their reliance on an uninterrupted source of electric supply, and significantly higher costs.

Although these options have advantages, systems using air instead of natural gas are the most widely employed alternative in replacing natural gas-operated pneumatic control devices. It is important to note that maintaining a constant, reliable supply of dry, compressed air in a plant environment is a significant cost, albeit more economic than natural gas. Therefore, a parallel strategy to install low-bleed devices in conjunction with the switch to instrument air systems (refer to *Lessons Learned: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*), and to design a maintenance schedule to keep the instruments and control devices in tune, is often economic. Such actions can significantly reduce the consumption of instrument air in the overall system and, therefore, minimize both the size of the compression system and the electricity consumption over the life of the plant.

Lessons Learned

The lessons learned from Natural Gas STAR Partners are:

- ★ Installing instrument air systems has the potential to increase revenues and substantially reduce methane emissions.

- ★ Instrument air systems can extend the life cycle of system equipment, which can accumulate trace amounts of sulfur and various acid gases when controlled by natural gas, thus adding to the potential savings and increasing operational efficiencies.

- ★ Remote locations and facilities without a reliable source of electric supply often need to evaluate alternate power generation sources. When feasible, solar-powered air compressors provide an economical and ecologically beneficial alternative to expensive electricity in remote production areas. On site generation using microturbines running on natural gas is another alternative.

- ★ A parallel strategy of installing low-bleed devices in conjunction with the switch to instrument air systems is often economic.

- ★ Existing infrastructure can be used; therefore, no pipe replacement is needed. However, existing piping and tubing should be flushed clear of accumulated debris.

- ★ Rotary air compressors are normally lubricated with oil, which must be filtered to maintain the life and proper performance of membrane dryers.

- ★ Use of instrument air will eliminate safety hazards associated with flammable natural gas usage in pneumatic devices.

- ★ Nitrogen-drive systems may be an alternative to instrument air in special cases, but tends to be

NMED Exhibit 99 - 0010

expensive and handling of cryogenic gas is a safety concern.

★ Report reductions in methane emissions from converting gas pneumatic controls to instrument air in your Natural Gas STAR Annual Report.

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NMED Exhibit 99 - 0011

United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 52, 60 and 61

[FRL–5691–2]

RIN 2020–AA27

Credible Evidence Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In an October 22, 1993 Federal Register, EPA solicited public comment on a proposal to amend 40 CFR Parts 51, 52, 60 and 61 to eliminate language that has been read to provide for exclusive reliance on reference test methods as the means of demonstrating compliance with various emission limits under the Clean Air Act (''CAA'' or ''Act''). These revisions—generally referred to as the ''credible evidence'' revisions—were designed to clarify that non-reference test data can be used in enforcement actions, and to remove any potential ambiguity regarding this data's use for compliance certifications under Section 114 and Title V of the Act. In the same document, EPA proposed an ''enhanced monitoring'' rule under Section 114 and Title V. EPA subsequently decided to suspend development of the original enhanced monitoring rule and develop a compliance assurance monitoring (''CAM'') approach to serve the same statutory goals as the original enhanced monitoring proposal. Today's rulemaking finalizes the previously proposed credible evidence revisions to Parts 51, 52, 60 and 61. EPA will take final action regarding enhanced monitoring and CAM in a separate rulemaking.

DATES: *Effective Date:* April 25, 1997. *Judicial Review:* Under CAA section 307(b)(1), judicial review of this nationally applicable final action is available only by the filing of 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 this rule. Under CAA section 307(b)(2), the regulations that are the subject of today's rule may not be challenged later in civil or criminal proceedings brought by EPA in reliance on them.

ADDRESSES: *Docket.* Supporting information used in developing this rulemaking is contained in Public Docket No. A–91–52. This docket is available for public inspection and copying between 8:00 a.m. and 5:30 p.m. on weekdays, excluding federal holidays, at the EPA Air and Radiation Docket and Information Center, Room M–1500, Waterside Mall, 401 M Street SW., Washington, DC 20460; telephone (202) 260–7548. A reasonable fee may be charged for photocopying docket materials.

FOR FURTHER INFORMATION CONTACT: Gregory Jaffe, Air Enforcement Division (Mailcode 2242–A), Office of Regulatory Enforcement, U.S. Environmental Protection Agency, 401 M Street, SW, Washington, D.C. 20460; telephone (202) 564–2260.

SUPPLEMENTARY INFORMATION: The contents of the preamble are listed in the following outline:

I. Background
A. Statutory and Regulatory Authority
B. Benefits of the Credible Evidence Revisions
C. Public Participation
II. Summary of Final Rule
A. 40 CFR Part 51, § 51.212
B. 40 CFR Part 52, § 52.12
C. 40 CFR Part 52, § 52.30
D. 40 CFR Part 60, § 60.11
E. 40 CFR Part 61, § 61.12
III. Major Issues
A. Use of Credible Evidence in Enforcement Actions
B. Use of Credible Evidence in Compliance Certifications
C. EPA's Authority To Promulgate the Credible Evidence Revisions
1. Statutory Authority
2. The *Kaiser Steel* Decision Does Not Constrain EPA's Authority To Amend its Regulations
3. Despite Commenters' Claims, Clean Air Act Case Law Does Not Mandate Exclusive Reference Tests
4. The 1990 CAA Amendments Further Support EPA's Authority
5. Commenters' Attempts To Narrow the Scope of Sections 113(e) and 113(a) Are Unpersuasive
6. EPA Can Promulgate the Credible Evidence Revisions Without Reproposal
D. Stringency
1. Emissions Limits Require Continuous Compliance (Consistent With Any Averaging Times) Except During Periods Where Compliance is Specifically Excused
2. Commenters' Advocacy of Noncontinuous Compliance Would Lead to Numerous Anomalies
3. Comments Regarding Continuous Compliance Are Not Directed at Today's Action, but Rather at Underlying Emission Standards
4. Enforcement Using Continuous Monitoring Data Does Not Increase the Stringency of Applicable Requirements
5. Sources Must Comply Both With Good Operation and Maintenance Requirements and With Emission Limits
E. SIP Call
IV. Administrative Requirements
A. Docket
B. Office of Management and Budget (OMB) Review
C. Unfunded Mandates Reform Act
D. Regulatory Flexibility Act
E. Paperwork Reduction Act
F. Submission to Congress and the General Accounting Office

I. Background

A. Statutory and Regulatory Authority

The credible evidence revisions are based on EPA's long-standing authority under the Act, and on amplified authority provided by the 1990 CAA Amendments. Section 113(a) of the Act authorizes EPA to bring an administrative, civil or criminal enforcement action ''on the basis of any information available to the Administrator.'' In this provision, which predates the 1990 CAA Amendments, Congress gave EPA clear statutory authority to use any available information—not just data from reference tests or other federally promulgated or approved compliance methods—to prove CAA violations. (The preamble will generally use the phrase ''reference tests'' to include all these compliance methods. Where appropriate, the phrase ''reference tests'' will also include test conditions specified in individual regulations.)

In the 1990 CAA Amendments, Congress included an enforcement title (Title VII) to enhance EPA's compliance and enforcement authorities. Among other things, Congress revised Section 113(e)(1) of the Act to overrule a federal court decision (*Kaiser Steel*, discussed below) that had held that only specified reference test data could prove violations. Thus, although the pre-existing authority of Section 113(a) forms the principal basis for today's action, the credible evidence revisions are also supported by the language, history and intent of the 1990 CAA Amendments. *See also* Section III.C. below.

In addition to clarifying EPA's, states' and citizens' enforcement authorities under the Act, the credible evidence revisions eliminate any potential ambiguity regarding the use of non-reference test data as a basis for Title V compliance certifications. Such potential ambiguity could arise from comparing the draft compliance assurance monitoring (CAM) approach and associated Part 70 changes, which would allow sources to include CAM data as a basis for certifying compliance, with various EPA regulations that could be read on their face to specify reference test methods as the sole means of determining compliance.

B. Benefits of the Credible Evidence Revisions

As a preliminary matter, EPA wishes to clearly state that this rulemaking merely addresses an evidentiary issue. The credible evidence revisions are not

intended to and will not serve to affect the stringency of underlying emission standards by amending the nature of the compliance obligation. This rulemaking does not amend existing emission standards nor does it modify generic regulations affecting the compliance obligation such as exceptions for startup, shutdown, and malfunctions. See, e.g., 40 CFR 60.8(c). This regulation also does not designate any particular data as probative of a violation of an emission standard. Rather, this regulation merely removes what some have construed to be a regulatory bar to the admission of non-reference test data to prove a violation of an emission standard, no matter how credible and probative those data are that a violation has occurred. The credible evidence revisions do not affect the compliance obligation and thus do not affect the stringency of existing emission standards. What compliance obligation is imposed by any given emission standard remains an issue ultimately to be determined based on that emission standard and not this rulemaking.

For these reasons, we do not believe that this rulemaking affects whether emission standards require intermittent or continuous compliance. However, as made clear below, and in the detailed response to comments document, EPA's position continues to be that an emission standard requires continuous compliance unless the emission standard specifically provides otherwise.

Today's credible evidence revisions will benefit sources, state environmental agencies, EPA and the public. EPA, states and citizens will be able to use credible evidence to assess a source's compliance status and respond to noncompliance. This will help ensure that the government and citizens alike can respond to sources that are not complying with air pollutant emission standards on an ongoing basis, thus furthering the protection of public health and the environment. At the same time, sources will be able to use credible evidence for contesting allegations of noncompliance in enforcement actions. Accordingly, today's rulemaking exemplifies EPA's ''common sense'' approach to environmental protection, which encourages smarter, cheaper and more flexible means of achieving environmental goals without compromising the fundamental health and environmental protections provided by federal environmental laws.

In the past, state regulatory authorities and EPA have relied primarily on infrequent on-site inspections and even more infrequent reference tests in order to check compliance with emission limits at major stationary sources. According to a September, 1990, General Accounting Office (GAO) report, these on-site inspections were performed approximately once a year; the reference tests, typically once every five years. ''Air Pollution: Improvements Needed in Detecting and Preventing Violations,'' GAO, No. GAO/RCED–90–155, September 1990, at 12, 19. These methods are inadequate to ensure that sources continuously stay within their emission limits: for example, Pennsylvania officials have estimated that, in comparison with continuous emissions monitoring, on-site inspections may be 50 times less likely to detect non-compliance. *Id.* at 18. Reference tests may not yield a representative emissions picture because the sources typically schedule, set up and run the tests themselves. This allows sources to ''fine tune'' their operations and emissions control processes prior to the tests, and generate results that may not be typical of day-to-day source operations. *Id.* at 19–20. Reference tests can also be expensive and burdensome: They can cost up to $100,000, and take a week or more to complete. *See, e.g.*, 43 FR 7568, 7571 (1978).

In contrast to the above approach, today's rule will make it clear that various kinds of information other than reference test data, much of which is already available and utilized for other purposes, may be used to demonstrate compliance or noncompliance with emission standards. (The preamble generally refers to this other information as ''non-reference test data''). EPA, state agencies and industry routinely rely on many types of information, including engineering calculations, indirect estimates of emissions, and direct measurement of emissions by a variety of means, in order to assess compliance with CAA requirements. Where available, continuous emission monitoring (CEM) data and well-chosen parametric monitoring data, such as the operating temperature and air flow rate of a regenerative thermal oxidizer, generally provide accurate data regarding a source's compliance with emission limits and standards. These data also generally cover a greater percentage of a source's time in operation and are more representative of a source's ongoing compliance status than sporadic performance testing.

Under today's rule both sources and potential enforcers will be put on the same evidentiary footing in an enforcement action. Further, since 1992, EPA's Part 70 operating permit regulations have allowed the use of this data in compliance certifications. Today's action reaffirms this approach, and removes any potential ambiguity regarding the use of such data for this purpose.

Today's action reflects EPA's efforts to make existing regulatory programs work better rather than creating additional requirements. By ensuring greater compliance with existing emissions limits, the credible evidence revisions will help minimize the need for further requirements to achieve air quality goals. *See* the October, 1993, proposal, 58 FR 54654.

C. Public Participation

The final credible evidence revisions were developed with the benefit of insight from many parties that will be affected by the regulations, including State and local air pollution control agencies, large and small industries, trade associations and environmental organizations. Many comments regarding credible evidence issues were received during the development and after the proposal of the original enhanced monitoring rule, in 1991 through 1995. Many additional comments were received after the Agency announced that it was continuing to go forward with the credible evidence revisions in 1996.

To obtain the views of all interested parties at the early stages of developing the enhanced monitoring rulemaking, EPA published a notice in the Federal Register on August 8, 1991, to make available a Public Information Document on enhanced monitoring and to provide notice of a public meeting to be held on August 22, 1991, on the subject (56 FR 37700–37701, August 8, 1991). In response to the public meeting, EPA received many comments which were included in the docket for the proposed regulations.

Over the next four years, EPA held over one hundred informal informational and discussion sessions with representatives of interested organizations to receive their views on enhanced monitoring, as well as a second informational meeting with approximately fifty attendees held on August 12, 1993. Following publication of the proposed enhanced monitoring regulations on October 22, 1993 at 58 FR 54648, EPA conducted a public hearing in Washington, D.C., on November 19, 1993. Testimony was given by twelve individuals, representing industry and environmental organizations.

In addition, during the public comment period, which was first scheduled to close on December 30, 1993, and was extended until January 31, 1994, in response to requests for

extension, EPA received comments from a wide variety of interested parties concerning the enhanced monitoring proposal, including numerous comments on credible evidence issues. In the fall of 1994, EPA held a series of informational meetings with interested parties affected by the rule. The Agency then reopened the public comment period on specific issues to solicit additional comments, and held an additional stakeholder meeting. In response to the reopened public comment period, EPA received over 200 additional comment letters.

In April, 1995, EPA announced that it was suspending development of the enhanced monitoring rule while it developed the CAM approach to serve the same statutory goals. In a September, 1995, public draft of the CAM approach, EPA stated that it would hold further discussions with stakeholders before it proceeded to finalize the credible evidence revisions. On March 8, 1996, EPA announced that a public meeting on credible evidence issues would be held on April 2, 1996. To focus the meeting's discussion, EPA released a paper on March 21, 1996, entitled ''The Use of Information Other Than Reference Test Results for Determining Compliance With the Clean Air Act'' (sometimes referred to as the ''Credible Evidence White Paper''). EPA distributed this paper by electronic bulletin board to the same stakeholders who were involved in the enhanced monitoring and CAM rulemakings, further distributed it to various other interested parties, and made it generally available to the public.

The public meeting was held on April 2, 1996, where twenty-three organizations and individuals presented oral statements and written comments. At the meeting, EPA announced that, although the rulemaking docket would not formally be re-opened, additional written comments would be accepted for at least another 30 days. Moreover, EPA stated that it would meet with any interested parties to discuss the credible evidence rules. As a result, many additional written comments have been received, and numerous additional EPA/stakeholder meetings have been held.

Section III of this preamble contains a description of the most significant public comments and EPA's responses to them. Summaries of other public comments on the credible evidence revisions received over the past five years, together with the Agency's responses, are available in the docket in a document entitled ''Credible Evidence Revisions: Detailed Response to Comments Document'' (referred to in this preamble as the ''Detailed Response Document'').

II. Summary of Final Rule

The credible evidence revisions consist of various changes to 40 CFR 51.212, 52.12, 52.30, 60.11 and 61.12. These revisions provide minor modifications to existing regulatory provisions to clearly allow for the use of any credible evidence—that is, both reference test and comparable non-reference test data—to prove or disprove violations of the Act in enforcement actions. These revisions make clear that enforcement authorities can prosecute actions based exclusively on any credible evidence, without the need to rely on any data from a particular reference test. The revisions also have the effect of eliminating any potential ambiguity regarding the use of non-reference test data as a basis for Title V compliance certifications. The credible evidence revisions do not call for the creation or submission of any new emissions or parametric data, but rather address the role of existing data in enforcement actions and compliance certifications. As such, today's final action is distinct and separable from the bulk of the proposed enhanced monitoring rule, which addressed new monitoring requirements.

By clearly providing that federally approved SIP test methods or Agency reference test methods are not the exclusive means of establishing noncompliance or compliance, EPA in no way intends to alter the underlying emission standards. The Agency will still use the reference methods for exactly what they are: test methods of reference against which to compare information generated by means other than the reference tests. The National Bureau of Standards maintains a number of standards against which other measuring devices, used in scientific or commercial applications, are calibrated. Similarly, where a SIP, New Source Performance Standard or permit specifies EPA Method 25A, for example, for determining the amount of volatile organic compounds (''VOCs'') that are emitted, the ''other evidence'' that could establish compliance would have to relate to the likely measurement of VOCs that would be obtained by a Method 25A measurement. This could include, for example, consideration of key operating parameters for the facility as correlated with emissions during a Method 25A test.

A. 40 CFR Part 51, § 51.212

Section 51.212(c) is revised to clarify that the inclusion in a state implementation plan (SIP) of enforceable test methods for SIP emissions limits does not preclude enforcement based on other credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed. This revision does not affect the existing requirements in §§ 51.212(a) and (b) for periodic testing and inspections, and establishment of a system of violation detection and investigation.

The proposed revisions to § 51.212 contained detailed lists of ''presumptively credible evidence'' and ''presumptively credible monitoring methods.'' After consideration of public comments, EPA has decided to delete these lists because they are potentially confusing and unnecessary. While EPA continues to believe that the listed evidence and monitoring methods are indeed credible, the Agency recognizes that both judicial and administrative tribunals routinely make determinations concerning the admissibility and weight of evidence on a case-by-case basis.

B. 40 CFR Part 52, § 52.12

Section 52.12(c) is revised to clarify that, for purposes of federal enforcement, any credible evidence relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed may be used to establish whether or not SIP violations have occurred. As with § 51.212 above, EPA has deleted the proposed lists of presumptively credible evidence and monitoring methods for the same reasons stated above. Under today's final action, where an emission limitation specifies a particular monitoring or testing method approved by EPA for use in the SIP to determine compliance, data from such method will continue to be the benchmark against which other emissions or parametric data, or engineering analyses, will be measured. Similarly, where there are no approved SIP methods, the test methods specified in part 60 of this chapter will remain the standard against which other such information will be evaluated.

C. 40 CFR Part 52, § 52.30

Proposed § 52.30(a), which concerned compliance certifications, has been revised in accordance with § 51.212 above, and the same comments apply. The enforcement-related § 52.30(b) is rendered unnecessary by today's final § 52.12(c), which effectively

NMED Exhibit 101 - 0003

encompasses it. Finally, the entire section has been renumbered as § 52.33.

D. 40 CFR Part 60, § 60.11

Similar to the existing regulation, § 60.11(a) states that compliance with Part 60 standards shall be determined in accordance with the applicable performance tests and performance testing provisions in this part. A new § 60.11(g) clarifies that nothing in § 60.11 precludes the use, including exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed, for purposes of submitting compliance certifications or establishing whether or not a source has violated or is in violation of any Part 60 standard, including opacity standards.

The first sentence in today's final § 60.11(a) has been modified from the proposal. EPA has decided to use mandatory phrasing in the first sentence (''Compliance with standards * * * shall be determined in accordance with the applicable performance tests * * *'') as is included in the existing regulation, rather than adopt the permissive language proposed in 1993 (''Compliance with standards * * * may be determined by performance tests * * *). The rationale for retaining this mandatory language is to make clear that, although the regulation is being modified to clarify that it does not establish an exclusive method of determining compliance, the reference tests remain the benchmark against which other emissions or parametric data, engineering analyses, or other information will be evaluated. For similar reasons, EPA included in § 60.11(g) the requirement that evidence or information gathered by other means than the reference tests be ''relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed''. This phrase means that the evidence or information must bear on whether a facility would have been found to be in compliance, during the time period in question, if the appropriate performance test had been conducted. It does not mean that, to prove a violation occurred, ideal testing conditions, for example the sun light at a certain angle to the tester for an opacity reading, must exist if other credible evidence, such as continuous opacity monitor data, can establish that a violation occurred. These changes have been made in response to comments that EPA's proposal did not give full recognition to the role of reference tests in determining compliance with emission standards. Section 60.11(g) combines the requirements of the proposed subsections (g) and (h) with the exception of presumptions included in those sections which have been deleted. The clarifying language in § 60.11(g) renders unnecessary the previously proposed language in § 60.11(b). Accordingly, the proposed language for that subsection is deleted from today's rule. The proposed changes to subsection (e) have been deleted as unnecessary due to changes to subsections (a) and (g). Finally, § 60.11(f) is revised so as to clarify that it does not countermand subsection (g).

Under today's revisions, information generated from an appropriate and properly conducted test method established under the general provisions of Part 60 or in the applicable subpart will still generally be the best method for determining a source's compliance during the test period. Other emissions or parametric data, or engineering analyses, may be considered if relevant to the results that would have been obtained by the appropriate, properly conducted reference test methods.

E. 40 CFR Part 61, § 61.12

Today's revisions to § 61.12 generally mirror the revisions to § 60.11, largely for the same reasons. Section 61.12(b) remains unchanged from its current promulgated version because credible evidence has always been used to establish violations of these standards.

III. Major Issues

Throughout the development of this rulemaking, various commenters have expressed concerns regarding the proposed rule's potential effects on CAA enforcement, compliance certifications and emissions standards. The most significant of these comments, together with EPA's responses, are discussed below.

A. Use of Credible Evidence in Enforcement Actions

Commenters raised various concerns regarding the potential use of credible evidence in enforcement actions. Some commenters argued that the use of such evidence would be unconstitutional, unprecedented and unfair. Others expressed concern that EPA, states or citizen groups would use credible evidence to bring enforcement actions for insignificant violations. These comments are addressed below.

Industry commenters have argued that the use of credible evidence in enforcement actions would violate sources' constitutional right to due process. Specifically, the commenters argue that EPA must comprehensively identify the precise types of information that can be used as credible evidence, or else sources will not have sufficient ''fair warning'' regarding potential enforcement. EPA rejects this view. ''Fair warning'' jurisprudence holds that regulated sources must have adequate notice identifying ''the standards with which the agency expects parties to conform.'' *General Electric Co.* v. *U.S. EPA,* 53 F.3d 1324, 1329 (D.C. Cir. 1995). Today's rule does not establish or alter standards with which sources regulated under the CAA must comply. Rather, today's rule only concerns the evidence that can be used to prove violations of a standard, giving full recognition to the role of reference test methods under the standards. The Federal Rules of Evidence govern the admission of evidence in all federal district court litigation, including CAA enforcement actions, without any discernible constitutional infirmity. Similar evidentiary rules govern federal administrative and state environmental actions. Our legal system provides that a federal or administrative law judge will be the ultimate, independent arbitrator of the evidence's admissibility and credibility.

Credible evidence is far from a new concept in judicial and administrative actions. In private lawsuits such as contract disputes, and in governmental and citizen enforcement actions brought under environmental laws other than the CAA, litigants can and do use a wide variety of information to prove their claims, or to refute the claims of opposing parties. In all these lawsuits, the judge acts as the final, independent arbitrator of what constitutes credible and admissible evidence. Today's final rule addresses problems arising from certain CAA regulations, which predate the 1990 Amendments to the CAA, containing language that has been read to allow only a very limited amount of information, i.e., data from reference test methods, to be used as evidence of violations. As such, the rule merely corrects an anomaly that has been read into these regulations, and brings their potential enforcement into line with that of other CAA requirements such as the ''general duty obligations'' in 40 CFR 60.11(d) (for NSPS standards) and 40 CFR 61.22(c) (for National Emission Standards for Hazardous Air Pollutants (NESHAPs)), and with other environmental statutes. It should be emphasized that the determination that evidence or information is credible is merely a threshold determination that

the evidence or information in question is technically relevant, and therefore, legally admissible in an enforcement action. In light of section 113(a) providing that the Administrator may bring an enforcement action based on ''any information'', EPA believes that Congress intended this threshold to be a low one.

Industry commenters have also argued that using credible evidence in enforcement actions is unfair because sources will not know what credible evidence may be used against them. EPA believes that this claim lacks merit. This issue is no different in CAA enforcement than in any civil or criminal matter resolved by our nation's courts. Further, EPA disagrees with the notion that sources will likely be faced with an unknown and unlimited array of evidence. To the contrary, with regard to sources subject to Title V permits, EPA generally expects that most if not all of the data that EPA would consider as potentially credible evidence of an emission violation at a unit subject to monitoring under the agency's proposed CAM rule would be generated through means of appropriate, well-designed parametric or emission monitoring submitted by the source itself and approved by the permitting authority, or through other requirements in the source's permit. Sources not subject to CAM should still be readily able to discern the information, for example information about the operation of pollution control devices, that is relevant to their compliance with applicable regulation.

Some industry representatives have expressed concern that the use of credible evidence in compliance determinations will reveal multiple minor violations for which EPA, the states or citizens will bring lawsuits. It is not EPA's intent to foster frivolous lawsuits, and EPA does not expect that such lawsuits will occur as the result of today's action. As EPA explained in the Credible Evidence March 1996 memorandum, EPA generally focuses its judicial enforcement resources on violations that (1) may threaten or result in harm to public health or the environment, (2) are of significant duration or magnitude, (3) represent a pattern of noncompliance, (4) involve a refusal to provide specifically requested compliance information, (5) involve criminal conduct, or (6) allow a source to reap an economic windfall. *See* March 1996 Memorandum, p. 5.

An examination of EPA's judicial enforcement cases over the past few years reveals that EPA has focused its judicial enforcement resources on large, significant cases rather than a large number of relatively minor matters. The Credible Evidence March 1996 memorandum contains several examples that illustrate this point. In contrast, EPA's approach to minor unexcused violations generally has been to exercise prosecutorial discretion and use tools such as notices of violation and administrative compliance and penalty orders. In every case, EPA considers the nature and extent of the violation and all other circumstances surrounding the violation in determining whether and what kind of enforcement response is appropriate. Further, for any type of noncompliance, EPA generally will not bring a federal enforcement action where a state or local permitting authority has taken timely and appropriate action under existing policies to resolve the violations. Finally, for all violations, EPA will apply all other existing specific enforcement policies, such as the May, 1996, *Policy on Compliance Incentives for Small Businesses*, in accordance with their terms. EPA does not intend to use credible evidence to change any of these policies.

EPA has a balanced enforcement program that seeks to assure compliance using the mix of the compliance and enforcement tools available to it. Deterrence is also an overall goal of the program. Judicial enforcement against minor CAA violations generally is a lower enforcement priority, because EPA believes its other enforcement and compliance assistance tools allow it to respond to such violations without the need to file an action in federal court. Accordingly, in considering whether to bring a judicial action, or whether to use some other enforcement or compliance tool, EPA generally takes into consideration such factors as number and duration of the exceedances, harm or risk posed by the exceedance, potential for recurrence, the source's compliance history, and other circumstances surrounding the violation. For example, if a source were installing a new unit subject to an NSPS standard and had some difficulty getting the control equipment to operate properly after the ''shakedown'' period permitted before the initial performance test (*see* 40 CFR 60.8(a)) but solved the problem promptly after the test, this generally would be a low enforcement priority, absent other circumstances indicating a need for judicial action.

These same general policies regarding EPA's use of judicial and administrative enforcement actions were discussed in Section I.D. of the August 2, 1996, CAM draft approach. Therein, EPA provided various specific examples of circumstances where the Agency was or was not likely to take compliance or enforcement action based on the examination of CAM data.

Finally, the NSPS general provisions and many SIPs generally excuse sources from compliance with emissions limits during periods of startup, shutdown or malfunction. *See* 40 CFR 60.11(c). Some specific NSPS standards additionally excuse sources from compliance during certain operating periods. Exceedances monitored during any of these specifically excused periods are not violations of the emission limit. Moreover, some NSPS standards specify averaging periods for determining compliance and noncompliance. As a result, many short term emissions values when averaged with other values in the relevant averaging period, will not constitute violations. The credible evidence proposal does not change any of these general or specific periods of excused noncompliance, or any averaging periods, or any of their effects on compliance.

Regarding citizen suits, in February, 1996, EPA performed a review of citizen enforcement actions under the Clean Water Act (CWA), and found that citizen enforcers generally do not focus on sporadic, inconsequential violations. This analysis was summarized in the Credible Evidence White Paper, and is included in the Air Docket. Although to date there have been far fewer CAA citizen suits than CWA citizen suits, there have been at least two notable CAA citizen cases involving serious violations: *National Wildlife Federation* v. *Copper Range Co.*, Civil Action No. 2:92–CV–186 (W.D. Michigan), involving one of the largest sources of particulate matter in Michigan's Upper Peninsula, which was emitting particulates at 230 lbs/hour (over five times its permitted limit) and toxic air pollutants including mercury, arsenic, cadmium and lead; and *Sierra Club* v. *Public Service Company*, 894 F. Supp. 1455 (D.C. Col. 1995), involving a power plant that had committed over 19,000 opacity emission violations, which had allegedly affected a nearby wilderness area. Both of these suits were ultimately settled (with the United States an intervenor) for multi-million dollar penalties and significant injunctive relief, including the installation of appropriate pollution controls.

EPA notes that today's rule creates no new rights or powers for citizen enforcers; instead, the rule clarifies existing EPA regulations. Citizens have been free to use credible evidence in Clean Air Act enforcement, and have won at least two court cases using it. *See Sierra Club* v. *PSC*, cited above, and *Unitek Environmental Services* v.

Hawaiian Cement, Civ. No. 95–00723 (D. Hawaii 1996). Also, EPA is aware of no increase in citizen suits in any of the five states—Kansas, Iowa, Nebraska, North Dakota and Georgia—whose SIPs, based on EPA's SIP Call, have specifically clarified that credible evidence can be used for enforcement, or in those states that have credible evidence provisions in other parts of their state law.

Finally, EPA takes this opportunity to further elaborate on certain credible evidence and enforcement issues that were discussed in the August, 1996, draft CAM approach preamble. Therein, EPA explained that ''the CAM rule cannot and does not replace a source's obligation to comply with otherwise applicable emission limits.'' Nonetheless, as a practical matter, ''EPA expects that a unit that is operating within appropriately established indicator ranges as part of an approved CAM plan will, in fact, be in compliance with its applicable limits.'' (*See* draft CAM rule § 64.6(c), which requires that ''the ranges shall be established so as to provide a reasonable assurance of compliance with emission limitations or standards for the anticipated range of operations at a pollutant-specific emissions unit.'') Such a unit generally will not be an enforcement target. However, if the Agency obtains information that the unit is in fact exceeding its applicable emission limit even though it is operating within its approved indicator ranges, the Agency will consider whether or not to take compliance or enforcement action in accordance with its general enforcement policies. Further, under the CAM approach, the source has such information, it would have to promptly remedy the exceedance and notify the permitting authority and submit a proposed permit modification to correct its CAM monitoring as required under draft CAM rule § 64.3(b)(5).

Under today's rule, the legal burdens regarding the establishment of violations or compliance in an enforcement action are not changed. The means of meeting these burdens will vary in different circumstances. Today's rule provides that where information (such as non-reference emissions data, parametric data or engineering analyses) is equivalent to information generated by reference test methods, the former may be used to establish compliance or noncompliance in an enforcement action. There is no need to establish that every test condition specified in a reference test method has been matched by a surrogate condition in the method used to generate the comparable information. Typically, reference test methods (and any additional test conditions specified in individual regulations) quantify the presence of particular physical attributes—for example, mass or concentration of a chemical or group of chemicals—over a specified period of time. As long as these two elements—quantification and specified time period—are retained and the data from the alternate method is related to the reference test, information generated by alternate methods yield data bearing on what the results of a reference test would have been, and the use of such information to establish compliance or noncompliance in an enforcement action will not affect the stringency of the underlying standard. Of course, non-reference data that is already quantified in the same units as the underlying standard, e.g., emissions data generated by properly operating and calibrated non-reference CEMs, should generally be comparable to reference test data, with all specified averaging periods still applying.

For example, Method 9, the NSPS reference method for opacity, requires that a trained visible emissions observer (VEO) view a smoke plume with the sun at a certain angle to the plume in order to properly illuminate it. In contrast, a continuous opacity monitor (COM) contains a calibrated light source that provides for accurate and precise measurement of opacity at all times. Notably, EPA uses COM data to certify and re-certify the credentials of VEOs under Method 9. Accordingly, since a comparable light source is provided by a COM, if COM data were offered in an enforcement action to prove or disprove opacity violations, there would be no need to establish that the sun was shining during the period the COM data was collected. Where a reference test method or test requirements in an individual regulation include plant operating conditions, e.g., a requirement that testing be conducted at a specified percentage of maximum plant capacity, this does not mean that the underlying standard applies only when the plant is operating at that capacity or that the ''other information'' would have to show that the plant was operating at the specified capacity during the period that the other ''credible evidence'' was obtained.

Where a party seeks to introduce other sorts of information in an enforcement action, for example, expert testimony as to whether a unit was able to meet its emission limit based on the operation or nonoperation of its control equipment during the period of alleged violation, the information would still need to be relevant to reference test data in the sense that it must be related to reference test data in some fashion. In the expert testimony example, this might be accomplished by a qualified expert opinion that a reference test would have demonstrated noncompliance in these same circumstances. Finally, where general burdens of proof for the proponent of this information are reduced through statutory provisions or other means, the same reduced burdens will apply in circumstances where EPA uses non-reference test data to assert noncompliance. *See, e.g.*, CAA section 113(e)(2).

B. Use of Credible Evidence in Compliance Certifications

Some commenters argued that today's final action will create new uncertainties and burdens for sources, because sources will not know what information they must consider before certifying compliance with Title V permit requirements. Previously, these commenters argue, sources would have needed to consider only the results of any specified reference tests, whereas under the credible evidence revisions almost any information could be potentially relevant to determining compliance. Thus, as a practical matter sources would need to ''go through every file drawer'' and examine a great deal of additional information before certifying compliance. Even then, sources would not know whether they had reviewed all compliance information that was potentially credible. According to some commenters, even if the source determined its compliance using a reference method, the source would still be uncertain as to whether it could certify compliance during that period, because other contemporaneous information might still indicate noncompliance. Still other commenters argue that allowing a broad array of information to be considered in compliance certifications would render the certification requirement void for vagueness.

At the outset, EPA notes that today's action merely eliminates any potential ambiguity or conflict between Parts 51, 52, 60, and 61 and Part 70 regarding the ability of sources to use non-reference test data in compliance certifications. Consistent with the congressional intent reflected in Title V and section 114(a)(3), Part 70 already contemplates use of non-reference test data in compliance certifications. There are other pending rulemakings—specifically, pending actions involving the CAM approach and Part 70—that are

proposing to modify existing Part 70 requirements to provide additional detail as to what information sources must consider when certifying compliance. Nothing in these rule revisions is meant to specify what degree of correlation there must be between CAM monitoring data and emissions violations or compliance certifications; rather this issue will be discussed in the CAM rulemaking.

In addition, EPA believes that the commenters have greatly exaggerated the purported uncertainties and burdens in certifying compliance under Part 70 and notes that facilities routinely determine their compliance with numerous statutory or regulatory obligations without government imposed ''checklists.'' Under Title V, the source's substantive CAA obligations (i.e., the source's applicable requirements) are clearly set forth in the source's CAA operating permit.

Contrary to the commenters' claims, sources that are certifying compliance using properly conducted continuous reference methods may generally certify compliance based solely on the continuous reference method data, although naturally such sole reliance would be inappropriate in the face of obvious contrary information or fraud as discussed below.

Of course, if a source becomes aware of other material information that indicates that an emission unit has experienced deviations (as that term is defined in the draft CAM approach) or may otherwise be out of compliance with an applicable requirement even though the unit's permit-identified data indicates compliance, the source must consider this information, identify and address it in the compliance certification, and certify accordingly. This ensures, among other things, that sources will not certify compliance in circumstances where doing so would constitute a violation of CAA section 113(c) and 18 U.S.C. Section 1001, which prohibits sources from knowingly making a false certification or omitting material information, or a violation of other prohibitions on fraud. EPA emphasizes, however, that its purpose here is to make clear that sources may not ignore obvious relevant information. EPA does not view compliance certification requirements as imposing a duty on the source to search out and review every possible document to determine its relevance on the issue of the source's compliance.

Following on the above discussion, the Agency takes this opportunity to restate that while a Title V permit can include a ''permit shield'' protecting it from allegations that it has failed to satisfy CAA *monitoring* requirements, such shield does not relieve the source of its obligation to comply with the underlying emission limits or other applicable requirements being monitored. In other words, even where a source receives a ''shield'' providing that the monitoring provisions set forth in its Title V permit constitute compliance with all monitoring requirements of the CAA, the source would not be shielded from allegations of noncompliance with the underlying substantive requirements (e.g., emission limits) being monitored even if the source's required monitoring failed to detect the violation. *See also* the October, 1993, proposal, 58 FR 54678.

Industry commenters argued that allowing credible evidence in Title V compliance certifications would render the certification requirement constitutionally void for vagueness. According to these commenters, reference test methods are necessary to define, in a consistent and reproducible manner, the level of performance that constitutes compliance; without a reference method, an emission limit would be incomplete. As discussed above, EPA in no way intends to eliminate reference tests or to alter their methodology. Instead, these tests, performed as specified under EPA and state regulations, will remain the benchmark against which to compare other emissions or parametric data, or engineering analyses, regarding source compliance.

Finally, numerous commenters argued that allowing credible evidence in compliance certifications and enforcement actions would disrupt the Title V permit process and cause substantial delays in the issuance of these permits because local permitting authorities would have to adjust many of the sources' emission limits, which the commenters contend were not intended to be complied with continuously. Such Title V gridlock could occur only if today's action in fact changed the stringency of emission standards.

C. EPA's Authority To Promulgate the Credible Evidence Revisions

1. Statutory Authority

Today's rulemaking and related SIP call are based primarily on EPA's existing authority prior to the 1990 CAA Amendments. Section 113(a) of the Act authorizes EPA to bring an administrative, civil or criminal enforcement action ''on the basis of any information available to the Administrator.'' This provision provides the Agency with clear statutory authority to use any available information to prove violations of requirements under the Act, and demonstrates that Congress did not intend to limit EPA to using reference test method results in bringing enforcement actions. The language of Section 113(a), together with the fact that the Act nowhere prohibits the use of information other than reference test results to prove violations, indicates that the Act does not limit the use of any information to prove a violation. Therefore, by law the Agency is limited only by general evidentiary rules in what it can use to prove a violation alleged in an enforcement action.

2. The Kaiser Steel Decision Does Not Constrain EPA's Authority To Amend Its Regulations

Although the Act sets no inherent limits on EPA's authority to use any type of information to prove a violation, some EPA regulations provide for specific test methods for determining compliance and have been read by some to constrain EPA's enforcement authority. In *United States* v. *Kaiser Steel Corp.,* No. CV–82–2623 IH (C.D. Cal. Jan. 17, 1984), the district court construed the language of EPA's regulations at 40 CFR 60.11 as limiting the admissible evidence of violations of opacity standards to observations utilizing Method 9, the opacity reference test method. Thus, when the Agency attempted to use expert testimony pertaining to opacity to prove the existence of violations without Method 9 test data, the court rejected the evidence and held that EPA could prove violations only on those days where the Method 9 test was conducted. This decision—which interpreted only EPA's existing regulations, not the Act—was specifically overruled by Congress in the 1990 CAA Amendments. Today's rulemaking is intended to clarify that EPA's regulations do not constrain EPA to using reference tests to prove a violation of an emission standard. Rather, EPA retains its full authority under Section 113(a) to use ''any information'' as the basis for an enforcement action.

3. Despite Commenters' Claims, Clean Air Act Case Law Does Not Mandate Exclusive Reference Tests

At least one commenter has asserted that the decision in *Portland Cement Ass'n* v. *Ruckelshaus,* 486 F.2d 375, 399 (D.C. Cir. 1973), *cert. denied,* 417 U.S. 921 (1974), stands for the proposition that CAA emission standards may be enforced only through an exclusive reference test method. First, the commenter relies on the court's ruling

that a reference test method must make measurements with ''reasonable accuracy'' and be ''objective.'' 486 F.2d at 401 & n. 103. Second, the commenter cited the court's concern with deviations between sampling methods used in gathering data to set an emission standard and sampling methods used in reference methods. The court stated that ''a significant difference between techniques used by the agency in arriving at standards, and requirements presently prescribed for determining compliance with standards [i.e., the reference method], raises serious questions about the validity of the standards.'' 486 F.2d at 396. EPA disagrees with this reading of *Portland Cement.*

These holdings, individually or together, do not support the conclusion that violations of an emission standard may only be demonstrated by an exclusive reference method. The court's statements regarding the reliability of reference methods were made in context of a challenge to an opacity standard. The industry petitioner argued that testing compliance with that standard, inspector observations, is inaccurate and therefore arbitrary. The court agreed that the evidence called the reliability of inspector observations into question and remanded to EPA for it to determine if there was a way to measure compliance with the standard with ''reasonable accuracy.'' In no way did the court imply that the opacity standard had to have an exclusive reference test but simply rejected the test EPA proposed to use as insufficiently supported.

The *Portland Cement* court's discussion of a compliance method that differed from the test method used to develop the standard also lends no support to the conclusion that an exclusive test method is required. It is true that the court mentioned reference methods ''outlined by regulation.'' However, the mere description of an agency practice (here, the inclusion of a reference test in a regulation setting an emission standard) does not transform that practice into a statutory requirement. Moreover, the thrust of the court's remarks was to caution EPA that, where EPA has established by regulation a reference method for sources to demonstrate compliance, the best data EPA can put forth to show that a standard is in fact achievable is data generated by the reference method. The D.C. Circuit, however, has specifically rejected the assertion that standards can only be supported by reference test data. *See National Lime Ass'n* v. *EPA,* 627 F.2d 416, 446, fn.103 (D.C. Cir. 1980). None of this, thus, supports the commenter's claim that a standard's supporting data must be generated using the reference method, and its supposed corollary that only reference method data can be used to enforce the standard, especially where, as here, that other information must be related back to a reference test method. At best, the commenter's arguments would apply only in the context of an original standard-setting, where an emission limitation or other standard newly promulgated by EPA was being challenged on the basis that the standard's supporting data was inadequate. Today's rule sets no new emission or work-practice standards, and amends no existing ones.

Thus, the commenter is mistaken. Neither of the two passages in *Portland Cement* cited by the commenter address whether exclusive reference tests are necessary, much less mandate establishment of such tests. Further, EPA regulations are inconsistent with the exclusivity argument of the commenter. For example, section 60.8(a) of Title 40 of the CFR provides a whole string of circumstances under which a source can alter or completely replace the reference test required by the regulation. Finally, today's final action regarding the use of non-reference test data in enforcement is fully consistent with the court's requirement that reference testing be conducted in a nonarbitrary manner.

4. The 1990 CAA Amendments Further Support EPA's Authority

Various provisions of the 1990 CAA Amendments provide additional support for EPA's position that reference tests are not the exclusive means of proving violations. As noted above, Congress specifically reversed the *Kaiser Steel* decision in Section 113(e) of the Amendments by providing that the duration of a violation may be established ''by any credible evidence (including evidence other than the applicable test method).'' The legislative history for this provision shows that Congress meant to clarify that in an enforcement action courts are not restricted to reference test method data, but may consider any evidence of violation or compliance admissible under relevant evidentiary rules. *See* S. Rep. No. 228, 101st Cong., 1st Sess. 1, 358 (1989) (''Senate Report''), *reprinted in* 1990 U.S. Code Cong. & Admin. News 3385, 3741 (''Reprint'').

Other provisions of the 1990 CAA Amendments also evidence Congressional intent that reference test methods should not be used as the exclusive means for assessing compliance with CAA emission limits. Most pointedly, the requirements in Section 114(a)(3) for enhanced monitoring and for compliance certifications based on a determination of whether compliance was continuous or intermittent presumes that data other than reference tests would be used for these purposes. As explained in the October, 1993, proposal, the use of non-reference test data is also consistent with the monitoring, compliance assurance, and compliance certification requirements in Sections 504(a), 504(c), and 503(b)(2) of the Act. *See* 58 FR 54649–50. In addition, Section 504(b) of the Act grants discretionary authority to the Administrator to prescribe procedures and methods for monitoring, and provides that continuous emission monitoring systems need not be required ''if alternative methods are available that provide sufficiently reliable and timely information for determining compliance.'' In sum, Congress' repeated emphasis on providing reliable and timely compliance information is inconsistent with the notion that only data from infrequently performed reference tests is relevant to compliance certifications and enforcement actions.

5. Commenters' Attempts To Narrow the Scope of Sections 113(e) and 113(a) Are Unpersuasive

Several industry commenters have claimed that the legislative history of the 1990 CAA Amendments shows that section 113(e)(1) does not provide authority for today's final action. Additionally, these commenters have asserted that the section's legislative history upon which EPA has relied is ambiguous.

In the October, 1993, proposal, EPA cited to the Senate Report's discussion of Section 113(e)(1). The Senate Report stated:

> This title of the bill enhances the ability of the Environmental Protection Agency * * * by making clear that the Agency may rely upon any credible evidence of violations in pursuing alleged violations.

Senate Report at 358, Reprint at 3741. The Report further explained:

> [T]he amendment clarifies that courts may consider any evidence of violation or compliance admissible under the Federal Rules of Evidence, and that they are not limited to consideration of evidence that is based solely on the applicable test method in the State implementation [plan] or regulation. For example, courts may consider evidence from continuous emission monitoring systems, expert testimony, and bypassing and control equipment malfunctions, even if these are not the applicable test methods. Thus, this amendment overrules the ruling in *United States v. Kaiser Steel Corp.,* No. 82–2623 (C.D. Cal. January 17, 1984) to the extent that

the court in that case excluded the consideration of such evidence.

Senate Report at 366, Reprint at 3749. Finally, the Report notes that data from enhanced monitoring and compliance certifications ''will facilitate enforcement, due in part to the fact that such data and certifications can be used as evidence.'' Senate Report at 368, Reprint at 3751.

The commenters, in turn, rely on the views of Senator Chafee regarding S. 1630, inserted into the Congressional Record at the time the legislation was introduced. Senator Chafee stated with regard to Section 113(e)(1):

> Subsection 113(e) also clarifies and confirms that once EPA establishes evidence of a violation using a formal test method, EPA can use other credible evidence to prove additional violations, or that violation has continued.

135 Cong. Rec. S 9650, 9655 (August 3, 1989).

EPA believes that the best reading of the legislative history still supports its interpretation of Section 113(e)(1). First, there is no ambiguity in the Senate Report, the language of which unreservedly supports enforcement actions brought on the basis of non-reference test data. Second, EPA does not believe that Senator Chafee's floor statement outweighs the clear statement in the Senate Report. The Senate Report is a more authoritative reflection of congressional intent than a floor statement produced at the beginning of the legislative process.

Various commenters also objected to EPA's reliance on Section 113(a) as a basis for today's action. One commenter argued that Section 113(a) does not preempt regulatorily specified reference test methods. Several commenters asserted that EPA's construction of Section 113(a) would render superfluous the new language in Section 113(e)(1) concerning credible evidence. These commenters claim that, under EPA's interpretation of Section 113(a), Congress could have ''fixed'' the *Kaiser Steel* decision simply by clarifying the scope of EPA's authority under Section 113(a).

These various commenters have misunderstood EPA's interpretation of Section 113(a). EPA has not asserted that Section 113(a) preempts reference test methods. Rather, EPA believes that Section 113(a) provides authority to amend current regulations to make clear that data from reference test methods are not the exclusive means of establishing noncompliance or compliance in enforcement actions. Given this interpretation of Section 113(a), Congress's passage of Section 113(e)(1) cannot be described as superfluous—particularly in light of the decision in *Kaiser Steel.*

6. EPA Can Promulgate the Credible Evidence Revisions Without Reproposal

Several commenters have argued that finalization of the proposed changes in Parts 51, 52, 60 and 61 without first reproposing those changes violates the Administrative Procedure Act (APA), the CAA, and due process. The commenters' main argument is based on EPA's presumed change in course on implementing the requirement in Section 114(a)(3) concerning enhanced monitoring and compliance certification. As noted above, the changes to Parts 51, 52, 60 and 61 were proposed in the same rulemaking that proposed an enhanced monitoring and compliance certification program. Since that proposal, EPA has re-evaluated its approach to enhanced monitoring and has made publicly available and has sought comment on a revised approach—the CAM approach—for satisfying the same statutory goals as the original enhanced monitoring proposal. Some commenters contend that switching to CAM will fundamentally change their view of the proposed changes to Parts 51, 52, 60 and 61 because those proposed changes were evaluated only in terms of how they would be implemented under the October, 1993, proposal on enhanced monitoring. Until CAM is formally proposed, these commenters assert, they cannot give meaningful comments on the credible evidence revisions. Further, the commenters argue that the proposed revisions provided insufficient notice and opportunity to comment because EPA has not adequately defined the term ''credible evidence.''

EPA believes today's rule has no procedural infirmities. EPA is today finalizing the enforcement-related portions of the proposal it made in 1993 with only minor changes.

The commenters' claim that they cannot meaningfully comment on credible evidence revisions prior to proposal of the CAM approach is not well-taken for two reasons. First, EPA does not believe that any knowledge of the draft CAM approach is necessary to comment on today's rulemaking. In today's final rule, EPA has removed any presumptions regarding the credibility of any specific data. If and when the draft CAM approach is finally adopted, CAM data will be treated under today's rule like any other potential source of compliance information. Thus, knowledge of the draft CAM approach is not critical to commenting on this rulemaking. In any event, the nature of the draft CAM approach has been generally available in some detail since September, 1995—well before EPA renewed its request for comment on today's rulemaking. Further, EPA has sought and received additional comment on the enforcement consequences of the draft CAM approach by distribution of a revision of the CAM approach in August, 1996. The revised approach specifically discussed the relationship of the draft CAM approach and today's action.

Second, the October, 1993, proposed rulemaking gave interested parties sufficient notice of the issues raised by the proposed changes to Parts 51, 52, 60 and 61. The Agency made clear that these revisions were designed to remove any potential ambiguity regarding the use of enhanced monitoring data in compliance certifications, and to clarify that any credible evidence of a violation of an emission standard was admissible to prove (or disprove) such a violation. *See* 58 FR 54677. To clarify that these credible evidence revisions extended beyond the data gathered under an enhanced monitoring program, EPA gave two specific examples of evidence collected outside the enhanced monitoring program that under the revised regulations could be used to prove a violation. *See* 58 FR 54676–54677. Thus, the October, 1993, proposal clearly put interested parties on notice that the credible evidence revisions were not merely an adjunct to the enhanced monitoring program. In fact, industry commenters on the October, 1993, proposal clearly understood the central issue posed by the proposed credible evidence changes, and they commented on it extensively. Today's final action promulgates revisions to *existing* regulations, and are not contingent upon *future* promulgation of the CAM approach or any other form of enhanced monitoring requirement.

Neither is this rulemaking procedurally deficient for not providing an express regulatory definition of the term ''credible evidence''—a term which Congress itself inserted, without definition, into the Act. The issues of credibility, admissibility and weight of evidence have been exhaustively addressed by federal and state court evidentiary rules regarding evidence, and the thousands of cases decided under them. Today's final action defers to those regulations and makes clear that there are no bars in regulations under the CAA which prevent the use of evidence or information other than reference test methods in compliance certifications and enforcement actions. Of course, in judicial enforcement

proceedings, what evidence is credible and admissible will be determined by the court taking into account how the evidence was gathered and the specifics of the emission standard and any associated reference method.

Finally, EPA believes that it has taken extensive steps, detailed in Section I.C. above, to ensure that the concerns of affected parties were fully aired. None of the additional public outreach actions that EPA undertook in 1996 were required by the APA or the CAA; instead, EPA undertook them voluntarily to ensure full input by interested parties regarding the credible evidence rules.

D. Stringency

Industry commenters have presented several arguments in support of their position that this rulemaking requires sources to be in continuous compliance and thus would effectively increase the stringency of underlying requirements, including SIP limits and standards established by EPA under the NSPS and NESHAP programs.

EPA believes that industry's arguments on this point are fundamentally wrong. It is not EPA's intent that these rules should increase the stringency of any applicable requirement. These rules do not do so because they maintain the focus of the compliance determination on whether or not the appropriate reference test would have shown a violation.

The commenters' arguments regarding increased stringency are as follows: applicable requirements are accompanied by specified reference tests. Any departure from past practice regarding the use of these tests, including the use of other credible information to directly assess compliance, particularly on a more frequent basis, will inevitably change the results of an inquiry into the compliance status of any source compared to exclusive reliance on the infrequent performance of the reference tests. Therefore, industry argues, using credible evidence would change the underlying applicable requirements—usually in a manner that makes them more stringent—without going through the necessary rulemaking procedures.

Industry's argument hinges on the premise that adoption of an emission standard that includes a particular form of reference test—one that is not required to be performed continuously as a matter of course—limits the compliance obligation. The scope of the compliance obligation is not at issue in this rulemaking. The scope of the compliance obligation prescribed by any particular standard shall be based on the emission standard and not this rulemaking. However, to fully respond to industry comments, and to give notice of the position EPA will take in future enforcement proceedings, EPA believes it is necessary to address in some detail the nature of the compliance obligation under emission standards with particular emphasis on the compliance obligation as it pertains to emission standards which have a reference test method that is not required to be performed continuously.

While the bulk of the commenters' concerns were expressed with respect to NSPS, the same concerns also apply in most cases to NESHAPs and SIPs. Likewise, EPA's responses focus on NSPS, but are generally applicable to other emissions limits as well.

1. Emissions Limits Require Continuous Compliance (Consistent With Any Averaging Times) Except During Periods Where Compliance Is Specifically Excused

To resolve commenters' claims of increased stringency, the nature of the compliance obligation facing owners and operators of sources of air pollution under the Act must be addressed. Under the CAA, its regulations, and the case law, a source's compliance with emission limitations must be continuous (consistent with any averaging times) except where a particular emission standard specifically provides for periods of noncompliance.

The Statute. The Clean Air Act defines the terms ''emission limitation'' and ''emission standard'' as meaning ''a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a *continuous* basis * * *.'' CAA section 302(k) (emphasis added). In accordance with this clear statutory statement, the Act authorizes penalties for multiple days of violation should a source fail to meet its continuing obligation. *See also* CAA sections 113(e)(2) (providing that ''a penalty may be assessed for each day of violation,'' and establishing a presumption of continuing violation if certain conditions are met) and 113(e)(1).

CAA Regulations. The Act's general requirement of continuous compliance is mirrored in the NSPS regulations, which generally require that sources comply with established emission limits except during certain defined time periods. NSPS provisions typically specify that compliance with stated limits is required ''on and after the date'' of an initial performance test conducted in accordance with 40 CFR 60.8. *See, e.g.,* 40 CFR 60.502. The need for continuous compliance is also discussed in the preambles to numerous NSPS, including many older ones. For example, in proposing standards for glass manufacturing plants (Subpart CC), EPA stressed the need for effective monitoring to assure that affected facilities are ''continuing to maintain the emission reduction observed during the performance test.'' 48 FR 50670, 50675 (1983). EPA has also made this point clear in publicly-available guidance memoranda. *See* Detailed Response Document at Section 4.

In addition to requirements for continuous compliance, NSPS regulations also typically contain specifically excused periods of noncompliance. These periods confirm that compliance is required at other times. They also confirm the basic reasonableness of this compliance scheme—that is, sources must generally comply continuously with their numerical emission limits, but not during periods of specifically excused noncompliance, and only in accordance with any specified averaging periods. For example, for many standards, compliance is not required during periods of startup, shutdown or malfunction. This exception is contained in the NSPS general provisions and in individual standards. *See* 40 CFR 60.8(c); *see also, e.g.,* 40 CFR 60.46a.

Case Law. In various judicial decisions, courts have approved of the basic NSPS regulatory scheme of continuous compliance accompanied by limited, specified exceptions for noncompliance. The courts have stated that the specified exceptions are needed because sources must comply at all other times. *See, e.g., Portland Cement,* 486 F.2d at 399 (court noted EPA's then-proposed ''startup, shutdown and malfunction'' compliance exclusion regulation with approval, suggested that it was a ''limited safety valve'' and stated that it imparts a construction of ''reasonableness'' to the standards as a whole and adopts a more flexible system of regulation that can be had by a system devoid of ''give''; (*Essex Chemical Corp.* v. *Ruckelshaus,* 486 F.2d. 427, 433 (D.C. Cir. 1973), *cert. denied,* 416 U.S. 969 (1974) (in a challenge to sulfuric acid plant and coal-fired steam generator NSPS standards, the court again noted with approval the proposed start-up, shutdown and malfunction exception and remanded the rule stating that ''such variant provisions appear necessary to preserve the reasonableness of the standards as a whole and that the record does not support the ''never to be

exceeded'' standard currently in force'') (emphasis added); and *Bunker Hill Co.* v. *EPA,* 572 F.2d 1286, 1301–02 (9th Cir. 1977) (in challenge to SIP sulfur dioxide standard, court observed that EPA regulations required that the standard be met ''all of the time,'' and thus EPA must typically promulgate upset provisions to excuse noncompliance beyond the source's control). Similarly, the proposition that compliance must be continuous is reflected in numerous judicial decisions involving challenges to various NSPS rulemakings. In these cases, both the D.C. Circuit Court and industry petitioners have emphasized that for an emission standard to be achievable it must be able to be continuously complied with over wide operating ranges at varied facilities. *See, e.g., Portland Cement, Essex Chemical, National Lime,* and *Sierra Club* v. *Costle,* 657 F.2d 298 (D.C. Cir. 1981). In *National Lime,* for example, the lime industry's trade association itself complained that the data underlying the promulgated numerical emission standards were insufficient to show that the standards were ''in fact achievable on a continuous basis.'' 627 F.2d at 430. In holding that EPA had not adequately demonstrated the achievability of the standards for the industry as a whole, the court explained that ''to be achievable, we think a uniform standard must be capable of being met under most adverse conditions that can reasonably be expected to recur . . . .'' *Id.* at 431. In *Sierra Club* v. *Costle,* various electric utility companies challenged a particulate standard on the basis that ''the data reflect only short term performance while the standard requires long term continuous compliance.'' 657 F.2d at 377 (emphasis added). This challenge was rejected by the court based on data showing that certain sources had ''consistently complied with the standard.'' *Id.* at 382.

2. Commenters' Advocacy of Noncontinuous Compliance Would Lead to Numerous Anomalies

Some industry commenters have argued that numerous emissions limitations do not require continuous compliance or, alternatively, that ''continuous'' does not have the straightforward meaning suggested above. The commenters' argument centers on NSPS standards issued under CAA section 111. In the commenters' view, many such standards do not contemplate that facilities will operate in compliance on a continuous basis with stated emissions limits, but rather require only an initial demonstration of compliance with stated limits upon start-up or shortly thereafter. After an initial performance test, continuous compliance is required only with respect to operation and maintenance ''in a manner consistent with good air pollution control practice'' as specified in 40 CFR 60.11(d). As to numerical emissions limits, commenters suggest that these must be met only on those infrequent occasions that a subsequent performance test is conducted. So long as any such performance test is passed, the source is in ''continuous'' compliance with numerical emissions limits without regard to whether its emissions in fact exceeded the numerical limit during the time between the tests, no matter how long that may be.

EPA rejects this view of the nature of the obligation to comply with NSPS and other emission limits under the CAA. *See* Detailed Response Document. EPA and the courts have long held that emission limits must be complied with continuously, consistent with any associated averaging periods, except where a particular limit provides otherwise. Adopting the commenters' view of compliance would lead to numerous anomalies.

In the April 2, 1996, public meeting and in follow-up written comments, several commenters argued that many reference test methods were selected specifically because they would only be performed infrequently—for example, on a yearly basis. These once a year tests would be proper for their associated emission standards, which in the commenters' view were intended to be complied with only 95% of the time. Specifically, performing a reference test once a year would yield ''acceptable'' compliance results, because on average a source would be found out of compliance only 5% of the time—that is, in one in twenty tests, or once every twenty years. According to these commenters, testing for compliance more frequently would be unfair, because it would increase the likelihood that the source would be found out of compliance during periods where the standard itself contemplated noncompliance. In order to avoid being found in noncompliance, sources would have to continuously stay below their emission limits—which in these commenters' view would effectively increase the stringency of the emission standard.

EPA disagrees with the commenters' notion that sources must meet their legal numerical air emission limits only seldomly. Further, EPA rejects as inconsistent with the Act and its underlying purposes the notion that sources can somehow be in routine ''compliance'' without staying within these limits on an ongoing basis. The fundamental goal of the CAA and the emission standards established under it, is to achieve clean air. Moreover, many emission standards, such as hazardous air pollutant standards under Section 112 and emission standards in State Implementation Plans designed to implement national ambient air quality standards, have a direct relationship to the protection of human health. Routine compliance with numerical emission standards is critical to achieving this goal. The commenters' view that such compliance is somehow not required would completely undercut these public health and safety goals.

If the commenters' view was correct, any EPA or state targeting of a specific source by requiring the source to perform more frequent reference tests would be unfair and presumably illegal, because any such increased frequency in reference testing would destroy the delicate balance of frequent noncompliance and infrequent testing that the commenters claim is contemplated by the rules. Under this view, EPA and states might not be able to require an apparently violating source to conduct a previously unscheduled reference test, because it would improperly raise the source's chances of being found in noncompliance and thereby ''increase the stringency of the underlying standards.''

The commenters'' argument is also inconsistent with the language, structure, and purpose of the CAA. For example, if the frequency of testing must be limited to meet the intent of the emission limits, to be fair to all sources EPA's regulations should have required that the tests be performed only at infrequent intervals. EPA's rules contain no such restrictions; rather, CAA section 114(a)(1)(D) grants EPA broad discretion to order reference tests whenever the Administrator deems it appropriate. Moreover, commenters'' argument is inconsistent with CAA section 113(e)(1), which even on its narrowest reading (note that EPA's reading is considerably broader) specifically provides for use of non-reference test data to prove continuing additional days of violation after an initial violation is established by reference test data, and by CAA section 113(e)(2), which establishes a presumption of continuing violation after notice of the violation has been given to the source, provided that EPA can make a prima facie showing that ''the conduct or events giving rise to the violation are likely to have continued or recurred past the date of notice.'' This presumption continues until the violator ''establishes that continuous compliance has been achieved.''

Likewise, sections 114(a)(3) and 504(a)-(c) regarding enhanced monitoring and certification as to whether compliance is continuous or intermittent, and prompt reporting of deviations, are simply inconsistent with a regulatory regime that would require only occasional demonstrations of compliance with emission limits. Taken together, these provisions, represent a fundamental statutory rejection of the commenters' argument. *See* Detailed Response Document, Section 4, which discusses other reasons why these comments are without merit.

3. Comments Regarding Continuous Compliance Are Not Directed at Today's Action, but Rather at Underlying Emission Standards

Industry commenters have argued that the quality and quantity of the data used in establishing emissions limitations, such as those under the NSPS and NESHAP programs, reflect a conscious decision by EPA that compliance with such standards would need to be demonstrated only periodically. It follows that requiring continuous compliance with stated limits at this juncture would effectively increase the stringency of the standards. As discussed above, EPA believes that the commenters' general arguments strain common sense. Commenters have pointed to various NSPS standards to support their views, but EPA finds these examples unpersuasive.

In particular, commenters have pointed to the NSPS for kraft pulp mills, 40 CFR Part 60, Subpart BB, and for steam electric generators constructed between 1971 and 1978, Subpart D, as reflecting a general acknowledgment by EPA that national standards need not be complied with at all times. EPA believes that, to the contrary, Subparts BB and D and other cases demonstrate that where EPA intended to allow affected sources to exceed stated emissions limits, the standards in question expressly so provide. It is true that in the development of some NSPS and NESHAP standards, EPA was concerned with the limited number and distribution of test runs and the inherent variability in levels of emissions from even well-controlled facilities. Where appropriate, EPA addressed those concerns by adjusting the numerical value of the standard, providing excess emissions allowances and provisions for noncompliance during certain upset conditions, or through changes in averaging times. With other standards, EPA did not provide for any departure from the general requirement that compliance must be continuous. Examples of all these approaches, and specific responses to comments regarding Subparts D and BB, are provided in the Detailed Response Document.

The commenters' assertions that sources cannot comply on a continuous basis are really directed not to the propriety of today's rules, but rather to the adequacy of the underlying NSPS and other emission standards that are not at issue in this rulemaking. To the extent there is any documentation that a well-run facility cannot comply consistently with underlying national emission standards, or applicable SIP requirements, such documentation would be relevant only to those existing standards, not to today's rule. EPA notes that despite several requests to commenters to identify any standards that cannot be complied with on a regular basis, no specific information has been provided to this rulemaking docket that demonstrates that well operated and maintained facilities employing pollution control technologies of the types upon which the underlying emission standards were based cannot comply with those standards on a continuing basis. The most that was submitted was a statistical re-analysis of the data relied upon by EPA in promulgating several emission standards and a one page graph purporting to show that an industrial boiler could not comply with the NO_X emission limit at low levels.

The agency has considered this comment concerning the Subpart D NO_X standard carefully, as it does not intend to impose requirements that are impossible for well-designed sources to meet, but believes that this concern is largely theoretical. The information provided by the commenter to EPA was vague and did not prove that the undisclosed source could not comply with the emission standard. Further, if a standard was impossible to achieve under some circumstance, EPA and citizens are not likely to bring enforcement cases in such instances. In reviewing CAA enforcement actions the agency has been unable to identify any case where either the agency or a citizen sought to enforce a standard that was impossible to achieve. The agency was also unable to identify any case in which a defendant established that compliance was not possible at the time of the alleged violation. This appears to be the case even in those states and localities that have had ''credible evidence'' rules for years.

Additionally, should it be determined that a standard could not be met during some relatively infrequent or inconsequential period of source activity, the potential for significant adverse impact on that source is remote. The agency has previously expressed its policy that, generally, judicial enforcement is not the appropriate vehicle to redress sporadic, infrequent violations with no environmental consequence. Further, it is unlikely that a citizen could prevail in enforcing a theoretically impossible standard since Courts will not issue an injunction where there is nothing to be done. Similarly, where one cannot establish that a source failed to act in a manner required by law a significant penalty will not be imposed by the courts. The agency is not aware of any situation in which it has filed, and one should not anticipate large numbers of citizen suits being filed, where there is nothing the source could have done or could do to achieve a greater degree of compliance. Moreover, the courts today have additional tools, including fee awards and sanctions available under the Federal Rules of Civil Procedure and other statutes to address meritless suits.

In further response to these industry comments, EPA has included in the record a 1993 study conducted by EPA Region V that shows that almost all (95%) of sources with sulfur dioxide CEMs were meeting their federal and state sulfur dioxide emission limits approximately 97% of the time, with excess emission periods totaling only 3%. *See* Region V Study, Figure 2. Because this 3% figure included excess emissions recorded during periods in which compliance is specifically not required, such as startup and shutdown, the percentage of operating time in noncompliance with the standard is even smaller and may mean that most sources are in compliance all the time. EPA Region V sources with continuous opacity monitors showed similar results: the average source's percentage of opacity exceedances was less than 2%, with 95% of sources at or below approximately 4%. *See* Study, Figure 1. As with the sulfur dioxide data, opacity exceedances during periods of startup, shutdown and other excused periods were not excluded. Accordingly, the percentage of actual noncompliance with opacity limits was even smaller. Note that these figures are for the average (50th percentile) and worst (95th percentile) facilities. The best run facilities have fewer excess emissions reports.

Additional CEM data from EPA Region V that focused specifically on exceedances from NSPS Subpart D SO_2 emission standards shows similar results. This data shows that Subpart D sources report few or no excess SO_2 emissions. Approximately two-thirds of the sources report no excess emissions

at all, during any three month reporting period. Further, since 1990, the vast majority of sources (95%) have reported total excess emissions averaging less than 2.5% of operating time; since 1993, less than 1.7%. Since these figures include all excess emission periods, including periods that are probably excused, the actual SO_2 exceedance rates were even lower.

These data show that there are not ''fundamental flaws'' in the subject standards such that the standard cannot be met. *Indeed,* the data demonstrate that most sources do comply all or nearly all of the time.

If the regulated community believes that a standard cannot be met across some meaningful range of normal operating conditions, or if specific exemptions beyond those currently provided are proper, we believe the appropriate action is for the affected industry to file a petition for amendment of the standard at issue or propose more specific permit conditions so that the matter can be fully assessed and addressed through the regulatory process. However, the information submitted by the commenters does not show that there currently exists a significant ''impossibility'' issue that is so widespread as to outweigh the benefits of the proposed rule.

4. Enforcement Using Continuous Monitoring Data Does Not Increase the Stringency of Applicable Requirements

Industry commenters have argued that the stringency of emission standards will be increased if enforceable data is obtained more frequently than has been ordinarily obtained in the past through reference testing. Further, the commenters argue that direct enforceability of this data would contradict EPA's stated positions in adopting standards under the NSPS and NESHAP programs because EPA intended that continuous monitoring would only show compliance with good operation and maintenance procedures, i.e., general duty requirements, and would not be otherwise used in enforcement. (*See, e.g.,* 38 FR 10820 (1973) (preamble to proposed startup, shutdown and malfunction regulation); 43 FR 7571 (1978) (preamble to final kraft pulp mill standards).

Because the NSPS and NESHAP emission standards must be met continuously, consistent with any averaging times and except during periods where compliance is specifically excused, any more frequent or continuous monitoring of the standards and any enforcement based on violations uncovered thereby have no effect on the stringency of the standards. To take a simple analogy, allowing the use of radar guns or increasing the number of police checking for speeding may raise the chance that a speeder will be detected, but this does not alter the legal stringency of a posted speed limit.

In some early NSPS, the agency required the installation of what were styled ''indicator monitors'' and provided policy guidance that such monitoring data would not be used as the sole basis of enforcement actions absent further rulemaking. 38 FR 10820. To the extent that the CAA Amendments of 1990 did not supersede this policy statement, today's action is that future rulemaking. These policy statements, like today's rulemaking, pertain only to the kinds of evidence EPA uses to prove violations. The policy change that was contemplated in our 1993 proposal and 1996 memorandum are supported by technological advances in the accuracy and reliability of continuous emission monitors, deficiencies in EPA's previous practices identified by GAO and others, and the language and intent of the Act and the 1990 CAA Amendments.

EPA's past statements regarding limitations on the use of data derived from continuous monitoring methods for purposes of enforcing standards were motivated in part by concerns over the cost and availability of such methods and their ability to accurately determine compliance. *See, e.g., National Lime,* 627 F.2d at 450 (responding to petitioners' argument that there was no adequately demonstrated technology for monitoring opacity, EPA stated that the continuous monitoring data would not be used to determine compliance with the opacity standard but ''to keep a check on the operation and maintenance of the control equipment,'' and that the monitors were reliable enough to perform this limited function). For example, in the 1973 startup, shutdown and malfunction regulation proposal, EPA noted that while continuous monitoring data would not, at that time, be used to determine compliance as a general matter, such data could be used if ''approved as [an] equivalent or alternative method for performance testing.'' 38 FR 10820. Indeed, the NSPS general provisions have long provided that in lieu of performance tests using reference methods, a source could demonstrate compliance using an approved equivalent or alternative method, and that EPA can waive reference tests where the source has otherwise satisfactorily demonstrated compliance. *See* 40 CFR 60.8(b).

Since the 1970s, the availability, cost and accuracy of methods that enable determinations of compliance on a continuous basis has improved markedly. *See, e.g.,* 1990 GAO report at 19, 22–23 (1986 and 1988 EPA studies showed CEM data highly reliable); *Continuous Emission Monitoring,* 1993, Jahake, Thomas Publishing Co. For these reasons, EPA believes it is appropriate as a technical matter to allow information derived from these methods to be used in compliance certifications and enforcement actions. In fact, more recent national standards issued by EPA provide for determining and enforcing compliance directly by use of continuous monitoring data.

5. Sources Must Comply Both With Good Operation and Maintenance Requirements and With Emission Limits

Industry commenters have claimed that as to the NSPS program, the only goal of the program was to insure that best demonstrated technology was employed, such that once an initial reference test demonstrated that compliance with the standards could be achieved, it need not be demonstrated thereafter, and that an affected source's only ongoing obligation was its ''general duty'' to employ good operation and maintenance practices to minimize emissions in accordance with 40 CFR 60.11(d).

EPA agrees that proper operation and maintenance of an emissions unit and any associated pollution controls in accordance with 40 CFR 60.11(d) is vital to complying with emission standards. However, while it is true that sources have a continuing duty to employ good operations and maintenance practices, this duty does not substitute for the sources' obligation to comply with its emission limits. The two obligations, while related, are separate requirements in the NSPS regulations and in legal effect.

EPA has made these points plain as far back as 1973 in the proposed NSPS startup, shutdown and malfunction rulemaking:

> It is anticipated that the initial performance test and subsequent performance tests will ensure that equipment is installed which will permit the standards to be attained and that such equipment is not allowed to deteriorate to the point where the standards are no longer maintained. In addition, the proposed regulation requires that the plant operator use maintenance and operating procedures designed to minimize emissions in excess of the standard.

38 FR 10820 (1973) (emphasis added). This preamble text clearly states both that proper equipment maintenance is vital to remaining within an emission

standard (otherwise equipment would deteriorate to the point where standards were not met) and that the general operation and maintenance obligation is a separate regulatory requirement. Additional discussion of the distinction between the emission limits and good operating practice requirements can be in the Detailed Response Document. These statements make it clear that good operating practices requirements are separate and distinct from the need to continuously comply with emissions limits.

E. SIP Call

In the October, 1993, proposal, EPA announced that it planned to call for States to amend their applicable implementation plans to ensure that owners or operators may use enhanced monitoring (or other monitoring approved for the source pursuant to part 70) for compliance certification purposes, and that data from this monitoring, along with any other credible evidence, may be used as evidence of a violation of an applicable plan. 58 FR 54660. In December, 1993, and February, 1994, the Office of Air and Radiation's Stationary Source Compliance Division, the division then responsible for writing and implementing the enhanced monitoring rules, issued memoranda to EPA's Regional offices instructing them to conduct the SIP call. As of September, 1996, fifteen states and local air pollution control districts, together with the Commonwealth of Puerto Rico, had responded to the call and submitted SIP amendments for EPA approval. Kansas, Iowa, Nebraska, North Dakota, Georgia and Puerto Rico had received approval; the other states and districts' revisions were pending.

For substantially the same reasons that allow EPA to go forward with today's final rule, EPA has the authority to initiate and continue this SIP call. EPA's decision to forego the enhanced monitoring approach in favor of the CAM proposal has no effect on the basic goals of the SIP call, which are to clarify that non-reference test data can be used in enforcement actions, and to remove any potential ambiguity regarding this data's use for Title V compliance certifications.

Today's action ensures that the evidentiary rules for CAA violations are consistent in all fifty states. EPA has surveyed those states that have responded to the SIP call and has determined that the credible evidence changes have not created the difficulties forecast by the commenters.

IV. Administrative Requirements

A. Docket

Today's final rulemaking action is subject to Section 307(d) of the Act. Accordingly, EPA has established a docket (No. A–91–52), which consists of an organized and complete file of all information submitted to, or otherwise considered by, EPA in the development of today's action and the CAM approach. The docket includes all memoranda and studies cited by EPA in this preamble. The principal purposes of the docket are: (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air Docket, which is listed under the **ADDRESSES** section of this document.

B. Office of Management and Budget (OMB) Review

Today's rulemaking is not a ''significant regulatory action'' because the revisions make only evidentiary changes and do not impose any additional implementation costs on regulated sources. Nevertheless, EPA submitted this final rule to OMB for review. Changes made in response to OMB suggestions and recommendations will be documented in the public record.

C. Unfunded Mandates Reform Act

Under section 202 of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, EPA generally must prepare a budgetary impact statement to accompany any proposed or final rule that includes a Federal mandate that may result in expenditure by State, local, or tribal governments in the aggregate, or by the private sector, of $100 million or more. Before promulgating a rule for which such a statement is needed, section 205 of the UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. 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.

EPA has determined that this rule does not contain a Federal mandate that may result in expenditures of $100 million or more for State, local, and tribal governments, in the aggregate, or the private sector in any one year. Today's rulemaking makes only evidentiary changes and does not impose any additional costs on regulated sources or State, local, or tribal governments. For the same reason, these evidentiary changes will not significantly or uniquely affect small governments. Accordingly, this rulemaking is not subject to the requirements of sections 202, 203, and 205 of the UMRA.

D. Regulatory Flexibility Act

EPA has determined that it is not necessary to prepare a regulatory flexibility analysis in connection with this final rule. EPA has also determined that this rule will not have a significant economic impact on a substantial number of small entities. As explained above, this rulemaking does not impose any additional implementation costs on small or large entities.

E. Paperwork Reduction Act

The information collection requirements for the proposed enhanced monitoring rule were previously submitted for approval to OMB under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.* In contrast, today's rule does not contain any information collection requirements subject to OMB review under the PRA.

F. Submission to Congress and the General Accounting Office

Under 5 U.S.C. 801(a)(1)(A) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121, 110 Stat. 847), EPA submitted a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives and the Controller General of the General Accounting Office prior to publication of this rule in today's Federal Register. For the same reasons that this rulemaking is not a ''significant regulatory action'' under Executive Order 12866, this rule is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects

40 CFR Part 51

Environmental protection, Air pollution control.

40 CFR Part 52

Air pollution control.

40 CFR Part 60

Air pollution control.

40 CFR Part 61

Air pollution control.

Dated: February 13, 1997.

Carol M. Browner,

Administrator, U.S. Environmental Protection Agency.

For the reasons set out in the preamble, 40 CFR Chapter I is amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

1. The authority citation for part 51 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7411, 7412, 7413, 7414, 7470–7479, 7501–7508, 7601, and 7602.

2. Section 51.212 is amended by revising paragraph (c) to read as follows:

§ 51.212 Testing, inspection, enforcement, and complaints.

* * * * *

(c) Enforceable test methods for each emission limit specified in the plan. For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, the plan must not preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. As an enforceable method, States may use:

(1) Any of the appropriate methods in appendix M to this part, Recommended Test Methods for State Implementation Plans; or

(2) An alternative method following review and approval of that method by the Administrator; or

(3) Any appropriate method in appendix A to 40 CFR part 60.

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 is revised to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

2. Section 52.12 is amended by revising paragraph (c) to read as follows:

§ 52.12 Source surveillance.

* * * * *

(c) For purposes of Federal enforcement, the following test procedures and methods shall be used, provided that for the purpose of establishing whether or not a person has violated or is in violation of any provision of the plan, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test procedures or methods had been performed:

(1) Sources subject to plan provisions which do not specify a test procedure and sources subject to provisions promulgated by the Administrator will be tested by means of the appropriate procedures and methods prescribed in part 60 of this chapter unless otherwise specified in this part.

(2) Sources subject to approved provisions of a plan wherein a test procedure is specified will be tested by the specified procedure.

3. Subpart A is amended by adding a new § 52.33 to read as follows:

§ 52.33 Compliance certifications.

(a) For the purpose of submitting compliance certifications, nothing in this part or in a plan promulgated by the Administrator shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

(b) For all federal implementation plans, paragraph (a) of this section is incorporated into the plan.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7411, 7413, 7414, 7416, 7601 and 7602.

2. Section 60.11 is amended by revising paragraphs (a) and (f) and by adding paragraph (g) to read as follows:

§ 60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by § 60.8, unless otherwise specified in the applicable standard.

* * * * *

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

PART 61—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

1. The authority citation for part 61 is revised to read as follows:

Authority: 42 U.S.C. 7401, 7412, 7413, 7414, 7416, 7601 and 7602.

2. Section 61.12 is amended by revising paragraph (a) and adding paragraph (e) to read as follows:

§ 61.12 Compliance with standards and maintenance requirements.

(a) Compliance with numerical emission limits shall be determined in accordance with emission tests established in § 61.13 or as otherwise specified in an individual subpart.

* * * * *

(e) For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this part, nothing in this part shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

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